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This document comprises a prospectus relating to Afren plc prepared in accordance with the Prospectus Rules of the UK Listing Authority made under section 73A of FSMA. A copy of this Prospectus has been filed with the FSA and has been made available to the public as required by section 3.2 of the Prospectus Rules.

Application has been made to the UK Listing Authority and to the London Stock Exchange respectively for admission of all of the New Ordinary Shares to: (i) the Official List; and (ii) the London Stock Exchange’s main market for listed securities. No application has been made or is currently intended to be made for the New Ordinary Shares to be admitted to listing or dealt with on any other exchange. It is expected that New Share Admission will become effective and that dealings on the London Stock Exchange in the Ordinary Shares will commence on 11 October 2010 (International Security Identification Number: GB00B0672758).

AFREN PLC

(incorporated in England and Wales with registered number 05304498)



Proposed issue of up to 76,776,564 Ordinary Shares in Afren plc in connection with the proposed Acquisition of Black Marlin Energy Holdings Limited and application for admission of up to 76,776,564 New Ordinary Shares in Afren plc to the Official List and to trading on the London Stock Exchange’s main market for listed securities

Sponsor

BofA Merrill Lynch

Prospective investors should read the entire document and, in particular, the risk factors set out in the section entitled “Risk Factors” when considering an investment in Afren plc.

The New Ordinary Shares will not be, and are not required to be, registered with the SEC under the US Securities Act, in reliance on the exemption from the registration requirements of the US Securities Act provided by section 3(a)(10) of that Act. In addition, the New Ordinary Shares will not be registered under the securities laws of any State of the United States, and will be issued in the United States in reliance on available exemptions from such state law registration requirements.

Neither the SEC nor any other US federal or state securities commission or regulatory authority has approved or disapproved the New Ordinary Shares or passed an opinion on the adequacy of this document. Any representation to the contrary is a criminal offence in the United States. Persons (whether or not US persons) who are affiliates (within the meaning of the US Securities Act) of Black Marlin Energy Holdings Limited or Afren plc prior to, or the Enlarged Group after, the Effective Date, may be subject to timing, manner of sale and volume restrictions on the sale in or into the United States of New Ordinary Shares received in connection with the Scheme under Rule 144 of the US Securities Act. Reference should also be made to paragraph 6.6.1 of Part 3 of this document.

No prospectus has been filed with the securities regulatory authorities of any Canadian province or territory with respect to the New Ordinary Shares. The New Ordinary Shares will not be offered or sold in Canada other than to Black Marlin Shareholders in reliance on an exemption from the prospectus and registration requirements of the applicable province or territory of Canada pursuant to sections 2.11 and 3.11 of National Instrument 45-106 – Prospectus and Registration Exemptions (“NI 45-106”).

Merrill Lynch International, which is authorised and regulated in the United Kingdom by the FSA, is acting only for Afren plc and no one else in connection with the New Share Admission and will not regard any other person as its client or be responsible to any person other than Afren plc for providing the protections afforded to its clients or for advising any other person on the contents of this Prospectus.

Apart from the responsibilities and liabilities, if any, which may be imposed on Merrill Lynch International by FSMA or the regulatory regime established thereunder or by the regulatory regime of any other jurisdiction where exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, Merrill Lynch International accepts no responsibility whatsoever for, and makes no representation or warranty, express or implied, in relation to, the contents of this Prospectus, including its accuracy, completeness or verification, or for any other statement made or purported to be made by it, or on its behalf, in connection with the Company, the New Ordinary Shares or the New Share Admission. Merrill Lynch International accordingly disclaims all and any responsibility or liability whether arising in tort, contract or otherwise (save as referred to above) which it might otherwise have in respect of this Prospectus or any such statement.

Dated: 24 August 2010

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SUMMARY

The following summary information does not purport to be complete and should be read as an introduction to the more detailed information appearing elsewhere in this Prospectus. Any decision by a prospective investor to invest in Ordinary Shares should be based on consideration of the document as a whole and not solely on this summarised information. Following the implementation of the relevant provisions of the Prospectus Directive in each member state of the European Economic Area, civil liability will attach to the persons who are responsible for this summary, including any translation thereof, in such member state but only if the summary is misleading, inaccurate or inconsistent when read together with the other parts of this Prospectus. Where a claim relating to the information contained in this Prospectus is brought before a court in a member state of the European Economic Area, the claimant may, under the national legislation of that member state where the claim is brought, be required to bear the costs of translating this Prospectus before the legal proceedings are initiated.

Introduction

On 2 June 2010, the Boards of Afren and Black Marlin announced that they had agreed the terms of a recommended proposal by Afren to acquire the entire issued and to be issued share capital of Black Marlin.

Summary of the Acquisition terms

The Acquisition will be implemented by way of a Scheme under BVI law pursuant to which the Scheme Shares will be transferred to Afren in exchange for the issue of New Ordinary Shares to Black Marlin Shareholders.

Under the terms of the Acquisition, Afren Shareholders will retain their shares in Afren and Black Marlin Shareholders will receive:

for every one Black Marlin Share 0.3647 New Ordinary Shares

and so in proportion for any other number of Black Marlin Shares held.

Reasons for, and benefits of, the Acquisition

Afren believes that the Acquisition will create significant value for its shareholders as it will:

- broaden Afren's exploration portfolio with high impact exploration interests focused on rift basins in Ethiopia, Kenya, Madagascar and the Seychelles;
- is expected to increase Afren's net prospective resources base in high impact rift basins;
- enhance geological and geographical diversification, creating a pan African independent E&P of scale;
- add six exploration wells, expected to be drilled through 2012;
- deliver a complementary portfolio extension and high growth reinvestment opportunities to leverage Afren's significant production and revenue growth; and
- strengthen Afren's technical management team via the retention of Black Marlin personnel and is expected to unlock further East African opportunities.

The Acquisition is consistent with Afren's pan-African strategic objective of seeking to deliver growth both organically and through acquisitions to enhance shareholder value.

Conditions to the Acquisition

The Acquisition is conditional on certain conditions which are customary for a transaction of this nature, including the sanction of the Scheme by Court Order and obtaining the Requisite Approval at the Shareholder Meeting and the approval of the Afren Shareholders.

Listing and admission to trading

Application has been made to the UK Listing Authority and the London Stock Exchange for the New Ordinary Share Admission in relation to the New Ordinary Shares proposed to be issued in connection with the Acquisition.

Information on Afren

Afren is an independent oil and gas exploration and production company, founded in 2004, admitted on AIM on 14 March 2005 and was admitted to listing on the Official List and to trading on the London Stock Exchange's main market for listed securities on 3 December 2009.

Adhering to its founding strategy to become the leading pure play African independent exploration and production company, Afren has today assembled a diversified portfolio of 15 assets across five African countries: Nigeria, Côte d'Ivoire, Ghana, Congo-Brazzaville and Nigeria and São Tomé & Príncipe JDZ. Afren's portfolio encompasses producing, development, appraisal and exploration opportunities that provide a balanced platform and opportunity set from which to deliver further significant organic growth into the foreseeable future.

Summary of reserves, resources and future net revenue

NSAI has produced a report, dated the date hereof with an effective date of 30 June 2010, on Afren's reserves and resources which is set out in Part 11 of this Prospectus. NSAI has prepared its assessment of Afren's asset base as at 30 June 2010, and has reviewed and incorporated only field studies and data that were available up to that date. NSAI has not included the Okwok field, OPL 907, OPL 917 and Ofa in its assessment as at 30 June 2010.

Reserves

NSAI has estimated, as of 30 June 2010, the proved, probable and possible reserves and future revenue to the Afren interest in the Okoro field located in OML 112 and in the Ebok Field located in OML 67, Gulf of Guinea, offshore Nigeria and in the Lion and Panthère fields located in Block CI-11, offshore Côte d'Ivoire.

The table below sets out NSAI's estimated oil and gas reserves and future revenue to the Afren interest in the following assets as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

Area/ Field/ Category	Afren Effective Working Interest Reserves before Royalty		Net Entitlement Reserves ⁽¹⁾		Future Net Revenue (MM\$)	
	Oil	Gas	Oil	Gas	Total	Present Worth at 10%
	(MMB BL)	(BCF)	(MMB BL)	(BCF)		
Offshore Nigeria						
Okoro Field						
Proved (1P)	9.3	(2)	7.6	(2)	214.4	191.6
Proved + Probable (2P) ⁽³⁾	13.5	(2)	11.0	(2)	330.1	283.1
Proved + Probable + Possible (3P)	16.9	(2)	13.8	(2)	419.7	348.9
Ebok Field						
Proved (1P)	43.5	(2)	38.0	(2)	863.7	673.7
Proved + Probable (2P) ⁽³⁾	62.0	(2)	53.8	(2)	1,209.1	878.9
Proved + Probable + Possible (3P)	76.7	(2)	66.4	(2)	1,540.8	1,039.1
Offshore Côte d'Ivoire						
Lion and Panthère fields						
Proved (1P)	0.4	10.4	0.3	5.7	22.9	23.6
Proved + Probable (2P) ⁽³⁾	0.7	17.0	0.4	10.0	34.5	34.0
Proved + Probable + Possible (3P)	0.9	25.0	0.5	14.5	61.2	51.9

(1) Net reserves are after deductions for royalty burdens.

(2) Gas reserves are not included because there is currently no viable market for produced gas.

(3) Proved + probable (2P) reserves have been prepared in accordance with the definitions and guidelines set forth in the 2007 PRMS approved by the SPE.

Contingent Resources

NSAI has estimated the contingent resources for the Kudu, Eland and Ibex fields located in Block CI 01, offshore Côte d'Ivoire; the Obo Discovery, offshore Nigeria; São Tomé & Príncipe in JDZ Block 1; and the Setu field located in OML 112, Gulf of Guinea, offshore Nigeria as of 30 June 2010.

The table below sets out NSAI's estimated gross oil and gas contingent resources as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

Area	Gross (100%) Volumes (MMBBL)					
	OOIP			Contingent ⁽²⁾ Oil Resources		
	Low	Best	High	Low	Best	High
	Estimate (1C)	Estimate (2C)	Estimate (3C)	Estimate (1C)	Estimate (2C)	Estimate (3C)
Offshore Côte d'Ivoire	59.2	81.1	104.8	13.5	19.8	27.9
JDZ Block 1	80.8	123.4	173.8	24.4	42.5	67.0
Offshore Nigeria	5.1	6.3	8.0	1.1	1.5	2.0
Area	Gross (100%) Volumes (BCF)					
	OGIP			Contingent ⁽²⁾ Gas Resources		
	Low	Best	High	Low	Best	High
	Estimate (1C)	Estimate (2C)	Estimate (3C)	Estimate (1C)	Estimate (2C)	Estimate (3C)
Offshore Côte d'Ivoire	105.7	160.1	237.0	66.2	101.5	152.4
JDZ Block 1 ⁽¹⁾	—	—	—	—	—	—
Offshore Nigeria ⁽¹⁾	—	—	—	—	—	—

(1) Gas reserves are not included because there is currently no viable market for produced gas.

(2) Contingent resources are those quantities of petroleum that are estimated to be potentially recoverable from known accumulations but for which the projects are not yet considered mature enough for commercial development due to one or more contingencies.

The Group provides for depletion and amortisation of tangible fixed assets on a net entitlement basis, which reflects the terms of the licenses and agreements related to each field.

Prospective Resources

NSAI has estimated the prospective resources for the La Noubi Permit, onshore Congo; the Kudu and Ibex Fields located in Block CI-01, offshore Côte d'Ivoire; Iris Marin and Ibekelia Licences, offshore Gabon; Keta Block, offshore Ghana; JDZ Block 1; Ebok Field, offshore Nigeria; OML 115, offshore Nigeria and OPL 310, offshore Nigeria as of 30 June 2010 as summarised below.

Oil

The table below sets out NSAI's estimated gross OOIP and unrisks prospective oil resources for the following assets as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

<i>Area</i>	<i>Gross (100%) Oil Volumes (mmbbl)</i>					
	<i>OOIP</i>			<i>Unrisks Prospective Oil Resources</i>		
	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>
Onshore Congo	521.5	1,025.9	1,744.0	114.6	251.6	481.9
Offshore Côte d'Ivoire	17.4	48.6	93.3	4.2	12.0	24.2
Offshore Gabon	282.0	390.3	513.2	52.5	97.3	159.4
Offshore Ghana	722.4	2,416.7	8,061.2	153.9	604.2	2,299.5
JDZ Block 1	734.1	1,003.0	1,348.5	229.4	350.1	518.4
Offshore Nigeria	812.2	1,552.1	2,516.6	304.4 ⁽¹⁾	584.5 ⁽¹⁾	972.4 ⁽¹⁾

Note:

(1) These prospective volumes include condensate associated with the OPL 310 prospective gas resources.

Gas

The table below sets out NSAI's estimated gross OGIP and unrisks prospective gas resources for the following assets as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus

<i>Area</i>	<i>Gross (100%) Gas Volumes (bcf)</i>					
	<i>OGIP</i>			<i>Unrisks Prospective Gas Resources</i>		
	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>
Offshore Côte d'Ivoire	197.4	544.9	949.6	157.5	436.1	763.6
Offshore Nigeria	1,358.0	2,115.8	3,129.3	991.1	1,565.3	2,373.5

Current trading and future prospects

Gross production from Okoro for the period to 30 June 2010 was 3,229,178 bbls (average gross 17,841 bopd). Management is considering two infill wells on Okoro that are expected to add gross incremental production of between 3,000 bopd and 5,000 bopd. Average gross production and NGL output from CI-11 and the associated Lion Gas Plant for the period to 30 June 2010 was 6,481 boepd.

Afren's Ebok development commenced in December 2009. First oil is expected in the fourth quarter of 2010.

Afren will continue its exploration and appraisal programme with drilling planned on the Ebok/Okwok/OML 115 complex during the second half of 2010. In the period to 2012 high impact exploration drilling across the combined portfolio is planned in Ghana, Nigeria, Kenya, Ethiopia, Madagascar and the Seychelles.

In March 2010, Afren entered into a reserves based debt facility agreement for up to US\$450 million, which is secured against Afren's share of production from the Ebok field. The facility will be available to be used for development of the Ebok, Okwok and OML 115 areas, in offshore south-east Nigeria. On 15 July 2010, Afren announced that terms have been agreed to acquire Energy Equity Resources Oil and Gas' residual interest in OML 115.

Therefore, Afren has an established base of production, a significant near term development expected to augment production in 2010 and potential growth in reserves and resources through a high impact exploration programme. In addition, Afren continues to evaluate acquisition opportunities.

Information on Black Marlin

Black Marlin's principal business activities are petroleum and natural gas exploration, development and production in Africa and the provision of seismic services.

Black Marlin currently owns equity in assets in Seychelles, Madagascar, Kenya and Ethiopia.

The table below shows EAX's land holdings (net and gross) in East Africa.

<i>LICENCES</i>	<i>AREA IN KM²</i>			<i>AREA IN ACRES</i>	
	<i>EQUITY</i>	<i>GROSS</i>	<i>NET</i>	<i>GROSS</i>	<i>NET</i>
Seychelles A	75.00%	14964 km ²	11223 km ²	3.7 million	2.8 million
Ethiopia	30.00%	47582 km ²	14275 km ²	11.8 million	3.5 million
Kenya 10A	20.00%	14747 km ²	2949 km ²	3.6 million	0.7 million
Kenya 01	50.00%	31850 km ²	15925 km ²	7.9 million	3.9 million
Kenya L17/L18	65.00%	4844 km ²	3149 km ²	1.2 million	0.8 million
Madagascar	40.00%	14900 km ²	5960 km ²	3.7 million	1.5 million
		<u>128887 km²</u>	<u>53481 km²</u>	<u>31.8 million</u>	<u>13.2 million</u>

Risk factors

A number of factors affect the business, prospects, financial condition and results of operations of the Group, and if the Acquisition completes, the Enlarged Group as summarised below.

Risk factors relating to the countries in which Afren, and if the Acquisition completes, the Enlarged Group, operates

- Risks associated with emerging and developing markets generally.
- The countries in which the Group operates and, if the Acquisition completes, the Enlarged Group will operate, face political, economic, fiscal, legal, regulatory and social uncertainties which could have a material adverse effect on Afren's or the Enlarged Group's business, financial condition and results of operations.
- The countries in which the Group operates and, if the Acquisition completes, the Enlarged Group will operate suffer from crime and governmental or business corruption which could have an adverse effect on Afren's business, financial condition and results of operations.
- The countries in which the Group operates suffer from terrorism, piracy and militant activity which could have a material adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's business, financial condition and results of operations.
- Underdeveloped infrastructure in the countries in which the Group and, if the Acquisition completes, the Enlarged Group operates could have an adverse effect on Afren's business, financial condition and results of operations.

- Uncertainties in the interpretation and application of laws and regulations in the jurisdictions in which Afren and Black Marlin operate may affect the Group's and, if the Acquisition completes, the Enlarged Group's ability to comply with such laws and regulations which may increase the risks with respect to the Group's and, if the Acquisition completes, the Enlarged Group's operations.
- Licensing and other regulatory requirements in the countries in which the Group and, if the Acquisition completes, the Enlarged Group operates may be subject to amendment or reform which could make compliance more challenging.
- The Group and, if the Acquisition completes, the Enlarged Group is exposed to the risk of adverse sovereign action by governments in the countries in which it operates.

Risk factors relating to the Oil and Gas Industry

- Any volatility and future decreases in crude oil prices could materially and adversely affect the Group's and, if the Acquisition completes, the Enlarged Group's business, prospects, financial condition and results of operations.
- The level of the Group's and, if the Acquisition completes, the Enlarged Group's crude oil and gas reserves, their quality and production volumes may be lower than estimated or expected.
- The Group and, if the Acquisition completes, the Enlarged Group faces drilling, exploration and production risks and hazards that may affect the Group's and, if the Acquisition completes, the Enlarged Group's ability to produce crude oil and natural gas at expected levels, quality and costs.
- Afren faces and, if the Acquisition completes, the Enlarged Group will face significant uncertainties in connection with its appraisal, exploration and development activities.
- The Group and, if the Acquisition completes, the Enlarged Group operates in a highly competitive industry.
- The Group and, if the Acquisition completes, the Enlarged Group, faces drilling and exploration risks and hazards which may lead to liability for environmental pollution, biodiversity loss or habitat destruction.

Risk factors relating to Afren's Business

- The Group's exploration and production operations are dependent on the Group's and, if the Acquisition completes, the Enlarged Group's compliance with the obligations under its licences, contracts and field development plans.
- There are risks inherent in Afren's and, if the Acquisition completes, the Enlarged Group's strategy of geographic diversification and acquisition of new exploration and development properties.
- The Group faces and, if the Acquisition completes, the Enlarged Group will face cost and timing risks in developing its near term development plans.
- The Group's and, if the Acquisition completes, the Enlarged Group's business strategy of significantly increasing reserves and production may require additional funding in the longer term.
- Some of Afren's employees are unionized and wage demands or work stoppages by unionized employees could materially and adversely affect Afren's, and if the Acquisition completes, the Enlarged Group's business, prospects, financial conditions, and results of operations.
- The Group depends and, if the Acquisition completes, the Enlarged Group will depend on key members of management and service providers and on its ability to retain and hire new qualified personnel and consultants.

- If the Group and, if the Acquisition completes, the Enlarged Group fails to consummate or integrate acquisitions successfully, the Group's and, if the Acquisition completes, the Enlarged Group's financial condition and future performance could be adversely affected.
- Failure to manage Afren's and, if the Acquisition completes, the Enlarged Group's future growth and performance may adversely affect its operations.
- The Group and, if the Acquisition completes, the Enlarged Group is obliged to comply with health and safety and environmental regulations and cannot guarantee that it will be able to comply with these regulations.
- Afren and, if the Acquisition completes, the Enlarged Group conducts the majority of its operation through partnerships with indigenous companies or through joint ventures which may increase the risk of delays, additional costs or the suspension or termination of the licences or the agreements pursuant to which it operates..
- Afren's and, if the Acquisition completes, the Enlarged Group's operations are subject to the risk of litigation.
- The Group does not and, if the Acquisition completes, the Enlarged Group will not insure against certain risks and its insurance coverage may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions.
- Failure to obtain necessary equipment and transportation systems could materially and adversely affect production.
- The Group and, if the Acquisition completes, the Enlarged Group may face unanticipated increased or incremental costs.
- The Group is and, if the Acquisition completes, the Enlarged Group will be subject to foreign exchange and inflation risks, which might adversely affect its financial condition and results of operations.
- Members of the Group and, if the Acquisition completes, the Enlarged Group, may engage in hedging activities from time to time that would expose the Group and, if the Acquisition completes, the Enlarged Group, to losses should markets move against the Group's and, if the Acquisition completes, the Enlarged Group's hedged position.
- The Group may be exposed to certain tax risks in Nigeria which might adversely affect its financial condition and results of operations.

Risk factors relating to an investment in Afren's Ordinary Shares

- The price of the Ordinary Shares may fluctuate.
- Further share issues could have an adverse effect on the market price of the Ordinary Shares as a whole or a dilutive effect on shareholders.
- Ordinary Shares may be unsuitable as an investment.
- Pre-emptive rights may not be available to US holders of the Company's Ordinary Shares.

Risk factors relating to the Acquisition

- The Acquisition is subject to a number of conditions which may not be satisfied or waived.
- A third party may be able to obtain a large enough shareholding in Black Marlin to delay or prevent completion of the Acquisition.
- The market value of listed securities may fluctuate and may not reflect the underlying asset value of Afren or, following completion of the Acquisition, the Enlarged Group.

- Existing Afren Shareholders will suffer a reduction in their proportionate ownership and voting interest in the ordinary share capital of Afren once the Acquisition becomes effective.
- If the Acquisition completes, the integration of Black Marlin and its subsidiaries could result in operating difficulties and other adverse consequences.
- A number of the joint operating agreements to which Black Marlin is party contain a change of control provision, which is likely to be triggered by the Acquisition, giving the counterparties to such JOAs a right of first refusal over Black Marlin's participating interest under the corresponding production sharing contracts.

RISK FACTORS

Any investment in the Ordinary Shares is subject to a number of risks. Prior to investing in the Ordinary Shares, prospective investors should consider carefully all of the information contained in this Prospectus including, in particular, the risk factors described below, which are not presented in any order of priority and may not be exhaustive. Additional risks and uncertainties relating to the Group and Black Marlin that are not currently known to Afren, or that it currently deems immaterial, may also have an adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's business. If this occurs the price of the Ordinary Shares may decline and investors could lose all or part of their investment. Investors should consider carefully whether an investment in Afren's Ordinary Shares and, if the Acquisition completes, the Enlarged Group's Ordinary Shares is suitable for them in light of the information in this Prospectus and their personal circumstances. If investors are in any doubt about any action they should take, they should consult a competent professional adviser who specialises in advising on the acquisition of listed securities.

RISK FACTORS RELATING TO THE COUNTRIES IN WHICH AFREN, BLACK MARLIN AND IF THE ACQUISITION COMPLETES, THE ENLARGED GROUP OPERATE

Risks associated with emerging and developing markets generally

The disruptions recently experienced in the international and domestic capital markets have led to reduced liquidity and increased credit risk premiums for certain market participants and have resulted in a reduction of available financing. Companies located in countries in the emerging markets such as those in the Gulf of Guinea where Afren operates or in East Africa where Black Marlin operates, may be particularly susceptible to these disruptions and reductions in the availability of credit or increases in financing costs, which could result in them experiencing financial difficulty. In addition, the availability of credit to entities operating within the emerging and developing markets is significantly influenced by levels of investor confidence in such markets as a whole and as such any factors that impact market confidence (for example, a decrease in credit ratings, state or central bank intervention in one market or terrorist activity and conflict) could affect the price or availability of funding for entities within any of these markets.

Since the advent of the global economic crisis in 2007, certain emerging market economies have been, and may continue to be, adversely affected by market downturns and economic slowdowns elsewhere in the world. As has happened in the past, financial problems outside countries with emerging or developing economies or an increase in the perceived risks associated with investing in such economies could dampen foreign investment in and adversely affect the economies of these countries (including, for example, countries in which Afren operates).

In addition, ongoing terrorist activity and armed conflicts in the Middle East and elsewhere have also had a significant effect on international finance and commodity markets. Any future national or international acts of terrorism or armed conflicts could have an adverse effect on the financial and commodities markets in the countries in which Afren operates and the wider global economy. Any acts of terrorism or armed conflicts causing disruptions of oil and gas exports in the Gulf of Guinea could adversely affect the Group's business, financial condition, results of operations or prospects.

Investors in emerging markets such as Nigeria, Ghana, São Tomé & Príncipe JDZ, Côte d'Ivoire, Congo-Brazzaville, Seychelles, Ethiopia, Kenya and Madagascar should therefore be aware that these markets are subject to greater risk than more developed markets, including in some cases significant legal, fiscal, economic and political risks. Accordingly, investors should exercise particular care in evaluating the risks involved in an investment in Afren and must decide for themselves whether, in the light of those risks, their investment is appropriate. Generally, investment in emerging and developing markets is suitable only for sophisticated investors who fully appreciate the significance of the risks involved. Investors are urged to consult with their own legal and financial advisers before making an investment in the Ordinary Shares.

The countries in which the Group operates and, if the Acquisition completes, the Enlarged Group will operate, face political, economic, fiscal, legal, regulatory and social uncertainties which could have a material adverse effect on Afren's or the Enlarged Group's business, financial condition and results of operations

Afren's and Black Marlin's operations are exposed to the political, economic, fiscal, legal, regulatory and social environment of the countries in which it operates, including Nigeria and São Tomé & Príncipe, Congo-Brazzaville, Côte d'Ivoire, Ghana, Seychelles, Ethiopia, Kenya and Madagascar. Afren's business involves a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. These risks include, but are not limited to, corruption, civil strife or labour unrest, armed conflict, terrorism, limitations or price controls on oil exports and limitations or the imposition of tariffs or duties on imports of certain goods. The operations of Afren and, if the Acquisition completes, the Enlarged Group in certain developing countries expose it to potential civil unrest and political or currency risk. As a significant oil producer and consumer market of great potential, Nigeria remains a key investment location, though corruption, policy drift and collapsing infrastructure, as well as insecurity in the Niger Delta, present significant risks to business operations in that country. In particular, recent escalation in civil unrest in Nigeria, including clashes between different religious groups, may pose a threat to the operations of Afren in that country and any intensification in the level of civil unrest may have a material adverse effect on Afren's business, results of operations or financial condition.

If the existing body of laws and regulations in the countries in which Afren or Black Marlin operate are interpreted or applied, or relevant discretions exercised, in an inconsistent manner by the courts or applicable regulatory bodies, this could result in ambiguities, inconsistencies and anomalies in the enforcement of such laws and regulations, which in turn could hinder the long term planning efforts of Afren and, if the Acquisition completes, the Enlarged Group and may create uncertainties in its operating environment.

Exploration and development activities in developing countries may require protracted negotiations with host governments, national oil companies and third parties and may be subject to economic and political considerations such as the risks of war, actions by terrorist or insurgent groups, community disturbances, expropriation, nationalisation, renegotiation, forced change or nullification of existing contracts or royalty rates, unenforceability of contractual rights, changing taxation policies or interpretations, adverse changes to laws (whether of general application or otherwise) or the interpretation thereof, foreign exchange restrictions, inflation, changing political conditions, the death or incapacitation of political leaders, local currency devaluation, currency controls, and foreign governmental regulations that favour or require the awarding of contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. Any of these factors detailed above or similar factors could have a material adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's business, results of operations or financial condition. If a dispute arises in connection with operations, in developing countries, Afren and, if the Acquisition completes, the Enlarged Group may be subject to the exclusive jurisdiction of foreign courts or foreign arbitration tribunals or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of England and Wales.

The countries in which the Group operates and, if the Acquisition completes, the Enlarged Group will operate suffer from crime and governmental or business corruption which could have an adverse effect on Afren's business, financial condition and results of operations

Afren and Black Marlin operate and conduct business in countries or regions of Africa which experience high levels of criminal activity and governmental and business corruption. Oil and gas companies operating in West Africa may be particular targets of criminal or terrorist actions. Criminal, corrupt or terrorist action against Afren or Black Marlin and their respective properties or facilities could have a material adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's business, results of operations or financial condition. In addition, the fear of criminal or terrorist actions against Afren could have an adverse effect on the ability of Afren to adequately staff and/or manage its operations or could substantively increase the costs of doing so.

The Nigerian government is conducting corruption and other investigations into the oil industry in Nigeria. Afren is not aware of any current or threatened investigations relating to Afren or any existing adverse findings against it, its directors, officers, employees or joint venture partners, but if any such investigations are made and substantiated in the future against Afren, its directors, officers or employees, or such persons are found to be involved in corruption or other illegal activity, this could result in criminal or civil penalties, including substantial monetary fines, against Afren, its directors, officers or employees. Any such findings in the future could damage Afren's reputation and its ability to do business, including by affecting its rights under the various product sharing contracts or by the loss of key personnel, and could adversely affect its financial condition and results of operations. Furthermore, alleged or actual involvement in corrupt practices or other illegal activities by the joint venture partners of Afren and Black Marlin, or others with whom Afren or Black Marlin conduct business, could also damage Afren's and, if the Acquisition completes, the Enlarged Group's reputation and business and adversely affect Afren's financial condition and results of operations.

The countries in which the Group operates suffer from terrorism, piracy and militant activity which could have a material adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's business, financial condition and results of operations

Militant activity is a major problem in the Niger Delta region of Nigeria, where a range of militant groups with differing goals operates. The main militant group in the region is the ethnic-Ijaw Movement for the Emancipation of the Niger Delta ("MEND"), which claims to be fighting for political power for the region's residents and a redistribution of oil revenues. Since MEND emerged in 2006, attacks and kidnappings have made the core states of Rivers, Delta and Bayelsa challenging operating environments for companies, particularly for companies in the oil and gas industry, which have been the main target of attacks. The security situation remains volatile in the Niger Delta region. Despite a recent surrender of weapons and the current ceasefire on the part of MEND, militant and criminal groups continue to operate in the region and are capable of carrying out armed attacks. While security installations and personnel remain the primary targets for any such incidents, foreign oil companies, such as Afren and their employees may be singled out. In summer 2009, an alleged threat against Afren was published in the media which was subsequently withdrawn within 48 hours with no adverse effect against Afren.

Instability in the Niger Delta, involving attacks and kidnapping by militants targeting the oil industry targets has severely disrupted production across a broad geographical area. Militant groups in the Niger Delta region frequently detain expatriates, particularly those employed in the oil sector. Most oil operators in the region have reduced operations substantially because of persistent community unrest and the direct threat of abduction, extortion and robbery. The security environment in the region is likely to remain volatile in the absence of a coherent government strategy to resolve insecurity. If Afren or its employees are the subject of any attacks, kidnappings or other security threats, this could have a material adverse effect on the Group's operations and production of oil in the Niger Delta.

In addition, there has been an increase in piracy and hijacking off the coast of East Africa, particularly in Somalia, in the recent past. Any such criminal attacks, hijackings and piracy directly or indirectly affecting the countries in which Black Marlin operates, could impact the Enlarged Group's ability to obtain insurance, transport equipment, employees, contractors and any hydrocarbons discovered and could have a material adverse effect on the exploration, operations and production undertaken by the Enlarged Group if the Acquisition completes.

Underdeveloped infrastructure in the countries in which the Group and, if the Acquisition completes, the Enlarged Group operates could have an adverse effect on Afren's business, financial condition and results of operations

Underdeveloped infrastructure and inadequate management of such infrastructure has led to regular electricity outages and water cuts in many states. Inadequate and unreliable electricity supply has hindered investment in the country, resulting in underperformance in various important sectors. For example, the Nigerian government announced in June 2008 that Nigeria would not be able to generate enough power to meet domestic energy needs by 2015. Many businesses rely on alternative electricity and water supplies, adding to overall business costs. The unstable pricing, and possible scarcity, of fuel for power generation also increases the operational challenges businesses face, adding to the potential fluctuation of overheads.

Although rail and road networks are poor and limit land based transport, state governments are gradually investing in road repair and construction. Telecommunications networks (fixed-line and mobile) have become more numerous and increasingly efficient. Bureaucracy presents a significant operational obstacle, and though anti corruption reforms by the Nigerian government have led to some improvement in this respect, progress may remain patchy.

Uncertainties in the interpretation and application of laws and regulations in the jurisdictions in which Afren and Black Marlin operate may affect the Group's and, if the Acquisition completes, the Enlarged Group's ability to comply with such laws and regulations which may increase the risks with respect to the Group's and, if the Acquisition completes, the Enlarged Group's operations

The courts in the jurisdictions in which the Group and, if the Acquisition completes, the Enlarged Group operate may offer less certainty as to the judicial outcome or a more protracted judicial process than is the case in more established economies. Businesses can become involved in lengthy court cases over simple issues when rulings are not clearly defined, and the poor drafting of laws and excessive delays in the legal process for resolving issues or disputes compound such problems. Accordingly, the Group could face risks such as: (i) effective legal redress in the courts of such jurisdictions being more difficult to obtain, whether in respect of a breach of law or regulation, or, in an ownership dispute, being more difficult to obtain, (ii) a higher degree of discretion on the part of governmental authorities and therefore less certainty, (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations, (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions, or (v) relative inexperience of the judiciary and courts in such matters.

Enforcement of laws in some of the jurisdictions in which Afren and Black Marlin operate may depend on and be subject to the interpretation placed upon such laws by the relevant local authority, and such authority may adopt an interpretation of an aspect of local law which differs from the advice that has been given to Afren and Black Marlin by local lawyers or even previously by the relevant local authority itself. There can be no assurance that contracts, joint ventures, licences, licence applications or other legal arrangements will not be adversely affected by the actions of government authorities and the effectiveness of and enforcement of such arrangements in these jurisdictions. In certain jurisdictions, the commitment of local businesses, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain and may be susceptible to revision or cancellation, and legal redress may be uncertain or delayed.

In the countries in which Afren and Black Marlin operate, currently Nigeria and São Tomé & Príncipe JDZ, Congo-Brazzaville, Côte d'Ivoire, Ghana, Seychelles, Ethiopia, Kenya and Madagascar, the state generally retains ownership of the minerals within that State and consequently retains control of (and in many cases, participates in) the exploration and production of hydrocarbon reserves. Accordingly, Afren's and, if the Acquisition completes, the Enlarged Group operations may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges to a greater extent than would be the case if its operations were largely in countries where mineral resources are not predominantly state owned. In addition, transfers of interests typically require government approval, which may delay or otherwise impede such transfers, and the government may impose obligations on Afren and, if the Acquisition completes, the Enlarged Group to complete minimum work within specified timeframes either generally or as a condition to approving such transfers. In the future, Afren and, if the Acquisition completes, the Enlarged Group may extend its interests in operations to other countries where similar circumstances may exist.

A recently enacted law in Nigeria (The Nigerian Oil and Gas Industry Content Development Act 2010) will impact upon Afren's and, if the Acquisition is completed, the Enlarged Group's operations in Nigeria. The legislation provides that Nigerian independent operators shall be given priority in consideration in the award of oil blocks, oil field licences, oil lifting licences and, generally, in all projects for which a contract is to be awarded in the oil and gas industry. All projects or contracts with a budget of more than US\$100 million are required to contain a specific 'Labour Clause' mandating a minimum percentage of Nigerian labour involvement and an operator or project promoter may retain a maximum of 5 per cent. of management

positions held by expatriates. In addition, certain restrictions are also placed on the maintenance of insurance risks outside Nigeria without the written approval of the National Insurance Commission.

As a result of the legislation, Afren, like all other operators in the industry, needs to streamline its internal processes mainly in relation to the procurement of goods and services in respect of oil and gas operations, in line with the provisions of the legislation. A further potential impact is that breach of these provisions may be an offence punishable by a fine of 5 per cent. of the project sum for each project in which the offence is committed or cancellation of the project.

Licensing and other regulatory requirements in the countries in which the Group and, if the Acquisition completes, the Enlarged Group operates may be subject to amendment or reform which could make compliance more challenging

Afren's and Black Marlin's current operations are, and Afren's and, if the Acquisition completes, the Enlarged Group's future operations will be, subject to licences, regulations and approvals of governmental authorities for exploration, development, construction, operation, production, marketing, pricing, transportation and storage of oil, taxation and environmental and health and safety matters. Afren and, if the Acquisition completes, the Enlarged Group cannot guarantee that such licences applied for will be granted or, if granted, will not be subject to possibly onerous conditions. Any changes to exploration, exploration and production, or production licences, regulations and approvals, or their availability to Afren, Black Marlin and, if the Acquisition completes, the Enlarged Group may adversely affect Afren's and, if the Acquisition completes, the Enlarged Group's assets, plans, targets and projections.

Afren is subject to extensive government laws and regulations governing prices, taxes, royalties, allowable production, waste disposal, pollution control and similar environmental laws, the export of oil and many other aspects of the oil business. Although Afren believes it has good relations with the current governments of Nigeria, offshore Nigeria and São Tomé & Príncipe JDZ, Congo-Brazzaville, Côte d'Ivoire and Ghana, there can be no assurance that the actions of present or future governments in these countries, or of governments of other countries in which Afren and, if the Acquisition completes, the Enlarged Group may operate in the future (including Seychelles, Ethiopia, Kenya and Madagascar, where Black Marlin currently operates) will not materially adversely affect the business or financial condition of Afren and, if the Acquisition completes, the Enlarged Group.

Furthermore, the oil and gas sector in Nigeria, in particular, is still developing, and there have been a number of changes in policy affecting the sector. Nigeria is pursuing a number of new policy directions with the aim of restructuring its upstream and deregulating its downstream sectors, but the adoption of new regulations and the implementation of suggested reforms may be subject to political and economic influences, which could create uncertainty in relevant sectors.

In August 2007, the Federal Government of Nigeria announced the overhaul of the oil sector and stated that it would be implementing reforms to deal with the deregulation and privatisation of the NNPC. These reforms were first suggested by the Oil and Gas Reform Committee set up in 2000 and another committee set up by the National Council on Privatisation, but the mooted plans were rejected by former president Olusegun Obasanjo. In 2009 the new Petroleum Industry Bill was submitted to the General Assembly and is yet to be passed as a law in order to be binding. The Petroleum Industry Bill seeks to bring together the provisions of many laws regulating the petroleum industry, but there is still uncertainty with respect to its effect on the industry.

The reforms were launched almost two years ago, and meaningful changes may only be made once the new Petroleum Industry Bill becomes law. In the meantime, there is uncertainty with respect to the level of implementation of the reforms, the timing of their completion and their possible impacts on the oil and gas industry in Nigeria.

The Group and, if the Acquisition completes, the Enlarged Group is exposed to the risk of adverse sovereign action by governments in the countries in which it operates

The oil and gas industry is central to the economies and future prospects for development in a number of the countries in which Afren and Black Marlin currently operate and, if the Acquisition completes, the Enlarged

Group, and therefore the industry can be expected to be the focus of continuing attention and debate. In certain developing countries, petroleum companies have faced the risks of expropriation or renationalisation, breach or abrogation of project agreements, application to such companies of laws and regulations from which they were intended to be exempt, denials of required permits and approvals, increases in royalty rates and taxes that were intended to be stable, application of exchange or capital controls, and other risks.

As with many countries, possible future changes in the government, major policy shifts or increased security arrangements could have to varying degrees an adverse effect on the value of investments. These factors could materially adversely affect Afren's and, if the Acquisition completes, the Enlarged Group's business, prospects or financial results.

RISK FACTORS RELATING TO THE OIL AND GAS INDUSTRY

Any volatility and future decreases in crude oil prices could materially and adversely affect the Group's and, if the Acquisition completes, the Enlarged Group's business, prospects, financial condition and results of operations

Oil and gas prices are based on world supply and demand and are subject to large fluctuations in response to relatively minor changes to the demand for oil, whether the result of uncertainty or a variety of additional factors beyond the control of Afren and, if the Acquisition completes, the Enlarged Group. Afren's, and, if the Acquisition completes, the Enlarged Group's operating results and financial condition will depend substantially upon prevailing oil and gas prices. Historically, prices for oil and gas have fluctuated widely for many reasons, including:

- global and regional supply and demand, and expectations regarding future supply and demand, for crude oil and petroleum products;
- geopolitical uncertainty;
- weather conditions and natural disasters;
- access to pipelines, railways and other means of transporting crude oil;
- prices and availability of alternative fuels;
- prices and availability of new technologies;
- the ability of the members of OPEC, and other crude oil producing nations, to set and maintain specified levels of production and prices;
- political, economic and military developments in oil producing regions generally and particularly in Nigeria and the Middle East;
- global and regional economic conditions; and
- market uncertainty and speculative activities by those who buy and sell oil and gas on the world markets.

Since Afren's foundation in December 2004 oil and gas prices both worldwide and in the domestic markets in Africa have both increased and decreased. The recent decline in international prices for crude oil, compared to the peaks experienced in mid-2008 has adversely affected and will continue to adversely affect the amount of revenue generated by the Group's and, if the Acquisition completes, the Enlarged Group's sales of crude oil and other petroleum products.

Historically, crude oil prices have been highly volatile. For example, such volatility was particularly pronounced over the course of the 2009 accounting period, as prices fluctuated in a range of US\$36.24 – \$79.18, and increased significantly during the year from US\$36.24 in January to US\$77.40 in December. The average monthly price for crude oil in June 2010 was approximately US\$75.25/bbl, a decrease of about 48.3 per cent. from the peak of approximately US\$145.61/bbl witnessed in the first week of July 2008 (Source: Datastream). Prices were again volatile in the first quarter of 2010, before generally decreasing in

the second quarter of 2010. The Group and, if the Acquisition completes, the Enlarged Group, can give no assurance as to the level of oil prices that will be achievable in the future.

Lower oil and gas prices may adversely impact on the economic exploitation of Afren's and, if the Acquisition completes, the Enlarged Group's assets, reducing revenues or net income, impairing Afren's ability to achieve its business objectives and may materially and adversely affect Afren's and, if the Acquisition completes, the Enlarged Group's financial results. No assurance can be given that oil and gas prices will be sustained at levels which will enable Afren and, if the Acquisition completes, the Enlarged Group to operate profitably.

The level of the Group's and, if the Acquisition completes, the Enlarged Group's crude oil and gas reserves, their quality and production volumes may be lower than estimated or expected

The reserves and resources set forth in this Prospectus represent estimates only and are based on the technical expert's report prepared by NSAI set out in Part 11. In general, estimates of economically recoverable oil reserves and the future net cash flow therefrom are based on a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates (which have inherent uncertainties), historical production from the properties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results.

If the assumptions upon which the estimates of Afren's and, if the Acquisition completes, the Enlarged Group's oil and gas reserves and resources have been based prove to be incorrect, Afren and, if the Acquisition completes, the Enlarged Group may be unable to recover and produce the estimated levels or quality of oil, natural gas and other hydrocarbons set out in this Prospectus and Afren's and, if the Acquisition completes, the Enlarged Group's business, prospects and financial results could be materially and adversely affected.

Estimation of underground accumulations of hydrocarbons is a subjective process aimed at understanding the statistical probabilities of recovery. Estimates of the quantity of economically recoverable oil and gas reserves, rates of production, net present value of future cash flows and the timing of development expenditures depend upon several variables and assumptions, including the following:

- production history compared with production from other comparable producing areas;
- interpretation of geological and geophysical data;
- effects of regulations adopted by governmental agencies;
- future percentages of international sales;
- future oil prices;
- capital expenditure; and
- future operating costs, tax on the extraction of commercial minerals, development costs and workover and remedial costs.

As all reserve estimates are subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities and qualities that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of additional exploration and future development expenditures; and
- future oil sales prices.

Many of the factors in respect of which assumptions are made when estimating reserves are beyond Afren's and Black Marlin's control and therefore these may prove to be incorrect over time. Evaluations of reserves

necessarily involve multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and petroleum engineering and geological interpretation. Exploration drilling, interpretation, testing and production after the date of the estimates may require substantial upward or downward revisions in Afren's, Black Marlin's and, if the Acquisition completes, the Enlarged Group's reserves or resources data. Moreover, different reservoir engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources will vary from estimates, and the variances may be material.

The uncertainties in relation to the estimation of reserves summarised above also exist with respect to the estimation of resources. The probability that prospective resources will be discovered, or be economically recoverable, is considerably lower than for proven, probable and possible reserves. Volumes and values associated with prospective resources should be considered highly speculative.

The Group and, if the Acquisition completes, the Enlarged Group faces drilling, exploration and production risks and hazards that may affect the Group's and, if the Acquisition completes, the Enlarged Group's ability to produce crude oil and natural gas at expected levels, quality and costs

Afren's oil and gas production operations and Black Marlin's exploration, operations and production are subject to all the risks common to its industry, including premature decline of reservoirs and invasion of water into producing formations, encountering unexpected formations or pressures, premature declines of reservoirs, blowouts, oil spills, explosions, fires, equipment damage or failure, natural disasters, geological uncertainties, unusual or unexpected rock formations and abnormal geological pressures, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks.

Afren's and Black Marlin's production and exploration facilities are also subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, vessel collision and damage from severe storms or other severe weather conditions. The offshore drilling conducted by Afren and Black Marlin involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable.

In the event that any of these occur, environmental damage, injury to persons and loss of life, failure to produce oil in commercial quantities or an inability to fully produce discovered Reserves could result. They can also put at risk some or all of Afren's licences which enable it to explore and/or produce, and result in Afren and, if the Acquisition completes, the Enlarged Group incurring fines or penalties as well as criminal sanctions potentially being enforced against Afren and, if the Acquisition completes, the Enlarged Group and/or its officers. Consequent production delays and declines from normal field operating conditions may result in revenue and cash flow levels being adversely affected.

Afren's and, if the Acquisition completes, the Enlarged Group's future success will depend, in part, on its ability to develop existing oil reserves in a timely and cost-effective manner. Certain of Afren's and Black Marlin's oil and gas properties are operated by third parties or may be subject to the decisions of operating committees controlled by national oil companies and, as a result, Afren, Black Marlin, and, if the Acquisition completes, the Enlarged Group has limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties.

Afren's and, if the Acquisition completes, the Enlarged Group's drilling activities may be unsuccessful and the actual costs incurred in respect of drilling, operating wells and completing well workovers may exceed budget. Afren and, if the Acquisition completes, the Enlarged Group may be required to curtail, delay or cancel any drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment. The occurrence of any of these events could have a material adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's business, prospects, financial condition and results of operations.

The marketability and price of oil and natural gas which may be acquired or discovered by Afren and, if the Acquisition completes, the Enlarged Group will be affected by numerous factors beyond the control of Afren

and, if the Acquisition completes, the Enlarged Group. The ability of Afren and, if the Acquisition completes, the Enlarged Group to market any natural gas discovered may depend upon its ability to acquire capacity in pipelines which deliver natural gas to commercial markets.

Afren faces and, if the Acquisition completes, the Enlarged Group will face significant uncertainties in connection with its appraisal, exploration and development activities

Appraisal results for discoveries are uncertain. Appraisal and development activities involving the drilling of wells across a field may be unpredictable and not result in the outcome planned, targeted or predicted, as only by extensive testing can the properties of the entire field be fully understood.

Exploration activities are capital intensive and their successful outcome cannot be assured. Afren and Black Marlin undertake exploration activities and incur significant costs with no guarantee that such expenditure will result in the discovery of commercially deliverable oil or natural gas.

Afren's and, if the Acquisition completes, the Enlarged Group's oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

In addition, drilling hazards or environmental damage could greatly increase the cost of operations and various field operating conditions may adversely affect the production from successful wells. Afren and Black Marlin are exploring in geographic areas where environmental conditions are challenging and costs can be high. The costs of drilling, completing and operating wells are often uncertain. As a result, Afren and, if the Acquisition completes, the Enlarged Group, may incur cost overruns or may be required to curtail, delay or cancel drilling operations because of many factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions, compliance with environmental regulations, governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment.

Afren and, if the Acquisition completes, the Enlarged Group will continue to gather data about its new venture opportunities and other projects. Additional information which comes to light could cause Afren and, if the Acquisition completes, the Enlarged Group to alter its schedule or determine that a new venture opportunity or project should not be pursued, which could adversely affect Afren's and, if the Acquisition completes, the Enlarged Group's prospects.

Under its production sharing contracts and other similar agreements, Afren finances exploration, development and operations and the related facilities and equipment and will only recover its costs if there is successful production in accordance with the terms of these agreements.

The Group and, if the Acquisition completes, the Enlarged Group operates in a highly competitive industry

The oil and gas industry is highly competitive including in the region in which Afren and, if the Acquisition completes, the Enlarged Group operates. The key areas in respect of which Afren faces and, if the Acquisition completes, the Enlarged Group will face competition are:

- acquisition of exploration and production licences at auctions or sales run by governmental authorities;
- acquisition of other companies that may already own licences or existing hydrocarbon producing assets;
- engagement of third party service providers whose capacity to provide key services may be limited;
- purchase of capital equipment that may be scarce; and
- employment of the best qualified and most experienced skilled management and oil professionals.

Afren and Black Marlin compete with oil and gas companies that possess greater technical, physical and financial resources. Many of these competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on an international basis.

The effects of this may include higher than anticipated prices for the acquisition of licences or assets, the poaching of key management or operatives, restriction on availability of equipment or services as well as potentially unfair practices including unconscionable pressure on Afren and, if the Acquisition completes, the Enlarged Group directly or indirectly or the dissemination of false or misleading information or rumours by competitors or third parties. The effects of this may include higher than anticipated prices for the acquisition of licences or assets, the poaching of key management or operatives, restriction on availability of equipment or services as well as potentially unfair practices including unconscionable pressure on Afren and, if the Acquisition completes, the Enlarged Group directly or indirectly or the dissemination of false or misleading information or rumours by competitors or third parties. Such unconscionable pressure can be expected to arise out of disparities in the relative bargaining power of the affected parties and includes the stronger party exploiting the weaker parties' disadvantage or relying on its rights in a harsh or oppressive manner, allowing the weaker party to make an incorrect assumption, failing to disclose a material fact, misrepresentation or otherwise unfairly benefiting from a transaction at the expense of the weaker party. If Afren and, if the Acquisition completes, the Enlarged Group is unsuccessful in competing against other companies, its business, results of operations or financial condition would be materially adversely affected.

The Group and, if the Acquisition completes, the Enlarged Group, faces drilling and exploration risks and hazards which may lead to liability for environmental pollution, biodiversity loss or habitat destruction

The Group's and, if the Acquisition completes, the Enlarged Group's operations are inherently subject to risks associated with natural catastrophes, fires, explosions, blowouts, encountering formations with abnormal pressure and crude oil spills, each of which could result in substantial damage to its property and the surrounding environment or in personal injury, biodiversity loss or habitat destruction and result in liability and reputational damage to the Group and, if the Acquisition Completes, the Enlarged Group.

Any of these risks and hazards could have material adverse effect on the Group's and, if the Acquisition completes, the Enlarged Group's business, prospects, financial condition and the trading price of the Ordinary Shares.

RISK FACTORS RELATING TO AFREN'S AND, IF THE ACQUISITION COMPLETES, THE ENLARGED GROUP'S BUSINESS

The Group's exploration and production operations are dependent on the Group's and, if the Acquisition completes, the Enlarged Group's compliance with the obligations under its licences, contracts and field development plans

The Group's and, if the Acquisition completes, the Enlarged Group's exploration and development operations must be carried out in accordance with the terms of its production sharing contracts, oil production licences and oil mining licences (and related farm-in agreements), as applicable (the "**Licences**"), annual work programmes and budgets as set forth therein. The relevant legislation provides that fines may be imposed and a Licence may be suspended or terminated if a licence holder or party to the contract fails to comply with its obligations under such Licence or agreement, or fails to make timely payments of levies and taxes for the licenced activity, provide the required geological information or meet other reporting requirements.

In addition, the Group's and, if the Acquisition completes, the Enlarged Group's subsidiaries, joint ventures and associates have obligations to develop the fields in accordance with the specific requirements under the applicable Licences, field development plans, laws and regulations. If they were to fail to satisfy such obligations with respect to a specific field, the Licence for that field may be suspended, revoked or terminated.

The authorities in Africa can, and do from time to time, inspect the Group's compliance with its Licences and relevant laws. There can be no assurance that the views of the relevant government agencies regarding the development of the Group's and, if the Acquisition completes, the Enlarged Group's fields or compliance

with the terms of its Licences will coincide with the Group's and, if the Acquisition completes, the Enlarged Group's views, which might lead to disagreements that cannot be resolved.

Some licences held by Afren and Black Marlin are solely exploration licences, and as such the assets which are the subject of such licences are not currently producing oil or gas. Rather these licences have a limited life before Afren or Black Marlin is obliged to seek to convert the licence to a production licence, extend the licence or relinquish the licence area. With respect to Afren, The exploration licence for Ofa expired in November 2009, the exploration licences for Iris Marin and La Noumbi expire in 2010 and the exploration licence for Ebok field expires in 2011. With respect to Black Marlin, the exploration licences for Blocks 2 and 6, and Blocks 7 and 8 in Ethiopia expire in 2011 (as extended) and 2012 (as extended) respectively, the exploration licences for Block 1, Block 10A and Block L17/L18 in Kenya expire in 2011 (as extended), 2012 and 2010 (as extended) respectively, the exploration licence for Block 1101 in Madagascar expires in 2010 (as extended) and the exploration licence for Areas A, B and C in the Seychelles expires in 2010. In the case of the extension to the exploration licence for Block 1101 in Madagascar, such extension was agreed verbally. Afren and, if the Acquisition completes, the Enlarged Group intends, where appropriate, to seek the appropriate authorities for time extensions of the relevant licences or conversions to production licences. Although there can be no assurance that any extension or conversion will be granted, these exploration licences do not impact upon the Group, and of the Acquisition completes, the Enlarged Group's current production schedule.

If oil is discovered during the exploration licence term, Afren is, and Black Marlin may be, required to apply for a production licence before commencing production. If Afren and Black Marlin (and, where applicable, its joint venture partners) comply with the terms of the relevant licence then it would normally expect that a production licence would be issued, however, no assurance can be given that the necessary production licences will be granted by the relevant authorities.

The suspension, revocation or termination of any of the Group's and, if the Acquisition completes, the Enlarged Group's Licences, as well as any delays in the continuous development of or production at its fields caused by the issues detailed above may have a material adverse effect on the Group's and, if the Acquisition completes, the Enlarged Group's business, financial condition and results of operations.

Each of Afren's and Black Marlin's and, if the Acquisition completes, the Enlarged Group's exploration and production licences have incorporated within them detailed work programmes which have to be fulfilled and normally within a specified timeframe. These may include seismic surveys to be performed, wells to be drilled, production to be attained, limits to production levels and construction matters.

Failure to comply with such obligations, whether inadvertent or otherwise, may lead to fines, penalties, restrictions and withdrawal of licences with consequent material adverse effects.

There are risks inherent in Afren's and, if the Acquisition completes, the Enlarged Group's strategy of geographic diversification and acquisition of new exploration and development properties

Afren has previously undertaken a number of acquisitions of assets, as described in paragraph 3 of Part 1 of this Prospectus. In addition, Afren's and, if the Acquisition completes, the Enlarged Group's strategies include that, from time to time as suitable opportunities arise, it may consider acquiring additional oil and gas properties. For example, in January 2010, Afren announced an agreement to develop OML 115 offshore South East Nigeria, adjoining the Ebok and Okwok development areas, as described in paragraph 3 of Part 1 of this Prospectus. In addition, on 15 July 2010, Afren announced an agreement to acquire a further residual interest in OML 115. Although Afren performs and, if the Acquisition completes, the Enlarged Group will perform a review of properties that it believes is consistent in industry practices prior to the acquisitions, such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, Afren and, if the Acquisition completes, the Enlarged Group will focus its due diligence efforts on higher valued properties or assets and will conduct due diligence on only a sample of the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Physical inspections may not be

performed on every well, and structural or environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

Afren and, if the Acquisition completes, the Enlarged Group may be required to assume pre closing liabilities with respect to an acquisition, including environmental liabilities, and may acquire interests in properties on an “as is” basis. In addition, competition for the acquisition of prospective oil properties is intense, which may increase the cost of any potential acquisition. To date, Afren’s exploration and development activities have principally been based in Nigeria, Côte d’Ivoire and nearby areas in West Africa and Black Marlin’s principal exploration activities have been in the Seychelles, Ethiopia, Kenya and Madagascar, Afren’s limited presence in other regions may limit its ability to identify and complete acquisitions in other geographic areas. There can be no assurance that any potential acquisition by Afren and, if the Acquisition completes, the Enlarged Group will be successful.

The Group faces and, if the Acquisition completes, the Enlarged Group will face cost and timing risks in developing its near term development plans

The Group has and, if the Acquisition completes, the Enlarged Group will have a number of appraisal and appraisal/development assets (in addition to its production assets) and as such certain parts of the Group’s and, if the Acquisition completes, the Enlarged Group’s business are at an early stage of development. The Group and, if the Acquisition completes, the Enlarged Group intends to continue its appraisal and development plans on respect of such assets, with a viewing to potentially converting possible reserves to probable reserves, and probable reserves to proved reserves and increasing its production. It is also seeking to convert prospective resources into reserves with the appraisal and development work required to do so involving significant investment by the Group and, if the Acquisition completes, the Enlarged Group in both capital expenditure and time for development. Prospective investors should consider the risks, expenses and difficulties frequently encountered by companies which undertake exploration and appraisal activities, particularly companies operating in emerging markets such as the time taken to assess production potential once hydrocarbons are discovered, the economic feasibility of production and logistical, regulatory and practical constraints that are sometimes inherent in operating in such markets.

The Group’s and, if the Acquisition completes, the Enlarged Group’s business strategy of significantly increasing reserves and production may require additional funding in the long term

Afren and, if the Acquisition completes, the Enlarged Group’s may, in the longer term, require additional financing for its future exploration, development, production or acquisition plans. The ability of Afren and, if the Acquisition completes, the Enlarged Group to arrange such financing in the future will depend in part upon prevailing financing market conditions as well as the business performance of Afren and, if the Acquisition completes, the Enlarged Group. Much of Afren’s and, if the Acquisition completes, the Enlarged Group’s existing borrowing is linked to a borrowing base profile, under which the availability of financing and its cost depends upon the reserves of the borrowing entity, over which Afren and, if the Acquisition completes, the Enlarged Group has limited control. If Afren’s and, if the Acquisition completes, the Enlarged Group’s revenues or reserves decline, it may not be able to raise additional funds (or any external debt or equity financing may not be on acceptable terms) or have the capital necessary (either from internal sources or through external debt or equity financing) to undertake or complete future drilling programmes or acquisitions.

Furthermore, any additional debt financing may involve re-financing costs or penalties or restrictive covenants, which may limit or affect Afren’s and, if the Acquisition completes, the Enlarged Group’s operating flexibility. Transactions financed partially or wholly with debt may increase Afren’s and, if the Acquisition completes, the Enlarged Group’s debt levels above industry standards and such high levels of leverage could:

- require the Group and, if the Acquisition completes, the Enlarged Group’s to dedicate a substantial portion of its cash flows from operations to payments on its debt, which could reduce the funds available for capital expenditures and other general corporate purposes;

- increases the risk of the Group and, if the Acquisition completes, the Enlarged Group being able to repay outstanding debt in a timely manner in the event of adverse changes in macro-economic conditions, interest rate environment, the political environment in the markets in which it operates and general and industry-specific conditions; and
- limit the Group's and, if the Acquisition completes, the Enlarged Group's ability to borrow additional funds or increase the cost of, or terms associated with, any such borrowing, particularly due to the financial and other restrictive covenants contained in the agreements governing its debt.

Some of Afren's employees are unionized and wage demands or work stoppages by unionized employees could materially and adversely affect Afren's and, if the Acquisition completes, the Enlarged Group's business, prospects, financial condition and results of operations

Afren employs local workers in each of the countries in which Afren operates. Additionally, it hires contractors who, in turn, have their own employees from the regions in which Afren operates. Some of its employees, and those employed by its contractors, are represented by labour unions under collective bargaining agreements, which need to be renewed from time to time. Afren or its contractors may not be able to negotiate acceptable new collective bargaining agreements or future restructuring agreements, which could result in labour disputes. Also, Afren may become subject to material cost increases or additional work rules imposed by agreements with labour unions. This could increase expenses in absolute terms and/or as a percentage of revenue. Although Afren believes it has good relations with its employees, work stoppages or other labour disturbances may occur in the future, which could materially and adversely affect Afren's and if the Acquisition completes, the Enlarged Group's business, prospects, financial condition and results of operations.

The Group depends and, if the Acquisition completes, the Enlarged Group will depend on key members of management and service providers and on its ability to retain and hire new qualified personnel and consultants

The Group's and, if the Acquisition completes, the Enlarged Group's future operating results depends in significant part upon the continued contribution of its key senior management, technical, financial, operations and marketing personnel. The Group's and, if the Acquisition completes, the Enlarged Group's management of that growth will require, among other things, stringent control of financial systems and operations, the continued development of its management control, the ability to attract and retain sufficient numbers of qualified management and other personnel, the continued training of such personnel, the presence of adequate supervision and continued consistency in the quality of its services.

The Group's and, if the Acquisition completes, the Enlarged Group's success is dependent on the ability of its management to operate the growing business and to manage the ongoing changes from accelerated growth and potential future acquisitions. Failure to manage the Group's and, if the Acquisition completes, the Enlarged Group's growth and development effectively could have a material adverse effect on the Group's and, if the Acquisition completes, the Enlarged Group's business, financial condition and results of operations.

In addition, the personal connections and relationships of Afren's and Black Marlin's key management are important to the conduct of its business. If the Group and, if the Acquisition completes, the Enlarged Group were to unexpectedly lose a member of its key management, its business and results of operations might be adversely affected. The Group and, if the Acquisition completes, the Enlarged Group does not currently maintain "key person" insurance.

If the Group and, if the Acquisition completes, the Enlarged Group fails to consummate or integrate acquisitions successfully, the Group's and, if the Acquisition completes, the Enlarged Group's financial condition and future performance could be adversely affected

Historically, the Group and, if the Acquisition completes, the Enlarged Group has acquired interests in additional assets on a regular basis and the Group (prior to the Acquisition) grown from a single asset in one country in 2004 to 15 assets in five countries as at the date of this Prospectus. While Afren currently maintains adequate procedures, systems and controls, where Afren and, if the Acquisition completes, the

Enlarged Group acquires another company or its assets in the future, integrating operations and personnel and pre or post completion costs may prove more difficult and/or expensive than anticipated, thereby rendering the value of any company or assets acquired less than the amount paid. The integration of acquired businesses requires significant time and effort on the part of Afren's and, if the Acquisition completes, the Enlarged Group's management. Integration of new businesses can be difficult, because Afren's and, if the Acquisition completes, the Enlarged Group's operational and business culture may differ from the cultures of the businesses it acquires, unpopular cost cutting measures may be required, internal controls may be more difficult to maintain and control over cash flows and expenditures may be difficult to establish. While Afren and, if the Acquisition completes, the Enlarged Group has successfully completed the integration of the businesses it has acquired thus far, it could experience difficulties in integrating future acquisitions as successfully, which could have an adverse effect on its financial condition and results of operations.

Failure to manage Afren's and, if the Acquisition completes, the Enlarged Group's future growth and performance may adversely affect its operations

Afren has experienced significant growth and development in a relatively short period of time and expects to continue to grow as production increases from its current oil reserves. Management of that growth requires, among other things, stringent control of financial systems and operations, the continued development of management controls and the training of new personnel. Failure to successfully manage Afren's and, if the Acquisition completes, the Enlarged Group's expected growth and development could have a material adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's business, results of operations or financial condition. Further, there can be no guarantee or assurance that such rapid growth will continue or that future targets or projections will be achieved or fulfilled.

The Group and, if the Acquisition completes, the Enlarged Group is obliged to comply with health and safety and environmental regulations and cannot guarantee that it will be able to comply with these regulations

Afren's and, if the Acquisition completes, the Enlarged Group's operations are subject to laws and regulations relating to the protection of human health and safety and the environment. Failure, whether inadvertent or otherwise, by Afren and, if the Acquisition completes, the Enlarged Group to comply with applicable legal or regulatory requirements may give rise to significant liabilities. Afren's and, if the Acquisition completes, the Enlarged Group's health, safety and environment policy is to observe local and national, legal and regulatory requirements and generally to apply best practice where local legislation does not exist.

The terms of licences or permissions may include more stringent environmental and/or health and safety requirements. The obtaining of exploration, development or production licences and permits may become more difficult or be the subject of delay due to governmental, regional or local environmental consultation, approvals or other considerations or requirements.

Afren and, if the Acquisition completes, the Enlarged Group incurs, and expects to continue to incur, substantial capital and operating costs in order to comply with increasingly complex health, safety, environmental laws and regulations. New laws and regulations, the imposition of tougher requirements in licences, increasingly strict enforcement of, or new interpretations of, existing laws, regulations and licences, or the discovery of previously unknown contamination may require further expenditures to:

- modify operations;
- install pollution control equipment;
- perform site clean-ups;
- curtail or cease certain operations; or
- pay fees or fines or make other payments for pollution, discharges or other breaches of environmental requirements.

Although the costs of the measures taken to comply with environmental regulations have not had a material adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's financial condition or results of operations to date, in the future, the costs of such measures and liabilities related to environmental damage caused by Afren and, if the Acquisition completes, the Enlarged Group may increase, adversely affecting Afren's and, if the Acquisition completes, the Enlarged Group's operating results and financial condition.

These factors may lead to delayed or reduced exploration, development or production activity as well as to increased costs.

Afren and, if the Acquisition completes, the Enlarged Group conducts the majority of its operations through partnerships with indigenous companies or through joint ventures which may increase the risk of delays, additional costs or the suspension or termination of the licences or the agreements pursuant to which it operates

Afren and, if the Acquisition completes, the Enlarged Group, has entered into partnerships with indigenous companies and joint ventures in respect of a majority of its assets. Afren, its indigenous partners and its joint venture parties and, if the Acquisition completes, the Enlarged Group, as applicable, must comply with the requirements of any applicable licence or related agreement pursuant to which it operates, in addition to joint operating agreements or other arrangements governing its relationship with the indigenous partners and joint venture partners, as applicable. Afren and, if the Acquisition completes, the Enlarged Group may suffer unexpected costs or other losses if an indigenous partner or a joint venture partner does not meet its obligations. Afren and, if the Acquisition completes, the Enlarged Group may also be subject to claims by its indigenous partners or joint venture partners regarding potential non-compliance with its own or Black Marlin's obligations. It is also possible that the interests of Afren and, if the Acquisition completes, the Enlarged Group on the one hand and those of indigenous partners or its joint venture partners on the other will not always necessarily be aligned resulting in possible project delays, additional costs or disagreements.

In addition, failure by Afren's and, if the Acquisition completes, the Enlarged Group's indigenous partners or joint venture partners, as applicable, to comply with the obligations under the relevant licenses or the agreements pursuant to which Afren and, if the Acquisition completes, the Enlarged Group operates may lead to fines, penalties, restrictions and withdrawal of licenses or the agreements under which it operates. In the event that any of its indigenous partners or joint venture partners becomes insolvent or otherwise unable to pay debts as they come due, licenses or agreements awarded to them may revert back to the relevant government authority who will then reallocate the license. As Afren and, if the Acquisition completes, the Enlarged Group typically either share an undivided interest with its partners (at the fields where it has a participation interest) or has a contractual right to production with no participation interest, it relies on its partners or other entities as license holders. Although Afren and, if the Acquisition completes, the Enlarged Group anticipates that the relevant government authority may permit it to continue operations at a field during a reallocation process, there can be no assurances that it will be able to continue operations pursuant to these reclaimed licenses or that the any transition related to the reallocation of a license would not materially disrupt its operations or development and production schedule. The occurrence of any of the situations described above could materially and adversely affect Afren's and, if the Acquisition completes, the Enlarged Group's business, prospects, financial condition and results of operations.

Afren's and, if the Acquisition completes, the Enlarged Group's operations are subject to the risk of litigation

From time to time, Afren and, if the Acquisition completes, the Enlarged Group may be subject to litigation arising out of its operations. Damages claimed under such litigation may be material or may be indeterminate, and the outcome of such litigation may materially impact Afren's and, if the Acquisition completes, the Enlarged Group's business, results of operations or financial condition. While Afren and, if the Acquisition completes, the Enlarged Group assesses the merits of each lawsuit and defends itself accordingly, it may be required to incur significant expenses or devote significant resources to defending itself against such litigation. In addition, the adverse publicity surrounding such claims may have a material adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's business.

The Group does not and, if the Acquisition completes, the Enlarged Group will not insure against certain risks and its insurance coverage may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions

Afren and, if the Acquisition completes, the Enlarged Group consider that the extent of its insurance cover is reasonable based on the costs of cover, the risks associated with its business and industry practice. Afren's insurance currently includes cover for damage to or loss of certain production assets and its crude oil in storage, insurance for out-of-control wells (including coverage for redrill of and environmental damage caused thereby), third party liability coverage (including employer's liability insurance) and directors and officers liability insurance, in each case subject to excesses, exclusions and limitations. There can be no assurance that such insurance will be adequate to cover any losses or exposure for liability or that Afren and, if the Acquisition completes, the Enlarged Group will continue to be able to obtain insurance to cover such risks. For example, Afren and, if the Acquisition completes, the Enlarged Group does not have business interruption insurance in place and, therefore, it will suffer losses as a result of shut in or cessation in production.

Afren and, if the Acquisition completes, the Enlarged Group is unable to give any guarantee that expenses relating to losses or liabilities will be fully covered by the proceeds of applicable insurance. Consequently, Afren and, if the Acquisition completes, the Enlarged Group may suffer material losses from uninsurable or insured risks or insufficient insurance coverage. Afren and, if the Acquisition completes, the Enlarged Group is also subject to the future risk of unavailability of insurance, increased premiums or excesses, and expanded exclusions.

Failure to obtain necessary equipment and transportation systems could materially and adversely affect production

Oil and natural gas development and exploration activities are dependent upon the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for limited equipment such as drilling rigs or access restrictions may affect the availability of such equipment to Afren and, if the Acquisition completes, the Enlarged Group and may delay Afren's and, if the Acquisition completes, the Enlarged Group's development and exploration activities. In the areas in which Afren and, if the Acquisition completes, the Enlarged Group operates there is significant demand for drilling rigs and other related equipment. Failure by Afren and, if the Acquisition completes, the Enlarged Group to secure necessary equipment could adversely affect Afren's and, if the Acquisition completes, the Enlarged Group's business, results of operations or financial condition.

The Group contracts or leases services and capital equipment from third party providers and, if the Acquisition completes, the Enlarged Group will continue to do so. Such equipment and services can be scarce and may not be readily available at the times and places required. In addition, costs of third party services and equipment have increased significantly over recent years and may continue to rise. Scarcity of equipment and services and increased prices may in particular result from any significant increase in exploration and development activities on a region by region basis which might be driven by high demand for oil and gas. In the regions in which the Group operates and, if the Acquisition completes, the Enlarged Group will operate, there is significant demand for capital equipment and services. The unavailability and high costs of such services and equipment could result in a delay or restriction in Afren's and, if the Acquisition completes, the Enlarged Group's projects and adversely affect the feasibility and profitability of such projects, and therefore have an adverse affect on the Company's business, financial condition, results of operations and prospects.

Afren relies and, if the Acquisition completes, the Enlarged Group will continue to rely upon transportation systems owned and operated by third parties which may become unavailable. Afren and, if the Acquisition completes, the Enlarged Group, maybe unable to access these or alternative transportation systems could be subject to increased tariffs imposed by such third parties for transportation of its oil and gas.

The Group and, if the Acquisition completes, the Enlarged Group may face unanticipated increased or incremental costs

The crude oil and gas business is a capital-intensive industry. To implement its business strategy, the Group has invested, and continues to invest and, if the Acquisition completes, the Enlarged Group will continue to invest, in drilling and exploration activities and infrastructure. The Group's and, if the Acquisition completes, the Enlarged Group's current and planned expenditures on such projects may be subject to unexpected problems, costs and delays, and the economic results and the actual costs of these projects may differ significantly from the Group's and, if the Acquisition completes, the Enlarged Group's current estimates.

The Group relies and, if the Acquisition completes, the Enlarged Group will continue to rely on oil field suppliers and contractors to provide materials and services in conducting the exploration and production activities of the Group and, if the Acquisition completes, the Enlarged Group. Any competitive pressures on the oil field suppliers and contractors, or substantial increases in the worldwide prices of commodities, such as steel, could result in a material increase of costs for the materials and services required by the Group and, if the Acquisition completes, the Enlarged Group to conduct its business. For example, due to high global demand and a limited number of suppliers, the cost of oil field services and goods has increased significantly in recent years and could continue to increase. Future increases could have a material adverse effect on the Group's and, if the Acquisition completes, the Enlarged Group's operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the Group's properties, its planned level of spending for exploration and development and the level of its reserves. Prices for the materials and services the Group and, if the Acquisition completes, the Enlarged Group depends on to conduct its business may not be sustained at levels that enable the Group and, if the Acquisition completes, the Enlarged Group to operate profitability.

The Group and, if the Acquisition completes, the Enlarged Group may also need to incur various unanticipated costs, such as those associated with personnel, transportation and government taxes. Personnel costs, including salaries, are increasing as the standard of living rises in the countries in which the Group and, if the Acquisition completes, the Enlarged Group operates and as demand for suitably qualified personnel for the oil and gas industry increases. Although there have been no strikes in the history of the Group and, if the Acquisition completes, the Enlarged Group, industrial action, and the increased costs associated with such action, could occur.

With respect to decommissioning, licencees are invariably obliged under the terms of relevant licences or local law, to dismantle and remove equipment, to cap or seal wells and generally make good production sites. Afren's accounts for the year ended 31 December 2009 make provisions based on Afren's estimate of the aggregate decommissioning costs to be incurred at the end of each of Afren's licences. These are estimates based on currently known facts and circumstances including the current extent of Afren's operations. No guarantee can be given that such provisions shall in due course turn out to be sufficient.

An increase in any of these decommissioning costs or the other costs detailed above could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

The Group is and, if the Acquisition completes, the Enlarged Group will be subject to foreign exchange and inflation risks, which might adversely affect its financial condition and results of operations

The Group and, if the Acquisition completes, the Enlarged Group will report its results of operations and financial condition in US dollars and Afren's share price is quoted on the London Stock Exchange in GBP sterling. As a consequence shareholders may experience fluctuations in the market price of the Ordinary Shares as a result of, amongst other factors, movements in the exchange rate between GBP sterling and the US dollar.

Afren's revenues and most of its working capital are and, if the Acquisition completes, the Enlarged Group's revenues and most of its working capital will be, in US dollars. Afren converts and, if the Acquisition completes, the Enlarged Group will convert funds to foreign currencies as its payment obligations in jurisdictions where the US dollar is not an accepted currency become due. Certain of Afren's costs are and, if the Acquisition completes, the Enlarged Group will be incurred in currencies other than US dollars, including Naira and CFA. Accordingly, Afren is and, if the Acquisition completes, the Enlarged Group will

be subject to inflation in the countries in which it operates and fluctuations in the rates of currency exchange between the US dollar and these currencies, and such fluctuations may materially affect Afren's and, if the Acquisition completes, the Enlarged Group's business, results of operations or financial condition. Consequently, construction, exploration, development, administration and other costs may be higher than Afren and, if the Acquisition completes, the Enlarged Group anticipates.

Members of the Group and, if the Acquisition completes, the Enlarged Group, may engage in hedging activities from time to time that would expose the Group and, if the Acquisition completes, the Enlarged Group, to losses should markets move against the Group's and, if the Acquisition completes, the Enlarged Group's hedged position

The nature of Afren's and, if the Acquisition completes, the Enlarged Group's operations results in exposure to fluctuations in commodity prices. Afren uses and, if the Acquisition completes, the Enlarged Group will continue to use, financial instruments and physical delivery contracts to hedge its exposure to these risks and may continue to do so in future. If Afren and, if the Acquisition completes, the Enlarged Group, engages in hedging it will be exposed to credit related losses in the event of non performance by counterparties to the associated financial instruments. Additionally, if product prices increase above those levels specified in any future hedging agreements, Afren and, if the Acquisition completes, the Enlarged Group could lose the cost of floors or ceilings or a fixed price could limit Afren and, if the Acquisition completes, the Enlarged Group from receiving the full benefit of commodity price increases. If Afren and, if the Acquisition completes, the Enlarged Group enters into hedging arrangements, it may suffer financial loss if it is unable to commence operations on schedule or is unable to produce sufficient quantities of oil to fulfil its obligations.

The Group may be exposed to certain tax risks in Nigeria which might adversely affect its financial condition and results of operations

The petroleum tax laws in Nigeria do not fully anticipate some of the newer deal structures being implemented in oil and gas transactions in Nigeria. The structures that Afren has used for the acquisitions of the Okoro and Ebok assets may be subject to further assessment for tax purposes. Although Afren has sought the advice of internationally reputable tax advisors to clarify its position, there is a risk that the Nigerian tax authorities may take a different view from those advisors that might result in additional tax being imposed upon Afren, which could have an adverse effect on Afren's financial position and results of operations.

RISK FACTORS RELATING TO AN INVESTMENT IN AFREN'S AND, IF THE ACQUISITION COMPLETES, THE ENLARGED GROUP'S ORDINARY SHARES

The price of the Ordinary Shares may fluctuate

The market price of the Ordinary Shares may, in addition to being affected by Afren's and, if the Acquisition completes, the Enlarged Group's actual or forecast operating results, fluctuate significantly as a result of factors beyond Afren's and, if the Acquisition completes, the Enlarged Group's control, including among others:

- the results of exploration, development and appraisal programmes and production operations;
- changes in securities analysts' recommendations or the failure to meet the expectations of securities analysts;
- changes in the performance of the upstream oil sector as a whole and of Afren's and, if the Acquisition completes, the Enlarged Group's competitors;
- fluctuations in stock market prices and volumes, and general market volatility; and
- involvement of Afren, any Group company or any other companies in the Enlarged Group (if the Acquisition completes) in litigation.

Further share issues could have an adverse effect on the market price of the Ordinary Shares as a whole or a dilutive effect on shareholders

Afren has historically issued new shares, often on non-pre-emptive basis, in order to finance its expansion and working capital requirements. Any additional offering by the Company, including in relation to any acquisitions, whether or not on a pre-emptive basis, could have an adverse effect on the market price of the Ordinary Shares as a whole. If additional funds are raised through the issuance of equity or equity linked instruments, shareholders may experience a dilution in their percentage holdings in the Ordinary Shares if such issuance is not made on a pre-emptive basis.

Ordinary Shares may be unsuitable as an investment

The Ordinary Shares may not be a suitable investment for all recipients of this Prospectus. Before making any investment, prospective investors are advised to consult an investment adviser, authorised by the FSA, who specialises in advising on the acquisition of listed securities. The value of the Ordinary Shares and the income received from them can go down as well as up and investors may get back less than their original investment.

Pre-emptive rights may not be available to US holders of the Company's Ordinary Shares

Under UK law and in accordance with the existing shareholder authorities, subject to certain exceptions, prior to the issuance of any new Ordinary Shares for cash, the Company must offer holders of existing Ordinary Shares pre-emptive rights to subscribe and pay for a sufficient number of Ordinary Shares to maintain their existing ownership percentages. These pre-emptive rights may, depending on the specific offer terms, be transferable during the subscription period for the related offering and may be quoted on the London Stock Exchange.

US holders of Ordinary Shares may not be able to receive, trade or exercise pre-emptive rights for Ordinary Shares unless a registration statement under the US Securities Act is effective with respect to such rights or an exemption from the registration requirements of the US Securities Act is available. The Group does not currently plan to register the Ordinary Shares or any future rights under US securities laws. If US holders of Ordinary Shares are not able to receive, trade, or exercise pre-emptive rights granted in respect of their Ordinary Shares in any rights offering by the Company, then they may not receive the economic benefit of those rights. In addition, their proportional ownership interests in the Company will be diluted.

RISK FACTORS RELATING TO THE ACQUISITION

The Acquisition is subject to a number of conditions which may not be satisfied or waived

The implementation of the Scheme is subject to the satisfaction (or waiver, where applicable) of a number of conditions, including:

- approval of the Scheme and the related resolutions by the requisite majorities of the Black Marlin Shareholders; and
- sanction of the Scheme by the Court at the Court Hearings.

Additionally, as the Acquisition has been classified as a class 1 transaction for the purpose of the Listing Rules, the Acquisition will also require the approval of the Afren Shareholders. There is no guarantee that these (or other conditions) will be satisfied (or waived, if applicable), in which case the Acquisition will not take effect. The conditions to the Acquisition are summarised in more detail in Part 3 of this document.

A third party may be able to obtain a large enough shareholding in Black Marlin to delay or prevent completion of the Acquisition

Black Marlin is a listed entity whose common shares are freely traded on the TSXV. It is possible that an existing or new shareholder with significant shareholding in Black Marlin could use, or could threaten to use, its shareholding to vote against the Acquisition when shareholder consent is sought. Such an action could materially delay or prevent the implementation of the Acquisition and therefore deprive the parties of some or all of the anticipated benefits of the Acquisition.

The market value of listed securities may fluctuate and may not reflect the underlying asset value of Afren or, following completion of the Acquisition, the Enlarged Group

Prospective investors should be aware that the value of an investment in the Enlarged Group may go down, as well as up. The market value of the Ordinary Shares can fluctuate and may not always reflect the underlying asset value. A number of factors outside the control of the Enlarged Group may impact on its performance and the price of the Ordinary Shares. Such factors include the operating and share price performance of other companies in the industry and markets in which the Enlarged Group operates, speculation about the Enlarged Group's business in the press, media or investment community, changes to the Enlarged Group's trading forecasts, the publication of research reports by analysts and general market conditions.

Ownership reduction

Since the Acquisition is to be effected by means of a Scheme under which Black Marlin Shareholders will be offered New Ordinary Shares once the Acquisition becomes effective, existing Afren Shareholders will suffer a reduction in their proportionate ownership and voting interest in the ordinary share capital of Afren.

If the Acquisition completes, the integration of Black Marlin and its subsidiaries could result in operating difficulties and other adverse consequences

If the Acquisition completes, the process of integrating Black Marlin and its subsidiaries may create unforeseen operating difficulties and expenditures and pose management, administrative and financial challenges. Specifically, integrating operations and personnel and pre-completion or post-completion costs may prove more difficult and/or expensive than anticipated, thereby rendering the value of the Acquisition less than the value paid. The integration of the Acquisition may require significant time and effort on the part of Afren and, if the Acquisition completes, the Enlarged Group's management. The challenges of integrating Black Marlin may also be exacerbated by differences between Afren's and Black Marlin's operational and business culture, the need to implement unpopular cost cutting measures, difficulty in maintaining internal controls and difficulty in establishing control over cash flows and expenditures. While Afren has successfully completed the integration of the businesses it has acquired thus far, it could experience difficulties in integrating Black Marlin successfully, which could have an adverse effect on Afren's and, if the Acquisition completes, the Enlarged Group's financial condition and results of operations.

A number of the joint operating agreements ("JOAs") to which Black Marlin is party contain a change of control provision, which is likely to be triggered by the Acquisition, giving the counterparties to such JOAs a right of first refusal over Black Marlin's participating interest under the corresponding production sharing contract

The JOAs relating to the Black Marlin's assets in Ethiopia, Kenya and the Seychelles each contain a change of control provision, pursuant to which the other parties to the JOAs shall have the right to acquire the participating interest of the party who is subject to the change of control. The value to be paid for such participating interest is determined in accordance with the provisions of the respective JOA, which includes the need for an independent expert valuation in the event of any dispute. The JOAs are based on the standard Association of International Petroleum Negotiators (AIPN) JOA, which contains this right of first refusal language. None of the corresponding production sharing contracts contains a similar right of first refusal provision.

In the event that the counterparties to the relevant JOAs elect to exercise their right of first refusal following the Acquisition, it is possible that Black Marlin will be obliged to transfer its participating interest in the corresponding production sharing contract and it is possible, therefore, that the Enlarged Group (if the Acquisition completes) will not (i) hold the participating interests in these blocks, which range from 30 to 75 per cent. of the blocks; and (ii) if any such blocks are found to have hydrocarbons the commercial extraction of which is economically viable, will not then benefit from such production. Although Black Marlin has undertaken in the Arrangement Agreement to use commercially reasonable efforts to obtain, and assist Afren in obtaining, waivers in relation to these pre-emption rights and although as at the date of this Prospectus, the Group is not aware of any counterparty to the relevant JOAs having elected to exercise its right of first refusal, if exercised, these rights of first refusal are material in the context of completion of the Acquisition and, taken together, if exercised could negate the benefits of the Acquisition as set out above.

DIRECTORS, SECRETARY AND ADVISERS

Directors	Mr. Egbert Imomoh (<i>Chairman</i>) (<i>Non-Executive Director</i>) Dr. Osman Shahenshah (<i>Chief Executive</i>) Mr. Shahid Ullah (<i>Chief Operating Officer</i>) Mr. Constantine Ogunbiyi (<i>Executive Director</i>) Mr. Darra Comyn (<i>Group Finance Director</i>) Mr. Ennio Sganzerla (<i>Non-Executive Director</i>) Mr. Peter Bingham (<i>Non-Executive Director</i>) Mr. John St. John (<i>Non-Executive Director</i>) Mr. Toby Hayward (<i>Non-Executive Director</i>)
Company Secretaries	Ms. Shirin Johri Mr. Elekwachi Ukwu
Registered Office	Kinnaird House 1 Pall Mall East London SW1Y 5AU United Kingdom
Website	www.afren.com
Sponsor and Broker	Merrill Lynch International Bank of America Merrill Lynch Financial Centre 2 King Edward Street London EC1A 1HQ United Kingdom
English Legal Advisers to Afren	White & Case LLP 5 Old Broad Street London EC2N 1DW United Kingdom
English Legal Advisers to the Sponsor	Ashurst LLP Broadwalk House 5 Appold Street London EC2A 2HA United Kingdom
Financial Advisers to Afren	CIBC World Markets plc Cottons Centre Cottons Lane London SE1 2QL United Kingdom

**Auditors and Reporting
Accountants to Afren**

In respect of information on Afren
Deloitte LLP
2 New Street Square
London EC4A 3BZ
United Kingdom

*In respect of information on Black Marlin and Black
Marlin Energy Limited*
BDO Chartered Accountants & Advisors
Suite 305, Al Futtaim Tower Al Maktoum Street
Deira P.O. Box 1961
Dubai U.A.E

Registrars

Computer Share Investor Services plc
PO Box 82, The Pavilions
Bridgwater Road
Bristol BS99 7NH
United Kingdom

Principal Bankers

Lloyds TSB Bank Plc
39 Threadneedle Street
London EC2R 8AL
United Kingdom

Financial PR

Pelham Public Relations
No.1 Cornhill
London EC3V 3ND
United Kingdom

DOCUMENTS INCORPORATED BY REFERENCE

This Prospectus should be read and construed in conjunction with:

- (a) the audited consolidated financial statements of Afren as at and for the financial year ended 31 December 2009, together with the notes thereto and the audit report thereon, which can be found on pages 77 to 114 of the Annual Report; and
- (b) the audited consolidated financial statements of Afren as at and for the financial year ended 31 December 2007 and 31 December 2008, together with the notes thereto and the audit report thereon, which can be found on pages 440 to 485 of the 2009 Prospectus.

Such documents shall be incorporated in, and form part of this Prospectus, save that any statement contained in a document which is incorporated by reference herein shall be modified or superseded for the purpose of this Prospectus to the extent that a statement contained herein modifies or supersedes such earlier statement (whether expressly, by implication or otherwise). Any statement so modified or superseded shall not, except as so modified or superseded, constitute a part of this Prospectus.

Where documents incorporated by reference themselves incorporate information by reference, such information does not form part of this Prospectus.

Copies of documents incorporated by reference in this Prospectus may be obtained (without charge) from the registered office of Afren.

PRESENTATION OF INFORMATION

Investors should rely only on the information in this Prospectus. No person has been authorised to give any information or make any representations other than those contained in this Prospectus and, if given or made, such information or representations must not be relied on as having been authorised by Afren. Without prejudice to any obligation of Afren to publish a supplementary prospectus pursuant to section 87G of FSMA or paragraph 3.4 of the Prospectus Rules, the publication of this Prospectus does not, under any circumstances, create any implication that there has been no change in the affairs of the Group since, or that the information contained herein is correct at any time subsequent to, the date of this Prospectus.

The contents of this Prospectus are not to be construed as legal, business or tax advice. Each prospective investor should consult his, her or its own solicitor, independent financial adviser or tax adviser for legal, financial or tax advice.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Prospectus contains forward-looking statements which reflect Afren's current views or, as appropriate, those of the Directors, with respect to financial performance, business strategy, plans and objectives of management for future operations (including development plans relating to Afren's business). These forward looking statements relate to the Group and the sectors and industries in which it operates. Statements that include the words "expects", "intends", "plans", "believes", "projects", "anticipates", "estimates", "will", "targets", "aims", "may", "would", "could", "continue" and similar statements of a future or forward-looking nature identify forward-looking statements for purposes of the US federal securities laws or otherwise.

All forward-looking statements included in this Prospectus address matters that involve risks and uncertainties. Accordingly, there are or will be important factors that could cause Afren's actual results to differ materially from those indicated in these statements. These factors include, but are not limited to, those described in the part of this Prospectus entitled "*Risk Factors*", which should be read in conjunction with the other cautionary statements that are included in this Prospectus. Other important factors that could cause actual results to differ materially from Afren's expectations include, among others, the following:

- price fluctuations in crude oil, gas and refined products markets and related fluctuations in demand for such products;
- operational limitations, including equipment failures, labour disputes and processing limitations;
- the availability or cost of transportation routes and traders' fees charged for arranging transportation;
- changes in governmental regulation, including regulatory changes affecting the availability of permits, and governmental actions that may affect operations or the Group's planned expansion;
- unfavourable changes in economic or political conditions in West Africa and/or East Africa;
- unplanned events or accidents affecting the Group's operations or facilities;
- incidents or conditions affecting the export of crude oil and gas; and
- reservoir performance, drilling results and implementation of the Group's oil expansion plans.

Any forward-looking statements in this Prospectus reflect Afren's current views with respect to future events and are subject to these and other risks, uncertainties and assumptions relating to the Group's operations, results of operations, growth strategy and liquidity.

Any forward-looking statements speak only as at the date of this Prospectus. Subject to any obligations under the Prospectus Rules, the Listing Rules and/or the Disclosure and Transparency Rules, Afren undertakes no obligation to update publicly or review any forward-looking statement, whether as a result of new information, future developments or otherwise. All subsequent written and oral forward-looking statements attributable to Afren or individuals acting on behalf of Afren are expressly qualified in their entirety by this paragraph. Prospective investors should specifically consider the factors identified in this Prospectus that could cause actual results to differ before making an investment decision.

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

Historical Financial Information

The financial information in this Prospectus has been prepared in accordance with IFRS. The significant accounting policies applied to the financial information are incorporated by reference in this Prospectus.

Certain Reserves Information

The SEC permits oil and gas companies, in their filings with the SEC, to disclose proved reserves that they have demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The crude oil reserves data presented in this Prospectus have been estimated at the request of Afren by NSAI, an international oil and gas consultant, in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (“PRMS”) approved by the Society of Petroleum Engineers (“SPE”) and thus proved reserves may differ from those estimated according to definitions used by the SEC. Crude oil resource data pertaining to Black Marlin have been prepared by McDaniel in accordance with the standard set out in National Instrument 51-101 and COGEH and by GCA in accordance with the SPE PRMS guidelines and definitions.

Further, Afren uses certain terms in this Prospectus in referring to its reserves and resources and Black Marlin’s resources, such as “probable” or “possible” reserves that the SEC’s guidelines would also permit the respective parties to include (in addition to proved reserves, as described above) in filings with the SEC if Afren and Black Marlin were subject to reporting requirements under the US Securities Exchange Act of 1934 (as set out in rule 4-10 of Regulation S-X and item 1200 of Regulation S-K, as recently amended). Prospective investors should read the NSAI Report produced by NSAI on the Afren’s reserves and resources dated the date hereof (with an effective date of 30 June 2010) included in Part 11 of this Prospectus and the McDaniel and GCA Reports produced by McDaniel & Associates Consultants Ltd (dated the date hereof) and GCA dated the date hereof (with an effective date of 31 March 2010) included in Parts 12 and 13 of this Prospectus for more information on the Company’s reserves and resources and Black Marlin’s resources and the reserves and resources definitions used.

Hydrocarbon Data

General

Afren uses standards prepared by the SPE and reviewed and sponsored jointly by the WPC, the AAPG and the SPEE. Since 2006, Afren has engaged NSAI to conduct reviews of the Group’s hydrocarbon reserves and resources. Unless otherwise stated herein, the estimates set forth in this Prospectus of Afren’s proven, probable and possible reserves and resources are based on reports prepared for the Group by NSAI in accordance with the standards prepared by the SPE and reviewed and sponsored jointly by the WPC, the AAPG and the SPEE. For further information regarding these standards see the NSAI Report in Part 11 of this Prospectus.

Black Marlin uses standards established under the National Instrument 51-101 and COGEH. Black Marlin has engaged McDaniel and GCA to conduct reviews of the Group’s hydrocarbon resources. Unless otherwise stated herein, the estimates set forth in this Prospectus of Black Marlin’s resources are based on reports prepared for Black Marlin by McDaniel in accordance with the standards established under National Instrument 51-101 and COGEH and by GCA in accordance with the SPE PRMS guidelines and definitions. For further information regarding these standards see the McDaniel and GCA Reports in Part 12 and 13 of this Prospectus.

Presentation in NSAI Report

The NSAI Report reports its estimations as follows:

- crude oil in millions of barrels (MMBBL) (a barrel being equivalent to 42 US gallons); and
- natural gas and natural gas liquid in billions of cubic feet (BCF) at standard temperature and pressure bases.

The actual number of barrels of crude oil produced, shipped or sold may vary from the barrel equivalents of crude oil presented herein, as a tonne of heavier crude oil will yield fewer barrels than a tonne of lighter crude oil. The conversion of data for other companies in tonnes into barrels and from cubic feet into boe may be at different rates.

NSAI has prepared its assessment of Afren's asset base as at 30 June 2010, and has reviewed and incorporated only field studies and data that were available up to that date. NSAI has not included Okwok, Ofa, OPL 907 and OPL 917 in its assessment as at 30 June 2010.

Presentation in the GCA Report and the McDaniel Report

The resource estimates in the McDaniel Report have been prepared in accordance with the resource definitions and the standards set out in the Canadian National Instrument 51-101 and the COGEH and by GCA in accordance with the SPE PRMS guidelines and definitions.

While COGEH defines Petroleum Initially-In-Place, the use of GIIP, STOIIP, OGIP and OOIP in the tables in the McDaniel Report is consistent with the COGEH glossary that provides for defining products (oil and gas) in the same manner as Petroleum Initially-In-Place.

NO INCORPORATION OF WEBSITE INFORMATION

The contents of Afren's website, any website mentioned in this Prospectus or any website directly or indirectly linked to these websites have not been verified and do not form part of this Prospectus and investors should not rely on such information.

EXPECTED TIMETABLE AND INDICATIVE ACQUISITION STATISTICS

Expected timetable

Application for Interim Court Order	26 July 2010
Record date for Black Marlin Shareholders	3 August 2010
Black Marlin Shareholders' meeting	10 September 2010
Record date for Afren Shareholders	17 September 2010
Afren General Meeting	21 September 2010
Scheme Court Hearing	6 October 2010
Obtain Scheme Court Order	8 October 2010
Effective date of Scheme	8 October 2010
Issue of New Ordinary Shares	8 October 2010
New Ordinary Share Admission	11 October 2010
Commencement of dealings on the London Stock Exchange of New Ordinary Shares	11 October 2010

Acquisition Statistics

Number of existing Ordinary Shares in issue (as at 23 August 2010)	891,125,768
Number of New Ordinary Shares to be issued pursuant to the Scheme	up to 76,776,564
Number of Ordinary Shares in issue upon completion of the Acquisition	up to 967,902,332
New Ordinary Shares to be issued as a percentage of the enlarged issued share capital of Afren	up to 7.9 per cent.

PART 1

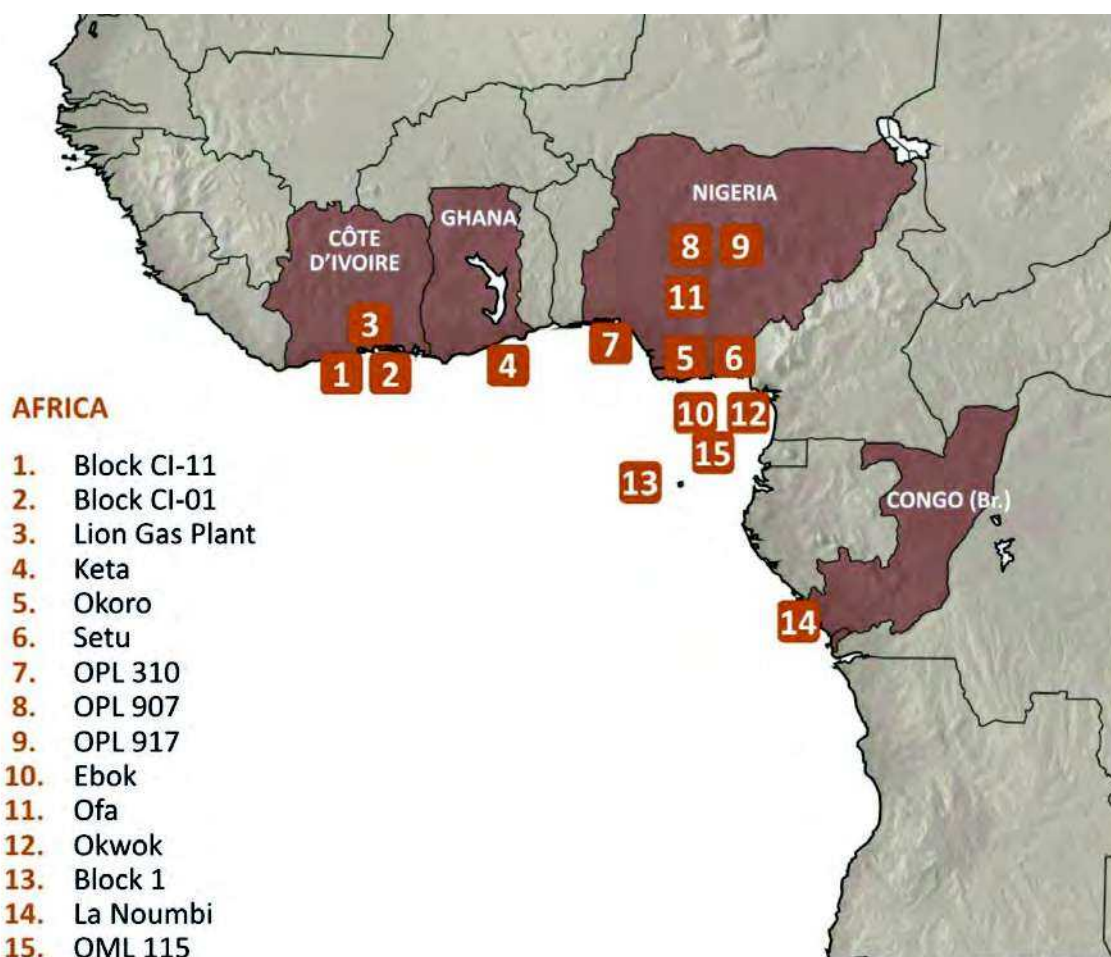
INFORMATION ON THE GROUP

1. Introduction

Afren is an independent oil and gas exploration and production company that was founded in 2004 and admitted to AIM on 14 March 2005 and, subsequently, on 3 December 2009, Afren's Ordinary Shares were admitted to the Official List and to trading on the main market of the London Stock Exchange. With a focus purely on Africa, the founding vision to become the leading pure-play African independent exploration and production company was based on a clear and differentiated strategy of utilising relationships of the Board and management to partner with indigenous companies, national oil companies and host governments, in growing an upstream portfolio of significant scale.

Adhering to the founding strategy Afren has to date assembled a diversified portfolio of 15 assets across five West African countries: Nigeria, Côte d'Ivoire, Ghana, Congo-Brazzaville and offshore Nigeria and São Tomé & Príncipe JDZ. This includes a farm-out agreement entered into with Addax in relation to Okwok, which is subject to completion. Afren's portfolio today encompasses producing, development, appraisal and exploration opportunities that provide a balanced platform and opportunity set from which to deliver further significant organic growth into the foreseeable future.

The following map shows the location of Afren's assets, together with the Okwok field.



Source: Afren

Afren is currently producing oil from the Okoro field in Nigeria and oil and gas from the Lion and Panthère fields in Block CI-11 in Côte d'Ivoire, as well as processing gas at the Lion Gas Plant in Côte d'Ivoire. Net daily production in 2009 for the Group averaged 22,100 bopd from upstream and midstream activities. The Ebok field is under development and first oil is expected in the fourth quarter of 2010.

2. Strengths, Strategy and Prospects

Afren's vision is to strengthen its position as a leading African independent oil and gas exploration and production company. The Directors believe that Afren's key strengths and strategic advantages are:

An exclusive pan African focus

Over the past two decades, Africa's proven oil reserves have grown by over 110 per cent. (Source: BP Statistical Review of World Energy (June 2010)). Sub Saharan Africa has witnessed growth of over 185 per cent. reserves over the same period (Source: BP Statistical Review of World Energy (June 2010)). No other region has matched this growth statistic, with many established producing regions showing a contraction in reserves base over the same period. According to the BP Statistical Review of World Energy (June 2010), in this region there is:

- an estimated 52 billion barrels of proved oil reserves, of which 41 per cent. is in Nigeria; and
- an estimated 230 tcf of gas reserves, of which 80 per cent. is in Nigeria.

Management considers that in this region there is:

- a fiscally stable environment and high margin barrels;
- an established oil exploration and production industry, at an earlier stage of maturity than other major hydrocarbon provinces;
- significant exploration prospectivity with positive early indications of a secondary market emerging in the Gulf of Guinea; and
- significant opportunities to commercialise gas.

Currently, approximately 15 per cent. of oil and gas supplied to the US originates from West Africa, and this is projected by industry sources to increase to 30 per cent. over the next decade highlighting the future dependence on the West African hydrocarbon resource base, a region in which Afren is competitively advantaged through its indigenous identity and strong access to opportunities through the Board and management (Source: US Department of Energy, Energy Information Administration). Afren has an established foothold in West Africa, where its portfolio is currently focused, and also around the Gulf of Guinea. The Company's initial focus was on Africa as a whole and consistent with this it continues to evaluate and consider growth opportunities on a pan African basis.

Strong African representation on the Board and management

Afren benefits from an experienced Board and senior management with extensive African experience and relationships, including:

- Afren's Chairman Egbert Imomoh, a Nigerian national, who has over 30 years working experience including as deputy managing director of Shell Nigeria with responsibility for more than one million bopd of operated production. Mr. Imomoh has a long history of managing oil and gas operations in Africa, allowing him to develop strong relationships with partner companies, government and authorities, indigenous companies and community relations.
- The Group's Chief Executive, Osman Shahenshah, with more than 20 years experience in oil, gas and energy corporate finance. His track record in oil and gas financing, acquisitions and strategic advisory includes advising on the financing of Mobil's Oso asset (Nigeria), the Escravos gas flaring reduction project (Nigeria), a US\$1.6 billion financing at N'Kossa (Congo-Brazzaville) and the financing of Block CI-11 (while at IFC).

- Afren's Chief Operating Officer, Shahid Ullah, who has spent over 15 years working in Nigeria and other west African countries. Mr. Ullah was responsible for and co-ordinated the development of Etame (Gabon) and the Abana field (Moni Pulo, Nigeria).
- Afren's Group Finance Director, Darra Comyn, who has 24 years of experience as a finance practitioner and has held senior positions in international corporates with an emerging markets focus. Mr. Comyn is responsible for leading and directing Afren's group-wide finance function, ensuring adherence to all corporate governance requirements and providing the Executive team with accurate and effective financial information for decision-making purposes.
- Constantine Ogunbiyi, a Nigerian national and an Executive Director, who has extensive experience of African acquisitions and structured and project financings, both with Afren and in his previous career as a lawyer with major international law firms. Mr. Ogunbiyi is responsible for the group-wide business and corporate development function and has led in the negotiations of each of the major asset acquisitions of the Group.

The extensive experience and relationships of the Board are complemented by members of Afren's senior management team who are based in Nigeria and Côte d'Ivoire, including operational managers and financial controllers. Afren benefits from fully staffed offices in all operational locations, covering the Company's operational requirements. These offices are staffed primarily by locally-based employees, further evidencing Afren's commitment to Africa. This 'on the ground' presence provides the Group with direct insight into local issues, as well as allowing the Group to react to operational matters promptly.

An established operational track record

Afren is operator on all of its core development and production assets in Nigeria and Côte d'Ivoire. The Company fulfils the role of technical advisor to Amni at the producing Okoro field and to Oriental at the Ebok field. During 2008, Afren successfully operated and drilled a total of nine wells in Nigeria and Ghana and maintained an excellent environmental health and safety record. In 2009, Afren continued with a multi-well appraisal drilling campaign at the Ebok field in Nigeria achieving a 100 per cent. success rate and maintaining its excellent environmental health and safety record.

The Okoro field in Nigeria marked Afren's maiden operated full field development, in a period of under two years from signing the agreement to first oil in June 2008. At the end of 2009, the field had cumulatively produced a total of 8.1 million barrels, with an average production rate of 18,800 bopd and process uptime of 99.6 per cent. achieved in 2009.

The Ebok field represents Afren's current major development project. Following completion of a successful three well appraisal campaign in November 2009, development work commenced and first oil is expected in the fourth quarter of 2010.

Proved reserves and production growth

At the time of its initial public offering in March 2005, Afren's sole oil and gas interest was a 4.41 per cent. interest in the JDZ Block 1, with no reserves. Effective at 30 June 2010, Netherland Sewell & Associates ("NSAI") independently certified a net 2P working interest reserves before royalty of 79.1 mmboe. Based on NSAI's gross 2C contingent resource estimates and applying Afren's effective working interests, the Company is estimated to have net contingent resources of 26.9 mmboe effective at 30 June 2010. The total net 2P working interest reserves before royalty and net working interest contingent resource base to Afren is therefore 106 mmboe. NSAI has also estimated substantial gross prospective resource potential related to the Group's exploration acreage. Applying Afren's effective working interests it is estimated that the Company has net prospective resources of 1,039 mmboe.

Afren is actively engaged in exploration activities in all five African countries in which it has a presence. Through a selective exploration strategy, Afren is exposed to the high impact Cretaceous fairway along the West African transform margin, where it has secured OPL 310 in Nigeria, the Keta Block in Ghana and Block CI-01 in Côte d'Ivoire (attractive prospectivity has been identified in both the primary Cretaceous intervals and younger Tertiary intervals), and selected under explored basins elsewhere in West Africa where

working hydrocarbon systems have been established and the potential for material discoveries exists (for example, the Vandji play in Congo-Brazzaville).

Over the period ending 2012 Afren intends to drill key exploration and appraisal wells across the Ebok/Okwok/OML115 area, OPL 310 and the Keta block that have the potential to add substantially to the Company's reserves base (the petroleum agreement dated November 2009 was ratified by the Ghanaian parliament on 19 February 2010).

At the Okoro field, crude oil exports continue to run smoothly via the nearby Ima terminal, where the increased storage capacity (in excess of 1 mmbbls) provides a benefit through the sale of increased parcel sizes and improved shipping and sales economics. The year to date gross production at Okoro to 30 June 2010 was 3,229,178 bbls, equivalent to an average gross daily production rate of 17,841 bopd. Two infill drilling targets have been identified at Okoro, and are expected to add incremental gross production of 3,000 bopd to 5,000 bopd.

In Côte d'Ivoire, the year to date gross production at block CI-11 to 30 June 2010 was 4,837,202 mcf and 220,552 bbls, equivalent to average gross daily production rates of 26.7 mmcfd and 1,219 bopd respectively. Over the same period natural gas liquid output at the Lion Gas Plant was equivalent to an average gross daily production rate of 654 boepd. Production in Côte d'Ivoire over the first quarter of 2010 was impacted due to maintenance work involving the low pressure compressor on the Gulftide production platform and turbo expander at the Lion Gas Plant. Following completion of necessary work, gas production at CI-11 was restored to a gross rate of 30 mmcfd in April 2010. The Lion Gas Plant also received reduced third party inlet volumes over the period as a result of work on the gas compression systems at the CNR operated Espoir and Baobab facilities.

At CI-11, a major mapping and seismic re-interpretation exercise has been undertaken applying current understanding of regional Upper Cretaceous depositional systems. The final results of this study will assist in defining plans to access and produce incremental oil and gas reserves.

Development of the Ebok field offshore south east Nigeria is underway, with first oil expected in the fourth quarter of 2010.

Continued growth through partnerships and acquisitions

Afren's significant reserves growth to date has been achieved through a combination of accessing and developing discovered but undeveloped assets through partnerships with indigenous companies (in relation to Okoro, Ebok and Okwok) across the Gulf of Guinea (Nigeria in particular) and selective acquisitions where Afren is strategically advantaged (for example, the acquisition of Devon Energy's assets in Côte d'Ivoire and Ghana and Black Marlin's assets in East Africa).

Afren will continue to explore selective acquisition opportunities that are consistent with its strategic objectives. The discovered but undeveloped oil and gas fields across Sub-Saharan Africa, more specifically in Nigeria, offer a rich opportunity set. With the vast majority of these fields residing as "fallow" assets in the major oil companies' portfolios, they typically fall below the materiality threshold of the major oil companies, given a growing focus on exploring the deeper water regions for very large discoveries.

There are encouraging signs that indicate a secondary asset market is emerging in the Gulf of Guinea, as certain governments' emphasis turns to realising the full benefit of the natural resources and encouraging greater local and indigenous participation in order to achieve this. Attractive acreage is increasingly being awarded to indigenous companies who, in turn, are looking to partner with independent oil companies that can bring both technical expertise and financial resources. Afren intends to continue its partnership based approach in growing the reserves base.

In addition, to complement its fallow field strategy and in direct response to the Nigerian government's objective to increase the level of local participation in the oil and gas sector, Afren has established an indigenous company, First Hydrocarbon Nigerian (FHN) with the support of two leading Nigerian financial institutions, First City Monument Bank Plc and Guaranty Trust Bank Plc. FHN will acquire substantial oil and gas assets in Nigeria from the major international oil companies' portfolios. Over time, FHN will be

owned by a wider Nigerian stakeholder base, ensuring diversity of ownership and a reflection of Afren's Nigerian focus.

Grow and maintain exposure to high impact exploration growth opportunities

In balance with its established production and development platform, the Company has also assembled an exploration portfolio that provides exposure to an estimated net resource base of 1,039 mmboe. This most notably offers future offshore drilling opportunities along the West African Transform Margin (Côte d'Ivoire, Ghana and offshore south west Nigeria) in addition to onshore exploration potential within the Lower Congo Basin (Congo Brazzaville). Consistent with Afren's exploration strategy, all of its exploration assets are located in basins where the presence of hydrocarbons has been proven, but are typically under-explored and hold remaining potential for large discoveries. It is the Company's strategy to continue to grow its exploration portfolio, in parallel with its production and development activities, with the intention of providing what it perceives to be quality opportunities in which to reinvest a portion of internally generated revenues to deliver growth.

3. History of the Group

Afren was incorporated in December 2004 and its share capital was admitted to trading on AIM in March 2005. Afren has since developed a diversified portfolio of 15 assets comprising production, near term development and high impact exploration assets across Côte d'Ivoire, Nigeria, offshore Nigeria and São Tomé & Príncipe JDZ, Ghana, Congo-Brazzaville.

The Group's first asset, acquired on 8 March 2005, was an indirect 4.41 per cent. interest in JDZ Block 1 in offshore Nigeria and São Tomé & Príncipe JDZ through a 49 per cent. equity interest in DEER. This acquisition gave Afren its foothold in offshore Nigeria and São Tomé & Príncipe JDZ and its proven deep water reserves.

On 18 July 2005, Afren acquired from Ascent Resources plc a 12.86 per cent. interest in the Iris Marin licence in Gabon. This acquisition provided Afren with access to the Gamba sandstone reservoir which is productive in the nearby Etame field. In April 2007 Afren increased its equity interest in the Iris Marin licence area from 12.86 per cent. to 16.67 per cent. following the withdrawal of Petroleum Oil & Gas Corporation Pty Limited of South Africa.

On 24 March 2006, Afren, AERL and Amni signed a production sharing and technical services agreement for the development of the Okoro and Setu fields in offshore Nigeria.

On 3 January 2007, Afren acquired a 20 per cent. interest in the Ibekelia TEA licence area. The Ibekelia licence is located adjacent to the Gamba, Ivinga and Olowi oilfields.

On 3 April 2007, AERL on behalf of itself and Amni signed a contract with Bumi Armada Berhad (which was later amended and novated) for the use of the Armada Perkasa FPSO for an initial five-year term with an option to extend. The Armada Perkasa FPSO has a storage capacity of 380,000 barrels and a processing capacity of 27,000 bopd.

On 12 November 2007, Afren entered into a share purchase agreement with Devon Energy to acquire Devon Energy Ghana Holdings Limited, which indirectly holds a 95 per cent. working interest and operatorship of the Keta Block, located offshore eastern Ghana in the Volta Basin.

On 20 February 2008, AGER through a joint venture agreement with GEC, signed production sharing contracts for OPL 907 and OPL 917 located in onshore Nigeria within the Anambra Basin. Under the terms of the production sharing contracts, AGER took a 41 per cent. interest in OPL 907 and a 42 per cent. interest in OPL 917, and AGER acts as operator of both assets. The joint venture agreement between Afren and GEC defines the commercial terms under which Afren participates with GEC in the exploration and development of the two licences. Afren's interests are held through AGER in which Afren holds an 80 per cent. economic interest.

On 5 March 2008, Devon Energy, Devon International Holdings Ltd, Afren C1 (II) Limited and Afren entered into a share purchase agreement pursuant to which on 24 September 2008, Afren CI (II) Limited

acquired Devon Energy and Devon International Holdings Ltd's interests in Côte d'Ivoire comprising (i) a 47.9592 per cent. working interest and operatorship of the producing Block CI-11, (ii) a 65 per cent. direct interest and operatorship with rights over an additional 15 per cent. interest in the undeveloped Block CI-01, and (iii) a 100 per cent. interest in the onshore Lion Gas Plant. The consideration for the acquisition was US\$184 million (after working capital adjustments). The transaction yielded immediate production, complementing production start up at the Okoro field in Nigeria, increased probable reserves by 67 per cent. to 70 million boe and represented a strategic new entry into Côte d'Ivoire.

On 31 March 2008, Afren Resources signed a farm-in agreement with Oriental jointly to develop the Ebok field located offshore South-East Nigeria. Oriental had been awarded a 100 per cent. interest and operatorship of Ebok by the ExxonMobil/NNPC Joint Venture in May 2007.

On 3 April 2008, Afren announced that it had raised £118.75 million pursuant to a placing with institutional investors of 95 million new ordinary shares of one penny each in the capital of the Company at 125 pence per share.

On 10 June 2008, Afren announced first oil from the Okoro field in Nigeria.

On 8 October 2008, Afren entered into a strategic alliance agreement with Sojitz Corporation jointly to pursue significant oil and gas acquisition opportunities in Africa. Under the terms of the agreement, the alliance will terminate on the earlier of 8 October 2011 or the date upon which Sojitz has invested a total of US\$500 million in joint acquisitions. Sojitz Corporation is to provide financial support to the alliance for the purpose of funding material joint acquisitions, among other things, including by securing funding and credit support from the Japanese Government.

On 24 October 2008, Afren, through its subsidiary Afren Energy Ghana Limited, signed a farm-out agreement with Mitsui Ghana in respect of the Keta Block, pursuant to which on 28 November 2008 Mitsui Ghana acquired a 20 per cent. participating interest in the petroleum agreement governing the Keta Block together with a 22.2 per cent. interest in a joint operating agreement with Gulf in return for a significant contribution to the Cuda-1x exploration well.

On 26 March 2009, Afren announced the successful outcome of the Ebok field appraisal. An independent assessment of the in-place oil and recoverable oil reserves from the Ebok field preliminarily confirmed a P50 STOIP of 148 mmbbls oil for the FB-1 and FB-2 areas of the field. Recoverable reserves were calculated at 41.2 mmbbls. The independent assessor further assigned a 14 mmbbls oil of resources to the FB-1 and FB-2 field area. An additional 21 mmbbls oil of contingent reserves and 33 mmbbls prospective resources were assigned to other areas of the field including the Ebok West and Ebok North Fault Blocks.

On 15 April 2009, Afren announced that it had raised £84.8 million (US\$126.3 million) pursuant to a placing with institutional investors of 265 million new ordinary shares of one penny each in the capital of the Company at 32 pence per share.

On 3 July 2009, Afren announced that it had established FHN with the support of two leading Nigerian financial institutions, FCMB and Guaranty Trust Bank Plc. FHN was established to fulfil the Nigerian Government's criteria for indigenous operators and is to be used as vehicle to acquire substantial oil and gas assets in Nigeria, including stakes in assets currently under negotiation, assets that may become available that are held by international independents and by the joint ventures between the Nigerian Government and international oil companies, and assets that may be divested in connection with indigenous licensing rounds.

On 25 August 2009, Afren announced that it had entered into a farm-out agreement with Addax for the development of the Okwok field, located in OML 67 offshore Nigeria, in consideration for Afren agreeing to drill one appraisal well in the farm-out area and paying all costs associated therewith. Under the terms of the farm-out agreement, Afren as technical adviser, will acquire a 28 per cent. legal interest and a 70 per cent. effective working interest (before cost recovery), reverting to 56 per cent. (after cost recovery) pre hurdle point and 35 per cent. (after cost recovery) post hurdle point, subject to gross volumes lifted. The hurdle point is the period following the cost recovery period when available petroleum lifted equals US\$1.2 billion in value. The assignment of Addax's interests is not effective until Afren completes the drilling of the well. Afren is required to have completed the drilling of the well by 31 March 2011. Afren was also granted an

option, exercisable within six months after the drilling of the appraisal well is complete (and, if Afren elects, the production testing of one or more of the crude oil bearing sections of that well), to purchase Addax's residual interest in the project.

On 3 November 2009, Afren announced a drilling update on the Ebok-5 appraisal well and approval by the Department of Petroleum Resources of Phase 1a of the field development plan for Ebok.

On 10 November 2009, the Company announced a placing to institutional investors of 129.5 million New Shares and the sale of 24.5 million Founder Shares at a placing price of 81 pence per Ordinary Share to raise approximately £104.9 million (US\$175 million) in proceeds for the Company (before expenses).

On 10 November 2009, holders of 40,000,000 warrants over Ordinary Shares exercised their warrants at an exercise price of 37.95 pence per warrant, raising approximately £15 million (US\$25 million) for the Company.

On 3 December 2009, Afren's Ordinary Shares were admitted to the Official List and to trading on the main market of the London Stock Exchange.

On 12 January 2010, the Company announced the successful completion and outcome of the Ebok-6 appraisal well. The Ebok-6 appraisal well was drilled by the Transocean Adriatic IX jack up drilling unit to a total depth of 4,296 ft md on the Ebok D2 Southern Lobe, with drilling operations completed on 27 November 2009. The well encountered a greater than expected total gross hydrocarbon column of 107 ft (comprising 82 ft in the D2 and 25 ft in the LD1A reservoirs).

On 28 January 2010, the Company announced that it had entered into a Joint Venture Agreement with Oriental Energy Resources Limited and Energy Equity Resources for participation in the exploration, appraisal and development of OML 115 offshore South East Nigeria, adjoining the Ebok and Okwok development area. Under the terms of the farm-in agreement with EER, Afren, as Technical Advisor, will acquire a 32.5 per cent. legal interest. The effective economic interest of between 77 and 100 per cent. reverts to between 81.25 and 65 per cent. (post cost recovery associated with the initial exploration work programme). Following cost recovery by both Afren and EER, Afren's effective economic interest will revert to between 32.5 and 40.625 per cent. of field revenues. Afren has undertaken to fund the drilling of one exploration well, after which Afren and EER will jointly fund costs *pro-rata* (81.25 per cent. and 18.75 per cent. respectively).

On 17 March 2010, Afren and its partners Oriental Resources and Amni International Petroleum Development Company, signed a contract with Transocean for the GSF High Island VII jack up rig, to carry out planned drilling of their assets located in offshore south east Nigeria. The contract duration is for 210 days at an operating rate of \$84,000 per day.

On 25 March 2010 the Company announced that it had finalised arrangements for a new up to US\$450 million reserves based lending (RBL) debt facility. The up to US\$450 million of RBL debt has a maturity of maximum five years, is repayable semi-annually and has a margin of between 4 per cent. to 5.5 per cent. over LIBOR. The three Mandated Lead Arrangers and Technical Banks, BNP Paribas, Crédit Agricole Corporate and Investment Bank and Natixis will support the development funding of the Ebok field to establish initial production. Subject to certain conditions being met, the Facility shall extend to the development funding of subsequent phases of the Ebok field, the Okwok field, OML 115, or other development projects located in Oil Mining Lease 67, offshore Nigeria. The facility has been secured against Afren's share of production from the Ebok field, with the borrowing base being determined by the Project reserves, based on the assessment of Netherland, Sewell & Associates, Inc and the Technical Banks' assessments.

On 29 March 2010, the Company announced its full year results for the period ending 31 December 2009. The Company reported a normalised profit after tax of US\$50.6 million, cash at bank of US\$321 million and gross debt of US\$267 million, representing a net cash position at end 2009 of US\$54 million.

On 25 June 2010, Afren announced that the Ebok deep exploration well located on OML 67 has been drilled to a depth of 11,375 feet (10,085 feet true vertical depth). The well, which has been temporarily abandoned,

has suggested high quality reservoir sands in the Biafra and Isongo formations for which further technical worked is planned.

On 15 July 2010, the Company announced that terms had been agreed to acquire Energy Equity Resources' remaining 7.5 per cent. licence interest in OML 115. Following completion of that transaction, Afren's interest will increase to 40 per cent.

4. Summary of Reserves and Resources

NSAI has produced a report, dated the date hereof with an effective date of 30 June 2010, which is set out in Part 11 of this Prospectus, on Afren's reserves and resources as at 30 June 2010 the results of which are summarised below. NSAI has not included the Okwok field, OPL 907, OPL 917 and Ofa in its assessment as at 30 June 2010.

Reserves

NSAI has estimated the proved, probable and possible reserves and future revenue to the Afren interest in the Okoro field located in OML 112 and in the Ebok Field located in OML 67, Gulf of Guinea, offshore Nigeria and in the Lion and Panthère fields located in Block CI-11, offshore Côte d'Ivoire.

The table below sets out NSAI's estimated oil and gas reserves and future revenue to the Afren interest in the following assets as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

<i>Area/ Field/ Category</i>	<i>Afren Effective Working Interest Reserves before Royalty</i>		<i>Net Entitlement Reserves⁽¹⁾</i>		<i>Future Net Revenue (MM\$)</i>	
	<i>Oil (MMB BL)</i>	<i>Gas (BCF)</i>	<i>Oil (MMB BL)</i>	<i>Gas (BCF)</i>	<i>Total</i>	<i>Present Worth at 10%</i>
Offshore Nigeria						
Okoro Field						
Proved (1P)	9.3	(2)	7.6	(2)	214.4	191.6
Proved + Probable (2P) ⁽³⁾	13.5	(2)	11.0	(2)	330.1	283.1
Proved + Probable + Possible (3P)	16.9	(2)	13.8	(2)	419.7	348.9
Ebok Field						
Proved (1P)	43.5	(2)	38.0	(2)	863.7	673.7
Proved + Probable (2P) ⁽³⁾	62.0	(2)	53.8	(2)	1,209.1	878.9
Proved + Probable + Possible (3P)	76.7	(2)	66.4	(2)	1,540.8	1,039.1
Offshore Côte d'Ivoire						
Lion and Panthère fields						
Proved (1P)	0.4	10.4	0.3	5.7	22.9	23.6
Proved + Probable (2P) ⁽³⁾	0.7	17.0	0.4	10.0	34.5	34.0
Proved + Probable + Possible (3P)	0.9	25.0	0.5	14.5	61.2	51.9

(1) Net reserves are after deductions for royalty burdens.

(2) Gas reserves are not included because there is currently no viable market for produced gas.

(3) Proved + probable (2P) reserves have been prepared in accordance with the definitions and guidelines set forth in the 2007 PRMS approved by the SPE.

Contingent Resources

NSAI has estimated the contingent resources for the Kudu, Eland and Ibex fields located in Block CI 01, offshore Côte d'Ivoire; the Obo Discovery, offshore Nigeria; São Tomé & Príncipe in JDZ Block 1; and the Setu field located in OML 112, Gulf of Guinea, offshore Nigeria as of 30 June 2010.

The table below sets out NSAI's estimated gross oil and gas contingent resources as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

<i>Gross (100%) Volumes (MMBBL)</i>						
<i>Area</i>	<i>OOIP</i>			<i>Contingent⁽²⁾ Oil Resources</i>		
	<i>Low</i>	<i>Best</i>	<i>High</i>	<i>Low</i>	<i>Best</i>	<i>High</i>
	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>
	<i>(1C)</i>	<i>(2C)</i>	<i>(3C)</i>	<i>(1C)</i>	<i>(2C)</i>	<i>(3C)</i>
Offshore Côte d'Ivoire	59.2	81.1	104.8	13.5	19.8	27.9
JDZ Block 1	80.8	123.4	173.8	24.4	42.5	67.0
Offshore Nigeria	5.1	6.3	8.0	1.1	1.5	2.0

<i>Gross (100%) Volumes (BCF)</i>						
<i>Area</i>	<i>OGIP</i>			<i>Contingent Gas Resources</i>		
	<i>Low</i>	<i>Best</i>	<i>High</i>	<i>Low</i>	<i>Best</i>	<i>High</i>
	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>
	<i>(1C)</i>	<i>(2C)</i>	<i>(3C)</i>	<i>(1C)</i>	<i>(2C)</i>	<i>(3C)</i>
Offshore Côte d'Ivoire	105.7	160.1	237.0	66.2	101.5	152.4
JDZ Block 1 ⁽¹⁾	—	—	—	—	—	—
Offshore Nigeria ⁽¹⁾	—	—	—	—	—	—

(1) Gas reserves are not included because there is currently no viable market for produced gas.

(2) Contingent resources are those quantities of petroleum that are estimated to be potentially recoverable from known accumulations but for which the projects are not yet considered mature enough for commercial development due to one or more contingencies.

The Group provides for depletion and amortisation of tangible fixed assets on a net entitlement basis, which reflects the terms of the licenses and agreements related to each field.

Prospective Resources

NSAI has estimated the prospective resources for the La Noubi Permit, onshore Congo; the Kudu and Ibex Fields in Block CI-01, offshore Côte d'Ivoire; Iris Marin and Ibekelia Licenses, offshore Gabon; Keta Block, offshore Ghana; JDZ Block 1; Ebok Field, offshore Nigeria and São Tomé & Príncipe JDZ, the Ebok field, offshore Nigeria; OML 115, offshore Nigeria and OPL 310, offshore Nigeria as of 30 June 2010 as summarised below. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

Oil

The table below sets out NSAI's estimated gross OOIP and unrisks prospective oil resources for the following assets as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

<i>Gross (100%) Oil Volumes (mmbbl)</i>						
<i>Area</i>	<i>OOIP</i>			<i>Unrisks Prospective Oil Resources</i>		
	<i>Low</i>	<i>Best</i>	<i>High</i>	<i>Low</i>	<i>Best</i>	<i>High</i>
	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>	<i>Estimate</i>
Onshore Congo	521.5	1,025.9	1,744.0	114.6	251.6	481.9
Offshore Côte d'Ivoire	17.4	48.6	93.3	4.2	12.0	24.2
Offshore Gabon	282.0	390.3	513.2	52.5	97.3	159.4
Offshore Ghana	722.4	2,416.7	8,061.2	153.9	604.2	2,299.5
JDZ Block 1	734.1	1,003.0	1,348.5	229.4	350.1	518.4
Offshore Nigeria	812.2	1,552.1	2,516.6	304.4 ⁽¹⁾	584.5 ⁽¹⁾	972.4 ⁽¹⁾

(1) These prospective volumes include condensate associated with the OPL 310 prospective gas resources.

Gas

The table below sets out NSAI's estimated gross OGIP and unrisks prospective gas resources for the following assets as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

Area	Gross (100%) Gas Volumes (bcf)					
	OGIP			Unrisks Prospective Gas Resources		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Offshore Côte d'Ivoire	197.4	544.9	949.6	157.5	436.1	763.6
Offshore Nigeria	1,358.0	2,115.8	3,129.3	991.1	1,565.3	2,373.5

5. Summary of future net revenue

NSAI has estimated the future net revenue to the Afren interest in the Okoro field located in OML 112, offshore Nigeria and in the Lion and Panthère fields located in Block CI-11, offshore Côte d'Ivoire, as of 30 June 2010 and to the Afren interest in the Ebok field located in OML 67, offshore Nigeria as of 30 June 2010. For further details please refer to the table setting out NSAI's estimated future revenue to the Afren interest in paragraph 4 above.

6. Overview of Assets

Afren currently has the following assets in its portfolio:

	<i>Legal Interest</i>	<i>Effective Working Interest</i>		<i>Fiscal system</i>	<i>Expiry</i>
		<i>Pre-Cost recovery</i>	<i>Post-cost recovery</i>		
Nigeria					
Okoro (OML 112)	0%	95%	50%	Royalty Tax Concession	12 February 2018
Setu (OML 112)	0%	95%	50%	Royalty Tax Concession	12 February 2018
Ebok (OML 67)	40%	100%	50%	Royalty Tax Concession	Initial term – May 2012
Okwok	28%	70%	56% ⁽¹⁾	Royalty Tax Concession	
OML 115	40%	100%	40%	Royalty Tax Concession	20 May 2019
OPL 310	40%	91%	21%/70% ⁽³⁾	Royalty Tax Concession	10 February 2019
OPL 907 ⁽⁷⁾	40% ⁽²⁾	51.25% ⁽²⁾	41% ⁽²⁾	PSC	20 February 2018
OPL 917 ⁽⁷⁾	42% ⁽²⁾	70% ⁽²⁾	42% ⁽²⁾	PSC	20 February 2018

	<i>Legal Interest</i>	<i>Effective Working Interest</i>		<i>Fiscal system</i>	<i>Expiry</i>
		<i>Pre-Cost recovery</i>	<i>Post-cost recovery</i>		
Ofa (OML 30) ⁽⁷⁾	32.5%	See Table 1		Royalty Tax Concession	Initial term – November 2009 (subject to regulatory review, renewal may be granted for a further period of 20 years)
Côte d’Ivoire					
CI-11	47.9592%	47.9592%		PSC	Typically 25 years from development approval
CI-01	65% ⁽⁴⁾	65% ⁽⁴⁾		PSC	Typically 25 years from development approval
Lion Gas Plant	100%	100%		100%	N/A
Ghana					
Keta Block	70%	70% ⁽⁵⁾		Royalty Tax Concession	18 February 2016
Congo-Brazzaville					
La Noumbi	14%	14%		PSC	Under renewal
JDZ					
Block 1	4.41%	4.41% ⁽⁶⁾		PSC	22 March 2013

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- (1) Afren’s interest is 56 per cent. pre hurdle point and post hurdle point Afren’s interest is 35 per cent. The hurdle point is the point following the Cost Recovery Period when available petroleum lifted equals US\$1.2 billion in value. The assignment of Addax’s interests is not effective until Afren completes drilling of the first approved well. Afren is required to have completed the drilling of the well by 31 March 2011.
- (2) Afren’s interests are held through AGER in which Afren holds an 80 per cent. economic interest in relation to current assets.
- (3) Afren’s interest is 21 per cent. during short period of Optimum (local partner) cost recovery period.
- (4) 65 per cent. direct interest and 15 per cent. additional rights.
- (5) 77.7 per cent. if GNPC is carried.
- (6) Indirect interest via 49 per cent. ownership of DEER.
- (7) The NSAI Report does not include an analysis of Afren’s Nigerian appraisal assets in the Anambra Basin (OPL 907 and 917) or Ofa (OML 30).

Table 1 – for Ofa, Afren's effective working interest depends upon its cumulative production as follows:

<i>Cumulative Production (mmbbls)</i>	<i>Effective Working Interest</i>
0	50%
5	32.50%
10	26.50%
15	22.50%
20	20%
30	15%

7. Production

Afren is currently producing oil from the Okoro field located in OML 112, offshore Nigeria and oil and gas from the Lion and Panthère fields in Block CI-11, offshore Côte d'Ivoire, as well as processing gas at the Lion Gas Plant in Côte d'Ivoire.

The Group reported full year average net production in 2009 of 22,100 boepd of oil, natural gas and natural gas liquids from the Okoro field in Nigeria, Block CI-11 and the Lion Gas Plant in Côte d'Ivoire respectively.

At the Okoro field, crude oil exports continue to run smoothly via the nearby Ima terminal, where the increased storage capacity (in excess of 1 mmbbls) provides a benefit through the sale of increased parcel sizes and improved shipping and sales economics. The year to 30 June 2010 gross production at Okoro was 3,229,178 bbls (average gross 17,841 bopd). Management is considering two infill drilling wells on Okoro, which are expected to add incremental gross production of 3,000 bopd to 5,000 bopd.

In Côte d'Ivoire, gross production at block CI-11 for the year to 30 June 2010 was 4,837,202 mcf and 220,552 bbls, equivalent to average gross daily production rates of 26.7 mmcf/d and 1,219 bopd respectively. Over the same period natural gas liquid output at the Lion Gas Plant was equivalent to an average gross daily production rate of 654 boepd. Production in Côte d'Ivoire over the first quarter of 2010 was impacted due to maintenance work involving the low pressure compressor on the Gulf tide production platform and turbo expander at the Lion Gas Plant. Following completion of necessary work, gas production at CI-11 was restored to a gross rate of 30 mmcf/d in April 2010. The Lion Gas Plant also received reduced third party inlet volumes over the period as a result of work on the gas compression systems at the CNR operated Espoir and Baobab facilities.

At CI-11, a major mapping and seismic re-interpretation exercise has been undertaken applying current understanding of regional Upper Cretaceous depositional systems. The final results of this study will assist in defining plans to access and produce incremental oil and gas reserves.

Development of the Ebok field offshore south east Nigeria is underway, with first oil expected in the fourth quarter of 2010.

Oil Production

The Group achieved first oil in the Okoro field in June 2008 at a rate of 3,000 bopd, rising to approximately 22,000 bopd by the end of 2008. In 2009, gross production at the Okoro field averaged 18,800 bopd. At the Okoro field, the year to 30 June 2010 production was 3,229,178 bbls on a gross basis (average gross 17,841 bopd). Oil production at Block CI-11 to 30 June 2010 was 1,219 bopd on a gross basis.

The following table sets out the number of production wells drilled since 2008, together with the average crude oil production and total production estimates until 30 June 2010:

	<i>2008</i>	<i>2009</i>	<i>H1 2010</i>
Production wells	16	16	16
Average crude oil production (bopd)	4,350	20,600	19,059
Total production (mmbbls) (crude oil/condensate, gas, LPG)	3.42	9.4	4.4

The following table sets out the actual number of wells drilled since 2007, together with the number of wells management anticipates will be drilled through 2010:

	2007	2008	2009	2010
Number of exploration wells drilled	2	2	4	4
Number of production wells drilled	0	7	0	11
Total wells	<u>2</u>	<u>9</u>	<u>4</u>	<u>15</u>

Gas Production

Natural gas production at the Lion and Panthère fields in Block CI-11 in 2009 was 10.9 bcf (gross), equivalent to an average gross daily production rate of 30.7 mmcf/d. At the Lion and Panthère fields, year to 30 June 2010 production was 4.8 bcf (gross), equivalent to an average gross daily production rate of 26.7 mmcf/d.

The Lion Gas Plant in Côte d'Ivoire was built to improve margins by extracting and selling high value natural gas liquids from gas produced at Block CI-11. Gas production from adjacent Blocks CI-26 and CI-40, operated by Canadian Natural Resources Limited, was added to the process stream, providing third party tariff revenue from the use of the Block CI-11 pipeline infrastructure, and additional gasoline and butane sales revenue at the Lion Gas Plant.

In 2009 average daily NGL output at the plant averaged 1,143 boepd. During the period to 30 June 2010, 654 boepd of NGLs were stripped from the inlet gas stream at the Lion Gas Plant from a process stream of rich gas produced at Blocks CI-11, CI-26 and CI-40. Inlet volumes received at the Lion Gas Plant were significantly reduced during the first half of 2010 as a result of maintenance work on gas compression facilities at CI-11 and also the CNR operated Espoir and Baobab fields. With a total inlet capacity of 75 mmcf/d, the produced butane is sold into the local market at a price of US\$248 per metric ton with the gasoline spiked into the Block CI-11 crude stream and sold onto the open market.

8. Description of Business and Operations

8.1 *Regional Setting*

All of Afren's current interests lie in sedimentary basins along the West African margin. This margin was created by the rifting of South America from Africa, beginning in the earliest Cretaceous, and the subsequent opening of the South Atlantic. All basins share a history of early Cretaceous extension or transtension, followed by deposition of a later Cretaceous to Tertiary 'post-rift' sequence. The early extensional tectonics created depocentres and structural trapping geometries. In most cases, the post-rift sequence has been modified to some extent by later tectonic or halokinetic processes, created further potential structural and stratigraphic trapping configurations for hydrocarbons.

Compared with other deepwater regions such as the Gulf of Mexico, Africa's Atlantic margin is relatively under-explored. There are high expectations of discovery from the pre-salt succession in the deepwater of the Lower Congo Basin of Angola and Congo-Brazzaville and the pre-salt structures in deepwater Gabon are believed to contain gas. In the Gulf of Guinea, there is potential in Côte d'Ivoire and Ghana where the Jubilee field was discovered in 2007.

Black Marlin currently owns equity in assets in Seychelles, Madagascar, Kenya and Ethiopia. Further details are set out in Part 2 of this Prospectus.

8.2 *Nigeria*

Regional Overview

With a production capacity of over 3.2 million bopd, Nigeria is the largest producer in Africa and the fifth largest in OPEC (Source: IHS Global Insight Report: Nigeria (Energy)). According to the BP Statistical Review of World Energy (June 2010), Nigeria holds the second largest oil reserves and the largest natural gas reserves in Africa. In addition, according to the BP Statistical Review of World Energy (June 2010), Nigeria holds the eighth largest natural gas reserves in the world. Most of Nigeria's 36 billion barrels of proven oil reserves are located onshore, in over 250 fields of around

50 million barrels each, along the coast of the prolific Niger Delta region (Source: IHS Global Insight Report: Nigeria (Energy)). The country is heavily dependent on its oil industry and oil revenue accounts for over 95 per cent. of foreign-exchange earnings and 65 per cent. of government revenue (Source: US Department of Energy, Energy Information Administration). The Nigerian government has set a target of achieving four million bopd, but is unlikely to achieve this target until 2012, at the earliest. According to the BP Statistical Review of World Energy (June 2010), the country is estimated to have in excess of 185 tcf in gas reserves and the Federal Government has introduced a gas master plan that will end gas flaring and monetise its resources. Nigeria is pursuing a number of new policy directions with the aim of restructuring its upstream and deregulating its downstream sectors. The most significant issue facing Nigeria is the continued violence and militant activity in the Niger Delta region, which has led to long term shut ins of up to 40 per cent. of the country's production capacity (Source: IHS Global Insight Report: Nigeria (Energy)).

According to the BP Statistical Review of World Energy (June 2010), in 2009, Nigeria produced an average of 2.06 million bopd and 2.6 per cent. of the world total. In 2008 two licences were awarded in Nigeria, both to Afren for onshore blocks in the Niger Delta and the Anambra Basin, and 11 wells were drilled in the country (Source: Wood Mackenzie, Upstream Insight, Sub-Sahara Africa exploration review 2008 (February 2009)).

2009

Production in Nigeria

Total oil production (thousand bopd)	2,061
Natural gas production (bcf)	879

Reserves in Nigeria

Oil proved reserves (billion barrels)	37.2
Natural gas proved reserves (tcf)	185.4

Source: BP Statistical Review of World Energy (June 2010), US Department of Energy, Energy Information Administration.

Summary of Afren's Operations in Nigeria

Nigeria	Local Partner	Work Programme
Okoro (OML 112)	Amni	Production
Setu (OML 112)	Amni	Appraisal
Ebok (OML 67)	Oriental	Development/Appraisal
OML 115	Oriental	Exploration
OPL 310	Optimum	Exploration
OPL 907	GEC	Appraisal
OPL 917	GEC	Appraisal
Ofa (OML 30)	IEL	Appraisal
Okwok (OML 67)	Oriental	Appraisal/Exploration

Reserves – offshore Nigeria

NSAI has estimated the proved, probable and possible reserves to the Afren interest in the Okoro field located in OML 112, offshore Nigeria and to the Afren interest in the Ebok field located in OML 67, offshore Nigeria as of 30 June 2010.

The table below sets out NSAI's estimated net oil and gas reserves in the Okoro field and the Ebok field as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

<i>Country/Category</i>	<i>Net Working Interest Reserves⁽³⁾</i>	
	<i>Oil (mmbbl)</i>	<i>Gas (bcf)</i>
Offshore Nigeria⁽²⁾		
Okoro Field ⁽²⁾		
Proved (1P)	9.3	(1)
Proved + Probable (2P)	13.5	(1)
Proved + Probable + Possible (3P)	16.9	(1)
Ebok Field ⁽²⁾		
Proved (1P)	43.5	(1)
Proved + Probable (2P)	62.0	(1)
Proved + Probable + Possible (3P)	76.7	(1)

(1) Gas reserves are not included because there is currently no viable market for produced gas.

(2) Oil reserves for offshore Nigeria include crude oil only.

(3) Net working interest reserves are before deductions for royalty burdens.

Resources – offshore Nigeria

NSAI has estimated the contingent resources in the Setu field located in OML 112, offshore Nigeria as of 30 June 2010.

NSAI has estimated the prospective resources for the Ebok field, offshore Nigeria, OML 115, offshore Nigeria and OPL 310, offshore Nigeria as of 30 June 2010. In its assessment NSAI estimates gross unrisked best estimate prospective resources at block OPL 310 of 521 mmboe, and estimates gross unrisked best estimate prospective volumes of 128.3 mmbbl and 205.5 mmbbl at the Ebok field and OML 115 respectively.

The table below sets out NSAI's estimated gross OOIP and contingent oil resources, estimated gross OGIP and contingent gas resources, estimated gross OOIP and unrisked prospective oil resources and estimated gross OGIP and unrisked prospective gas resources in offshore Nigeria as of 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus

<i>Resources</i>	<i>Gross (100%)</i>					
	<i>OOIP (mmbbl)/OGIP (bcf)</i>			<i>Resources (mmbbl)/(bcf)</i>		
	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>
Contingent Resources – Oil	5.1	6.3	8.0	1.1	1.5	2.0
Contingent Resources – Gas ⁽¹⁾	–	–	–	–	–	–
Unrisked Prospective Resources – Oil	812.2	1,552.1	2,516.6	304.4 ⁽¹⁾	584.5 ⁽¹⁾	972.4 ⁽¹⁾
Unrisked Prospective Resources – Gas (Offshore)	1,358.0	2,115.8	3,129.3	991.1	1,565.3	2,373.5

(1) Gas resources are not included because there is currently no viable market for produced gas.

(2) These prospective volumes include condensate associated with the OPL 310 prospective gas resources.

Okoro and Setu Fields (OML 112) – Afren’s first greenfield development

Overview of Licence

		<i>Afren's Legal</i>	<i>Afren's Effective</i>	
		<i>Interest</i>	<i>Working Interest</i>	
<i>Licence details – Okoro and Setu (OML 112)</i>			<i>Pre-cost</i>	<i>Post-cost</i>
Area km²:	438	0%	<i>recovery</i>	<i>recovery</i>
Expiry:	12 February 2018			
Licence type:	Royalty Tax Concession			
Main plays:	Tertiary Agbada reservoirs			
Partner:	Amni			
2010 work programme:	Ongoing wellhead and FPSO preventative maintenance programmes and infill drilling			
Future work programme:	Ongoing wellhead and FPSO preventative maintenance programmes			
Data available:	3D seismic data. Exploration, appraisal and production well data plus oil and gas production data. Downhole temperature and pressure data			

Background

The Okoro and Setu fields are two oil and gas fields located within OML 112 in shallow water in the eastern part of the offshore Niger Delta. OML 112 was originally awarded to Amni in 1990 as part of the Nigerian government’s indigenous licensing programme.

In March 2006, Afren and AERL entered into a Production Sharing and Technical Services Agreement with Amni to appraise and develop the Okoro and Setu fields within a defined area in the eastern part of the OML 112 block. The majority of Afren’s obligations were subsequently novated to Afren Okoro. Under the terms of this agreement, Afren Okoro financed the appraisal and development programme and will recover costs preferentially, with an eight per cent. uplift on its capital, from oil production revenue until payback is achieved. Thereafter, profit oil will be shared equally between AERL and Amni.

Field Technical Background

The Okoro field was discovered in 1973 by Japan Petroleum with the drilling at the Okoro-1 well. The full potential of the field was not recognised until some complex subsurface velocity anomalies were resolved. Between September and December 2006, Amni and Afren appraised the Okoro field in the area of the velocity anomalies with the Okoro-3 and Okoro-3 Side Track (ST) wells. Okoro-3 encountered oil in the “Upper Hydrocarbon Sands”, and Okoro-3ST found both the “Upper and Lower Hydrocarbon Sands” to be oil-bearing. This well and the sidetrack confirmed the potential size and extent of the field. The intersected reservoir sands had excellent porosity in the 30-35 per cent. range and multiple-Darcy permeability recorded. The Okoro oil was found to be approximately 25° API with low viscosity and a low GOR.

These successful results allowed Amni and Afren to move forward with a field development plan for the Okoro field, which was approved by the Nigerian Government in March 2007. Afren and Amni estimate combined P50 oil reserves for the Upper and Lower Sands in the Okoro field of 28.9 mmbbls.

Exploration and appraisal drilling at the Setu field was conducted by Amni with the Setu East-1 and Setu East-2 wells in 2002. Five oil-bearing zones were encountered in the Agbada formation and all were successfully tested at rates above 1,900 bopd. 90 per cent. of the oil in-place volumes in the Setu field are located in the 7402 sand which makes the tie-back of the relatively modest oil volumes easier to undertake.

An appraisal well, Setu East-2 was drilled approximately 2.7 km west-southwest of the Setu East-1 well by Amni in 2002 but was not successful. Further analysis of the Setu field has been undertaken and revised development scenarios are being evaluated by Afren and Amni. It is expected that production will be focused from the 7402 sand reservoir where 90 per cent. of the field reserves are accounted for. NSAI estimates gross 2C contingent resources of 1.5 mmbbls at Setu, assuming three of the five zones are developed.

The independent reserves audit completed by NSAI estimated proved net oil reserves of 9.3 mmbbls for the Okoro field and proved plus probable reserves of 13.5 mmbbls as at 30 June 2010.

Field Development

In September 2006, AERL signed a nine month drilling contract for the Global Sante Fe Adriatic VI jack-up drilling rig to carry out development drilling on the Okoro and Setu fields.

The initial field development plan, approved by the partners and the Nigerian authorities, called for the drilling of five horizontal wells from a wellhead platform location with fluids to be transported via flexible pipelines to a FPSO. Afren's ongoing reservoir simulation work indicated that incremental oil volumes could be accessed if a further two horizontal production wells were added to the programme. The two additional wells were approved and drilled within the existing Global Santa Fe Adriatic IV jack-up drilling rig contract. The drilling rig arrived in late January 2008 and commenced operations shortly afterwards. With the sub-sea template installed, the rig began operations on the first two wells targeting the Lower Hydrocarbon sands. Additional data was also acquired to refine existing sub-surface uncertainties.

Afren elected to build the wellhead platform. The wellhead platform and subsea template structures were all designed in the UK and constructed by a Nigerian contractor, CMES, at the naval dockyard in Lagos.

The wellhead platform was installed in May 2008 and commissioned throughout June 2008, when the flowlines connecting it to the FPSO were also installed. Three flowlines were laid between the wellhead platform and field production unit, the Amada Perkasa FPSO. These comprised an 8" export line, a 6" test line and a 4" gas-lift line.

The Armada Perkasa FPSO, operating under a five-year contract by Malaysian conglomerate Bumi Armada Berhad, was spread-moored approximately 800m south-east of the field. The 72,000 dwt vessel was built in 1975 as a trading tanker and converted for FPSO duty 12 years ago. It has an oil storage capacity of 380,000 barrels and a processing capacity of 27,000 barrels of liquids a day, producing stabilised crude for storage inside the vessel. Sales of the produced oil are made via export tankers which moor up behind the FPSO to receive the stabilised crude oil via a 11" offloading hose. Two gas-lift compressors provide a total of 20 mmcf/d for gas-lift activities for the production wells. Associated gas will be used for gas-lift, to aid well productivity when the field begins to produce water.

The Armada Perkasa FPSO's crew is made up mainly of Nigerian nationals, many from the onshore community local to the Okoro field. Work required to upgrade the FPSO for Okoro specific duty, including the installation of a 10 point fixed mooring system, commenced in July 2007 and was completed in January 2008. The vessel arrived in Nigeria in March 2008.

Due to the unconsolidated nature of the reservoir, sand control screens were used in the well completions. Down hole gauges were also installed in all wells to allow careful monitoring of the reservoir pressures and so optimise the deliverability of the individual wells.

First oil from the first two production wells in the Okoro field was achieved on 10 June 2008 when production commenced from the first two production wells at a rate in excess of 3,000 bopd of 27°API gravity oil, in line with expectations. With the batch drilling of a further three wells, production was increased to approximately 16,000 bopd, and then to 22,000 bopd with no water when the final two production wells were installed in December 2008.

In late June 2009, Afren began to observe minor water production from two of the seven production wells. This is consistent with the dynamic reservoir model and in line with anticipated field performance. Continuing sub-surface and reservoir management work has identified two attractive infill drilling locations that will add incremental reserves and production, utilising the two remaining well slots available at the Okoro wellhead platform. Management is considering infill drilling which is expected to add incremental gross production volumes of between 3,000 bopd to 5,000 bopd. Work is also continuing on defining the best option to economically produce the oil reserves at the Setu field.

Ebok (OML 67)

Overview of Licence

		<i>Afren's Effective Working Interest</i>		
		<i>Afren's Legal Interest</i>	<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>
<i>Licence details – Ebok (OML 67)</i>				
Area km ² :	42	40%	100%	50%
Expiry:	Initial term – May 2012			
Licence type:	Royalty Tax Concession			
Main plays:	Tertiary Agbada 'D' series of reservoirs, Qua Iboe, Biafra and Isongo formations			
Partner:	Oriental			
2010 work programme:	Phase 1; Field development, exploration and appraisal drilling			
Future work programme:	Phase 2; Ongoing field development, exploration and appraisal drilling			
Data available:	3D seismic data. Exploration and appraisal well data. Field studies			

Background

The Ebok field is an existing discovered, undeveloped field located in OML 67 approximately 55km offshore Nigeria in approximately 41m of water. The Ebok field was awarded to Oriental by the ExxonMobil/NNPC Joint Venture pursuant to a farm-out agreement between Mobil, NNPC and Oriental dated 25 May 2007. The farm-out agreement has been structured such that the Ebok field benefits from the Nigerian marginal field fiscal and tax regime.

On 31 March 2008, Afren Resources signed a farm-in agreement with Oriental. Under the terms of the farm-in agreement, Afren Resources is responsible for funding all capital and operating costs for the development of the field, and will recover the costs from 100 per cent. of net field revenues. Following cost recovery, Afren Resources and Oriental will share net revenues equally. Afren Resources and Oriental entered into a collaboration agreement pursuant to the provisions of the farm-in agreement to pursue other potential development assets in the region.

Field Technical Background

The Ebok-1 discovery well was drilled by the ExxonMobil/NNPC Joint Venture in 1968. A total of 271ft of net oil pay was encountered in Ebok-1 in four sands between 2,600ft and 3,600ft. Although the zones were not production tested, 23°API gravity oil was recovered from the Ebok-1 well. The Ebok-2 (oil) and Ebok-3 (drilled off structure) wells were subsequently drilled in 1970. The Ebok area is also covered with 3D seismic data from 1992 to complement the data set available from the wells drilled to date.

Ebok is also located close to the ExxonMobil/NNPC Joint Venture producing fields and is 55km south-east of ExxonMobil's onshore QIT Terminal. The initial estimated STOIP at the field prior to the last quarter of 2008 appraisal drilling was 77-167 mmbbls with a mean of 118 mmbbls, of which 25 mmbbls was estimated by management as recoverable.

Operations Update

Ebok-4, drilled by the Transocean Trident IV jack-up drilling unit, was spudded on 24 November 2008. The well reached a measured depth of 3,838ft on 17 December 2008.

The well encountered a total gross oil column of 284ft in high-quality reservoir sands ranging in depth from 2,560ft to 3,718ft. Of these gross pay intervals, 274ft is calculated as net oil pay. After an extensive logging and sampling programme, drill stem testing delivered a rate of 1,450 bopd of 20° to 25° API crude oil. Well test analysis indicated that high skin conditions, which restrict oil flow into the well bore, were prevailing over the test interval and as such constrained the surface flow rates. Well test analysis and dynamic reservoir simulation modelling confirmed that flow rates of approximately 3,500 bopd per well in a production scenario will be achieved. This is also consistent with offset production data from analogous fields in the area.

Ebok-5 was drilled by the Transocean Adriatic IX jack-up drilling unit. The well reached a measured depth of 3,743 ft and was completed on 17 November 2009.

The well was drilled on the West Fault Block area of the Ebok field and encountered a total gross oil column of 377 ft (comprising 323 ft in the D1 and LD-1E reservoir sands, in addition to a further 54 ft of gross oil pay in the D2 and LD-1F reservoirs) well in excess of pre-drill expectations.

Ebok-6 was drilled by the Transocean Adriatic IX jack-up drilling unit. The well reached a measured depth of 4,296 ft and was completed on 27 November 2009.

The well targeted the Southern Lobe area of the Ebok field and encountered a significantly greater than expected total gross hydrocarbon column of 107 ft (comprising 82 ft in the D2 and 25 ft in the LD1A reservoirs). The D2 reservoir was encountered in line with expectations, with additional pay and increased volumes proven in the LD1A reservoir.

The Ebok-4, Ebok-5 and Ebok-6 well results have led to a substantial increase in reserves and resources initially estimated for the Ebok field. As at 30 June 2010, NSAI estimates gross 2P recoverable reserves at the Ebok field of 101.5 mmbbls with additional gross unrisks best estimate prospective resource potential of 128.3 mmbbls also identified.

On 25 June 2010, Afren announced that the Ebok deep exploration well located on OML 67 has been drilled to a depth of 11,375 feet (10,085 feet true vertical depth). The well, which has been temporarily abandoned, has suggested high quality reservoir sands in the Biafra and Isongo formations for which further technical work is planned.

Field Development Plan and Outlook

Following an announcement in September 2009 that Afren and Oriental had signed a rig contract with Transocean for the Adriatic IX jack-up drilling rig, drilling commenced on 25 September 2009 with the spudding of the Ebok-5 appraisal well and was followed by the drilling of the Ebok-6 appraisal well.

The Ebok Phase 1 development received development approvals from the Department of Petroleum Resources on 2 October 2009 and commenced in December 2009. The wellhead support structure (WSS) was installed at the field in March 2010, and the Transocean Adriatic IX jack up drilling rig is on location drilling ahead. The initial development phase consists of six horizontal production wells and one water injection well in the central Fault Block 1 and Fault Block 2 areas of the field with first oil expected in the fourth quarter of 2010.

In January 2010, production, processing and storage facilities for the Ebok development were contracted. The Virini Prem tanker is owned by Mercator, a major Indian shipping company, and has been converted into a floating storage offloading vessel (FSO). The vessel has been designed with a storage capacity of 1.2 million barrels and will be spread-moored near a mobile offshore production unit (MOPU). The selected pre-existing MOPU will have an initial oil production capacity of up to 50,000 bopd, an initial water injection capacity of up to 25,000 bwpd and initial gas lift/injection capacity of 9/6 mmcf/d and will also incorporate 2 x 3.5 MW gas turbine power generators, being fully compliant with DPR approved process design. The unit will process the total well fluids, producing stabilised crude for storage in the FSO with subsequent regular offtake by tanker. The FSO and MOPU will be leased to the Ebok development over an initial seven year period at a rate of US\$98,750 per day, with an option to extend.

Refurbishment and integration work on the MOPU is underway and the scope of work includes refurbishment to full ABS class requirements and the installation of production processing and accommodation modules. The FSO is undergoing conversion work in the Yulian shipyard in China. The scope of work includes the installation of new dual-fuel boilers and a DPR approved fiscal metering package. All work remains on schedule for first oil in the fourth quarter of 2010.

Opting for the MOPU and FSO development configuration has provided an estimated total cost saving of over US\$50 million in upfront costs and day rate charges compared to alternative FPSO solutions that were considered. Additionally, the selected configuration offers the most flexibility to efficiently and cost-effectively increase processing and storage capacity if required in the future.

Future development phases will target the West Fault Block (Phase 2, incorporating the installation of an additional dedicated wellhead platform (WHP) and six development wells tied back to the central Ebok MOPU and FSO facilities), the upside potential established in the Southern Lobe (Ebok 6), full development of the D1 reservoir in the Central Fault Block 1 and Fault Block 2 area of the field and any other commercial reserve additions from future exploration and appraisal drilling activity.

OML 115

Overview of Licences

			<i>Afren's Effective Working Interest</i>	
		<i>Afren's Legal Interest</i>	<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>
<i>Licence details – OML 115</i>				
Area km²:	228	40%	100%	40%
Expiry:	20 May 2019			
Licence type:	Royalty Tax Concession			
Main plays:	Tertiary Agbada 'D' series of reservoirs, Qua Iboe, Biafra and Isongo formations			
Partner:	Oriental			
2010 work programme:	Exploration drilling and subsurface studies			
Future work programme:	Ongoing exploration studies			
Data available:	3D seismic data. Exploration well data. Subsurface studies			

Background

OML 115 is located in the translational structural setting of the prolific offshore eastern Niger Delta (South East Nigeria), surrounding the Afren – Oriental operated Ebok and Okwok development area and close to the giant Zafiro Complex. The southern portion of the Okwok structure (Okwok South) extends into OML 115 and significant additional prospectivity has been defined within the channelized Qua Iboe system.

Following the farm-in to develop the nearby Ebok Field with Oriental in March 2008, Afren had entered into a collaborative agreement with Oriental to pursue other assets in the region. Afren subsequently farmed-in to the Okwok field in August 2009. In January 2010, Afren announced a Joint Venture Agreement with Oriental and Energy Equity Resources ('EER') to participate in the exploration, appraisal and development of OML 115. This represented another important milestone within the collaboration agreement. OML 115 benefits from the Nigerian Royalty Tax Fiscal terms.

Under the terms of the initial farm-in agreement with EER, Afren as Technical Advisor acquired a 32.5 per cent. legal interest. The effective economic interest of between 77 and 100 per cent. reverts to between 81.25 and 65 per cent. (post cost recovery associated with the initial exploration work programme). It was agreed that following cost recovery by both Afren and EER, Afren's effective economic interest will revert to between 32.5 and 40.625 per cent. of field revenues. Afren undertook to fund the drilling of one exploration well, after which Afren and EER would jointly fund costs *pro rata* (81.25 per cent. and 18.75 per cent. respectively).

On 15 July 2010, Afren announced that terms had been agreed to acquire Energy Equity Resources' remaining 7.5 per cent. licence interest in OML 115. Following the transaction, Afren's legal interest will increase to 40 per cent.

Outlook

The near-term work programme consists of detailed sub-surface technical studies to determine an optimum exploration well location, targeted for Q4 2010. NSAI has estimated gross unrisks best estimate prospective resources at OML 115 of 205.5 mmbbls. Afren is committed to drill one exploration well on the block by the end of Q1 2011.

OPL 310

Overview of Licences

			<i>Afren's Effective Working Interest</i>	
		<i>Afren's Legal Interest</i>	<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>
<i>Licence details – OPL 310</i>				
Area km ² :	1,850	40%	91%	21%/70% ⁽¹⁾
Expiry:	10 February 2019			
Licence type:	Royalty Tax Concession			
Main plays:	Cretaceous shelfal to deep water clastics in structural and stratigraphic traps over basement highs			
Partner:	Optimum			
2010 work programme:	Continued technical and commercial studies. Purchase of 2D and 3D seismic data, exploration drilling			
Furure work programme:	Farm down. Potential 3D seismic data acquisition in 2010. Development or exploration wells in late 2010 or 2011.			
Data available:	2D and 3D seismic and regional well data			

(1) Afren's interest is 21 per cent. during short period of Optimum's cost recovery period.

Background

OPL 310 is an exploration block situated in western Nigeria, adjacent to Chevron's Aje oil and gas field and with access to the newly completed West African gas pipeline. OPL 310 was awarded to indigenous company Optimum in 1993.

On 16 January 2009, Afren Investments entered into a farm-in agreement for a long term 70 per cent. working interest of the block with local partner Optimum. Afren is technical operator and holds a 40 per cent. legal interest, and a 21 per cent. short term and a 70 per cent. long term post cost recovery effective working interest in the block.

Outlook

Located adjacent to the highly prospective Aje field (declared a commercial discovery in February 2009), OPL 310 represents a high impact shallow to deep water exploration opportunity in the under explored west Nigeria offshore. The existing seismic database covering the area has been acquired, and work is ongoing to further assess the prospectivity of the block and finalise a drilling location with the intention of spudding a well during late 2010/2011. There are several prospects already identified in the Cenomanian, Turonian and Albian sandstone reservoirs, with trapping configurations typically 4-way dip closures over basement highs. As at 30 June 2010, NSAI estimates gross unrisked best estimate prospective resources for OPL 310 of 521 mmboe.

8.3 Nigeria – Additional Assets

The NSAI Report does not include an analysis of Afren's Nigerian appraisal assets in the Anambra Basin (OPL 907 and 917), Ofa (OML 30) and Okwok. Accordingly, no reserves or contingent resources have been presented in respect of these assets and all production data in respect of such assets is based on management's data.

Anambra Basin – OPL 907 and OPL 917

Background

Exploration activity occurred with some success in the Anambra Basin between the 1950s and the 1980s. Six discoveries were made from a total of 30 exploration wells, drilled without the benefit of modern seismic data techniques. The discoveries made were predominantly gas and were not followed up due to the lack of a gas market. The Anambra basin is under-explored and is considered to have potential gas resources in excess of five tcf. Recent initiatives launched by the Nigerian government in developing the country's gas resources have now made the Anambra Basin an attractive commercial proposition.

In February 2008, AGER entered into production sharing contracts for two licences in the Anambra Basin, onshore southeast Nigeria, OPL 907 and OPL 917. AGER holds the interest in these licences through a joint venture with Global Energy Company Limited of Nigeria. AGER holds a 41 per cent. interest in OPL 907 and a 42 per cent. interest in OPL 917, and acts as operator for both licences.

Overview of Licences

		<i>Afren's Effective Working Interest</i>		
		<i>Afren's Legal Interest</i>	<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>
<i>Licence details – OPL 907</i>				
Area km ² :	1,462	41% ⁽¹⁾	51.25%	41% ⁽¹⁾
Expiry:	20 February 2018			
Licence type:	PSC			
Main plays:	Late Cretaceous deltaic to shallow marine clastics in fault related traps			
Partner:	Buston, Allene, Kaztec, VP, De Atai, Bepta			
<i>Licence details – OPL 917</i>				
Area km ² :	2,285	42%	70%	42% ⁽¹⁾
Expiry:	20 February 2018			
Licence type:	PSC			
Main plays:	Late Cretaceous deltaic to shallow marine clastics in fault related traps			
Partner:	Petrolog, VP, De Atai, Goland			
2010 work programme:	2D seismic reprocessing			
Future work programme:	1,600km 2D seismic acquisition; 1 well (OPL 907) + 2 wells (OPL 917) in 2011/2012			
Data available	Limited 2D seismic and well data			

(1) Afren's interest is held through AGER in which Afren holds 50 per cent. in AGER.

OPL 907

Background

The OPL 907 licence covers an area of 1,462km² and has been only lightly explored to date with no notable exploration success. The first stage of the initial work programme includes collation and evaluation of existing data, followed by the acquisition of 2D seismic data and the drilling of one exploration well. Currently Afren is reprocessing 2D seismic data on the block in order to best define the new seismic acquisition programme.

The other joint venture participants are indigenous Nigerian companies: Buston Energy Resources Ltd (25 per cent.), Allenne Exploration & Production Ltd (14 per cent.), Kaztec Engineering Ltd (5 per cent.), VP Energy Ltd (3 per cent.), De Atai Oil Services International Ltd (2 per cent.) and Bepta Oil & Gas Ltd (10 per cent.).

OPL 917

Background

The OPL 917 licence covers 2,285 km² and contains the Igbariam discovery. The Igbariam-1 well was drilled by Shell/BP in 1971, with gas and condensate discovered in Cretaceous sandstones. A total of over 200 ft of net hydrocarbon pay was encountered but the well was not tested. Estimated in place volumes for the Igbariam discovery stand at 300 bcf and 80 mmbbls condensate, within the Turonian – Maastrichtian deltaic to shallow marine Nkporo formation. The first stage of the initial work programme includes collation and evaluation of the existing data, followed by the acquisition of 2D seismic data and the drilling of two exploration wells. Currently Afren is reprocessing 2D seismic data on the block in order to best define the new seismic acquisition programme.

The other joint venture participants are indigenous Nigerian companies: Petrolog Oil & Gas Ltd (18 per cent.), VP Energy Ltd (17 per cent.), De Atai Oil Services International Ltd (10 per cent.) and Goland Petroleum Development Company Ltd (13 per cent.).

Outlook

Together with its partners, Afren is currently finalising an environmental impact assessment programme ahead of the planned seismic acquisition programme across both blocks. It is also reprocessing all available 2D seismic data on the blocks to help better define the next phase of seismic acquisition on the blocks. Afren believes that OPL 907 and OPL 917 are capable of yielding up to ten drillable prospects of similar size to Igbariam with a probability of success ranging between 30 to 40 per cent. The main hydrocarbon plays consist of late Cretaceous deltaic to shallow marine clastics in fault related traps. Drilling is likely to commence on the two blocks in 2012, with one well initially on OPL 907 and two wells on OPL 917.

Ofa (OML 30)

Overview of Licence

			<i>Afren's Effective Working Interest</i>	
		<i>Afren's Legal Interest</i>	<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>
<i>Licence details – Ofa (OML 30)</i>				
Area km²:	52km²	32.5%	See table below	See table below
Expiry:	Initial term – November 2009 (subject to regulatory review, renewal may be granted for a further period of 20 years)			
Licence type:	Royalty Tax Concession			
Main plays:	Tertiary Agbada reservoirs			
Partner:	IEL			
2010 work programme:	Assessing potential for future field development			
Future work programme:	Assessing potential for future field development			
Data available:	3D seismic and well data plus field studies			

Afren's effective working interest depends upon its cumulative production as follows:

<i>Cumulative Production (mmbbls)</i>	<i>Effective Working Interest</i>
0	50%
5	32.50%
10	26.50%
15	22.50%
20	20%
30	15%

Background

The Ofa field is located in OML 30 onshore in the northern Niger Delta. In December 2006 Afren entered into a farm-in agreement with IEL for the appraisal and development of the Ofa field. Under the terms of this agreement (as amended and restated in October 2008), Afren is responsible for paying all costs for the development of the field, and will recover the costs from 90 per cent. of net field revenues.

The licence terminates at the end of the initial period and the DPR will then terminate if the operator cannot show verifiable progress. However, Afren believes that it has shown verifiable progress on the field by spudding a well and the investment it has made to date. No termination notice has been received by IEL, Afren's partner, to date, and Afren's partner and the JV operator are negotiating a replacement field to Ofa due to its non-commercial nature.

Field Technical Background

The Ofa field was discovered by Shell with the Ofa-1 well in 1970 and appraised by the Ofa-2 well, with up to eight potential oil bearing zones encountered. Shell completed the well in the deepest zone (N4000) in 1979 and unsuccessfully attempted to flow the well under natural depletion. The lack of flow was believed to be due to the heavy nature of the crude oil. Ofa was awarded to IEL as part of the 2003 marginal field licensing round.

In 2007, Afren carried out a test programme on three of the eight potential oil zones using a hydraulic workover rig. An electric submersible pump was used to supplement any natural flow in order to determine if commercial flow-rates could be achieved.

The lowermost zone (N4000) initially produced oil at rates up to 1,000 bopd but production was not sustained due to production of water. A second test of the N1000/M8800 zones was undertaken but despite initial minor oil production, the zones only produced formation water.

In October 2008 an amended and restated farm-in agreement was signed with IEL and IEL are in discussions with the farmers and the Nigerian Government on other field development options on Ofa or other marginal fields.

Outlook

Following these test results, Afren has decided not to proceed with development at the present time, but will assess with IEL the potential for other field development options.

The NSAI Report does not include an analysis of Afren's potential working interest in Ofa (OML 30). Accordingly, no reserves or contingent resources have been presented in the NSAI Report in respect of this asset.

Okwok (OML 67)

Agreement to develop the Okwok field

On 25 August 2009, Afren announced that it had entered into a farm-out agreement with Addax for the development of the Okwok field, located in OML 67 offshore Nigeria, in consideration for Afren agreeing to drill one appraisal well in the farm-out area and paying all costs associated therewith.

Under the terms of the farm-out agreement, Afren as technical adviser, will acquire a 28 per cent. legal interest and a 70 per cent. effective working interest (before cost recovery), reverting to 56 per cent. (after cost recovery) pre-hurdle point and 35 per cent. (after cost recovery) post-hurdle point, subject to gross volumes lifted. The hurdle point is the period following the cost recovery period when available petroleum lifted equals US\$1.2 billion in value. The assignment of Addax's interests is not effective until Afren completes the drilling of the well. Afren is required to have completed the drilling of the well by 31 March 2011.

Afren was also granted an option, exercisable within six months after the drilling of the well is complete (and, if Afren elects, the production testing of one or more of the crude oil bearing sections of that well), to purchase Addax's residual interest in the project.

Overview of Licence⁽¹⁾

		<i>Afren's Effective Working Interest</i>	
	<i>Afren's Legal Interest</i>	<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>
<i>Licence details – Okwok</i>			
Area km ² :	40	28%	70%
Expiry:	Initial term – 2011		56%
Licence type:	Royalty Tax Concession		
Main plays:	Tertiary Agbada 'D' series of reservoirs, Qua Iboe, Biafra and Isongo formations		
Partner:	Oriental, Addax, Petroleum		
2010 work programme:	Appraisal drilling to define commerciality and field development requirements		
Future work programme:	Field development, exploration and appraisal drilling		
Data available:	3D seismic data and well data plus field studies		

(1) This table assumes that Afren completes the drilling of the well by 31 March 2011 and Addax's interests under assigned to Afren pursuant to the terms of the farm-out agreement.

(2) Afren's interest is 56 per cent. pre-hurdle point and 35 per cent. post-hurdle point. Hurdle point is the point following the cost recovery period when available petroleum lifted equals US\$1.2 billion in value.

Background

The Okwok field is located in OML 67 offshore south east Nigeria, approximately 15 km east of the Ebok field development and adjacent to and surrounded by OML 115. In August 2009 Afren entered into a joint venture agreement with Oriental and Addax Petroleum for the appraisal and development of the Okwok field. Under the terms of the agreement, Afren as Technical Advisor, will acquire from Addax Petroleum a 28 per cent. legal interest and an effective 70 per cent. economic interest (pre cost recovery), reverting to 56 per cent. (post cost recovery), subject to gross volumes lifted. Afren has undertaken to fund the drilling of one exploration or appraisal well, after which Afren and Addax Petroleum will jointly fund field development costs *pro-rata* (70 per cent. and 30 per cent. respectively).

In 2001, Mobil Producing Nigeria Limited contributed Okwok to Nigeria's Marginal Field Program, which was established by the Nigerian government to encourage greater indigenous participation in the oil and gas sector. Pursuant to this program, Oriental completed a farm-in agreement for Okwok with Mobil and the Nigerian National Petroleum Corporation in May 2006. Addax Petroleum subsequently entered into a JVA with Oriental, acquiring a 40 per cent. interest in Okwok and assumed the role of Technical Advisor. The field benefits from the Nigerian Marginal Field Fiscal and Tax Regime.

Following the farm-in to develop the nearby Ebok Field with Oriental in March 2008, Afren had entered into a collaborative agreement with Oriental to pursue other assets in the region. The Okwok and OML 115 acquisitions represent important steps within this collaboration agreement, focused on a region where a large number of existing fields similar to Okwok and Ebok are good candidates for future development.

Field Technical Background

Okwok is an undeveloped oil field located in OML 67, 50 km offshore in 132 ft of water and 15 km east of the Afren/Oriental owned Ebok development.

The field was discovered by the ExxonMobil/NNPC JV in 1967 (Okwok-1), and two subsequent appraisal wells were drilled in 1968 (Okwok-2 and Okwok-3) but not production tested. The wells encountered oil in the LD1 and D2 series of reservoirs with over 100 ft of oil pay logged in the Okwok-2 well at the D2 level plus multiple 50 ft oil bearing sections in the LD1 in Okwok-1 and Okwok-2.

Oriental and Addax Petroleum drilled a further three wells in 2006 which found over 100 ft of oil pay in the D2 of Okwok-4st and an approximate equivalent amount of pay in the LD1 series in Okwok-8. The Okwok-4ST1 well sampled 32 API quality crude, while Okwok-8 tested 27°API quality crude oil at a rate of 1,200 bopd per day from the LD1 reservoir interval.

Outlook

Following the 2009 appraisal drilling success on the Ebok field and reserves upgrade by NSAI, Ebok offers significant synergies that will provide an optimal development solution for Okwok, providing scope for cost reduction and savings at both fields. Joint storage and export operations together with shared services are expected to result in reduced costs for the development of both fields. The near term work programme at Okwok consists of ongoing detailed subsurface studies to determine an optimum appraisal well location ahead of planned appraisal drilling in the second half of 2010.

8.4 *Nigeria – Offshore Nigeria and São Tomé & Príncipe (JDZ Block 1)*

Regional Overview

The São Tomé & Príncipe JDZ is in the centre of the Gulf of Guinea, a part of the Atlantic Ocean southwest of Africa, offshore Nigeria. The US National Intelligence Council projects that African oil imports will account for 25 per cent. of total US imports by 2015, primarily from Gulf of Guinea countries, Nigeria and Angola. The Gulf of Guinea is regarded by industry sources as one of the world's top oil and gas exploration regions and has the potential to be one of Africa's largest oil producers.

Overview of Afren's Operation in offshore Nigeria and São Tomé & Príncipe

Nigeria	Operator	Work Programme
JDZ Block 1 ⁽¹⁾	Total	Exploration

(1) Following an announcement on 15 July 2010, Total has signed an agreement to acquire Chevron's 45.9 per cent. interest in JDZ Block 1 and is now the operator.

JDZ Block 1

Resources – JDZ Block 1

NSAI has estimated the contingent and prospective resources for JDZ Block 1, offshore Nigeria and São Tomé & Príncipe JDZ as at 30 June 2010.

The table below sets out NSAI's estimated gross OOIP and contingent oil resources, estimated gross OGIP and contingent gas resources and estimated gross OOIP and unrisks prospective oil resources in JDZ Block 1 as at 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

	<i>Gross (100%)</i>					
	<i>OOIP (mmbbl)</i>			<i>Resources (mmbbl)</i>		
	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>
<i>Resources</i>						
Contingent Resources						
– Oil	80.8	123.4	173.8	24.4	42.5	67.0
Contingent Resources						
– Gas ⁽¹⁾	–	–	–	–	–	–
Unrisked Prospective Resources – Oil	734.1	1,003.0	1,348.5	229.4	350.1	518.4

(1) Gas resources are not included because there is currently no viable market for produced gas.

Overview of Licence

		<i>Afren's Legal Interest</i>	<i>Afren's Effective Working Interest</i>		
			<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>	
<i>Licence details – JDZ Block 1</i>					
Area km²:	704	4.41%	4.41%	4.41% ⁽¹⁾	
Expiry:	22 March 2013				
Licence type:	PSC				
Main plays:	Oligo Miocene deepwater clastics in toe thrust related traps				
Partner:	Chevron (Op.), Addax, Sasol, DEER				
2010 work programme:	Seismic reprocessing, continued geophysical studies.				
Future work programme:	Exploration well prior to licence expiry in 2014.				
Data available:	3D seismic data and well data				

(1) Indirect interest via 49 per cent. ownership of DEER.

Background

The São Tomé & Príncipe JDZ covers approximately 34,500 km² and was established in February 2001 upon the ratification of a formal bilateral treaty resolving overlapping maritime boundary claims of the two host nations, Nigeria and the island nation São Tomé & Príncipe, in the Gulf of Guinea. This treaty allocated 60 per cent. of the resources in the JDZ to Nigeria and 40 per cent. to São Tomé & Príncipe. The treaty expires in 2046, with a provision for review in 2036. The affairs of the JDZ are administered by the Joint Development Authority which was officially inaugurated in January 2002, and reports to a joint ministerial council.

JDZ Block 1 was awarded to a consortium of Chevron (51 per cent. and operator), Esso Exploration and Production Nigeria São Tomé “One” Limited (40 per cent.) and DEER (9 per cent.) in April 2004. The consortium members paid a signature bonus of US\$123 million for the right to develop JDZ Block 1 under a long-term production sharing agreement, which became effective on 22 March 2005. The Obo discovery is located in JDZ Block 1, in 1,720 m of water. The Obo-1 well was drilled by Chevron in 2006.

Outlook

The JDZ Block 1 participants have agreed to enter the next exploration period, and discussions with the Joint Development Authority are progressing. One commitment well will be required during this phase. In the neighbouring blocks a multi-well drilling campaign was undertaken, from which a much

clearer understanding of the next steps to commerciality and future exploration will come once the results of these wells are made available publicly.

On 15 July 2010, Total announced the signature of an agreement to acquire Chevron's 45.9 per cent. interest. Total is the operator of the nearby Akpo field, presenting development synergies with JDZ Block 1.

8.5 Côte d'Ivoire Regional

Overview

Gas forms the dominant source of power generation in Côte d'Ivoire, with current demand met by existing domestic production but with limited capacity to satisfy significant forecast demand growth over the medium to longer term. The gas reserves discovered in the 1980s have begun to be developed and utilised. The main producing fields include Lion, Panthère and Foxtrot. Côte d'Ivoire's recoverable oil reserves have been estimated at 100 million barrels and recoverable gas reserves at 1.0 tcf (Source: US Department of Energy, Energy Information Administration).

West African Transform Margin

The West African transform margin was formed by the rift separation of South America and Africa in the early Cretaceous. It is defined as an east-west trending segment almost 500 km long, bound to the east by the coastward extension of the Chain Fracture Zone and bound to the west by the coastward extension of the Romanche Fracture Zone. Regional structure is dominated by these southwest northeast fracture trends and the stratigraphy is largely comprised of rift, transitional, and drift sequences.

Côte d'Ivoire/Tano Basin

Several oil and gas discoveries have been made in the Côte d'Ivoire/Tano Basin, most notably, the Jubilee field. The post transform period in the Tano Basin has the same tectonic and stratigraphic history as the rest of the Côte d'Ivoire Basin. Late Cretaceous and younger rocks have been identified as having excellent hydrocarbon source potential. Within the Côte d'Ivoire/Tano Basin, excellent source rocks exist in the Cenomanian-Maastrichtian succession. Kerogen has also been found in smaller concentrations in Albian shales.

In the Côte d'Ivoire Basin/Tano Basin, good hydrocarbon reservoirs are found in the Late Albian to Middle Albian succession. Late Albian sandstones tend to have very high porosities, averaging about 23 per cent. Excellent quality reservoirs are found in the Aptian fluvial-lacustrine succession and Late Cretaceous to Tertiary sediment are found close to the coastal margin.

2009

Production in Côte d'Ivoire

Total oil production (thousand bopd)	58.9

Reserves in Côte d'Ivoire

Oil proved reserves (billion barrels)	0.10
Natural gas proved reserves (tcf)	1

Source: US Department of Energy, Energy Information Administration.

Overview of Afren's Operations in Côte d'Ivoire

	Working Interest	Local Partner	Work Programme
<i>Côte d'Ivoire</i>			
Block CI-11 (Lion and Panthère fields)	47.9592%	Petroci	Production
Block CI-01 (Kudu, Eland and Ibex fields)	65%	Petroci	Appraisal
Lion Gas Plant	100%	N/A	Production

Reserves – offshore Côte d'Ivoire

NSAI has estimated the proved, probable and possible reserves to the Afren interest in the Lion and Panthère fields located in Block CI-11, offshore Côte d'Ivoire as of 30 June 2010.

The table below sets out NSAI's estimated net oil and gas reserves to Afren's interest in offshore Côte d'Ivoire as at 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

<i>Country/Category</i>	<i>Net Working Interest Reserves⁽¹⁾</i>	
	<i>Oil (mmbbl)</i>	<i>Gas (bcf)</i>
Lion and Panthère Fields		
Proved (1P)	0.4	10.4
Proved + Probable (2P)	0.7	17.0
Proved + Probable + Possible (3)	0.9	25.0

(1) Net reserves on a working interest basis before deductions for royalty burdens.

Resources – offshore Côte d'Ivoire

NSAI has estimated the contingent resources for the Kudu, Eland and Ibex Fields in Block CI-01, offshore Côte d'Ivoire as at 30 June 2010 and the prospective resources for the Kudu and Ibex Fields in Block CI-01, offshore Côte d'Ivoire as at 30 June 2010.

The table below sets out NSAI's estimated gross OOIP and contingent oil resources, estimated gross OGIP and contingent gas resources, estimated gross OOIP and unrisked prospective oil resources and estimated gross OGIP and unrisked prospective gas resources in offshore Côte d'Ivoire as at 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

<i>Resources</i>	<i>Gross (100%)</i>					
	<i>OOIP (mmbbl)</i>			<i>Resources (mmbbl)</i>		
	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>
Kudu, Eland and Ibex Fields						
Contingent Resources – Oil	59.2	81.1	104.8	13.5	19.8	27.9
Contingent Resources – Gas	105.7	160.1	237.0	66.2	101.5	152.4
Kudu and Ibex Fields						
Unrisked Prospective Resources – Oil	17.4	48.6	93.3	4.2	12.0	24.2
Unrisked Prospective Resources – Gas	197.4	544.9	949.6	157.5	436.1	763.6

Block CI-11 (Lion and Panthère fields)

Overview of Licence

		<i>Afren's Legal Interest</i>	<i>Afren's Effective Working Interest</i>		
			<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>	
<i>Licence details – Block CI-11</i>					
Area km²:	77	47.9592%	47.9592%	47.9592%	
Expiry:	Typically 25 years from development approval				
Licence type:	PSC				
Main plays:	Albian, Senonian Maastrichtian channel sands				
Partner:	Petroci, CIPEM SK Energy				
2010 work programme:	Sub surface evaluation and wireline workovers				
Future work programme:	Infill drilling and workovers				
Data available:	2D and 3D seismic data plus well and field study data				

Background

The Lion and Panthère fields, contained within Block CI-11, are located approximately 13 km offshore Côte d'Ivoire in water depths ranging from 60m to 95m. The Lion and Panthère fields have been developed via a mobile offshore production platform and four tethered caissons. The oil and gas is piped to Abidjan, where the oil is sold on the open market and the gas is processed by the Lion Gas Plant and sold under two long term contracts to domestic end users, where it is used for power generation. Afren's partners in the block are Petroci, CIPEM and SK Energy Co Ltd (formerly SK Corporation).

Field Technical Background

The Lion field is predominantly oil and the Panthère field predominantly gas bearing.

The Lion field was discovered by Phillips in the 1980s with the drilling of the B1-7X and B1-8X wells. The B1-7X well proved the existence of the Lion sand reservoir with oil shows on the overall structural high. The B1-8X well flowed oil and gas at commercial rates from Senonian slope-canyon reservoirs.

Commercial delineation of the Lion field started in 1994 with the drilling of the Lion A-1 well. The Senonian accumulations were appraised in 1996 with the drilling of the Lion A-3 well. In 1996 a new oil reservoir in the Foxtrot section was found by the Lion A-4ST and a new oil reservoir in the Cenomanian was found by the Lion B-4ST. First production was established in 1995.

The Panthère gas field was originally discovered and delineated by Phillips in 1982, with the drilling of the B1-5X, B1-9X and B1-10X wells. The field was not developed at that time due to gas market constraints. Delineation of the field for commercial development began with the drilling of the Panthère C-1 well by UMC in 1993. UMC subsequently drilled the C-2, D-1 and D1A wells. The Panthère field commenced production in November 1995.

Operations Update and Production Outlook

As of 31 December 2009, Block CI-11 produced a total of 32.9 mmbbl of oil and 333.6 bcf of gas.

Gross oil and gas production at Block CI-11 during the full year 2009 was 1,230 bopd and 30 mmcf, equivalent to 6,360 boepd. Year to date gross production at block CI-11 to 30 June 2010 was 220,552

bbls and 4,837,202 mcf, equivalent to average gross daily production rates of 1,219 bopd and 26.7 mmcfd. Production was impacted over the period due to maintenance work involving the low pressure compressor on the Gulftide production platform. Following completion of the necessary work, gas production at CI-11 was restored to 30 mmcfd in April 2010.

Following the assumption of operating control by Afren in September 2008 an extensive facilities maintenance programme has been completed. Marine growth removal on the central platform and surrounding caisson structures was successfully carried out and work on the wellheads is ongoing prior to commencing planned wireline workovers in a number of the wells.

Subsurface evaluation work is also ongoing, focusing in particular on applying the latest understanding of the Cretaceous depositional model, with the aim of identifying infill drilling opportunities at Block CI-11 to target the remaining upside potential. Due to the lack of gas demand when the field was originally developed, there are high GOR zones within the structure that are yet to be completed and produced whilst two closures in the Foxtrot Sands are yet to be tested. Additional potential within the Turonian and Senonian intervals could also yield additional upside potential. Any rig based workover opportunities will also be coordinated with this programme, which is expected to prove up additional reserves and increase production rates.

Block CI-01 (Kudu, Eland and Ibex fields)

Overview of Licence

		<i>Afren's Legal Interest</i>	<i>Afren's Effective Working Interest</i>	
			<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>
<i>Licence details – Block CI-01 (Kudu, Eland and Ibex fields)</i>				
Area km ² :	1,208	65% ⁽¹⁾	65% ⁽¹⁾	65% ⁽¹⁾
Expiry:	Typically 25 years from development approval			
Licence type:	PSC			
Main plays:	Late Cretaceous shelfal to deep water clastics in structural and stratigraphic traps			
Partner:	Petroci, SK Energy			
2010 work programme:	Continued technical and commercial studies. Possible purchase of 2D seismic data			
Future work programme:	Potential 3D seismic data acquisition in 2010. Development or exploration/appraisal wells in 2011.			
Data available:	3D and 2D seismic and well data			

(1) 65 per cent. direct interest and 15 per cent. additional rights accruing pursuant to a carrier arrangement with SK Energy.

Background

Block CI-01, covering the previously discovered Kudu, Eland and Ibex fields, was licensed to UMC in 1994 and is located offshore in the easternmost part of Côte d'Ivoire. The block extends from near the shoreline to 1,900m water depth and is about 52 km from Abidjan. Afren's other partners in the block are Petroci and SK Energy Co Ltd (formerly SK Corporation).

Field Technical Background

Five separate significant hydrocarbon accumulations, Kudu, Eland, Ibex, Impala and Assinie were previously discovered by Esso and Agip in the late 1970s through to the mid-1980s.

The Kudu field was discovered by Agip in 1984 with the drilling of the E1-1X well, which tested 23.6 mmcfd and 738 bcpd from the Cenomanian sand. Subsequent delineation drilling by UMC in

1997 lead to the Kudu-1 appraisal well that tested 26.3 mmcf/d and 728 bcpd from a separate reservoir compartment in the Cenomanian. Kudu is a combination structural and stratigraphic trap, with faulting along the northern limit and erosion of the reservoir to the east and west.

Esso discovered the Eland field in 1978 with the drilling of the IVCO-19 well, which tested 12.4 mmcf/d and 520 bcpd from the Cenomanian. Esso followed up this discovery in 1981 with the drilling of the IVCO-23 well which tested 13.0 mmcf/d and 430 bcpd, also from the Cenomanian.

The Eland discovery is a combination of a structural and stratigraphic trap. The Cenomanian reservoir is within an erosional remnant above an Albion tilted faulted structure. The reservoir is truncated on all sides and covered by Turonian and younger shales. Both RFT and DST pressure data indicate likely communication exists between the two wells.

The Ibex discovery is located in the eastern part of the block in approximately 270ft of water. It is south-east of the Kudu and Eland fields. The discovery well was drilled by Esso in 1985 near the eastern truncation edge of a sand rich Maastrichtian canyon system that is draped over a portion of an anticline. It found oil and gas pay in four sands at depths between 5,714ft and 6,974ft. A drill stem test in the oil zone flowed rates of up to 2,992 bopd, 43.4° API gravity oil and 19.8 mmcf/d gas.

Field Development and Outlook

Out of the 16 wells drilled to date on the block, 10 have found hydrocarbons (representing a 63 per cent. technical success rate) with five fields defined (Kudu, Eland, Ibex, Impala and Assinie). The last well drilled on the block was in 1998 by Ocean Energy. Consequently, the block has not benefited from the latest sub surface understanding of the Cretaceous depositional systems which have led to world class discoveries adjacent to Block CI-01 across the border in Ghana. Significant additional exploration prospectivity is being defined as a result of ongoing work, incorporating the latest regional understanding of the Cretaceous in this area. Work is also currently underway on reviewing the existing fields on the Block where potential exists for the discoveries to be materially larger than first mapped as a result of this latest sub-surface understanding.

Development planning for the existing discoveries is in hand, with the original development concept now being reviewed in light of the substantial upwards revision to Ibex volumes following an independent assessment by NSAI and follow on upside potential at the other discoveries. Gross 2C contingent resources for CI-01 have been estimated at 19.8 mmbbls and 101.5 bcf, equivalent to 37.3 mmboe, with additional best estimate prospective upside of 12 mmbbls and 436.1 bcf, equivalent to 87.2 mmboe. As a result Afren will now seek to drill additional well(s) on the block in order to define the scale of the planned early development. Afren is in the process of obtaining an exclusive exploitation authorisation for CI-01.

Lion Gas Plant

Background

The Lion Gas Plant was constructed by Ocean Energy in 1998 to improve margins by extracting and selling high value natural gas liquids from gas produced at Block CI-11. Gas production from adjacent Blocks CI-26 and CI-40, operated by Canadian Natural Resources Limited, was added to the process stream, providing third party tariff revenue from the use of the Block CI-11 pipeline infrastructure, and additional gasoline and butane sales revenue at the Lion Gas Plant.

The Lion Gas Plant has a total inlet capacity of 75 mmcf/d and strips out gasoline and butane from the rich gas stream it receives, delivering dry gas to the power sector. Butane is sold into the local market, whilst the gasoline is sold on the international market. The Lion Gas Plant enjoys tax exempt status, therefore cash generated offers a high margin per barrel of product extracted.

Outlook

Natural gas liquid output for the full year 2009 stripped from the inlet gas stream at the Lion Gas Plant was 1,140 boepd. Year to date average gross daily output as at 30 June 2010 was 654 boepd. Output over the period was impacted due to maintenance work on the turbo expander. The Lion Gas Plant

also received reduced third party inlet volumes over the period as a result of work on the gas compression systems at the CNR operated Espoir and Baobab facilities. With a total inlet capacity of 75 mmcf/d, the produced butane is sold into the local market at a price of US\$21.09/boe with the gasoline spiked into the Block CI-11 crude stream and sold onto the open market. Afren is continuing to evaluate the feasibility of extracting propane at the plant which could be used to supply customers in the industrial sector.

8.6 **Ghana**

Regional Overview

During the initial opening of the South Atlantic in the Aptian and Albian, Eastern Ghana was a shallow seaway in a gradually subsiding basin that received substantial clastic input from the Volta River drainage system. The Dzita well in the centre of the modern Volta Delta has over 1,500 m of net sandstone in the Aptian and Albian. As the Atlantic continued to open, the continental shelf of the Brazil margin moved past what is now Ghana and caused a rapid deepening of the basin. The resultant accommodation space was filled by a Cenomanian clastic wedge that is up to 3,500 m thick. The Cenomanian section marks the transition from a shallow water seaway between Africa and South America to a deep water environment with a very narrow shelf.

The prolific and widespread Turonian/Cenomanian hydrocarbon source rock was then deposited in deep water when the Atlantic Basin became anoxic. The first major drop in sea level after this long term high stand occurred during the Santonian at 85-90 mya. The sea level drop was accompanied by a major structural event and rotation of Africa which caused a reactivation of the Romanche Fracture Zone and formed the Volta Fan Fold Belt inversion structures.

The Volta River system drained a granitic and Palaeozoic sedimentary provenance over a large part of the interior throughout much of the Cretaceous and has deposited significant clastic material into the Keta Basin providing excellent reservoirs for the prospects in the Keta Block.

In the Campanian, large volumes of sands were transported into the deep water basin after being stored in the Volta drainage system and shelf edge deltas during the preceding long term high stand of sea level.

The sandstone reservoir quality of the Campanian sequence, where present across the Gulf of Guinea, is generally excellent.

Oil production in Ghana commenced in 1978 when the Saltpond field came on stream. Ghana has a modest upstream oil industry with one onshore and five offshore sedimentary basins. The main drive behind the oil and gas industry in Ghana is the need to reduce the country's dependence and reliance on hydroelectricity. Subsequent exploration drilling in Ghana yielded modest technical success, with further discoveries being made during the late 1970s and 1980s in the Tano Shallow Water block. More recently Ghana has experienced considerable exploration and appraisal success, with discoveries in the deepwater Cretaceous fairways opening up a world class hydrocarbon exploration province. In June 2007, Kosmos Energy drilled its first exploration well on the West Cape Three Points Block and discovered the Mahogany field. This was followed, in August 2007, by Tullow Oil's Hyedua-1 exploration well on the Deepwater Tano Block which also encountered a significant oil accumulation. The results of Hyedua-1 well confirmed the Mahogany-Hyedua field as one continuous structure, extending across the two blocks. This new field was renamed Jubilee. Jubilee was the largest discovery to be made in Sub-Saharan Africa during 2007 with initial probable reserves estimated at 480 million barrels (subsequently upgraded to 1.2 billion barrels following successful appraisal wells) (Source: Wood Mackenzie Ghana Overview). Tullow Oil has been designated the operator of the Jubilee field.

Between the first quarter of 2008 and end of 2009, 13 exploration and appraisal wells were drilled offshore Ghana resulting in five further discoveries in the Côte d'Ivoire/Tano Basin. The Odum heavy oil and the Tweneboa oil/gas/condensate fields were made on the West Cape Three Points and the Deepwater Tano blocks respectively. The Mahogany-Deep discovery was encountered by the Mahogany-3 appraisal well, in a deeper reservoir, which is independent of the Jubilee field. In addition, the Ebony field was discovered on the Shallow water Tano Block and the Sankofa field was also discovered on the Cape Three Points Block.

The Dzata field, discovered in early 2010, encountered a gas/condensate reservoir in a deeper Cenomanian/Albian anticlinal structural trap- similar to the Baobab field in Côte d'Ivoire. The Dzata well was drilled in water depths of 1,874 metres, making it the deepest well to be drilled to date, offshore Ghana. The well has also opened up the prospectivity of a deeper petroleum play in the Ghana section of the Côte d'Ivoire/Tano Basin.

The Tweneboa-2 appraisal well was also completed in the first quarter of 2010. The appraisal results has led to the review of the Tweneboa recoverable reserves from 250 to 400 million barrels of oil equivalent.

On the West Cape Three Points Block, the Dahoma-1 exploration well was completed in April 2010, however, the well encountered water bearing reservoirs.

(Source: Wood Mackenzie Ghana Overview).

Proposed Drilling Activity in 2010

Exploration and appraisal drilling in Ghana is expected to continue during 2010. The Jubilee field partners are expected to lead exploration and appraisal drilling in Ghana – with continued drilling on the West Cape Three Points and Deepwater Tano blocks.

The partners also plan to drill two additional appraisal wells on the Tweneboa field during 2010. The Tweneboa-3 well is expected to test the Tweneboa eastern fairway. On the West Cape Three Points Block, the fourth exploration well is expected to be spudded before the end of 2010.

The Mahogany-5 appraisal well located in the southeast part of the Jubilee Field was successfully completed in the second quarter of 2010. The drilling completes the appraisal of the southeast Jubilee area and follows successes at the Mahogany-3, Mahogany-4 and Mahogany Deep-2 wells.

On the Deepwater Tano License, the Owo-1 exploration well, which was spudded in June 2010, has intersected a significant column of excellent quality light oil. Results of drilling, wireline logs and samples of reservoir fluids have established Owo-1 as a major new field requiring further appraisal. Following completion of logging operations, the well will be sidetracked 0.6 km east to provide additional information on lateral reservoir distribution and to intersect a deeper part of the Owo channel system.

Eni is progressing with its drilling campaign on its South Cape Three Points and Cape Three Points blocks. The company spudded the Asase Ya Duru-1 exploration well on the South Cape Three Points Block in the first quarter of 2010.

Despite the disappointing results of Hess's Ankobra well on the Tano Cape Three Points Block, the operator has acquired additional 3D seismic. Hess plans to drill an exploration well towards the end of 2010 or early 2011.

On the Cape Three Points Deep Block, Vanco and Lukoil are evaluating the Dzata-1 well results. The successful evaluation will determine if the partners will proceed with an appraisal well. The partners have also acquired 3D seismic over the southern region of the block and the potential exists for a further exploration well in this area.

(Source: Wood Mackenzie Ghana Overview).

Although as yet, its upstream oil industry has yielded only minimal crude oil production, Ghana is one of four West African countries with an oil refinery. The Tema refinery operated by the Tema Oil Refinery Corporation has an operating capacity of 43,000 bopd running on crude imported from Nigeria. The state oil company, Ghana National Petroleum Corporation is responsible for importing crude and refined petroleum products. An Energy Commission was mandated in 1983 and established in 1998 to regulate and manage the utilisation of energy resources in the country.

Ghana has a tax/royalty concession scheme where increased government share of oil revenue is captured through an additional profit tax that is payable when investors make certain levels of return on investment.

2009

Production in Ghana

Total oil production (thousand bopd)	7.08
Crude oil production (thousand bopd)	6.00

Reserves in Ghana

Oil proved reserves (billion barrels)	0.015
Natural gas proved reserves (tcf)	0.800

Source: US Department of Energy, Energy Information Administration.

Overview of Operations in Ghana

<i>Ghana</i>	<i>Operator</i>	<i>Work Programme</i>
Keta Block	Afren	Exploration

Resources – offshore Ghana

NSAI has estimated the prospective resources for the Keta Block, offshore Ghana as at 30 June 2010. The table below sets out NSAI's estimated gross OOIP and unrisked prospective oil resources for offshore Ghana as at 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

	<i>Gross (100%)</i>					
	<i>OOIP (mmbbl)</i>			<i>Resources (mmbbl)</i>		
	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>
<i>Resources</i>						
Unrisked Prospective						
Resources – Oil	722.4	2,416.7	8,061.2	153.9	604.2	2,299.5

Keta Block*Overview of Licence*

		<i>Afren's Legal Interest</i>	<i>Afren's Effective Working Interest</i>		
			<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>	
<i>Licence details – Keta Block</i>					
Area km²:	4,400	70%	70%	70%	
Expiry:	18 February 2016				
Licence type:	Royalty Tax Concession				
Main plays:	Cretaceous deepwater clastics in combined structural/stratigraphic traps				
Partner:	Mitsui, GNPC, Gulf				
2010 work programme:	Continued subsurface studies, prospect selection and well planning.				
Future work programme:	Commitment exploration well in 2011. 3D seismic commitment or partial relinquishment by end 2012 upon optional renewal.				
Data available	2D and 3D seismic and well data				

(1) 77.7 per cent. if GNPC is carried.

Background

The Keta Block is a high impact, deep water exploration asset in easternmost Ghana offshore along the highly prospective but under-explored West African Transform Margin. Covering an area of 4,400 km², the block is located offshore Eastern Ghana, at the heart of the Volta River Basin in water depths ranging from 1,000m to 2,800m. Multiple play types offer diverse hydrocarbon potential, with the primary targets being Cretaceous deep water clastics in combined structural/stratigraphic traps that offer giant field potential. The play concept is similar to that proved successfully in the recent Jubilee and Odum discoveries, the Odum discovery reported to have been made in Campanian sands which is extremely promising for the Keta Block. Several Upper Cretaceous closures have been identified on the Block, ranging in size from 100 mmbbls to 600 mmbbls. Stratigraphic upside potential offers gross potential in excess of two billion bbls, making the Keta Block world class acreage in an under explored fairway.

In June 2008, Afren completed the acquisition of an initial 88 per cent. working interest and the right to operate in the area from Devon Energy. Afren, through its subsidiary Afren Energy Ghana Limited (formerly Devon Energy Ghana Limited) assigned a two per cent. working interest to Gulf on 18 June 2008 although this two per cent. working interest has since been bought back. On 24 October 2008, Afren Energy Ghana Limited subsequently entered into a farm-out agreement with Mitsui Ghana, a subsidiary of Mitsui & Co, reducing its working interest in the Keta Block to 68 per cent. The previous petroleum agreement expired on 31 December 2009. A new petroleum agreement on substantially the same terms as the previous one was approved by cabinet and parliament on 19 February 2010. The current petroleum agreement expires on 18 February 2016.

In 2009, Afren drilled the Cuda-1 and Cuda-1ST1 wells. The well and sidetrack encountered an unexpectedly severe high pressure zone in the top of the upper Cretaceous which ultimately required the well to be plugged and abandoned. This was prior to the well penetrating the primary Cretaceous objectives which remain of high potential but untested.

Outlook

Following the completion of drilling operations at the Cuda-1 exploration well in December 2008, a decision was made to enter the second phase of the Keta Block licence which requires the drilling of one commitment well within a two year period (pending government approvals). In accordance with the terms of the licence, a mandatory reduction in the block size by 10 per cent. was agreed with the Ghanaian authorities. This relinquishment does not in any way impact Afren's currently defined prospectivity. Post well analysis of Cuda-1 has been finalised, and plans to safely re-drill the prospect have been developed in the event that the same prospect is selected for drilling again in 2011. Additional on block 2D seismic data has also been purchased and interpreted, identifying new leads which have been incorporated into the block inventory.

8.7 Congo-Brazzaville

Regional Overview

The entire coastal area of Congo-Brazzaville lies within the Congo Basin. The northern limit of the basin is the Mayumba Spur in southern Gabon, a basement high, which separates it from the Gabon Basin to the north. The Congo Basin extends as far south as the Ambriz spur offshore mainland Angola. All the productive oil fields of Congo-Brazzaville, Cabinda, the Democratic Republic of Congo and northern Angola lie within this basin.

The Congo Basin shows the characteristic features of a pull-apart basin. The basement rocks that outcrop to the east are progressively downfaulted to the west by a series of normal faults. The faults generally run north-south, paralleling the basement outcrop. In Congo-Brazzaville, the eastern edge of the basin, where the basement outcrops, is roughly 50 km inland. The edge of the offshore shelf area (regarded as being at the 200-metre isobath) lies about 60 km offshore. The Congo Basin, like the Gabon basin, contains a widespread evaporate (salt) layer that separates two distinct sedimentary sequences (the pre-salt and the post-salt sequences). The basement faulting associated with extensional (rift) tectonics has structurally influenced the pre-salt sediments. The post-salt sediments

have been widely disrupted by halokinetic movement of the underlying salt. Both the pre-salt and post-salt sediments are oil-bearing.

Congo-Brazzaville produces an average of 274,860 bopd in 2009 and 0.3 per cent. of the world total (Source: BP Statistical Review of World Energy (June 2010)). Congo-Brazzaville is the fourth largest oil producer in, and contains the third largest proven natural gas reserves in, sub-Saharan Africa.

(Source: US Department of Energy, Energy Information Administration).

2009

Production in Congo-Brazzaville

Total oil production (thousand bopd)	274

Reserves in Congo-Brazzaville

Oil proved reserves (billion barrels)	1.9

Natural gas proved reserves (tcf)	3.2

Source: BP Statistical Review of World Energy (June 2010), US Department of Energy, Energy Information Administration.

Overview of Afren's Operations in Congo-Brazzaville

Congo-Brazzaville	Operator	Work Programme
La Noumbi Permit	Maurel et Prom	Exploration

Resources – onshore Congo-Brazzaville

NSAI has estimated the prospective resources for the La Noumbi permit, onshore Congo-Brazzaville as at 30 June 2010. The table below sets out NSAI's estimated gross OOIP and unrisks prospective oil resources for onshore Congo-Brazzaville as at 30 June 2010. This information has been extracted without material adjustment from the NSAI Report in Part 11 of this Prospectus.

	<i>Gross (100%)</i>					
	<i>OOIP (mmbbl)</i>			<i>Resources (mmbbl)</i>		
	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>	<i>Low Estimate</i>	<i>Best Estimate</i>	<i>High Estimate</i>
<i>Resources</i>						
Unrisks Prospective						
Resources – Oil	521.5	1,025.9	1,744.0	114.6	251.6	481.9

La Noumbi Permit

Overview of Licence

		<i>Afren's Legal Interest</i>	<i>Afren's Effective Working Interest</i>		
			<i>Pre-cost recovery</i>	<i>Post-cost recovery</i>	
<i>Licence details – La Noumbi Permit</i>					
Area km²:	2,830	14%	14%	14%	
Expiry:	Under renewal				
Licence type:	PSC				
Main plays:	Pre-salt Toca & Djeno in faulted structural traps				
Partner:	Maurel et Prom (Op.), ENI				
2010 work programme:	Post well studies and ongoing work to define potential future drilling targets				
Future work programme:	Ongoing studies and prospect selection				

Data available: 2D seismic and well data

Background

The La Noumbi permit covers approximately 2,830 km² of under explored acreage onshore Congo-Brazzaville and lies directly to the south of the Gabon border and on trend with the prolific M'Boundi field.

In November 2006, Afren completed the acquisition of the entire issued share capital of Heritage Congo Limited, which holds a 14 per cent. interest in the La Noumbi exploration licence. The co-venture partners are Maurel et Prom, holding a 48.5 per cent. stake and acting as the operator, and Eni S.p.A (which acquired Burren Energy in early 2008) holding the remaining 37.5 per cent. interest.

2D seismic acquisition was completed in early 2007 resulting in a total of 940 km of new, good-quality seismic data. This data has been combined with reprocessed older 2D seismic data acquired in the 1980s and an attractive prospect inventory has been developed.

The Doungou-1 exploration well was spudded on 13 August 2007 and reached a total depth of 2,602m on 26 September 2007. This was the first exploration well drilled by the current joint venture. The well encountered good oil shows at several levels but the reservoir quality in the primary Vandji formation target was poor due to low permeability. The well was plugged and abandoned.

Activity Updates and Outlook

The exploration well was spudded in December 2009 and completed in March 2010. The well reached a final depth of 2,550 m in the Lower Cretaceous Djeno formation. Between 1,775m and 1,875m a siltstone area displayed hydrocarbon indicators. Measurements taken upon completion of drilling indicate this interval to be mainly composed of gas and does not suggest a viable commercial development due to its distance from potential markets. The well was therefore plugged and abandoned. The well data will be used to further the Company's regional understanding and in helping to redefine the prospectivity of the block, where the joint venture still has plans to test a number of other attractive prospects.

8.8 Gabon

Afren is in the process of relinquishing its former assets in Gabon due to uneconomic prospectivity and has written down the value of these assets by US\$ 0.5 million in the 31 December 2009 financial statements. However, Afren expects that there will be some further non material exit costs in 2010.

9. Environmental, Health and Safety and Social Responsibilities

The Group is committed to performing responsibly and positively towards the people, the physical environments and the host societies that its business may affect. It aims to protect people in terms of safety and health, protect the environment and fulfil social commitments and has established an Environment, Health & Safety and Social ("EHSS") management system which specifies mandatory processes and requirements and gives guidance on how the EHSS management requirements should be met. The monitoring of operations and feedback on results help to ensure that the Group's EHSS policies and procedures are implemented effectively and assists in making changes necessary to improve EHSS performance.

Environment

The Group is subject to various environmental laws and regulations in each of the jurisdictions it operates. The Group has undertaken environmental impact assessments for each of its producing assets, monitors its environmental performance on a monthly basis and has appropriate oil spill contingency plans and response capabilities in place. It is currently in compliance with the environmental rules and regulations in Nigeria, Côte d'Ivoire and Ghana.

In addition to compliance with such legal and regulatory requirements, the Group has established certain environmental policies in order for its business to be carried out in such a way as to protect the environment. Such policies include, but are not limited to, the following:

- Identifying and assessing potential environmental issues, assessing associated risks and establishing operational controls that aim to eliminate acute impact and to eliminate or limit emissions to permitted emission quality thresholds;
- Identifying significant environmental issues where improvement targets need to be set and to seek and monitor such improvements;
- Establishing and applying environmental operational standards and processes including environmental impact assessments and environmental management plans;
- Setting environmental related targets and measuring, appraising and reporting performance against such targets;
- Analysing deviations from emission thresholds to identify control failures and implement the necessary corrective action;
- Seeking ways to minimise energy use in operations;
- Reducing waste generation as far as it is practical and disposing of waste in a responsible manner without creating legacy issues and liabilities; and
- Carrying out periodic audits and assessments of environmental controls as part of a continuous improvement process.

Social

The Group also has a primary and continuing commitment to behaving ethically and improving the quality of life of its workforce and host communities as well as respecting the traditional rights and cultural heritage of its host communities. In order to achieve such a commitment, the Group carries out the following social policies among others:

- Screening, via a social impact assessment, the social risks and issues over all phases of the operation;
- Establishing a plan to manage social risks and issues over the lifetime of an operation;
- Building and maintaining relationships with host communities, key individuals and organisations in order to engage in consultation, communication and ensure mutual expectations are realistic and achievable; and
- Investigating and managing grievances that may be raised by host communities.

Health, safety and security

The Group is also committed to complying with health and safety regulations and in protecting the health, safety welfare and security of its employees and all personnel affected by and involved in its activities. Various policies have been established in this respect such as the application of health and safety standards across the Group and performance of audits and assessments of health and safety risks as part of the continuous improvement process.

Afren actively manages security risks in all its operations to ensure the safety of all personnel working in its operations. Security measures are implemented at all facilities and are subject to regular audit and review. Security of assets and information is also given careful consideration in the assessment of security risks.

10. Transportation

Afren's Okoro crude oil production is sold free on board and lifted from the Armada Perkasa FPSO and transported to its export markets. The offtake process and export of the produced crude oil is running smoothly with process uptime of 97 per cent. As at 30 June 2009, a total of 28 export liftings had been successfully executed with an average parcel size of 160,000 bbls.

Afren's Block CI-11 crude oil production is transported to Abidjan via Afren's own pipeline system to storage tanks at the SIR refinery. Transfer to export tankers occurs via SIR's export system. Gas production from Block CI-11 gas is transported to Abidjan via Afren's own pipeline to the 100 per cent. Afren owned Lion Gas Plant.

11. Sales and Marketing

Afren sells its Okoro crude oil production to Shell Western Supply and Trading Limited under an agreed marketing arrangement. The current agreement is for one year and expires on 30 April 2011. Okoro crude oil production is now exported and sold via the nearby Ima terminal, where the increased storage capacity (in excess of 1 mmbbls) provides a benefit through the sale of increased parcel sizes and improved shipping and sales economics. The average price realisation since production start up has been on average a premium to Brent.

Afren's Block CI-11 crude oil is sold to Shell Western Supply & Trading Limited under an evergreen term contract (effective from 9 April 2009) with termination rights subject to a three month notice period. The average price realisation since Afren acquired the asset has been on average at a premium to Brent.

Gas production from Block CI-11 and from adjacent blocks CI-26 and CI-40 is processed at the Lion Gas Plant and then sold to local power plants and the SIR refinery. Block CI-11 gas is sold under two long term contracts to the local SIR refinery and the state power producer, SOGEPE. The average price realisation for Block CI-11 gas during 2009 was US\$4.60/mmbtu.

Natural gas liquids are extracted from the gas streams of Blocks CI-11, CI-26 and CI-40 and are bottled at the Lion Gas Plant. Butane production is sold into the local market at a fixed price of US\$21.09/boe, whilst produced gasoline is spiked into the Lion crude stream and jointly sold with Block CI-11 crude oil, receiving prevailing global crude oil prices.

12. Insurance

Afren's producing oil and gas properties are located in Nigeria and Côte d'Ivoire. All assets are insured by Afren through Willis, save in respect of Okoro in Nigeria, which is insured by Amni through AON under its own separate policies.

The oil and gas properties are insured by resident insurers under individual insurance policies for each relevant venture (reinsured to the London insurance markets with reinsurers with a minimum of S&P (or equivalent) A- rating). Coverage under the terms of these policies includes property damage, operators extra expense (well control, seepage, pollution and redrill), third party liabilities to or arising from the assets of the Company and in Côte d'Ivoire for its co-venturers or operating companies, including legal and contractual liabilities from the Company's activities. Coverage, limits and deductibles in force are in line with international oil industry insurance standards.

The Company will procure construction all risks insurance coverage in respect of its development of the Ebok field. Coverage is for works executed anywhere in the world in performance of contracts wherein Afren are at risk relating to Ebok including loss of, or damage to, the pipelines, risers, umbilicals, christmas trees and completions to be installed.

Afren's philosophy is to arrange such other insurance from time to time in respect of its other operations as required and in accordance with industry practice. It does not currently have business interruption or key man insurance in place, but does have appropriate operators extra expense, cargo, directors' and officers', employer liability, public indemnity and travel insurance.

13. Competition

The Group's competitors include major oil and gas companies and independent oil and gas companies. The major international oil companies in the region include ExxonMobil, Shell, Total, Chevron, Eni, Agip, Addax and Tullow. The oil and gas business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of oil and gas production and in the recruitment and employment of qualified

personnel. In addition, in West Africa, Afren will compete with oil and gas companies in the bidding for exploration and production licences that are made available by governments or are for sale by third parties. Competition for such assets is likely to come from companies already present in the region in which the exploration and production licences are located as well as new entrants.

14. Dividend Policy

The Directors do not expect that Afren will pay any dividends in the foreseeable future, and in any event until such time as it is prudent to do so, having regard to the level of revenue generated by the Group's operations and the retained earnings to fund its operations and exploration and development programmes. For the foreseeable future, any earnings will be reinvested in developing the businesses of the Group.

PART 2

INFORMATION ON BLACK MARLIN

1. Introduction

1.1 *Corporate history*

Black Marlin was incorporated in the BVI on 8 November 2001 as “Upstream Petroleum Holdings Limited” pursuant to the BVI International Business Companies Act and commenced operations shortly thereafter. On 21 April 2006 “Upstream Petroleum Holdings Limited” changed its name to “Black Marlin Energy Limited” (“**Black Marlin Energy**”) and the company was automatically re-registered as a business company under the BVI BCA on 1 January 2007.

By a resolution of the directors of Black Marlin Energy dated 14 December 2005, its authorised capital was increased to US\$50,000 divided into 50,000 shares with a par value of US\$1.00 each to US\$100,000,000 divided into 500,000,000 shares with a par value of US\$0.20 each.

Black Marlin Energy was acquired by Kristina Capital Corporation (“**KCC**”), a company listed on the TSXV, pursuant to merger agreement between KCC and Black Marlin Energy dated 19 November 2009 (the “**KCC Acquisition**”). The KCC Acquisition, which was a “Reverse Takeover” under the rules of the TSXV, completed on 18 March 2010. On 19 November 2009, KCC entered into a purchase and sale agreement with 147884 Alberta Ltd., a company controlled by the President of KCC, pursuant to which KCC agreed to sell all its oil and gas interests in the Porcupine Property to 147884 Alberta Ltd for nominal consideration. The transaction represented the sale of substantially all of KCC’s assets and received shareholder approval on 28 December 2009 and regulatory approval concurrently with the KCC Acquisition. In a notification on 1 February 2010, the Minister of Energy and Resources of Saskatchewan cancelled Special Exploratory Permit Block EP 60 and Special Exploratory Permit Block EPP 61 within the Porcupine Property.

Under the KCC Acquisition, a wholly owned subsidiary of KCC, incorporated in the BVI and established for the purpose of participating in the KCC Acquisition, merged with Black Marlin Energy and all the issued common share capital in Black Marlin Energy was exchanged for common shares in the capital of KCC on a one-for-one basis at the deemed price of C\$0.50 per share post-consolidation. As part of the KCC Acquisition, KCC changed its name to “Black Marlin Energy Holdings Limited”.

1.2 *Business activities*

Black Marlin’s principal business activities are petroleum and natural gas exploration, development and production in Africa and the provision of seismic services.

1.3 *Head office and registered office*

Black Marlin’s head office is located at Office 1008, Fortune Tower, Floor 10, Jumeirah Lake Towers, P.O.Box 450307, Dubai, UAE and its registered office is located at Codan Trust Company (BVI) Limited, P.O.Box 3140, Romasco Place, Wickhams Cay 1, Road Town, Tortola VG 1110, BVI.

2. Subsidiaries

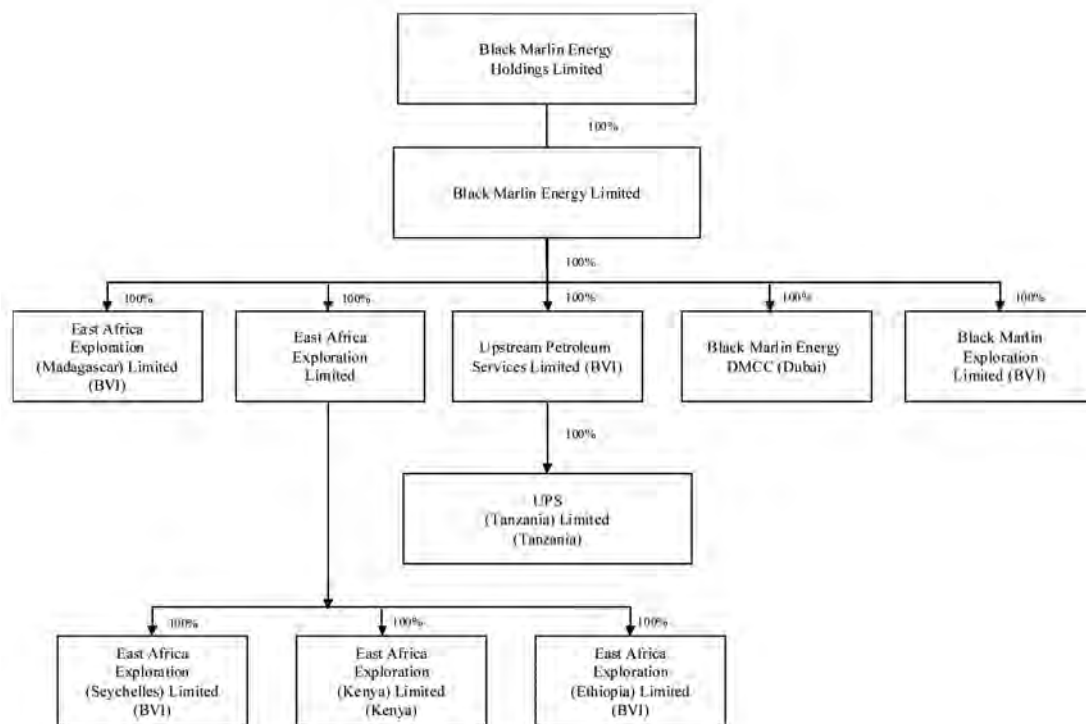
Black Marlin has five principal wholly-owned subsidiaries:

- East Africa Exploration Limited (“**EAX**”) (explores for hydrocarbons in East Africa and represents Black Marlin’s exploration and production interests);
- Upstream Petroleum Services Limited (“**UPSL**”) (engaged in the provision of seismic services, which is non-core to Afren’s existing activities and is under strategic review as set out below);
- Black Marlin Energy DMCC (“**DMCC**”) (for the purposes of carrying out business in Dubai);

- East African Exploration Madagascar Limited; and
- Black Marlin Exploration Limited (inactive).

EAX, UPSL, East African Exploration Madagascar Limited and Black Marlin Exploration Limited are incorporated in the British Virgin Islands and DMCC is registered in Dubai.

The following chart shows the current structure of Black Marlin and its subsidiaries.



UPSL

UPSL has one further subsidiary, UPS (Tanzania) Limited. East Africa Exploration (Seychelles) Limited and East Africa Exploration (Ethiopia) Limited are incorporated in the British Virgin Islands; East Africa Exploration (Kenya) Limited is incorporated in Kenya; and UPS (Tanzania) Limited is incorporated in Tanzania.

In 2007 UPSL was engaged in a series of projects in East Africa for EAX, Artumas Group Inc., RAKGAS International FZ, Etablissements Maurel et Prom and Dominion Petroleum Limited.

Following completion of the Acquisition, Afren intends to undertake a strategic review of the seismic business contained in UPSL, such that it will be divested in a manner to be determined by Afren and on transaction terms and at a valuation acceptable to Afren.

EAX

EAX has a further three subsidiaries (East Africa Exploration (Seychelles) Limited, East Africa Exploration (Kenya) Limited and East Africa Exploration (Ethiopia) Limited).

In 2007, EAX acquired equity in concessions in Tanzania (the Nyuni concession), Kenya (L17/L18), Madagascar (Block 1101) and secured an exploration licence and received an overriding royalty interest in the Petroquest acreage in the Seychelles.

In 2008, EAX further expanded its interests in East Africa with a farm-in to Block 1 in Kenya (50 per cent. equity plus an option to earn a further 30 per cent.), a farm-in to Blocks 2, 6, 7 and 8 in Ethiopia's Ogaden Basin (30 per cent.) and a license award in the Seychelles (75 per cent.).

In 2009, EAX exchanged its 10 per cent. Tanzania interests for Aminex's 25 per cent. share of the Kenya L17/L18 Block and grew further with a farm-in to Africa Oil Corporation's Block 10A in Kenya (20 per cent.).

Description of Black Marlin's business

Black Marlin currently owns equity in assets in Seychelles, Madagascar, Kenya and Ethiopia. UPSL has the ability to conduct seismic surveys elsewhere in Africa and is not constrained to the East African region.

The table below shows a summary of Black Marlin's asset base:

<i>Licences</i>	<i>Working Interest</i>	<i>Area in km²</i>		<i>Area in Acres</i>	
		<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>
Seychelles A, B and C	75.00%	14964 km ²	11223 km ²	3.7 million	2.8 million
Ethiopia	30.00%	46410 km ²	13923 km ²	11.5 million	3.4 million
Kenya 10A	20.00%	14747 km ²	2949 km ²	3.6 million	0.7 million
Kenya 01	50.00%	31850 km ²	15925 km ²	7.9 million	3.9 million
Kenya L17/L18	65.00%	4905 km ²	3149 km ²	1.2 million	0.8 million
Madagascar	40.00%	14900 km ²	5960 km ²	3.7 million	1.5 million
		<u>127776 km²</u>	<u>53129 km²</u>	<u>31.6 million</u>	<u>13.1 million</u>

Notes:

- (1) Source: Ethiopia and Kenya 10A (GCA Report); Seychelles, Kenya L17/L18 and Madagascar (McDaniel Report); and Kenya 01 (management estimates).

3. Resources

The following remaining information in this Part 2, is a summary of resource data and related information derived from the independent resource report prepared by Gaffney, Cline & Associates in relation to the crude oil and natural gas resources of Black Marlin dated the date hereof (with an effective date of 31 March 2010) (the "**GCA Report**") and the independent resource report prepared by McDaniel & Associates Consultants Ltd. in relation to the resources of Black Marlin (the "**McDaniel Report**") dated the date hereof both of which are set out in full in Parts 12 and 13 of this Prospectus.

For the purposes of this Part 2 of this Prospectus, "**Prospective Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

The estimation of Prospective Resource volumes for high-risk and poorly calibrated basins can be subject to large variation from the introduction of new information. The estimates presented in the GCA Report and the McDaniel Report are based on all of the information available; however, new data or information is likely to have a material effect on the resource assessment values. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

While COGEH specifically defines Petroleum Initially-In-Place (PIIP), the use of OIIP and GIIP in the tables below is consistent with the COGEH Glossary that provides for defining products (oil and gas) in place in the same manner as PIIP.

Property Description and Location

Ethiopia

Blocks 2, 6, 7 and 8 are located in the Ogaden basin, in southern Ethiopia. Blocks 2 and 6 are part of the same production sharing contract ("PSC") which encompasses, according to the GCA Report, a combined

area of 24,570 square km. Blocks 7 and 8 are part of a separate PSC covering an overall area of 21,840 square km, according to the GCA Report. The operator for both PSCs is Africa Oil Corporation (55 per cent., formerly Lundin East Africa BV); EAX (Ethiopia) Ltd has farmed in for a 30 per cent. interest and New Age (African Global Energy) Limited holds the balance of 15 per cent.. The combined total gross area is 46,410 square km (11.5 million acres) and EAX (Ethiopia) Ltd's net area under licence is 13,923 square km (3.4 million acres).

Exploration in the Ethiopia area began in the 1970's with Tenneco discovering the Calub and Hilal gas fields approximately 200 kilometers to the east of Block 6. Exploration continued into the 1980's but then effectively ceased until 2007. Three wells have been drilled within the blocks and all were subsequently plugged and abandoned: El Kuran-1, El Kuran-2 and Bodle-1. Both of the El Kuran wells gave indications of hydrocarbons and a small amount of oil was reportedly recovered from the Jurassic, Hamanlei formation. The main potential reservoirs in the basin are clastic sediments of the Carboniferous age Calub formation and the Triassic age Adigrat formation. In addition some permeable Jurassic carbonate rocks in the Hamanlei formation can be considered potential reservoirs.

Blocks 2, 6, 7 and 8 are located on the edge of the Paleozoic – Mesozoic Ogaden Basin. The Ogaden basin has a proven hydrocarbon system as confirmed by the Calub and Hilal discoveries and a number of oil and gas shows reported in the exploration wells drilled in the area. Petronas is currently progressing appraisal and development drilling plans to commercialize the field, with one well drilled in 2009.

Table 1A: Ethiopia. Oil Prospective Resources

<i>Licence</i>	<i>Lead</i>	<i>Reservoir</i>	<i>Gross Best Estimate (MMBbl)</i>	<i>Black Marlin Working Interest %</i>	<i>Net Best Estimate (MMBbl)</i>	<i>GCoS</i>
Block 07	Lead A	Upper Hamanlei	88	30	26.4	0.14
		Adigrat	83	30	24.9	0.09
		Calub	106	30	31.8	0.12
Block 07	Lead B	Upper Hamanlei	50	30	15.0	0.12
		Adigrat	52	30	15.6	0.08
		Calub	98	30	29.4	0.10
Block 07	Lead C	Upper Hamanlei	103	30	31.0	0.12
		Adigrat	112	30	33.6	0.08
		Calub	86	30	25.8	0.10
Block 06	Lead D	Upper Hamanlei	40	30	12.0	0.13
		Adigrat	112	30	33.6	0.09
		Calub	34	30	10.2	0.11

Notes:

- (1) Source: GCA Report.
- (2) Net Prospective Resources are stated herein in terms of Black Marlin's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSA. In this regard these volumes stated herein will exceed the volumes which will arise to Black Marlin under the terms of the PSA.
- (3) It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
- (4) The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the recategorization of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.
- (5) The Prospective Resource volumes are for Oil or Gas, not Oil and Gas. In other words either oil will be found or gas will be found but volumes for each Lead for oil cannot be summed to the gas presented in Table 1B.

Table 1B: Ethiopia. Gas Prospective Resources

<i>Licence</i>	<i>Lead</i>	<i>Reservoir</i>	<i>Gross Best Estimate (BCF)</i>	<i>Black Marlin Working Interest %</i>	<i>Net Best Estimate (BCF)</i>	<i>GCoS</i>
Block 07	Lead A	Adigrat	525	30	157.5	0.09
		Calub	1,129	30	338.7	0.12
Block 07	Lead B	Adigrat	326	30	97.8	0.08
		Calub	1,120	30	336.0	0.10
Block 07	Lead C	Adigrat	724	30	217.2	0.08
		Calub	1,010	30	303.0	0.10
Block 06	Lead D	Adigrat	221	30	66.3	0.09
		Calub	394	30	118.2	0.11

Notes:

- (1) Source: GCA Report.
- (2) Net Prospective Resources are stated herein in terms of Black Marlin's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSA. In this regard these volumes stated herein will exceed the volumes which will arise to Black Marlin under the terms of the PSA.
- (3) It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
- (4) The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the recategorization of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.
- (5) The Prospective Resource volumes are for Oil or Gas, not Oil and Gas. In other words either oil will be found or gas will be found but volumes for each Lead for gas cannot be summed to the oil presented in Table 1A.

The PSC for Blocks 2 and 6 has an effective date of 7 November 2006; that for Blocks 7 and 8 has an effective date of 11 July 2007. Both PSCs have an initial exploration period of four years, followed by two additional exploration periods each lasting a further two years before entering an exploitation phase lasting up to 25 years. A letter dated 1 March 2010 approves the one year extension of both PSC initial exploration periods to 6 November 2011 and 10 July 2012 respectively. The Government of Ethiopia retains a 10 per cent. back-in right in respect of Blocks 2 and 6 and 15 per cent. in respect of Blocks 7 and 8 into successful exploration and contractors are allowed to recover all their costs out of 60 per cent. of the production. Oil royalty rates range from 7.5 per cent. for the first 20,000 bopd to 15 per cent. for production above 100,000 bopd and gas royalty rates range from 7 per cent. for the first 50 mmcf to 12.5 per cent. for production above 200 mmcf. The government's share of profit oil ranges from 35 per cent. for Blocks 2 and 6 and 37.5 per cent. for Blocks 7 and 8 for the first 20,000 bopd to 70 per cent. for Blocks 2 and 6 and 72.5 per cent. for Blocks 7 and 8 for production above 100,000 bopd; its share of profit gas ranges from 33 per cent. for Blocks 2 and 6 and 35.5 per cent. for Blocks 7 and 8 for the first 50 mmcf to 60 per cent. for Blocks 2 and 6 and 62.5 per cent. for Blocks 7 and 8 for production above 200 mmcf.

In May 2009, Black Marlin entered into a farm-in agreement with the operator of Blocks 2, 6, 7 and 8. Under the terms of this farm-in agreement, Black Marlin was required to contribute to the past costs of the licence and to the acquisition of 500km of 2D seismic at an estimated cost of US\$3.7 million.

During the first exploration period, the partners of the farm-in are obligated to obtain 30,000km of line kilometres of airborne gravity and magnetic data; 2,500km of 2D seismic data; and to drill one exploration well. To date, the airborne commitment has been satisfied and UPSL will commence an initial 500km of 2D seismic survey in the second quarter of 2010. During the second exploration period, the partners of the farm-in are obligated to acquire 2,600km of 2D seismic and to drill one exploration well. During the third exploration period, the partners of the farm-in are obligated to acquire 200km of seismic and to drill a total of four wells (one appraisal and three exploration).

Kenya

Black Marlin has equity interests in three licences in Kenya: L17/L18 (where it operates through EAX (Kenya) Ltd with a 65 per cent. equity interest), Block 1 (where it operates with a 50 per cent. equity interest) and Block 10A (where it has a non-operated 20 per cent. equity interest).

Block 1

Block 1 is located on the western margin of the Mandera-Lugh basin in northeastern Kenya bordering both Somalia and Ethiopia. Based on management estimates, the block covers an area of 31,850 square km (7.9 million acres). The operator is EAX (Kenya) Ltd (50 per cent.), with Lion Petroleum Corporation owning the remaining 50 per cent.. Black Marlin's net area under licence is 15,891 square km (3.9 million acres).

Early exploration occurred during the 1970's when Burmah Oil conducted gravity and seismic surveys over Block 1. This was followed during the 1980's when Amoco and Total acquired a combined 850 kilometers of 2-D seismic data. After this exploration effectively ceased until Lion Petroleum Corporation was awarded the block in November 2007. EAX (Kenya) Ltd farmed into the block in January 2009 taking a 50 per cent. interest and becoming operator of the block pursuant to the joint operating agreement with Lion Petroleum Corporation. The main exploration potential in Block 1 is believed to lie in the Jurassic and Upper Triassic section by analogy with the Ogaden basin. Gas is the most likely hydrocarbon type if present in the Mansa Guda reservoirs as the Elgal shales (the source rock) are likely to be within the gas window or over mature. The Jurassic reservoirs are more likely to be oil bearing as there is a separate potential source rock which may not have been buried so deep. An oil seep close to the well Tarbaj-1 in the southwest corner of the block confirms the presence of hydrocarbons.

The Mandera-Lugh sedimentary basin is located in north-eastern Kenya and continues partly into Somalia and Ethiopia where it is connected to the much larger and extensive Ogaden basin (see description of the Black Marlin Ethiopian assets). Analogies with the Ogaden basin also suggest there may be other potential source rocks and reservoirs. The Bur Mayo and the Kalicha-Seir formations in the Mandera-Lugh basin appear comparable to the Lower and Upper Hamanlei (Jurassic) formations in the Ogaden basin. If analogous these formations should have high total organic content ("TOC") source rocks and in addition permeable reservoirs.

The PSC for Block 1 was signed on 19 November 2007 and became effective in February 2008. The PSC has an initial exploration period of three years, followed by two additional exploration periods each lasting a further two years before entering an exploitation phase lasting up to 25 years. The Government of Kenya retains an 18 per cent. back-in right into successful exploration and contractors are permitted to recover their costs at a rate of 20 per cent. per annum from 55 per cent. of the production. The government's share of profit oil ranges from 55 per cent. for the first 20,000 bopd to 78 per cent. for rates above 100,000 bopd and oil profits are subject to an additional profits tax if the price of oil exceeds US\$50/bbl.

In January 2009, EAX (Kenya) Ltd entered into a farm-in agreement with the operator of Block 1. Under the terms of this agreement, EAX (Kenya) Ltd acquired a 50 per cent. equity stake in exchange for a contribution to the costs of a seismic programme and the acquisition and processing of other data. EAX (Kenya) Ltd also has the option under the farm-in to acquire a further 30 per cent. equity interest in Block 1 in exchange for a contribution to the costs of either an exploration well or a seismic programme in the second exploration phase (at the election of EAX (Kenya) Ltd).

During the first exploration period, the PSC partners are obligated to obtain 1,200km of 2D seismic data. A letter dated 23 April 2009 approved an extension of the first exploration period until 17 October 2011 and states that during the initial exploration period the Joint Venture will be expected to acquire gravity and magnetic data and 1,200km of 2D seismic data. It is anticipated that this will be completed in 2010. During the second exploration period, the farm-in partners are obligated to acquire 25 square km of 3D seismic and to drill one exploration well. During the third exploration period, the partners of the farm-in are obligated to acquire 25 square km of 3D seismic and to drill a further exploration well.

Block 10A

Block 10A is located in the northern region of the Anza Basin in northern Kenya. The block covers a total of 14,747 square kilometres (3.6 million acres), according to the GCA Report, and is north-west from the adjacent Block 9 where the operator, CNOOC (the Chinese National Oil Company) has recently drilled the Bogal-1 well. The operator is Africa Oil Corporation (55 per cent.); its partners are EAX (Kenya) Ltd (20 per cent.) and Raytec Metals Corporation (25 per cent.). According to the GCA Report, EAX (Kenya) Ltd's net area under licence is 2,949 square km (0.7 million acres).

In March of 1985, Amoco signed the Block 10 PSC which covered approximately 84,500 square km of north-western Kenya and encompassed the northern region of the Anza Basin. In 1990, Amoco relinquished 50 per cent. of the block and the remaining portion was divided into three separate blocks: Block A, Block B and Block C. Later that year, Shell farmed-in for a 50 per cent. interest and became operator of all three blocks. Three exploration wells were drilled by Amoco in Block 10A (Sirius-1, Bellatrix-1 and Chalbi-3) but abandoned throughout 1988 and 1989. The Sirius-1 well gave indications of migratory hydrocarbons in the Upper Cretaceous but in 1993-94 both Amoco and Shell relinquished the blocks. No exploration was conducted on Block 10A until Africa Oil Corporation was awarded the PSC in October of 2007.

Block 10A is located in the northern part of the Anza graben which in turn is part of Central-African Mesozoic rift system that also includes the Muglad graben in Sudan, and the Lamu graben in Kenya. The southern part of Block 10A has been interpreted to provide the best exploration potential. This is supported by the presence of oil and gas shows and the high maturity level of organic rocks in wells Bellatrix-1 and Sirius-1. The latter well establishes the presence of an Upper Cretaceous lacustrine source rock that may have generated low-sulphur/paraffinic oil.

The PSC for Block 10A has an effective date of January 2, 2008. The PSC has an initial exploration period of four years, followed by two additional exploration periods each lasting a further eighteen months before entering an exploitation phase lasting up to 25 years. The Government of Kenya retains a 13 per cent. back-in right into successful exploration and contractors are permitted to recover their costs at a rate of 20 per cent. per annum from 60 per cent. of the production. The government's share of profit oil ranges from 55 per cent. for the first 10,000 bopd to 77.5 per cent. for rates above 140,000 bopd; its share of profit gas is to be determined on an oil-equivalent basis; and oil profits are subject to an additional profits tax if the price of oil exceeds US\$50/bbl.

Table 2: Kenya. Summary of Prospective Resources

<i>Licence</i>	<i>Lead</i>	<i>Gross Best Estimate (MMbbl)</i>	<i>Black Marlin Working Interest %</i>	<i>Net Best Estimate (MMbbl)</i>	<i>GCoS</i>
Block 10A	Lead A	103	20	20.6	0.08
Block 10A	Lead B	82	20	16.4	0.09
Block 10A	Lead C	12	20	2.4	0.10
Block 10A	Lead D	53	20	10.6	0.08

Notes:

- (1) Source: GCA Report.
- (2) Net Prospective Resources are stated herein in terms of Black Marlin's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSC. In this regard these volumes stated herein will exceed the volumes which will arise to Black Marlin under the terms of the PSC.
- (3) It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
- (4) The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the recategorization of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.

In May 2009, EAX (Kenya) Ltd entered into a farm-in agreement with the operator of Block 10A. Under the terms of this farm-in agreement, EAX (Kenya) Ltd was required to contribute to the past costs of the licence and to the acquisition of 750km of 2D seismic at an estimated cost of US\$3 million.

During the first exploration period, the PSC partners are obligated to obtain 750km of seismic and to drill one exploration well. During the second exploration period, the PSC partners are obligated to drill one exploration well. During the third exploration period, the PSC partners are obligated to drill one further exploration well.

L17/L18

The Block L17/L18 PSC area is located in the Lamu coastal basin, in southern offshore Kenya. The individual blocks L17 and L18 cover an area of approximately 1,275 and 3,630 square km respectively and are situated in water depths varying from a few meters along the shoreline up to around 500 metres. EAX (Kenya) Ltd (65 per cent.) is the operator; Somken holds the remaining 35 per cent. working interest. According to the McDaniel Report, the combined total gross area is 4,905 square km (1.2 million acres) and EAX (Kenya) Ltd's net area under licence is 3,250 square km (0.8 million acres).

Block L17/L18 was originally part of Block L10 awarded to Dana Petroleum and Pancontinental in 2000. Woodside Energy farmed into Block L10 in 2003 and after an extensive 2-D marine survey relinquished the shallow water part of the block, which was re-designated as Block L17/L18 and re-awarded in October 2007. There are several potential source rocks for the Cretaceous in the southern Lamu basin including the Permo-Triassic Karoo interval and sections within the Lower to Middle Jurassic, and there are oil seeps in the Lamu Basin and Pemba Island linked to a Jurassic source which implies that the structures in Block L17/L18 might be oil bearing. The main reservoir targets are in the Upper Cretaceous although there may be additional potential in clastic reservoirs within the Tertiary. The hydrocarbons are expected to have been generated in the deep Pemba trough south of Block L18 and have been assumed to be gas for the purposes of this report.

The PSC for L17/L18 had an initial effective date of 24 January 2008. However, a letter dated 3 August 2009 approves the extension of the first exploration period to 24 October 2010. The PSC has an initial exploration period of two years, followed by two additional exploration periods (the first lasting two years and the second lasting three years) before entering an exploitation phase lasting up to 25 years. The Government retains a 15 per cent. back-in right into successful exploration and contractors are permitted to recover their costs at a rate of 20 per cent. per annum from 55 per cent. of the production. The government's share of profit oil ranges from 50 per cent. for the first 10,000 bopd to 75 per cent. for rates above 100,000 bopd; its share of profit gas ranges from 50 per cent. for the first 60 mmcf to 75 per cent. on production above 600 mmcf; and oil profits are subject to an additional profits tax if the price of oil exceeds US\$50/bbl.

Table 3: Prospectivity of Block L17/L18

<i>Block</i>	<i>Number of leads considered</i>	<i>Unrisked Mean In Place (gross)</i>	<i>Unrisked Mean resources (gross)</i>	<i>Risked Mean Resources (gross)</i>	<i>Risked resources (net)</i>
L17/L18(1)	11	811 Bcf	563 Bcf	30 Bcf	20 Bcf

Notes:

- (1) Source: McDaniel Report.
- (2) The net risked resources are based on Black Marlin's working interest of the property gross risked resources.

During the first exploration period, the PSC partners are obligated to process available seismic; to acquire 25 geochemical cores; and to acquire 1,000km of marine 2D seismic. The commitment to acquire cores has been satisfied and the commitment to acquire 1000km of 2D seismic data will be satisfied by the third quarter of 2010. During the second exploration period, the partners of the farm-in are obligated to acquire 1,000km of seismic and to drill one exploration well. During the third exploration period, the partners of the farm-in are obligated to acquire 1250km of seismic and to drill a further two exploration wells. Note that the

seismic can be marine, terrestrial or transition-zone seismic, with the required commitment changing accordingly; the minimum monetary commitment does not change.

Madagascar

Block 1101 is located on the eastern flank of the Ambilobe basin in northern Madagascar. The Block encompasses an area of approximately 14,900 square km (3.7 million acres) onshore and lies adjacent to Exxon's Ampasindava Block and Sterling Energy's Ambilobe Block. The operator is Candax Energy (60 per cent.) with Black Marlin retaining the remaining 40 per cent.. Black Marlin's net area under licence is 5,960 square km (1.5 million acres).

There has to date been limited exploration activity in the block with one well drilled in 1901 near the village of Ankaramy (to 193 metres) and a second well drilled in 1963. The block was held by Maxus and Triton Energy in the 1990's. Triton's interest was later acquired by Amerada Hess Corporation, before the latter relinquished the Malagasy offshore acreage that was later to be acquired by Sterling Energy Plc. Recently, 220km of 2D seismic has been acquired over the southern area of the block. The main exploration target are sands of the Isalo formation. There are proven heavy oil accumulations in the Isalo formation in Central Madagascar such as Bermolanga and Tsimiroro, indicating good reservoir conditions.

The PSC for Block 1101 has an effective date of 24 July 2007. The PSC has an initial exploration period of two years followed by two additional exploration periods each lasting a further two years before entering an exploitation phase lasting up to 25 years. The first phase would have ended in July 2009, however the Government of Madagascar has granted a one year extension taking it to July 2010. No formal application for further extension has been made and Black Marlin has not received any indication that objections will be made to such an extension. The Government of Madagascar has no back-in rights into successful exploration and contractors are allowed to recover their entire costs from 60 per cent. of the production. Oil royalty rates range from 8 per cent. for the first 20,000 bopd to 20 per cent. for rates above 130,000 bopd; gas royalty rates range from 6 per cent. for the first 424 mmcf to 10 per cent. on production over 847 mmcf. The government's share of profit oil ranges from 20 per cent. for the first 10,000 bopd to 70 per cent. for production above 130,000 bopd; its share of profit gas ranges from 5 per cent. for the first 424 mmcf to 45 per cent. for production above 1,695 mmcf.

Table 4: Prospectivity of Block 1101.

<i>Number of leads considered</i>	<i>Unrisked Mean In Place (gross)</i>	<i>Unrisked Mean resources (gross)</i>	<i>Risked Mean Resources (gross)</i>	<i>Risked resources (net)</i>
3	959 MMbbls	191 MMbbls	9 MMbbls	4 MMbbls

Notes:

- (1) Source: McDaniel Report.
- (2) The net risked resources are based on Black Marlin's working interest of the property gross risked resources.

During the first exploration period, the PSC partners are obligated to perform a geochemical survey; carry out field mapping; and drill an exploration well to a minimum of 800m. The geochemical survey has been completed and the exploration well is anticipated for Q4 2010. During the second exploration period, the PSC partners are obligated to acquire 300km of seismic and to drill two exploration wells to a minimum of 800m each. The PSC partners are obligated for the third exploration period to acquire 150km of seismic and to drill one well to a minimum of 800m.

Seychelles

Areas A, B and C are located in the Seychelles micro-continent covering a combined area of approximately 14,964 square km (3.7 million acres). Areas A and B are located in mainly shallow water in the northern half of the Seychelles plateau while Area C is in shallow water to the south. The operator is Black Marlin

(75 per cent.); Avana Petroleum has a 25 per cent. working interest. Black Marlin's net area under licence is 11,249 square km (2.8 million acres).

The bulk of exploration activity commenced in 1977 when three separate PSCs were signed by a consortium led by Oxoco, Siebens and Burmah Oil (later acquired by Amoco). Between 1977 and 1979 this consortium acquired a total of 6,400 kilometers of seismic which revealed several structural and stratigraphic leads. Between 1980 and 1981 Amoco drilled three wells (Owen Bank A-1, Reith Bank-1 and Seagull Shoals-1); all were plugged and abandoned with indications of hydrocarbons shows. Amoco commissioned a further 27,900 kilometers of aeromagnetic survey and 7,100 kilometers of seismic as well as other gravity and geochemical surveys but relinquished the acreage in 1986 following the collapse of oil prices. In 1985, Enterprise Oil (later acquired by Shell) signed an Agreement for the South-Eastern Shelf plus Constant, Coetivy and Fortune Banks with an option to later include Platte Banks. It surveyed a total of 4,870 kilometers of seismic and in 1990 it drilled the Constant Bank-1 well which was plugged and abandoned. A further consortium of Texaco, Ultramar (now ENI) and Enterprise Oil conducted a group-shoot acquisition programme in 1991 but later relinquished their areas. The main exploration target is the Permo-Triassic Karoo interval which comprises non-marine sands inter-bedded with shales. The Karoo formation contains both the source rock and the reservoir. Other potential reservoirs in the volcanic rocks and Jurassic clastic sediments may exist although further exploration work is needed.

The complexity of the tectonic evolution of the Seychelles plateau is due to the imposition of three phases of rifting and drifting that isolated the micro-continent from the centre of Gondwana. The first sedimentary rocks of Seychelles began forming during the Permo-Carboniferous time as part of the early Karoo section on the Gondwana paleo-continent. The western Seychelles margin can be reconstructed to a position adjacent to Somalia and as a northern extension of Madagascar prior to drifting from Africa in the Upper Jurassic. A second phase of rifting occurred during the mid Cretaceous when India and Seychelles separated from Madagascar. The Madagascar landmass acted as a major sediment source for the Seychelles micro-continent during this period. During this time a significant part of Seychelles was covered by basalts and volcanic rocks. The third and final rift phase occurred in the late Cretaceous with the drift between Seychelles and India initiating during the early Paleocene.

The PSC for Areas A, B and C has an effective date of November 28, 2008. The PSC has an initial exploration period of two years, followed by two additional exploration periods (the first lasting two years and the second lasting three years) before entering an exploitation phase lasting up to 25 years. The Government of Seychelles has no back-in rights into successful exploration and contractors are allowed to recover 100 per cent. of their costs from 100 per cent. of the production. Oil and gas royalty rates are both flat at 5 per cent.; revenues incur an Additional Petroleum Profit Tax that ranges from 30 per cent. to 45 per cent. depending on previous production revenues.

Table 5: Prospectivity of Areas A, B and C in Seychelles (oil in MMbbls; gas in bcf)

<i>Number of leads considered</i>	<i>Unrisked Mean In place (gross)</i>		<i>Unrisked Mean resources (gross)</i>		<i>Risked Mean Resources (gross)</i>		<i>Risked resources (net)</i>	
	<i>OIIP</i>	<i>GIIP</i>	<i>Oil</i>	<i>Gas</i>	<i>Oil</i>	<i>Gas</i>	<i>Oil</i>	<i>Gas</i>
9	1,464	1,492	291	1,035	25	87	19	65

Notes:

- (1) Source: McDaniel Report.
- (2) The net risked resources are based on Black Marlin's working interest of the property gross risked resources.

During the first exploration period, the PSC partners are obligated to obtain 2,000km of 2D seismic and 150 square km of 3D seismic. The partners have acquired 3,637km of 2D seismic data in 2007 and a further 1,271km was acquired in 2009. During the second exploration period, the PSC partners are obligated to acquire 1,500km of 2D seismic and to drill one exploration well. During the third exploration period, the partners of the farm-in are obligated to acquire 1,000km of 2D seismic and to drill two further exploration wells.

PART 3

SUMMARY OF THE ACQUISITION

1. Introduction

On 2 June 2010, the Boards of Black Marlin and Afren announced that they had agreed the terms of a recommended proposal by Afren to acquire the entire issued and to be issued share capital of Black Marlin in consideration for the issue of New Ordinary Shares by Afren. On 11 August 2010, Black Marlin and Afren executed and delivered an amended and restated arrangement agreement. The Acquisition will be effected by way of a scheme of arrangement pursuant to section 179A of the BVI BCA (the “**Scheme**”) and will be conditional on, amongst other things, the approval of Black Marlin Shareholders and the sanction of the Scheme by the Court. The Acquisition is also conditional on the appropriate regulatory clearances and the approval of the Afren Shareholders in a shareholder general meeting. The Scheme is expected to become effective, and the Acquisition to complete, on or about 8 October 2010.

The Acquisition has been unanimously recommended by the Boards of Black Marlin and Afren.

2. Summary of the Acquisition terms

The Acquisition will be implemented, subject to the satisfaction or waiver of certain conditions, by means of a BVI Court-sanctioned scheme of arrangement between Black Marlin and Black Marlin Shareholders pursuant to which the Scheme Shares will be transferred to Afren in exchange for an issue of New Ordinary Shares to Black Marlin Shareholders.

Under the terms of the Acquisition, Afren Shareholders will retain their shares in Afren and Black Marlin Shareholders will receive:

for every one Black Marlin Share 0.3647 New Ordinary Shares

and so in proportion for any other number of Black Marlin Shares held. Any fractional entitlements to New Ordinary Shares arising out of the application of this exchange ratio shall be rounded down to the nearest whole number of New Ordinary Shares.

The terms of the Acquisition are based on the equity market capitalisations of the two companies at the time of the execution of the Arrangement Agreement. The exchange ratio was calculated by taking into account the share capital of Black Marlin on a fully diluted basis and values each Black Marlin share at C\$0.51 (rounded to the nearest Canadian cent) based on:

- (i) the twenty-day volume weighted average price for Afren on the main market of the London Stock Exchange for the twenty trading days prior to, and including, 1 June 2010 of 90 pence (rounded to the nearest pence) per share; and
- (ii) an exchange rate of C\$1.5399 per pound sterling.

On this basis, Black Marlin is valued at approximately C\$106.5 million. This represents a premium per Black Marlin share of approximately 35 per cent. calculated by comparing the implied price per Black Marlin share as calculated above with Black Marlin’s share price of C\$0.38 (rounded to the nearest Canadian cent) on the TSXV as at market close 1 June, being the last trading day prior to announcement of the Acquisition.

On the Effective Date, all Black Marlin Options (excluding those held by RAKGAS International FZ) unexercised at the Effective Time will be cancelled and exchanged for a number of Afren Shares set out in an option exchange agreement executed by each holder of Black Marlin Options. The Black Marlin Options held by RAKGAS International FZ will be deemed to be exchanged for a number of stock options of Afren of equivalent value set out in an option rollover agreement between Afren and RAKGAS International FZ and determined in accordance with the exchange ratio and the terms of the existing option agreement between RAKGAS International FZ and Black Marlin. All Black Marlin Warrants outstanding immediately

prior to the Effective Time shall be terminated and the holder thereof shall cease to have any rights with respect thereto. The warrant holders will not receive any compensation for such termination. Further details in relation to these option arrangements are set out in paragraph 6.2 of this Part 3.

Immediately following the Effective Date, assuming a maximum of 76,776,564 New Ordinary Shares are issued pursuant to the Acquisition and that no other Ordinary Shares are issued in the period from the publication of this document to the Effective Date, it is expected that Black Marlin Shareholders and Black Marlin option-shareholders will hold approximately 7.9 per cent. and Afren's Existing Shareholders will hold approximately 92.1 per cent. of Afren's enlarged resultant issued share capital.

The New Ordinary Shares will be issued credited as fully paid and will rank *pari passu* in all respects with the Ordinary Shares in issue at the time the New Ordinary Shares are issued pursuant to the Acquisition, including the right to receive and retain dividends and other distributions (if any) paid by reference to a record date after the Effective Date.

Application will be made to the UK Listing Authority for the New Ordinary Shares to be admitted to the Official List and to the London Stock Exchange for the New Ordinary Shares to be admitted to trading on the London Stock Exchange's main market for listed securities.

3. Reasons for, and benefits of, the Acquisition

The Acquisition is consistent with Afren's pan-African strategic objective of seeking to deliver growth both organically and through acquisitions to enhance shareholder value and represents a compelling strategic entry into East Africa. The acquisition will bring together two portfolios that offer a complementary fit, providing a balanced exposure across the full E&P value cycle of production, development, appraisal and exploration. Black Marlin's portfolio of assets represents an attractive, multi-country entry position in East Africa, a region that has emerged as an exploration province of global interest following recent significant discoveries across the region.

In particular, the Acquisition:

- broadens Afren's exploration portfolio with high impact exploration interests focused on rift basins in Ethiopia, Kenya, Madagascar and the Seychelles;
- is expected to increase Afren's net prospective resources base in high impact rift basins;
- enhances geological and geographical diversification, creating a pan African independent E&P of scale;
- adds six exploration wells, expected to be drilled through 2012;
- delivers a complementary portfolio extension and high growth reinvestment opportunities to leverage Afren's significant production and revenue growth; and
- strengthens Afren's technical management team via the retention of Black Marlin personnel and is expected to unlock further East African opportunities.

The 12 assets cover a large surface area of 128,887 square kilometres on a gross basis, and are all located in basins with proven or strong evidence of working hydrocarbon systems. The portfolio is focused on basins associated with Mesozoic rifting phases associated with the break up of Gondwanaland, all of which share a common origin, including source rocks and reservoirs, with basins that are productive today (Mughlad Basin in Sudan, Bombay High and Cambay High in India, Yemen, Tanzania, Mozambique and Uganda). A number of prospects have already been defined to date across the acreage, where the potential also exists to establish new hydrocarbon plays and further large scale resource bases.

The Acquisition will further enlarge and strengthen the Company's technical management team with the introduction of highly respected oil and gas industry professionals across key disciplines that have developed an advanced understanding of the regional hydrocarbon geology.

The Acquisition is consistent with Afren's pan-African strategic objective of seeking to deliver growth both organically and through acquisitions to enhance shareholder value and represents a compelling strategic entry into East Africa.

4. Irrevocable undertakings

The Black Marlin Directors and officers have undertaken to vote in favour of the resolutions to be proposed at the Black Marlin Shareholder Meeting relating to the Acquisition pursuant to certain voting and support agreements in respect of their own beneficial holdings of 7,918,750 Black Marlin Shares representing, in aggregate, approximately 3.91 per cent. of the existing issued share capital of Black Marlin.

Certain other Black Marlin shareholders who hold a total of 103,988,733 Black Marlin Shares representing, in aggregate, 51.35 per cent. of the existing share capital of Black Marlin (on a non-diluted basis) have also entered into similar voting and support agreements with Afren, whereby such Black Marlin Shareholders have undertaken to vote in favour of the resolutions to be proposed at the Black Marlin Shareholder Meeting. The voting and support agreements can be terminated by the Black Marlin Shareholders when the Arrangement Agreement is terminated (which includes the circumstance of Black Marlin terminating the Arrangement Agreement to enter into a binding commitment in relation to a superior proposal).

5. Conditions to implementation of the Scheme

In summary, the implementation of the Scheme is conditional upon (amongst others):

- the Scheme becoming unconditional and effective by 31 December 2010;
- Black Marlin procuring the Interim Order and the Court Order on terms consistent with the Arrangement Agreement;
- approval of the Scheme by (i) a majority in number of Black Marlin Shareholders who are present and vote, either in person or by proxy, at the Shareholder Meeting (or any adjournment thereof) and who represent 75 per cent. or more in value of the Black Marlin Shares voted by such Black Marlin Shareholders, and (ii) the separate approval of the Scheme by a simple majority of the Black Marlin Shareholders present in person or by proxy in such shareholder meeting, excluding the 7,918,750 votes attached to the Black Marlin Shares owned by, or over which control or direction is exercised by, certain directors and officers who have entered into option exchange agreements with Afren and Black Marlin representing approximately 3.91 per cent. of the issued and outstanding Black Marlin Shares (both such approvals, together the “**Requisite Approval**”);
- approval of the Acquisition by Afren Shareholders at the Afren General Meeting;
- the filing of a copy of the Court Order with the Registrar of Corporate Affairs;
- exemption of the New Ordinary Shares from the registration requirements of US securities law;
- the Scheme not being rendered illegal, or its completion either prohibited or prevented as a result of statute, rule, regulation or order or any preliminary or permanent injunction having been entered into or issued by any Governmental Entity (“**Legal Impediment**”);
- the Arrangement Agreement not having been terminated in accordance with its terms;
- no material adverse effect (as defined in the Arrangement Agreement) having occurred in relation to Black Marlin or Afren;
- the applicable consents, waivers and approvals in relation to material contracts (as defined in the Arrangement Agreement) having been obtained; and
- no action, investigation, proceeding or litigation is instituted or commenced by any Governmental Entity that is reasonably likely to set aside, challenge or appeal the validity of the Interim Order or Court Order, or restrain, enjoin, prohibit or make illegal, completion of the Scheme, or result in a material adverse effect with respect to Black Marlin or Afren.

6. Further details of the Acquisition

6.1 *Structure of the Acquisition*

The Acquisition will be effected by means of the Scheme. Under the Scheme, the Scheme Shares will be transferred to Afren in exchange for New Ordinary Shares. The Scheme will involve:

- an application by Black Marlin to the Court to order a meeting of the Black Marlin Shareholders to consider, and if thought appropriate, approve the Scheme (“**Interim Order**”);
- Requisite Approval of the Scheme at the Shareholder Meeting; and
- a Court hearing (“**Court Hearing**”) at which the Court will be asked to make an Order sanctioning the Scheme (“**Court Order**”).

The Scheme will be subject to the conditions and the full terms and conditions which are summarised in paragraph 5 above.

The Scheme will only become effective following the Court Hearing on filing with the Registrar of Corporate Affairs the Court Order.

Upon the Scheme becoming effective, it will be binding on all Black Marlin Shareholders, irrespective of whether or not they attended or voted at the Shareholder Meeting.

6.2 *Black Marlin options and warrants*

The holders of Black Marlin Options (“**Black Marlin Options**”) (other than RAKGAS International FZ) have agreed that all the Black Marlin Options that remain unexercised at the Effective Time shall be cancelled by Black Marlin and exchanged for that number of New Ordinary Shares of equivalent value as set out in an option exchange agreement executed by each holder. Pursuant to this arrangement, 18,832,500 Black Marlin Options, valued at £2,632,782 at 28 May 2010, will be exchanged for 2,924,328 Afren Shares (the calculation of such number of these shares representing equivalent value was based on the 20 day volume weighted average price of Afren Shares on the London Stock Exchange as of 28 May 2010).

Black Marlin Options held by RAKGAS International FZ, valued at £66,270 as at 28 May 2010, that remain unexercised at the Effective Time will be exchanged for, and will represent, 364,702 stock options in Afren as set out in an option rollover agreement between Afren and RAKGAS International FZ and determined based on the exchange ratio in accordance with the exchange ratio and the terms of the existing option agreement between RAKGAS International FZ and Black Marlin and for which no additional consideration was paid.

The holders of common share purchase warrants of Black Marlin (the “**Warrants**”) have agreed that the Warrants that have not been exercised prior to the Effective Time shall be cancelled by Black Marlin and each holder thereof shall cease to have any rights with respect thereto. The Warrantholder will not receive any compensation for such termination.

6.3 *Arrangement Agreement*

Black Marlin and Afren have entered into the Arrangement Agreement which provides, among other things, for the implementation of the Acquisition by way of the Scheme and which contains assurances and confirmations between the parties, including provisions to implement the Scheme on a timely basis and governing the conduct of the businesses of Black Marlin during the period prior to the Acquisition becoming Effective. In addition, the Arrangement Agreement contains certain covenants from each party to use commercially reasonable efforts to take the necessary actions to give effect to the Scheme and the Acquisition and covenants of Black Marlin regarding restrictions on the solicitation of alternative transactions and responding to alternative transaction proposals. The Arrangement Agreement also contains customary representations and warranties of Black Marlin.

The Arrangement Agreement also contains certain non-solicitation provisions, pursuant to which Black Marlin provides to Afren covenants not to solicit any offer, proposal or inquiry relating to a merger or take-over of Black Marlin or any of its subsidiaries. However, under the Arrangement Agreement, in the event that Black Marlin receives an unsolicited superior offer, Afren has the right

to amend the terms of the Arrangement Agreement and the board of Black Marlin is obliged to review such proposed amendments in good faith, to determine whether the superior offer is still preferable to the proposed amended Arrangement Agreement. The Arrangement Agreement contains various provisions which govern the options available to Black Marlin in such an event, which include, but are not limited to, termination, subject to payment of a break fee (as discussed below).

Termination and Break Fee

The Arrangement Agreement may be terminated in certain circumstances including (amongst others) if the conditions to the Arrangement Agreement become incapable of being satisfied (other than as a result of breach by the terminating party), breach of the Arrangement Agreement by either party, where the Black Marlin Board has withdrawn, modified or qualified adversely its recommendation and approval for the Acquisition or Black Marlin has entered into a binding agreement with regard to a superior proposal, the scheme fails to become effective by 31 December 2010 (or such later date as the parties may agree), failure to receive the required shareholder approvals or by the written agreement of both parties.

The Arrangement Agreement provides that Black Marlin shall pay Afren a break fee of US\$4,000,000 (“**Break Fee**”) where the Agreement is terminated in the circumstances summarised below and payment shall be made within two (2) business days of such termination.

- Afren or Black Marlin terminates the Arrangement Agreement in circumstances where the Black Marlin Shareholder resolution(s) required to implement the Acquisition do not receive the Requisite Approval in circumstances where a competing acquisition proposal (as defined in the Arrangement Agreement) from another person is made or announced prior to such Shareholder Meeting and within 12 months of termination of the Arrangement Agreement an acquisition of more than 50 per cent. of the consolidated assets or issued share capital of Black Marlin is completed or Black Marlin enters into an agreement providing for the foregoing;
- Afren terminates the Arrangement Agreement in circumstances where Black Marlin has not complied with the non-solicitation provisions contained in the Arrangement Agreement or in circumstances where there has been wilful or intentional breach by Black Marlin of its covenants under the Arrangement Agreement;
- Afren terminates the Arrangement Agreement in circumstances where the Black Marlin Board has withdrawn, modified or qualified adversely its recommendation and approval for the Acquisition, approved or recommended a competing acquisition proposal or entered into a binding agreement in relation to such a proposal, or failed to publicly recommend or re-affirm its recommendation within five business days of a request to do so by Afren after a competing acquisition proposal is made or announced or any person publicly announced an intention to make a competing acquisition proposal;
- Black Marlin terminates the Arrangement Agreement in order to enter into a written agreement with regard to a superior proposal (as defined in the Arrangement Agreement); or
- Afren terminates the Arrangement Agreement in circumstances where the Shareholder Meeting has been cancelled, postponed or adjourned by Black Marlin in breach of its obligations under the Arrangement Agreement.

Where the Arrangement Agreement is terminated by either Black Marlin or Afren where the Acquisition did not receive the Requisite Approval at the Shareholder Meeting or in circumstances where Afren terminates the Arrangement Agreement if certain conditions become incapable of being satisfied as a result of any breach (other than a wilful or intentional breach) by Black Marlin of any of its covenants under the Arrangement Agreement, Black Marlin shall pay to Afren up to a maximum of US\$2,000,000 within two business days of such termination on account of its reasonably incurred expenses in connection with the Arrangement Agreement.

Where the Arrangement Agreement is terminated by either Black Marlin or Afren where the Acquisition is not approved by Afren Shareholders at the Afren General Meeting or in circumstances

where Black Marlin terminates the Arrangement Agreement either when the Black Marlin Shareholder resolution(s) to implement the Acquisition does not receive the Requisite Approval or if certain conditions become incapable of being satisfied as a result of any breach by Afren of any of its covenants under the Arrangement Agreement, Afren shall pay to Black Marlin up to a maximum of US\$2,000,000 within two business days of such termination on account of its reasonably incurred expenses in connection with the Arrangement Agreement.

6.4 *The New Ordinary Shares*

The New Ordinary Shares will be issued credited as fully paid and will rank *pari passu* in all respects with the Ordinary Shares in issue at the time the New Ordinary Shares are issued pursuant to the Acquisition.

Applications will be made to the UK Listing Authority and to the London Stock Exchange for the New Ordinary Shares to be issued in connection with the Acquisition to be admitted to the Official List and to trading on the London Stock Exchange's main market for listed securities ("New Ordinary Share Admission").

The New Ordinary Shares are expected to be issued on the Effective Date. It is expected that the New Ordinary Share Admission will become effective, and that dealings for normal settlement in the New Ordinary Shares will commence, on the date on which the Scheme becomes effective.

6.5 *Suspension and De-listing of Black Marlin Shares*

It is expected that Black Marlin will close its register of members to transfers after close of business on the business day prior to the Effective Date (expected to be 8 October 2010). The last day of dealings in, and for registration of transfers of, Black Marlin Shares is expected to be the business day prior to the Effective Date. On the Effective Date, Black Marlin Shares will be de-listed from the TSXV.

6.6 *Settlement*

Subject to the Scheme becoming effective, settlement of the consideration to which any Black Marlin Shareholder is entitled under the Scheme will be implemented in full in accordance with the terms of the Scheme free of any liens, right of set-off, counterclaims or other analogous rights to which Afren may otherwise be, or claim to be, entitled against such Black Marlin Shareholder except for any withholding required by a Governmental Entity.

- (a) Afren will issue a physical share certificate representing the Afren Shares to each Black Marlin Shareholder whose name appears on the shareholder register of Black Marlin at the Effective Time for that number of Afren Shares that the Black Marlin Shareholder is entitled to pursuant to the Acquisition and in accordance with the information provided on the register of Black Marlin. The share certificates for New Ordinary Shares will be issued on the Effective Date and despatched by first class post (for Black Marlin Shareholders in the UK) or international airmail (for Black Marlin Shareholders outside the UK) to Black Marlin Shareholders as soon as practicable after the Effective Date to the last address appearing on the shareholder register of Black Marlin (or, in the case of joint holders, to the last address of that joint holder whose name stands first in the shareholder register of Black Marlin in respect of such joint holding), unless the Black Marlin Shareholder requests that the certificates be made available for collection from the Registrar's principal place of business.

Temporary documents of title will not be issued pending the despatch by post of new definitive share certificates. Registered holders intending to trade New Ordinary Shares following the Effective Date but prior to the issue of the new share certificates must make arrangements for alternative settlement for trades of New Ordinary Shares.

Following the Effective Time, the certificates for the Black Marlin Shares will cease to be of value nor represent any right or claim of any kind or nature against Black Marlin or Afren.

(b) *Fractional entitlements*

Fractional entitlements to New Ordinary Shares arising out of the application of the exchange ratio shall be rounded down to the nearest whole number of New Ordinary Shares.

6.6.1 ***Overseas shareholders***

United States

The New Ordinary Shares to be issued pursuant to the Scheme will be issued in the United States in reliance on the exemption from registration requirements of the US Securities Act provided by Section 3(a)(10) thereof and, as a consequence, will not be registered thereunder or under the securities laws of any state, district or other jurisdiction of the United States. Neither the SEC nor any state securities commission or other regulatory authority in the United States has approved or disapproved the New Ordinary Shares or passed an opinion upon the accuracy or adequacy of this document, the Scheme Document or any of the accompanying documents. Any representation to the contrary is a criminal offence in the United States.

For the purpose of qualifying for the exemption from the registration requirements of the US Securities Act (as described above), Black Marlin will advise the Court that Afren intends to rely on the exemption provided by Section 3(a)(10) on the basis of the Court's sanctioning of the Scheme as an approval of the Scheme following a hearing on its fairness to Black Marlin Shareholders, at which hearing all such holders are entitled to attend in person or through representation to support or oppose the sanctioning of the Scheme and with respect to which notification has been given to all such holders.

Black Marlin Shareholders who may be deemed to be affiliates of Black Marlin for the purposes of the US Securities Act before implementation of the Scheme or of Afren before or after implementation of the Scheme may be subject to restrictions on the sale of New Ordinary Shares received in connection with the Scheme under Rule 144 of the US Securities Act. Black Marlin Shareholders who are affiliates may, in addition to reselling their New Ordinary Shares in the manner permitted under Rule 144 of the US Securities Act, also sell their New Ordinary Shares under any other available exemption under the US Securities Act, including a transaction which satisfies the applicable requirements for resales outside the United States pursuant to Regulation S. Black Marlin Shareholders who may be deemed to be affiliates of Afren include individuals who, or entities that, control directly or indirectly, or are controlled by or are under common control with, Black Marlin or Afren and could include certain officers and directors of Afren and may include certain significant shareholders.

Black Marlin Shareholders who are citizens or residents of the United States should consult their own legal and tax advisers with respect to the legal and tax consequences of the Scheme in their particular circumstances.

Canada

The New Ordinary Shares to be exchanged under the Arrangement will be distributed in reliance on exemptions from the prospectus and registration requirements of Applicable Canadian Securities Laws, and the New Ordinary Shares will generally be "freely tradeable" under securities laws in force in Canada if the following conditions (as specified in National Instrument 45-102 – Resale of Securities) are satisfied: (i) the trade is not a control distribution (as defined in applicable securities legislation); (ii) no unusual effort is made to prepare the market or to create a demand for the shares that are the subject of the trade; (iii) no extraordinary commission or consideration is paid to a person or company in respect of the trade; and (iv) if the selling shareholder is an insider or an officer of the issuer, the selling shareholder has no reasonable grounds to believe that the issuer is in default of securities legislation.

Black Marlin Shareholders who are residents of Canada should consult their own legal and tax advisers with respect to the legal and tax consequences of the Scheme in their particular circumstances, and with respect to the application of applicable restrictions on resales both

within and outside Canada under the securities laws of the province or territory in which they are resident.

Other Jurisdictions

The implications of the Scheme for Overseas Shareholders may be affected by the laws of relevant jurisdictions. Such Overseas Shareholders should inform themselves about, and observe, any applicable legal requirements. Any person outside the UK, United States or Canada who is resident in, or who has a registered address in, or is a citizen of, an overseas jurisdiction and who is to receive New Ordinary Shares pursuant to the Scheme should consult his or her professional advisers and satisfy himself or herself as to the full observance of the laws of the relevant jurisdiction in connection with the Scheme, including obtaining any requisite governmental or other consents, observing any other requisite formalities and paying any issue, transfer or other taxes due in such jurisdiction.

In any case where: (i) the delivery of New Ordinary Shares would infringe the laws of the jurisdiction of a Black Marlin shareholder or would require Afren to comply with any governmental or other consent or negotiation, filing or formality with which Afren is unable to comply (or where Afren regards such compliance to be unduly onerous); or (ii) Afren considers that seeking such advice would be unduly onerous or disproportionate, then Afren may at its sole discretion:

- (1) place or sell such New Ordinary Shares either directly or indirectly (including on behalf of the relevant Black Marlin Shareholder) and deliver the net proceeds to such Black Marlin Shareholder or take any other action that Afren determines necessary to deliver the equivalent cash value to the Black Marlin Shareholder in relation to its entitlement to New Ordinary Shares as calculated at the close of business in Toronto on the Effective Date; or
- (2) determine that New Ordinary Shares be issued to a nominee of such Black Marlin shareholder.

This document has been prepared for the purposes of complying with English law, the Prospectus Rules and the Listing Rules, and the information disclosed may not be the same as that which could have been disclosed if this document had been prepared in accordance with the laws of jurisdictions outside the United Kingdom.

Overseas Shareholders should consult their own legal and tax advisers with respect to the legal and tax consequences of the Scheme in their particular circumstances.

PART 4

SELECTED FINANCIAL INFORMATION

The following sets out summary consolidated audited financial information for Afren for the three years ended 31 December 2009, in each case prepared in accordance with IFRS. The information has been extracted without material adjustment from the financial information incorporated by reference in this Prospectus, as further described in Part 5.

The summary should be read in conjunction with the information referred to above and with the Operating and Financial Review in Part 5. Investors are advised to read the whole of this Prospectus and not rely on the information summarised in this Part 4.

Summary income statement data

	<i>Years ended 31 December</i>			
	<i>2009</i>	<i>2008</i>	<i>2008</i>	<i>2007</i>
	<i>US\$000's</i>	<i>As restated</i>	<i>As reported</i>	<i>US\$000's</i>
		<i>US\$000's</i>	<i>US\$000's</i>	
Revenue	335,818	42,501	42,501	–
Cost of sales	(230,036)	(70,537)	(70,980)	–
Gross profit/(loss)	105,782	(28,036)	(28,479)	–
Administrative expenses	(27,215)	(32,491)	(32,491)	(18,100)
Other operating income/(expenses)				
– derivative financial instruments	(33,635)	54,682	54,682	(5,983)
– impairment reversal/(charge) on oil and gas assets	859	(38,212)	(38,212)	(12,037)
Operating profit/(loss)	45,791	(44,057)	(44,500)	(36,120)
Investment revenue	626	5,286	5,286	2,515
Finance costs	(36,950)	(25,760)	(25,760)	(5,171)
Other gains and (losses)				
– foreign currency gains/(losses)	(2,770)	(15,382)	(15,382)	(263)
– fair value of financial liabilities and financial assets	(5,034)	26,607	26,607	–
– impairment reversal/(charge) on available for sale investments	97	(2,296)	(2,296)	–
Share of loss of an associate	(1,227)	–	–	–
Profit/(Loss) before tax	483	(55,602)	(56,045)	(39,039)
Income tax expense	(17,261)	(520)	(520)	–
Loss after tax	(16,778)	(56,122)	(56,565)	(39,039)
Loss per share	–	–	–	–
Basic and diluted	2.6c	15.0c	15.1c	16.5c

Summary balance sheet data

	<i>Years ended 31 December</i>			
	<i>2009</i>	<i>2008</i>	<i>2008</i>	<i>2007</i>
	<i>US\$000's</i>	<i>As restated</i>	<i>As reported</i>	<i>US\$000's</i>
		<i>US\$000's</i>	<i>US\$000's</i>	
Non current assets	683,969	710,738	705,512	196,785
Current assets	416,013	211,403	216,186	104,316
Total assets	1,099,982	922,141	921,698	301,101
Current liabilities	(257,613)	(256,973)	(256,973)	(40,019)
Non current liabilities	(184,121)	(314,222)	(314,222)	(151,266)
Total liabilities	(441,734)	(571,195)	(571,195)	(191,285)
Accumulated losses	(129,895)	(122,991)	(123,434)	(58,666)
Total equity	658,248	350,946	350,503	109,816

Summary cash flow statement data

	<i>Years ended 31 December</i>			
	<i>2009</i>	<i>2008</i>	<i>2008</i>	<i>2007</i>
	<i>US\$000's</i>	<i>As restated US\$000's</i>	<i>As reported US\$000's</i>	<i>US\$000's</i>
Net cash generated/(used) in operating activities	278,288	(26,811)	(26,811)	(9,407)
Net cash used in investing activities	(209,059)	(459,418)	(459,418)	(86,442)
Net cash provided by financing activities	137,416	526,909	526,909	151,213
Net increase in cash and cash equivalents	206,645	40,680	40,680	55,364
Cash and cash equivalents at end of year or period	321,312	117,719	117,719	91,783

PART 5

OPERATING AND FINANCIAL REVIEW

The following information should be read in conjunction with the financial information in this Prospectus, including the notes thereto and the basis of preparation thereof. Prospective investors should read the whole of this Prospectus and not rely on the summarised data. The Group's consolidated financial information has been prepared in accordance with IFRS.

This discussion and analysis contains forward looking statements that involve risks and uncertainties. The Group's actual results could differ materially from those expressed or implied by such forward looking statements as a result of various factors, including those discussed below and elsewhere in this Prospectus. Factors that may cause such a difference include, but are not limited to, those discussed in the section entitled "*Risk Factors*".

The information in this operating and financial review has been extracted from the audited financial information in the Annual Report and Accounts for the years ended 31 December 2009 and 2007 prepared under IFRS, as incorporated by reference in this Prospectus. The financial information for the year ended 31 December 2008 has been extracted from the comparatives in the 2009 Annual Report and Accounts to reflect the finalisation of preliminary fair values in line with IFRS 3 Business Combinations, as disclosed in Note 31 of the 2009 Annual Report and Accounts as incorporated by reference in this Prospectus.

Unless indicated otherwise, references to any figures as at 2008 in this Part 5 are to such figures as restated.

1. Principal activity and overview

Afren is a leading independent oil and gas exploration and production company focused on West Africa. Since Afren's incorporation in 2004, the Group has grown primarily through strategic acquisitions and partnerships. Until 2008, the Group's operating activities comprised primarily exploration and it had no producing assets and no revenues. The Group produced its first oil in June 2008, when the Okoro field in Nigeria was brought into production. In September 2008, Afren acquired Devon Energy's interests in Côte d'Ivoire, which included producing oil and gas assets. The Group also has other development assets in Côte d'Ivoire and Nigeria and exploration assets in Nigeria, Congo-Brazzaville, Gabon, offshore Nigeria and São Tomé & Príncipe JDZ and Ghana.

The key trends in the financial statements during the periods under review are as follows:

- the commencement of revenues in 2008 resulting from production at Okoro beginning in June 2008 and from the acquisition of the Côte d'Ivoire assets in September 2008;
- the increases in non-current assets at 31 December 2009 and 31 December 2008, as compared with 31 December 2007 and 2006, which have been driven by:
 - investment in the development of the Ebok field during 2008 and 2009, which was offset by depreciation on the Okoro field;
 - investment in the development of the Okoro field during 2007 and 2008;
 - the acquisition of the Côte d'Ivoire assets in September 2008; and
 - investment in other intangible oil and gas assets.
- the increases in liabilities at the end of 2008, as compared with 2007, driven by debt financing incurred in relation to the development of the Okoro field and the acquisition financing for the Côte d'Ivoire assets and the subsequent decline to 31 December 2009 as debt repayment was initiated;

- increases in equity in the years ended 31 December 2009, 2008 and 2007, resulting primarily from private placements in December 2009, May 2009, April 2008 and June 2007 and the early conversion of convertible bonds in July 2008; and
- the history of losses, due primarily to the incurrence of development costs, finance costs and impairments in periods prior to the Group's first revenues, which has resulted in a substantial accumulated loss position.

2. Significant factors affecting results of operations

The results of Afren's operations and the period-to-period comparability of the financial results are affected by a number of factors. The significant external factors affecting Afren's results include volatility in oil and gas prices, the effect of mark-to-market movements on Afren's derivative financial instruments, and changes in interest rates and foreign exchange rates. The significant internal factors affecting Afren's results include production volumes, reserves and Afren's success in acquiring and developing oil and gas interests.

Price of crude oil

Afren's operations are significantly affected by the prevailing price of crude oil. Crude oil prices have historically been highly volatile, dependent upon the balance between supply and demand and particularly sensitive to OPEC production levels. Any volatility and future decreases in crude oil prices could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

The Group's exposure to the risk of changes in oil price is moderated by the Group's derivative financial instruments. See "*Derivative Financial Instruments*" below.

The average crude price was higher for 2008 compared with 2009. The average Brent quotation decreased by 36.6 per cent. from US\$97.27 per barrel for the year ended 31 December 2008 to US\$61.70 per barrel for the year ended 31 December 2009.

The following table presents information on Brent crude oil prices:

	<i>Year ended 31 December 2009 US\$</i>	<i>Year ended 31 December 2008 US\$</i>	<i>Six month period ended 30 June 2010 US\$</i>
Average price for the period	61.70	97.27	77.85
Highest price for the period	79.18	145.61	88.15
Lowest price for the period	36.24	34.58	67.37

Source: Bloomberg

Production volumes

The Group's revenues are mainly directly affected by oil prices and production volumes. The volume of the Group's crude oil and gas resources and their production volumes may be lower than estimated or expected.

The following table presents information on the Group's working interest oil and gas production:

	<i>Year ended 31 December 2009</i>	<i>Year ended 31 December 2008 (annualised)</i>
Average daily oil production for the period (bopd)	18,461	3,225
Total oil production for the period (mmbbls)	6.74	1.18
Total NGL production for the period (boepd)	1,143	274
Average daily gas production for the period (mcfd)	14.27	2.89
Total gas production for the period (mmcf)	5.21	1.06

The Group's production levels also affect the level of its reserves and depreciation.

Derivative financial instruments

The Group has entered into derivative financial instruments with respect to its production from Okoro and Block CI-11, such that it will receive a minimum price if the market price falls below certain levels, but will be subject to a discount from the market price if the oil price is above the minimum level. Further description of these arrangements is set out in paragraph 10 under the heading "*Derivative financial instruments*". These instruments are marked-to-market at each balance sheet date and any movement will be reflected in the net income statement. With volatile oil markets, there can be significant movements year on year. In 2007, Afren booked a charge of US\$6.0 million, compared with a gain of US\$54.7 million in 2008 and a charge of US\$33.6 million in 2009.

Oil and gas reserves

The costs of developing a field are spread over the life of the field based on the total net reserves and charged to the net income statement based on the number of barrels produced out of the total reserves (unit of production method). The reserves of the field are based on the latest technical estimates based on production history, pressure measurements, porosity of source rock, estimates of likely reservoir limits and other factors, and cannot be known with certainty during the life of the field. If there is a significant change in the estimated net reserves for a producing field, the total costs will be spread over a smaller or larger reserves number significantly increasing or decreasing respectively the cost per barrel and therefore the total cost of sales in a period. These reserves will also underpin the total value of the field used for impairment calculations, so in very significant cases a reduction to the reserves estimate can lead to an impairment write-down.

Exploration success and impairment

The Group faces risks in connection with its appraisal, exploration and development activities. There are risks inherent in the Group's strategy of geographic diversification and acquisition of new exploration and development properties. The Group's success or failure in its exploration and appraisal activities will affect the level of its reserves and resources.

In the years ended 31 December 2009, 2008 and 2007, the Group had an impairment reversal of US\$0.9 million and impairment charges of US\$38.2 million and US\$12.0 million respectively with respect to its intangible oil and gas assets, following unsuccessful exploration and appraisal activities.

Acquisitions

One of Afren's strategies is to seek out and pursue selective acquisition opportunities where it has strategic and competitive advantages. The Group's results may be positively affected by successful acquisitions. However, the Group may direct significant resources to identifying and evaluating such opportunities, without any assurance that an acquisition will be completed successfully.

Interest rates

The Group's exposure to the risk of changes in market interest rates relates primarily to the Group's bank borrowings, all of which now have floating interest rates. The Group has historically managed the interest rate risk by using a mix of fixed and variable rates on convertible bonds, loan notes and bank borrowings respectively. The Group may also be affected by changes in market interest rates at the time it needs to refinance any of its borrowings.

Exchange Rates

The Group's results are somewhat affected by changes in the US\$/GBP exchange rate, as a significant amount of the Group's staffing and other administrative costs are denominated in GBP and by the US\$/local currency exchange rates in relation to the countries in which the Group has operations, notably Nigeria and Côte d'Ivoire.

3. Results of operations

The following table sets out the Group's income statements for the years ended 31 December 2009, 2008 and 2007:

	<i>Years ended 31 December</i>			
	2009	2008	2008	2007
	<i>US\$000's</i>	<i>As restated US\$000's</i>	<i>As reported US\$000's</i>	<i>US\$000's</i>
Revenue	335,818	42,501	42,501	–
Cost of sales	(230,036)	(70,537)	(70,980)	–
Gross profit/(loss)	105,782	(28,036)	(28,479)	–
Administrative expenses	(27,215)	(32,491)	(32,491)	(18,100)
Other operating income/(expenses)				
– derivative financial instruments	(33,635)	54,682	54,682	(5,983)
– impairment reversal/(charge) on oil and gas assets	859	(38,212)	(38,212)	(12,037)
Operating profit/(loss)	45,791	(44,057)	(44,500)	(36,120)
Investment revenue	626	5,286	5,286	2,515
Finance costs	(36,950)	(25,760)	(25,760)	(5,171)
Other gains/(losses)				
– foreign currency losses	(2,770)	(15,382)	(15,382)	(263)
– fair value of financial liabilities and financial assets	(5,034)	26,607	26,607	–
– impairment reversal/(charge) on available for sale investments	97	(2,296)	(2,296)	–
Share of loss of an associate	(1,277)	–	–	–
Profit/(loss) before tax	483	(55,602)	(56,045)	(39,039)
Income tax expense	(17,261)	(520)	(520)	–
Loss after tax	(16,778)	(56,122)	(56,565)	(39,039)
Loss per share				
Basic and diluted	2.6 cents	15.0 cents	15.1 cents	16.5 cents

The following table sets out the Group's income statements for each of six month periods ended 30 June and 31 December, 2009, 2008 and 2007.

	<i>Six month period ended 31 December 2009</i>	<i>Six month period ended 30 June 2009</i>	<i>Six month period ended 31 December 2008</i>	<i>Six month period ended 31 December 2008</i>	<i>Six month period ended 30 June 2008</i>	<i>Six month period ended 31 December 2007</i>	<i>Six month period ended 30 June 2007</i>
	<i>US\$000's</i>	<i>US\$000's</i>	<i>As restated US\$000's</i>	<i>As reported US\$000's</i>	<i>US\$000's</i>	<i>US\$000's</i>	<i>US\$000's</i>
Revenue	180,656	155,162	42,501	42,501	–	–	–
Cost of sales	(95,406)	(134,630)	(67,083)	(67,526)	(3,454)	–	–
Gross profit/(loss)	85,250	20,532	(24,582)	(25,025)	(3,454)	–	–
Administrative expenses	(16,968)	(10,247)	(14,120)	(14,120)	(18,371)	(11,485)	(6,615)
Other operating income/(expenses)							
– derivative financial instruments	(10,741)	(22,894)	55,842	55,842	(1,160)	(4,855)	(1,128)
– impairment reversal/(charge) on oil and gas assets	3,411	(2,552)	(35,543)	(35,543)	(2,669)	(12,037)	–
Operating profit/(loss)	60,952	(15,161)	(18,403)	(18,846)	(25,654)	(28,377)	(7,743)
Investment revenue	325	301	2,740	2,740	2,546	1,919	596
Finance costs	(15,034)	(21,916)	(22,463)	(22,463)	(3,297)	(2,006)	(3,165)
Other gains/(losses)							
– foreign currency losses	(4,256)	1,486	(14,994)	(14,994)	(388)	(370)	107

	<i>Six month period ended 31 December 2009</i>	<i>Six month period ended 30 June 2009</i>	<i>Six month period ended 31 December 2008 As restated US\$000's</i>	<i>Six month period ended 31 December 2008 As reported US\$000's</i>	<i>Six month period ended 30 June 2008 US\$000's</i>	<i>Six month period ended 31 December 2007 US\$000's</i>	<i>Six month period ended 30 June 2007 US\$000's</i>
– fair value of financial liabilities and financial assets	(3,378)	(1,656)	26,607	26,607	–	–	–
– impairment reversal/(charge) on available for sale investments	–	97	(2,296)	(2,296)	–	–	–
Share of loss of an associate	(757)	(520)	–	–	–	–	–
Profit/(loss) before tax	37,852	(37,369)	(28,809)	(29,252)	(26,793)	(28,834)	(10,205)
Income tax expense	(16,099)	(1,162)	(520)	(520)	–	–	–
Profit/(loss) after tax	21,753	(38,531)	(29,329)	(29,772)	(26,793)	(28,834)	(10,205)
Gain/(loss)per share							
Basic	2.9 cents	(7.3) cents	(6.8) cents	(6.9) cents	(8.6) cents	(10.7) cents	(5.0) cents
Gain/(loss)per share							
Diluted	2.5 cents	(7.3) cents	(6.8) cents	(6.9) cents	(8.6) cents	(10.7) cents	(5.0) cents

Comparison of results of operations for the years ended 31 December 2009, 2008 and 2007

Revenue

Revenue was US\$335.8 million in 2009 and US\$42.5 million in 2008. The Group produced no revenue in 2007.

The Group announced first oil from Okoro in June 2008 and production built up as planned over the following two months. However, a delay in receiving a necessary government approval resulted in the first lifting occurring in October 2008, significantly reducing the total production in the period. In total, production at Okoro reached 6.9 mmbbls in 2009, as compared with 1.2 mmbbls in 2008. The Group sold 6.4 mmbbls during 2009 (gross), compared with just over 1.0 mmbbls during 2008.

The Group's oil sales are based on various benchmark prices, however, the Group uses Brent crude prices, with adjustments for quality, transportation feed and a regional price differential, as a proxy for market prices. In 2009, total revenue from Okoro was US\$292.1 million net of royalties, as compared with US\$37.1 million net of royalties in 2008. The average price per barrel achieved in 2009 from Okoro before royalties was US\$58.7, as compared with an average price of US\$48.1 per barrel before royalties in 2008.

In September 2008, the Group completed the acquisition of Devon Energy's interests in Côte d'Ivoire. This included a 47.9592 per cent. working interest and operatorship of the producing Block CI-11 and a 100 per cent. interest in the onshore Lion Gas Plant.

Block CI-11 contributed a US\$4.5 million profit to the Group's result in 2009 before tax, as compared with a US\$9.9 million loss for the period from the acquisition date to 31 December 2008.

In addition to production from Block CI-11, gas production from adjacent Blocks CI-26 and CI-40, operated by Canadian Natural Resources Limited, is processed at the Lion Gas Plant, providing third party tariff revenue from the use of the Block CI-11 pipeline infrastructure, and additional gasoline and butane sales revenue at the Lion Gas Plant. The Lion Gas Plant contributed a US\$3.4 million profit to the Group's result in 2009, as compared with a US\$1.6 million profit for the period from the acquisition date to 31 December 2008.

Cost of Sales

Total cost of sales was US\$230.0 million in 2009 and US\$70.5 million in 2008. The Group had no cost of sales in 2007. Cost of sales declined in the six month period ended 31 December 2009 as compared with the six month period ended 30 June 2009, largely reflecting operating efficiencies for Okoro and higher depreciation rates in the six month period ended 30 June 2009 as described below.

Cost of sales – operating expenses

In 2009, total operating expenses for the Okoro field amounted to US\$73.4 million, as compared with US\$38.7 million in 2008. Cost of sales was affected by a number of factors in 2008. The FPSO for the Okoro field arrived on site in March 2008 and Afren began incurring operating costs in relation to the FPSO in June 2008 when its certificate of readiness was signed. However, sales of production from the Okoro field only commenced in October 2008, resulting in relatively high operating expenses per barrel in 2008. Additionally, there was a ramp up period for initial production as the wells were completed while the majority of the operating costs are fixed.

In Côte d'Ivoire, total operating costs were US\$16.6 million in 2009 and US\$3.5 million in 2008.

Cost of sales – depreciation, depletion and amortisation

Due to the nature of the development structure of Okoro, where Afren funds the full field development cost and recovers out of sales revenues, there is a relatively high depreciation rate. During 2009, this averaged US\$20.6 per barrel, as compared with an average of US\$21.9 per barrel in 2008, excluding stock adjustments in both years.

Depreciation for Block CI-11 was calculated at US\$16.3 per barrel in 2009 and US\$14.0 per barrel in 2008, mostly relating to the impact of the acquisition costs.

In total, field depreciation came to US\$152.2 million, as compared with US\$28.7 million in 2008.

Cost of sales – oil stock provisions

In 2008, the cost of the acquisition of the Côte d'Ivoire assets was allocated over the acquired oil and gas assets and the other Company assets as required under IFRS. As part of this, the inventory acquired was valued at fair value at the time of completion, which was approximately US\$98 per barrel. The next lifting following the acquisition occurred in December and the acquired inventory was effectively sold at around US\$40 per barrel, leading to a significant loss on disposal. This one-off cost has been booked as part of the cost of sales and amounts to US\$5.2 million.

Administrative expenses

Total administrative expenses decreased to US\$27.2 million in 2009 from US\$32.5 million in 2008. Total administrative expenses were US\$18.1 million in 2007. The increase from 2007 to 2008 reflects the Company's growth, beginning production in Nigeria in 2008 from the Okoro field and operating a midstream business in Côte d'Ivoire, offset by cost control initiatives and favourable exchange rate movements in 2009.

The Group's total staff numbers increased to an average of 172 people in 2009 from an average of 92 people in 2008 and 38 people in 2007.

At the end of 2009, Afren had operating offices in both Lagos, Nigeria and Abidjan, Côte d'Ivoire as well as a technical office in Houston, USA and the corporate office in London.

In 2009, 2008 and 2007, significant effort went into reviewing and analysing new opportunities and deals through the year. The costs related to the deals that did not complete are expensed, but there is an intangible gain as the team gains knowledge and experience that can be applied in other transactions.

Administrative expenses were also affected in 2007 by the weakening of the US dollar through the year. As the majority of administrative expenses are denominated in either Sterling or Naira, the Dollar equivalent has grown by approximately 15 per cent. year-on-year. The impact of foreign exchange movements in 2008 were immaterial.

Other operating income/expenses – derivative financial instruments

The marked-to-market loss from derivative financial instruments was US\$33.6 million in 2009, compared with a gain of US\$54.7 million in 2008 and a loss of US\$6.0 million in 2007.

In May 2007, as part of the financing arrangements for the Okoro field, Afren entered into derivative financial instruments to protect against exposure to the variability in the price of expected Okoro oil production. In September 2008, similar arrangements were established in relation to the oil production from the Côte d'Ivoire assets. Further description of these arrangements is set out in paragraph 10 under the heading "*Derivative Financial Instruments*".

These derivative instruments are marked to market for each period and the gains and losses arising out of the changes in fair value are accounted for in the income statement.

During 2009, there was a gradual increase in the oil price, with Brent moving from around US\$40 per barrel in early January to around US\$80 at the year end. This movement offset much of the prior year gain on the derivative financial instruments, with losses of US\$15.3 million relating to Okoro and US\$18.3 million relating to Côte d'Ivoire, net of cash gains on the derivative instruments, which amounted to US\$11.4 million in aggregate 2009.

During the second half of 2008, there was a significant weakening in the oil price, with Brent moving from about US\$120 per barrel in June to nearer US\$40 per barrel in December. The change in fair value of the derivative instruments resulted in a gain of US\$13.4 million relating to Okoro and US\$41.3 million relating to Côte d'Ivoire in 2008, net of cash gains on the derivative instruments, which amounted to US\$3.6 million in aggregate in 2008.

During the second half of 2007, there was a significant strengthening in the oil price, with Brent moving from around US\$70 per barrel in May to over US\$90 per barrel in December. The change in fair value of the instruments in place equated to a loss of US\$6.0 million. The fair values of these derivative instruments are likely to remain volatile as they are marked to market at each balance sheet date and their value will depend on both the spot price and the forward curve.

Other operating income/expenses – impairment of oil and gas assets

In 2009, a total of US\$0.9 million accrued due to impairment reversal, which consisted of the following:

- In December 2008 Afren announced that the deep offshore Cuda-1x well on the Keta Block in Ghana had been plugged and abandoned after encountering an unexpectedly severe high pressure zone. The costs of the well were written off as it is unlikely that a significant part of the well will be reused. The total cost to Afren, expensed in 2008, was US\$23.8 million. This was subject to an insurance claim which was settled. The net effect of the insurance claim is a credit in the 2009 income statement of US\$7.8 million.
- Afren has formally agreed with its partner Bicta to relinquish its interest in the Ogedeh opportunity in Nigeria. All remaining costs of approximately US\$2.5 million relating to the asset have been written off;
- The Iris Marin licence in Gabon was due for renewal in May 2010. Following the analysis of the well results on the block from 2008, the operator made a formal recommendation to relinquish the block. Afren reviewed its position in the last quarter of 2009 and has formally relinquished its interest in the licence. As the partners are unlikely to go ahead with the Ibekelia TEA if there is no interest in the Iris Marin licence, Afren has written off all costs related to the remaining Gabon licences (US\$2.1 million).
- Following the results of the Tie Tie NE well on the La Noubi licence in Congo-Brazzaville, all costs incurred on the well in 2009 (US\$2.1 million) have also been expensed.

In 2008 a total of US\$38.2 million was written off, which consisted of the following:

- During December 2007 and January 2008, the Admiral prospect in the Themis Marin licence in Gabon was drilled by the operator, Sterling Energy. The well was drilled on budget within 11 days, but the reservoir target was encountered with limited hydrocarbon shows. The licence period expired in March 2008, and a decision was taken by the partners to relinquish the block. As such, Afren wrote down all the costs on the licence. In addition in July 2008 an exploration well (ICM-1) was drilled on the Charlie prospect in the Iris Marin licence area. The well encountered a thick reservoir section but was water bearing and all costs relating to the Charlie well were written off. A total of US\$5.2 million of costs relating to Gabon were written off in 2008.
- As noted above, in December 2008 Afren announced that the deep offshore Cuda-1x well on the Keta Block in Ghana had been plugged and abandoned at a total cost to Afren, expensed in 2008, of US\$23.8 million, part of which was recovered under an insurance claim in 2009.
- All costs related to the Eremor project were written off during 2008 following a review of future potential on this asset. This resulted in a US\$6.0 million writedown in 2008. In April 2009, Afren and Excel entered into a deed of release and settlement whereby they agreed to terminate the Eremor Financing, Production Sharing and Technical Services Agreement dated 17 July 2007.
- Other individually immaterial items written off in 2008 totalled US\$3.2 million.

In 2007 a total of US\$12.0 million was written off, which consisted of the following:

- In 2007 Afren signed an agreement with IEL to fund a re-entry into a well and carry out a well test on the Ofa field in Nigeria. In this agreement, Afren funded 100 per cent. of the capital costs in return for a 50 per cent. interest in the economic return from the field after recovering costs. The well test, was carried out in September 2007 but the results were inconclusive due to operational issues. A further test was carried out in November and Afren concluded that the test was not encouraging enough to warrant a full development. Therefore the full costs of the well and associated expenses have been written off in the 2007 accounts, a total of US\$7.1 million.
- The first prospect (Doungou-1) on the La Noumbi permit in Congo-Brazzaville was drilled by the operator, Maurel et Prom, during August and September 2007. Although the results were encouraging for the area as a whole, as it proved the existence of a working hydrocarbon system with oil and gas shows, the low permeability of the reservoir led to the well being plugged and abandoned. The well costs of US\$2.1 million were written off in 2007; however the encouraging result for the remaining potential of the licence led to a decision not to write off any further costs on the licence in 2007. The value of the licence has been further justified by the completion of a prospect inventory of the block, listing a further eight good quality prospects.
- The write down on the Themis Marin licence in Gabon is referred to above with respect to 2008. The write down for 2007 amounted to US\$2.4 million.
- In November 2006 Afren negotiated an option relating to the central block in Angola Cabinda, for a non-refundable deposit of US\$0.4 million. That licence has since been included in the 2008 licensing round for Angola and it appears unlikely that the option will remain of attractive value and hence it was written off.

Investment revenue

The Group's investment revenue comprises interest on bank deposits and was US\$0.6 million, US\$5.3 million and US\$2.5 million in 2009, 2008 and 2007 respectively. The relatively lower investment revenue in 2009 and higher investment revenue in 2008 reflected relatively lower and higher average cash balances through the respective years and a decrease in the average interest rate in 2009.

Finance costs

The following table sets out the Group's finance costs for the years ended 31 December 2009, 2008 and 2007:

	Years ended 31 December			
	2009	2008	2008	2007
	US\$000's	As restated US\$000's	As reported US\$000's	US\$000's
Convertible bond interest payable	–	5,512	5,512	10,514
Incentive on early conversion of bonds	–	9,332	9,332	–
Bank interest payable	21,270	19,750	19,750	3,198
Borrowing costs, amortisation and facility fee charges	11,941	6,905	6,905	2,530
Interest on loan notes	1,822	414	414	–
Unwinding of discount on loan notes	2,625	422	422	–
Unwinding of discount on decommissioning	1,050	350	350	–
	38,708	42,685	42,685	16,242
Less: Capitalised interest	(1,758)	(16,925)	(16,925)	(11,071)
	<u>36,950</u>	<u>25,760</u>	<u>25,760</u>	<u>5,171</u>

Total gross interest expense (including facility fees, amortisation of costs and unwinding of discount on loan notes where applicable (but excluding the incentive on early conversion of bonds and unwinding of discount on decommissioning)) amounted to US\$37.7 million in 2009, compared with US\$33.0 million in 2008 and US\$16.2 million in 2007. The increase in interest expense is primarily attributable to increased borrowings under the Okoro field development financing facility, resulting from drawings in 2008 and 2007 and the facilities for the acquisition of the Côte d'Ivoire assets. Finance costs in the six month period ended 31 December 2009 were lower than the costs for the six month periods ending 30 June 2009 and 31 December 2008, primarily due to the lower amount of outstanding debt.

In July 2008, an agreement was reached for early conversion of the £41.25 million senior unsecured convertible bonds resulting in a one off conversion incentive of US\$9.3 million being paid to the holders of the convertible bonds. As the bonds were repaid in July, interest payable on the bonds in 2008 was substantially less than in 2007 (US\$5.5 million in 2008 compared with US\$10.5 million in 2007).

In 2009, Afren also incurred a charge of US\$1.1 million relating to the unwinding of the discount from the abandonment provisions for the Okoro field and Block CI-11. In 2008, this charge was incurred for the first time, and was US\$0.4 million.

Capitalised interest was US\$1.8 million in 2009, as compared with US\$16.9 million in 2008 and US\$11.1 million in 2007. Capitalised interest includes all the interest charged relating to the Ebok development in 2009 from project approval, the Okoro field development financing facility up to first oil in June 2008, plus a share thereafter during completion of the drilling programme in late 2008. It also includes a proportion of the interest on the US\$50 million unsecured five year loan established in September 2007 with FCMB and the convertible bond interest.

During the fourth quarter of 2009, the Ebok field transferred to development and a proportion of the borrowing cost since that date have been capitalised using a weighted average rate of borrowing of approximately 6.1 per cent. The effective interest rate used for the interest capitalisation on Okoro in 2008 was 11.1 per cent. and 15.2 per cent. in respect of the FCMB loan and the convertible bond respectively. The Okoro loan interest is based on LIBOR plus a margin of between 4.5 per cent. and 5.75 per cent. Upon conversion of the bond, interest expense on remaining debt was capitalised based on rates of between 12.2 per cent. and 13.7 per cent.

Other gains and losses

The Group made a loss of US\$2.8 million due to foreign exchange differences in 2009, compared with loss of US\$15.4 million in 2008 and US\$0.3 million in 2007. In July 2008, following conversion of the sterling denominated convertible bond into shares, Afren reviewed the functional currency of the holding company and concluded that it should be changed from GBP sterling to US dollars, aligning it with all the major subsidiaries in the Group, which had changed their functional currencies from local currency to US dollars in 2007. The revised functional currency was adopted effective 1 July 2008. The US dollar equivalent of the sterling balances fell with the change in the exchange rate from around US\$1.98/£1.00 at the start of July to around US\$1.44/£1.00 at the year end, leading to the charge to the net income in 2008.

A secondary effect of the change in functional currency from GBP sterling to US dollars in July 2008 is a change in the accounting for warrants issued by Afren that are not related to contracts for work. The change in functional currency has resulted in certain sterling denominated warrants being accounted for as derivatives from that date, as they are no longer convertible at a fixed price in the holding company's functional currency. Accordingly the fair value of the warrants on 1 July 2008 of US\$27.1 million was recorded as a liability which resulted in a charge to retained earnings, after reversing the amounts previously recorded in equity, of US\$23.7 million. As Afren's share price decreased significantly between 1 July 2008 and the year end, there was a corresponding reduction in the value of the warrants to the warrant holder and the deemed liability to Afren. The fair value of the warrants on 31 December 2008 was US\$0.5 million and the resultant movement since July of US\$26.6 million appears as a gain in the income statement. The fair value of the warrants on 31 December 2009 was US\$5.5 million and the resultant movement since 31 December 2008 of US\$5.0 million appears as a loss in the income statement. The fair value of the warrants is likely to remain volatile, and increases in the share price will result in a charge to the net income as the value of the warrants to the warrant holder, and Afren's liability, increases.

Afren owned 20.9 per cent. of the outstanding shares of Gasol as at 31 December 2009, as compared with 2.3 per cent. as at 31 December 2008. As at 31 December 2008, the fair value of the investment in Gasol was written down to reflect the year end share price, resulting in the impairment charge on available for sale investments of US\$2.3 million. As a result of the increased ownership interest in Gasol, in 2009, Afren accounted for its interest using the equity method and incurred a US\$1.3 million loss in 2009, representing its share of Gasol's losses for the period. The fair value of the Gasol shares as at 31 December 2009 was US\$8.4 million.

Taxation

At 31 December 2009, 2008 and 2007, the Group had tax losses of US\$97.2 million, US\$102.0 million and US\$32.8 million in respect of which deferred tax assets were not recognised as there was insufficient evidence of future taxable profits. Such losses can be carried forward indefinitely. The Group had temporary differences of US\$15.6 million as at 31 December 2009, as compared with US\$34.2 million as at 31 December 2008 and US\$2.4 million as at 31 December 2007 in respect of share-based payments, property, plant and equipment and pensions in respect of which deferred tax assets have not been recognised as there is insufficient evidence of future taxable profits.

In 2009 the Group incurred a tax charge of US\$17.3 million, relating to its operations in Nigeria and Côte d'Ivoire, reflecting the current and deferred tax expense for the Okoro field and the CI-11 operations. Most of this expense relates to the Group's activity in the six month period ended 31 December 2009.

In 2008, the Group incurred a small overseas corporation tax charge of US\$0.5 million relating to the Block CI-11 operations acquired in September 2008.

Losses

Afren had losses after tax of US\$16.8 million, US\$56.1 million and US\$39.0 million in 2009, 2008 and 2007 respectively. The main factors impacting the losses have been impairment charges, accounting for the mark to market of the hedging position, administrative expenses, finance costs and foreign exchange losses. The 2008 results were also adversely impacted by the high level of operating costs during the start up phase of Okoro.

4. Cash flows

The following table sets out the Group's cash flow statements for the years ended 31 December 2009, 2008 and 2007:

	<i>Years ended 31 December</i>			
	2009	2008	2008	2007
	<i>US\$000's</i>	<i>As restated US\$000's</i>	<i>As reported US\$000's</i>	<i>US\$000's</i>
Operating profit/(loss) for the year	45,791	(44,057)	(44,500)	(36,120)
Depreciation, depletion and amortisation	154,783	30,030	30,473	973
Derivative financial instruments	48,458	(55,499)	(54,682)	5,983
Impairment of oil and gas assets	(859)	38,212	38,212	12,037
Provision for inventories – spare parts	–	1,206	1,206	–
Share-based payments charge	9,292	10,819	10,819	1,995
Operating cash flows before movements in working capital	257,465	(19,289)	(18,472)	(15,132)
Decrease/(increase) in trade and other operating receivables	533	(25,149)	(30,757)	(4,287)
Increase in trade and other operating payables	31,761	22,498	23,018	10,183
Increase in inventory (crude oil)	(11,588)	(5,608)	–	–
Derivative financial instruments realised losses	–	–	–	(817)
Corporation tax paid	–	–	–	(520)
Currency translation adjustments	117	737	737	(171)
Net cash generated/(used) in operating activities	278,288	(26,811)	(26,811)	(9,407)
Purchases of property, plant and equipment:				
– Oil and gas assets	(97,810)	(224,297)	(224,297)	(63,060)
– Other	(3,770)	(5,115)	(5,115)	(1,216)
Exploration and evaluation expenditure	(90,365)	(62,396)	(62,396)	(24,538)
Increase in inventories – spare parts	(9,700)	(2,709)	(2,709)	–
Purchase of investments	(1,815)	(1,501)	(1,501)	–
Investment revenue	599	5,349	5,349	2,372
Completion payment on 2008 acquired subsidiaries	(6,198)	–	–	–
Acquisition of subsidiaries, net of cash acquired	–	(168,749)	(168,749)	–
Net cash used in investing activities	(209,059)	(459,418)	459,418	(86,442)
Issue of ordinary share capital	326,969	238,313	238,313	84,625
Costs of share issues	(14,236)	(7,663)	(7,663)	(3,219)
Proceeds from borrowings	–	362,502	362,502	84,000
Borrowing costs	–	(11,597)	(11,597)	(7,338)
Incentive paid on early conversion of bonds	–	(9,332)	(9,332)	–
Repayment of borrowings	(148,447)	(29,032)	(29,032)	–
Interest and financing fees paid	(26,870)	(16,282)	(16,282)	(6,855)
Net cash provided by financing activities	137,416	526,909	526,909	151,213
Net increase in cash and cash equivalents	206,645	40,680	40,680	55,364
Cash and cash equivalents at beginning of period	117,719	91,783	91,783	35,665
Effect of foreign exchange rates	(3,052)	(14,744)	(14,744)	754
Cash and cash equivalents at end of period	321,312	117,719	117,719	91,783

Comparison of cash flows for the years ended 31 December 2009, 2008 and 2007

Net cash used in operating activities

Net cash generated from operating activities was US\$278.3 million in 2009, compared with net cash outflow of US\$26.8 million in 2008 and US\$9.4 million in 2007. In 2009 the net cash inflow from operating activities primarily related to the sale of oil produced at Okoro. In 2008 the net cash outflow from operating activities primarily related to the operating loss for the year, together with an increase in working capital requirements. In 2007 the net cash outflow from operating activities primarily related to the operating loss for the year, which was partly offset by a reduction in working capital requirements. In 2007 the business did not produce any revenue.

Net cash used in investing activities

Net cash used in investing activities amounted to US\$209.1 million, US\$459.4 million and US\$86.4 million in 2009, 2008 and 2007, respectively. The majority of this reflects the investments in the Okoro and the Ebok projects.

In September 2008, Afren completed the acquisition of Devon Energy's interests in Côte d'Ivoire.

The smaller amount used in investing activities in 2009, relates primarily to lower investments in property, plant and equipment – oil and gas assets due to the ongoing development of the Okoro field in 2008. This was partially offset by an increase in spending on exploration and evaluation in 2009, mostly related to the appraisal costs on Ebok and residual costs related to the Cuda 1x well.

A more detailed description of the Group's recent capital expenditure is set out in paragraph 7 under the heading "*Capital expenditures*".

Net cash provided by financing activities

Net cash provided by financing activities amounted to US\$137.4 million, US\$526.9 million and US\$151.2 million in 2009, 2008 and 2007, respectively.

In November 2009, Afren raised £104.9 million (US\$175.0 million) before commissions and expenses by placing 129.5 million new ordinary shares with institutional investors at a price of 81 pence per share, in conjunction with the admission of Afren's shares to the Official List and to the London Stock Exchange's main market. In conjunction with the placing, certain shareholders including some of the Directors exercised 40,000,000 warrants over Ordinary Shares issued pursuant to Afren's Founders' Investment and Warrant Scheme, raising approximately £15 million (US\$25 million) (before expenses).

In April 2009, Afren raised approximately US\$126.3 million (before expenses) via a placement of 265 million shares with institutional investors.

During 2009, the Group also made significant debt repayments totalling US\$148 million.

In 2008 and 2007 Afren raised approximately US\$315.0 million (before expenses) via private placements of shares with institutional investors.

In October 2008 Afren issued loan notes for proceeds of US\$45.0 million (before expenses) to Sojitz, a Japanese investment and industrial conglomerate, as part of a new strategic alliance.

Bank borrowings also increased significantly in 2008 and 2007, as a result of drawdowns on the Okoro development facility, a drawdown of a US\$50.0 million facility from FCMB in 2007 and the financing for the acquisition of the Côte d'Ivoire assets in September 2008.

During 2008 a material non-cash transaction occurred, which was the early conversion in July 2008 of the Group's £41.25 million senior unsecured convertible bonds originally issued in July 2006. Afren issued 71.1 million shares upon conversion of the bonds.

A more detailed description of the Group's recent financing activities is set out in paragraph 9 under the heading "*Capitalisation and capital resources*".

Cash and cash equivalents

The Group held cash and cash equivalents of US\$321.3 million at 31 December 2009, US\$117.7 million at 31 December 2008 and US\$91.8 million at 31 December 2007. A more detailed description of the Group's liquidity position is set out in paragraph 9 under the heading "*Liquidity*".

5. Balance sheet

The following table sets out a summary of the Group's balance sheets as at 31 December 2009, 2008 and 2007:

	<i>At 31 December</i>			
	<i>2009</i>	<i>2008</i>	<i>2008</i>	<i>2007</i>
	<i>US\$000's</i>	<i>As restated US\$000's</i>	<i>As reported US\$000's</i>	<i>US\$000's</i>
Assets				
Non current assets	683,969	710,738	705,512	196,785
Current assets	416,013	211,403	216,186	104,316
Total assets	1,099,982	922,141	921,698	301,101
Liabilities				
Current liabilities	(257,613)	(256,973)	(256,973)	(40,019)
Non-current liabilities	(184,121)	(314,222)	(314,222)	(151,266)
Total liabilities	(441,734)	(571,195)	(571,195)	(191,285)
Net current (liabilities)/ assets	158,400	(45,570)	(40,787)	64,297
Net assets	658,248	350,946	350,503	109,816
Equity				
Share capital	15,702	8,806	8,806	5,365
Share premium	755,169	446,958	446,958	146,245
Other reserves	17,272	18,173	18,173	16,872
Accumulated losses	(129,895)	(122,991)	(123,434)	(58,666)
Total equity	658,248	350,946	350,503	109,816

Non-current assets

Total non current assets stood at US\$684.0 million at 31 December 2009, compared with US\$710.7 million at 31 December 2008 and US\$196.8 million at 31 December 2007. The increase from 2007 to 2008 was primarily as a result of increases in property plant and equipment (oil and gas assets) and intangible oil and gas assets. The slight decrease in 2009 as compared with 2008 resulted primarily from a decline in the value of the Group's derivative financial instruments, and a slight decline in the value of intangible oil and gas assets due to transfers to property, plant and equipment.

Property Plant and Equipment – oil and gas assets

The increases in 2008 and 2007 from prior years reflect heavy investment in Okoro. The carrying value of oil and gas assets grew to US\$486.7 million in 2009, as compared with US\$465.6 million in 2008 and US\$140.9 million in 2007. The increase in 2008 also results from the acquisition of the Côte d'Ivoire assets in September 2008 with a net value at year end of US\$75.4 million. The smaller increase in 2009 reflects the transfer of the Ebok field costs from intangible oil and gas assets following all approvals being obtained during 2009, which was mostly offset by the significant depreciation over the period on both Okoro and the Côte d'Ivoire assets.

The following table sets out the Group's oil and gas assets at cost and at their carrying amount as at 31 December 2009, 2008 and 2007:

	<i>Production US\$000's</i>	<i>Development US\$000's</i>	<i>Gas Plant US\$000's</i>	<i>Total US\$000's</i>
Oil and gas assets				
Cost and carrying amount				
At 1 January 2007	–	–	–	–
Transfer from intangible assets	–	48,476	–	48,476
Additions	–	92,450	–	92,450
At 31 December 2007	–	140,926	–	140,926
Additions	125,221	154,855	107	280,183
Acquisitions of subsidiaries as reported	89,850	–	54,578	144,428
Acquisition of subsidiaries as restated	51,534	–	27,770	79,304
Transfers	289,737	(289,737)	–	–
At 1 January 2009 as reported	504,806	6,044	54,685	565,537
At 1 January 2009 as restated	466,492	6,044	27,877	500,413
Additions	14,510	68,319	79	82,908
Transfer from intangible assets	–	90,316	–	90,316
At 31 December 2009	481,002	164,679	27,956	673,637
Depletion, depreciation and amortisation				
At 1 January 2008	–	–	–	–
Charge for year as reported	27,804	–	1,364	29,168
Charge for the year as restated	27,614	–	1,111	28,725
Impairment charge	–	6,044	–	6,044
At 1 January 2009 as reported	27,804	6,044	1,364	35,212
At 1 January 2009 as restated	27,614	6,044	1,111	34,769
Charge for the period	147,753	–	4,443	152,196
At 31 December 2009	175,367	6,044	5,554	186,965
Carrying amount				
At 31 December 2007	–	140,926	–	140,926
At 31 December 2008 as reported	477,004	–	53,321	530,325
At 31 December 2008 as restated	438,878	–	26,766	465,644
At 31 December 2009	305,635	158,635	22,402	486,672

Intangible oil and gas assets

The following table sets out the Group's intangible oil and gas assets at carrying value as at 31 December 2009, 2008 and 2007:

Costs of exploration – pending determination

	US\$000's
At 1 January 2007	87,846
Additions	21,946
Transfer to tangible oil and gas assets	(48,476)
Amounts written off	(11,660)
At 31 December 2007	49,656
Additions	95,819
Acquisition of subsidiaries as reported	35,502
Acquisition of subsidiaries as restated	100,626
Amounts written off	(32,168)
At 1 January 2009 as reported	148,809
At 1 January 2009 as restated	213,933
Additions	67,265
Transfer to tangible oil and gas assets	(90,316)
Amounts written off	(6,721)
At 31 December 2009	184,161

The following table sets out the Group's carrying value of its significant intangible oil and gas assets:

	At 31 December			
	2009	2008	2008	2007
		As restated	As reported	
	US\$ millions	US\$ millions	US\$ millions	US\$ millions
Ebok (OML 67)	–	47.0	47.0	–
CI-01 (Kudu, Eland and Ibex fields)	102.5	101.0	35.9	–
La Noumbi Permit	29.3	28.9	28.9	28.0
JDZ Block 1	17.6	17.2	17.2	16.8
Keta Block	16.0	13.2	13.2	–
OPL 310	14.3	–	–	–
Other	4.5	6.6	6.6	4.9
Total	184.2	213.9	148.8	49.7

Additional detail regarding changes in the Group's intangible oil and gas assets is set out in paragraph 7 under the heading "Capital expenditures".

Other non-current assets

Non-current assets of US\$2.2 million and US\$20.4 million were recognised in 2009 and 2008 as part of the marked to market valuation of the hedging instruments. There were no such marked to market positions within non-current assets in 2007.

Current assets

Current assets have grown to US\$416.0 million at 31 December 2009, from US\$211.4 million at 31 December 2008, US\$104.3 million at 31 December 2007. The largest component of this is the cash balance of US\$321.3 million at 31 December 2009, compared with US\$117.7 million at 31 December 2008 and US\$91.8 million at 31 December 2007. The growth in inventories to US\$34.6 million at 31 December 2009 from US\$13.3 million at 31 December 2008 and US\$3.1 million at 31 December 2007 partially reflects the additional drilling inventories from the Okoro, Ebok and Cuda 1x wells, but mostly reflects the inclusion of oil inventory (following Okoro first oil in June 2008) of US\$20.1 million at 31 December 2009 and US\$8.7 million at 31 December 2008, relating to oil produced but not sold from production at Okoro and CI-11.

The increase in trade and other receivables to US\$55.6 million at 31 December 2009, compared with US\$51.2 million at 31 December 2008 and US\$9.4 million at 31 December 2007 reflects the increasing size of the business with operating activity in three countries at 31 December 2009. In addition the further increase at 31 December 2009 reflects the recovery of the oil price and the higher priced cargos lifted, but not paid for, at that date compared with 31 December 2008. There is also a short term component of the hedging position, amounting to a current asset of US\$4.5 million at 31 December 2009 and US\$29.2 million at 31 December 2008, compared with no short term asset in 2007, reflecting the significant fall in the forward curve of the oil price at the end of 2008.

Liabilities

Total current liabilities were US\$257.6 million at 31 December 2009, as compared with US\$257.0 million at 31 December 2008, and US\$40.0 million at 31 December 2007 due both to the increase in activity levels and the short-term portion of bank debt. Although significant debt was repaid during 2009, this was offset by longer term debt becoming current liabilities over the period.

Non current liabilities were US\$184.1 million at 31 December 2009, and the decrease of US\$130.1 million compared with 31 December 2008 was due primarily to movement of a portion of borrowings to current liabilities. Non current liabilities were US\$314.2 million at 31 December 2008, and the increase of US\$163.0 million compared with 31 December 2007 was due to a combination of additional loan draw downs and the recording, for the first time, of decommissioning provisions for Okoro and the operations in Côte d'Ivoire.

A more detailed description of the Group's debt financing is set out in paragraph 9 under the heading "Capitalisation and capital resources".

6. Share capital

The following tables set out Afren's authorised and allotted ordinary share capital as at 30 June 2009 and 31 December 2008, 2007 and 2006:

	<i>At 31 December</i>			
	<i>2009</i>	<i>2008</i>	<i>2008</i>	<i>2007</i>
	<i>US\$000's</i>	<i>As restated US\$000's</i>	<i>As reported US\$000's</i>	<i>US\$000's</i>
Authorised				
1,200 million ordinary shares of 1p each (equivalent to approx US\$1.59 cents) at 31 December 2009 (800 million at 31 December 2008 and 400 million at 31 December 2007)	19,111	11,600	11,600	7,836
		<i>Equity share capital allotted and fully paid Number</i>		<i>Share premium</i>
<i>Allotted equity share capital and share premium</i>		<i>Number</i>	<i>US\$000's</i>	<i>US\$000's</i>
As at 1 January 2007		191,539,496	3,752	58,266
Issued during the year for cash ⁽¹⁾		74,443,976	1,474	79,932
Non-cash shares issued ⁽²⁾		7,023,091	139	8,047
As at 31 December 2007		273,006,563	5,365	146,245
Issued during the year for cash ⁽¹⁾		100,490,511	1,977	228,673
Non-cash shares issued ⁽³⁾		73,494,785	1,464	72,040
As at 31 December 2008 as reported and restated		446,991,859	8,806	446,958
Issued during the period for cash ⁽¹⁾		438,722,357	6,843	305,890
Non-cash shares issued ⁽⁴⁾		3,351,138	53	2,321
As at 31 December 2009		889,065,354	15,702	755,169

- (1) Share premium figure is shown net of issue costs of US\$3.2 million, US\$7.7 million and US\$14.2 million in 2007, 2008 and 2009 respectively.
- (2) Non cash shares issued were in respect of contractual arrangements concerning the Okoro field development.
- (3) Non cash shares issued were primarily in respect of the conversion of the convertible bonds during 2008.
- (4) Non cash shares issued were primarily in respect of contractual arrangements of the Ebok field in 2009.

In December 2009, Afren's ordinary shares were admitted to the Official List and to the London Stock Exchange's main market.

7. Capital expenditures

Okoro

In 2006, Afren entered into a Production Sharing and Technical Services Agreement with Amni, the licence holder, to further appraise and develop the Okoro Setu fields within a defined exclusive area in the eastern part of the block. In accordance with this agreement, the Group funded the development costs for the field and provides technical services to Amni. In 2007, the Group's interest in the Okoro field was transferred to tangible oil and gas assets in property, plant and equipment following receipt of final approval for the Field Development Plan from the Nigerian Government. In June 2008 the Okoro field came on stream. Pursuant to the arrangement with Amni, the Group is recovering its costs, plus an additional uplift, through production.

Accordingly, in 2008 and 2007, the Group invested heavily in the development of Okoro where the carrying value grew to US\$390.3 million at 31 December 2008 compared with US\$138.3 million at 31 December 2007.

Following the completion of the development and full production in the first half of 2009 with its associated depreciation, the carried value fell to US\$264.3 million at 31 December 2009.

Côte d'Ivoire Acquisition

In September 2008, Afren completed the acquisition of Devon Energy's interests in Côte d'Ivoire. This comprised a 47.9592 per cent. working interest and operatorship of the producing Block CI-11; a direct 65 per cent. interest and operatorship (with rights over an additional 15 per cent. interest) in the undeveloped Block CI-01; and a 100 per cent. interest in the onshore Lion Gas Plant. The acquisition gave Afren a fully functioning, integrated upstream oil and gas and midstream business with high quality assets and around 100 experienced staff. The adjusted consideration for the acquisition, including transaction costs and working capital adjustments, was US\$184.3 million. The transaction took the form of an acquisition of 100 per cent. of the ordinary shares of Devon Côte d'Ivoire Ltd (Block CI-11), Devon CI One Corporation (Block CI-01) and Lion G.P.L., S.A. (Lion Gas Plant). The cash outflow on acquisition (the total consideration, less cash and cash equivalents acquired, accrued consideration and non cash costs of acquisition) was US\$168.7 million.

Ebok

Significant exploration costs incurred in 2008 include the Group's farm in for the development of the Ebok field located offshore South East Nigeria. In April 2008, Afren signed a Farm-In Agreement with Oriental, a leading Nigerian-based international oil and gas company, for the appraisal and potential development of the Ebok field. The first appraisal well on this discovery was spudded in November 2008. In July 2009 Afren allotted 2,701,138 ordinary shares with a market value approximately £1.35 million to Energy Investment Holdings Limited, representing a milestone payment in relation to the Ebok project. In December 2009, Phase 1 of the Ebok development commenced, following completion of a three-well appraisal campaign. Total costs as at 31 December 2009 (including signature bonuses paid) amounted to US\$158.6 million.

Other intangible oil and gas assets

Other intangible oil and gas assets with significant carrying balances as at 31 December 2009 relate to La Noumbi (US\$29.3 million), JDZ Block 1 (US\$17.6 million) and Keta Block, Ghana (US\$16.0 million). Additional amounts are payable in relation to JDZ Block 1 if proved reserves are discovered and upon

approval of a field development programme. The amount payable is based on the level of proved reserves and prevailing oil and gas prices and is subject to adjustment upon any subsequent amendments to such oil and gas reserves. Production bonuses are payable based on attainment of certain levels of cumulative production of crude oil (at 425 millions of barrels US\$50 million is payable and at 750 millions of barrels US\$50 million is payable).

Future capital expenditures

The Group's capital expenditures are driven largely by its development of new oil and gas projects through to production, and therefore, will fluctuate in accordance with its level of success in exploration and acquisition activities. The Group's most substantial capital expenditures in the near term will relate to the development of the Ebok project.

8. Contractual obligations and contingent liabilities

At 31 December 2009, 2008 and 2007, the Group had outstanding commitments for future minimum lease payments under non-cancellable operating leases, which fall due as follows:

	<i>At 31 December</i>			
	<i>2009</i>	<i>2008</i>	<i>2008</i>	<i>2007</i>
	<i>US\$000's</i>	<i>As restated US\$000's</i>	<i>As reported US\$000's</i>	<i>US\$000's</i>
Within one year	91,749	40,998	40,998	26,520
In the second to fifth years	102,516	103,109	103,109	125,339
	<u>194,265</u>	<u>144,107</u>	<u>144,107</u>	<u>151,859</u>

Operating lease commitments included rentals of US\$29.5 million at 31 December 2009, US\$28.6 million at 31 December 2008 and US\$25.2 million at 31 December 2007 within one year and US\$73.8 million at 31 December 2009, US\$100.0 million at 31 December 2008 and US\$120.8 million at 31 December 2007 between two and five years for the FPSO that is used on the Okoro field. In addition, US\$27.4 million at 31 December 2009, US\$5.5 million at 31 December 2008 and US\$nil at 31 December 2007 within one year relates to rentals for the terminal, security boats and transport for the Okoro field. At 31 December 2009, US\$30.6 million (US\$nil at 31 December 2008 and 31 December 2007) within one year primarily relates to the lease of rig and field transport rentals in respect of the Ebok field. Other operating lease commitments represents rentals payable by the Group for certain of its office properties and long term logistics contracts. Property leases are negotiated for an average term of three years and rentals are fixed for an average term of three years.

At 31 December 2009, 31 December 2008 and 31 December 2007, the Group had future capital commitments for oil and gas asset development and oil and gas asset exploration and evaluation as follows:

	<i>At 31 December</i>			
	<i>2009</i>	<i>2008</i>	<i>2008</i>	<i>2007</i>
	<i>US\$000's</i>	<i>As restated US\$000's</i>	<i>As reported US\$000's</i>	<i>US\$000's</i>
Capital commitments				
Oil and gas assets – Development	58,952	–	–	183,278
Oil and gas assets – Exploration & Evaluation	5,637	11,154	11,154	3,951
	<u>64,589</u>	<u>11,154</u>	<u>11,154</u>	<u>187,229</u>

The significant decrease in development commitments from US\$183.3 million at 31 December 2007 to nil at 31 December 2008 relates to the Group's satisfaction of commitments in relation to the Okoro field. The increase as at 31 December 2009 represents primarily commitments related to the development of Ebok.

As at 31 December 2008, the Group had a US\$6.0 million stand-by letter of credit issued by a bank in respect of contractual arrangements of the FPSO. There were no such stand-by letters of credit as at 31 December 2007.

As at 31 December 2007, the Group had a US\$17.6 million outstanding letter of credit issued by a bank relating to a drilling contract on the Okoro development. There were no such letters of credit outstanding as at 31 December 2008.

As part of the contractual arrangements on the Ofa field in Nigeria, Afren may be liable to contribute up to a maximum of US\$0.5 million in respect of the abandonment should certain events specified in the contract occur.

Upon meeting certain operational criteria, Afren is required to reimburse a proportion of the office costs incurred by its partner on the Okwok field in Nigeria. The estimated amount payable as at 31 December 2009 is US\$600,000 (US\$nil as at 31 December 2008 and 31 December 2007).

9. Capitalisation and capital resources

The capitalisation and indebtedness of the Group, extracted from the audited financial information as at 31 December 2009 incorporated by reference in this Prospectus (see page 5), is set out below. In addition, the capitalisation of the Group as at 30 June 2010, extracted without adjustment from the unaudited management financial information of the Group, is also set out below. The Group does not have any contingent or indirect indebtedness.

The following table sets out the Group's capitalisation and indebtedness as at 30 June 2010 and 31 December 2009:

	<i>As at 30 June 2010 US\$000s</i>	<i>As at 31 December 2009 US\$000's</i>
Total current debt	(72,000)	(117,634)
Guaranteed	—	—
Secured	(55,333)	(100,967)
Unguaranteed/unsecured	(16,667)	(16,667)
Total non-current debt (excluding current portion of long term debt)	(150,480)	(163,557)
Guaranteed	—	—
Secured	(80,480)	(31,891)
Unguaranteed/unsecured	(70,000)	(131,666)
Shareholders' equity	—	—
Share capital	(15,735)	(15,702)
Share premium	(756,469)	(755,169)
Other reserves	59,029	112,623
Total	<u>(935,654)</u>	<u>(939,439)</u>

The following table sets out the Group's net cash/(indebtedness) in the short and medium-long term as at 30 June 2010 and 31 December 2009:

	<i>As at 30 June 2010 US\$000's</i>	<i>As at 31 December 2009 US\$000's</i>
Cash	194,019	321,312
Cash equivalent	—	—
Trading securities	—	—
Liquidity	<u>194,019</u>	<u>321,312</u>
Current bank debt	(72,000)	(117,634)
Other current financial debt	—	—
Current financial indebtedness	<u>(72,000)</u>	<u>(117,634)</u>
Non-current bank loans	(105,480)	(118,557)
Bonds issued	—	—
Other non-current loans	(45,000)	(45,000)
Non-current financial indebtedness	<u>(150,480)</u>	<u>(163,557)</u>
Net financial cash (indebtedness)	<u>(28,460)</u>	<u>40,121</u>

Liquidity

The Group's liquidity requirements arise principally from its capital expenditure and working capital requirements. For the periods presented, the Group met its working capital requirements primarily from oil sales and the proceeds of equity and debt financings. The Company intends to satisfy its liquidity requirements going forward through cashflow from operations, existing cash balances (approximately US\$194 million as at 30 June 2010) and headroom under the US\$150 million Ebok facility (of which US\$25 million has been drawn down and a further US\$25 million was drawn down on 12 August 2010).

The Group held cash and cash equivalents of US\$194.0 million at 30 June 2010, US\$321.3 million at 31 December 2009, US\$117.7 million at 31 December 2008 and US\$91.8 million at 31 December 2007.

The Group's cash and cash equivalents balance at 30 June 2010 included US\$29.5 million and at 31 December 2009 included US\$5.4 million to which the Group had restricted access as a result of short term restrictions on project cash, pending completion of certain milestones. This compares with US\$58.9 million and US\$25.0 million to which the Group had restricted access at 31 December 2008 and 31 December 2007 respectively.

Financing

Equity financing

In November 2009, Afren raised £104.9 million (US\$175.0 million) before commissions and expenses by placing 129.5 million new ordinary shares with institutional investors, in conjunction with the admission of Afren's shares to the Official List and to the London Stock Exchange's main market. In conjunction with the placing, certain shareholders including some of the Directors exercised 40,000,000 warrants over Ordinary Shares issued pursuant to Afren's Founders' Investment and Warrant Scheme, raising approximately £15 million (US\$25 million) (before expenses).

In April 2009, Afren raised approximately US\$126.3 million (before expenses) via a placement of 265 million shares with institutional investors.

In July 2008, an agreement was reached for early conversion of the £41.25 million senior unsecured convertible bonds originally issued in July 2006. Afren issued 71.1 million shares upon conversion of the bonds.

In April 2008, Afren raised approximately US\$235.0 million (before expenses) via a placement of 95 million shares with institutional investors.

In June 2007, Afren raised approximately US\$65.0 million (before expenses) via a private placement of 55.3 million shares.

In April 2007, US\$15.0 million of equity funds were raised via a private placement with Standard Bank (US\$10.0 million) and BNP Paribas.

Debt financing

Total debt at 30 June 2010 amounted to approximately US\$222.48 million.

As at 30 June 2010, the drawdown on the Ebok facility was approximately US\$25 million under the initial US\$150 million facility, which is the only drawdown the Group has made under all its facilities in the year 2010 to date. In addition, an additional drawdown under the Ebok facility of US\$25 million was made on 12 August 2010. Since 30 June 2010 there has been a semi-annual repayment of US\$6.67 million relating to subordinate debt in Côte d'Ivoire.

The following table presents information on the Group's borrowings as at 31 December 2009, 2008 and 2007:

	<i>As at 31 December</i>							
	<i>2009</i>		<i>2008</i>		<i>2008</i>		<i>2007</i>	
			<i>As restated</i>		<i>As reported</i>			
	<i>Current</i>	<i>Non-current</i>	<i>Current</i>	<i>Non-current</i>	<i>Current</i>	<i>Non-current</i>	<i>Current</i>	<i>Non-current</i>
	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>
Convertible Bonds	–	–	–	–	–	–	–	69,206
Loan notes	–	37,216	–	33,205	–	33,205	–	–
Bank borrowings	117,634	112,230	111,218	260,741	111,218	260,741	–	77,485
	<u>117,634</u>	<u>149,446</u>	<u>111,218</u>	<u>293,946</u>	<u>111,218</u>	<u>293,946</u>	<u>–</u>	<u>146,691</u>

Bank borrowings relating to the US\$230 million Okoro Development facility from BNP Paribas, were US\$73.5 million at 31 December 2009, US\$191.6 million at 31 December 2008 and US\$32.4 million at 31 December 2007. Interest on the loan is based on LIBOR plus a margin of between 4.5 per cent. and 5.75 per cent. as at 31 December 2009. The facility is repayable in semi-annual instalments of approximately US\$30.0 million ending in 2011. The loan is secured by the assets of the Okoro field. The repayment profile is impacted by borrowing base calculations linked to the certified reserves of the Okoro field.

The acquisition of operations in Côte d'Ivoire was financed by a financing package arranged through BNP Paribas. The outstanding balance on the financing package was US\$111.7 million as at 31 December 2009 (US\$108.5 million at 31 December 2009 net of financing arrangement costs). Repayment instalments for US\$45.1 million (senior debt) of the facility amount are determined by borrowing base calculations linked to the certified reserves of the Côte d'Ivoire operations whilst US\$66.7 million (subordinate debt) of the facility is repayable in semi-annual instalments of US\$6.7 million which commenced in January 2010. Interest on the senior debt is based on LIBOR plus a margin of between 3.25 per cent. and 3.5 per cent. as at 31 December 2009. Interest on the subordinate debt is based on LIBOR plus a margin of 4.25 per cent. The senior debt includes certain financial covenants which are assessed on a quarterly basis.

Borrowings also include a balance of US\$47.9 million at 31 December 2009, US\$46.5 million at 31 December 2008 and US\$45.1 million at 31 December 2007, relating to an unsecured loan facility from First City Monument Bank plc. Interest on the loan is based on LIBOR plus a margin of 4.45 per cent. The loan is repayable in six equal semi-annual instalments commencing 2010 and ending in 2012.

In October 2008 Afren entered into a strategic alliance with Sojitz, a Japanese investment and industrial conglomerate, to jointly pursue acquisition opportunities of scale in Africa. Sojitz invested US\$45.0 million in the form of loan notes in Afren which become convertible bonds at the time of entering into or announcing joint acquisitions. The net proceeds from the issue of the loan notes were split between a liability component and an equity component at the date of issue. The liability component of the loan notes was US\$37.2 million as at 31 December 2009.

The July 2008 conversion of the £41.25 million senior unsecured convertible bonds reduced the Group's debt by approximately US\$70.9 million.

The following table presents information on the Group's debt maturity profile as at 30 June 2009 and 31 December 2009, 2008 and 2007:

	<i>As at 31 December</i>			
	2009	2008	2008	2007
		<i>As restated</i>	<i>As reported</i>	
	<i>US\$000's</i>	<i>US\$000's</i>	<i>US\$000's</i>	<i>US\$000's</i>
Due within one year	117,634	111,218	111,218	11,030
Due within two to five years	163,557	318,421	318,421	157,410
Due after five years	–	–	–	–
	<u>281,191</u>	<u>429,639</u>	<u>429,639</u>	<u>168,440</u>

In 2010 the Group estimates that it will be required to repay US\$117.6 million of debt principal repayments. The Group intends that it will be able to repay its borrowings through cash flow from operations.

The Group has also recently commenced the appraisal and development of the Ebok field in Nigeria. The anticipated capital expenditure has subsequently increased as a result of two factors: i) during 2009 the base case reserves and upside resources of Ebok increased and ii) as a result of the Company's development obligations in respect of Okwok, the potential appraisal and development costs in relation to the broader Ebok – Okwok complex. In March 2010, the Group secured a loan facility of up to US\$450 million with a maturity of up to five years. The facility is secured on Afren's share of production from the Ebok field, with the borrowing base being determined by the Project and is a reserves based facility intended to assist in the funding of the broader Ebok Okwok complex. This facility will provide the Group with additional financial flexibility with respect to the broader Ebok Okwok complex development programme.

A more detailed description of the Group's financing contracts, including the covenants, is set out in paragraph 14 of Part 10 under the heading "*Financing arrangements*".

10. Key financial risks

Financial risk management

The Group's principal financial instruments are cash and cash equivalents, trade and other receivables and its derivative instruments. The Group manages liquidity risk by ensuring that sufficient funds are available to meet its commitments as they fall due. The Group uses projected cash flows to monitor funding requirements for the Group's activities. The Group's exposure to the risk of changes in market interest rates is mitigated by regular reviews of available fixed and variable rate debts and taking the most favourable for the Group's needs. The interest on borrowings from BNP Paribas, Sojitz and FCMB is based on LIBOR plus a margin and therefore the interest charged is affected by movement in LIBOR.

Credit risk management

Credit risk refers to the risk that a counter-party will default on its contractual obligations resulting in financial loss to the Group. The Group reviews the credit risk of the entities that it sells its products to or that it enters into contractual arrangements with and will obtain guarantees and commercial letters of credit as may be considered necessary where risks are significant to the Group. The Group's business is diversified in terms of both region and the number of counter-parties and, other than transactions with major oil companies with high credit ratings and government organisations in Côte d'Ivoire, the Group does not have significant exposure to any single counter-party or group of counter parties with similar characteristics. The credit risk on cash is limited because the majority is deposited with banks with good credit ratings assigned by international credit rating agencies or banks backed by government guarantees. The Group's total maximum exposure to credit risk as at 31 December 2009 was US\$384 million, made up of cash and bank balances, derivative financial instruments and trade and other receivables.

Liquidity risk management

Liquidity and refinancing risks refer to the risk that the Group will not be able to obtain sufficient financing from lenders and the capital markets to meet its working capital and project financing and refinancing requirements. The Group maintains a rolling 18 month cashflow forecast which is reviewed on an ongoing basis by senior members of the finance team and at least monthly by the CEO. Should the cashflow forecast show a reduced working capital level, then forecast expenditure profiles are reviewed and unfunded commitments deferred until new financing is obtained.

Derivative financial instruments

	<i>As at 31 December</i>							
	<i>2009</i>		<i>2008</i>		<i>2008</i>		<i>2007</i>	
			<i>As restated</i>		<i>As reported</i>			
	<i>Current</i>	<i>Non-current</i>	<i>Current</i>	<i>Non-current</i>	<i>Current</i>	<i>Non-current</i>	<i>Current</i>	<i>Non-current</i>
	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>	<i>\$000's</i>
Derivative assets	4,523	2,153	29,161	20,354	29,161	20,354	–	–
Derivative liabilities	(5,240)	(379)	–	–	–	–	(1,408)	(4,575)
	(717)	1,774	29,161	20,354	29,161	20,354	(1,408)	(4,575)

In 2007 the Group entered into derivative financial instruments (swaps and call options) to economically protect against exposures to variability in the price of Okoro crude oil production for 2008, 2009 and 2010. The Group will receive a minimum amount if the market falls, but will be subject to a set discount from the market price if the oil price is above that minimum. The arrangement protects the Group against the risk of a significant fall in the price of crude oil by establishing a minimum price for the Okoro crude.

During 2008 on acquisition of the Block CI-11 in Côte d'Ivoire from Devon Energy, the Group entered into similar instruments to protect against variability in price of Block CI-11 crude oil production for 2008, 2009, 2010, 2011 and 2012.

In June 2009, an additional derivative contract in respect of Okoro crude was entered into for the period 2009 to 2011, giving the same protection for an additional tranche of crude production.

The loss of US\$33.6 million arising during the year ended 31 December 2009 as a result of the changes in fair value of these derivative financial instruments are accounted for in the income statement, as the criteria for hedge accounting were not met. The gain of US\$54.7 million in 2008 and the loss of US\$6.0 million in 2007 were treated similarly.

11. Critical accounting policies

Functional and presentation currencies

The Company's significant subsidiaries all have US dollar functional currencies. In July 2008, the sterling denominated convertible bond issued by Afren converted into shares and following this, Afren reviewed the functional currency of the holding company and concluded that it should be changed from pounds sterling to US dollars, aligning it with all the major subsidiaries in the Group. The majority of Afren's transactions, in value, and assets and liabilities are now in US dollars and hence it was appropriate to change the functional currency.

Business combinations

The acquisition of subsidiaries is accounted for using the purchase method. The cost of the acquisition is measured at the aggregate of fair values, at the date of exchange, of assets given, liabilities incurred or assumed, and equity instruments issued by the Group in exchange for control of the acquiree, plus any costs directly attributable to the business combination. The acquiree's identifiable assets, liabilities and contingent liabilities that meet the conditions for recognition under IFRS 3 are recognised at their fair value at the acquisition date.

Goodwill arising on acquisitions is recognised as an asset and initially measured at cost, being the excess of the cost of the business combination over the Group's interest in the net fair value of the identifiable assets, liabilities and contingent liabilities recognised.

If, after reassessment, the Group's interest in the net fair value of the acquiree's identifiable assets, liabilities and contingent liabilities exceeds the cost of the business combination, the excess is recognised immediately in the income statement.

Exploration, evaluation and oil and gas assets

The Group follows the successful efforts method of accounting for exploration and evaluation (**E&E**) costs. All licence acquisition, exploration and evaluation costs are initially capitalised as intangible fixed assets in cost centres by field or exploration area, as appropriate, pending determination of commerciality of the relevant property.

Directly attributable administration costs are capitalised insofar as they relate to specific exploration activities. Pre-licence costs and general exploration costs not specific to any particular licence or prospect are expensed as incurred.

If prospects are deemed to be impaired ('unsuccessful') on completion of the evaluation, the associated costs are charged to the income statement. If the field is determined to be commercially viable, the attributable costs are transferred to property, plant and equipment in single field cost centres. These costs are then depreciated on a unit of production basis.

All field development costs are capitalised as property, plant and equipment. Property, plant and equipment related to production activities are amortised in accordance with the Group's depletion and amortisation accounting policy.

Revenues

Revenue represents the sales value, net of VAT and royalties paid in kind or where the financial obligation does not fall directly to Afren, of the Group's share of oil liftings in the year together with gas and material tariff income and interest income. Oil and gas revenue is recognised when goods are delivered and title has passed. Interest income is accrued on a time basis by reference to the principal outstanding and at the effective interest rate applicable, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount.

Commercial reserves

Commercial reserves are proven and probable oil and gas reserves, which are defined as the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 per cent. statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable reserves and a 50 per cent. statistical probability that it will be less.

Depletion and amortisation – oil and gas assets

All expenditure carried within each field is amortised from the commencement of production on a unit of production basis, which is the ratio of oil and gas production in the period to the estimated quantities of commercial reserves at the end of the period plus the production in the period, generally on a field-by-field basis. Costs used in the unit of production calculation comprise the net book value of capitalised costs plus the estimated future field development costs. Changes in the estimates of commercial reserves or future field development costs are dealt with prospectively.

Where there has been a change in economic conditions that indicates a possible impairment in a discovery field, the recoverability of the net book value relating to that field is assessed by comparison with the estimated discounted future cash flows based on management's expectations of future oil and gas prices and future costs.

Any impairment identified is charged to the income statement as additional depletion and amortisation. Where conditions giving rise to impairment subsequently reverse, the effect of the impairment charge is also reversed as a credit to the income statement, net of any depreciation that would have been charged since the impairment.

Decommissioning

Provision for decommissioning is recognised in full when the related facilities are installed. A corresponding amount equivalent to the provision is also recognised as part of the cost of the related property, plant and equipment. The amount recognised is the estimated cost of decommissioning, discounted to its net present value, and is reassessed each year in accordance with local conditions and requirements.

Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment.

The unwinding of the discount on the decommissioning is included as a finance cost.

Impairment

Non-current assets are assessed for impairment when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Such triggering events are defined in IFRS 6 in respect of E&E assets and include the point at which determination is made as to whether commercial reserves exist.

Where there has been an indication of a possible impairment, management assesses the recoverability of the carrying value of the asset by comparison with the estimated discounted future net cash flows based on management's expectation of future production, oil prices and costs. Any identified impairment is charged to the income statement.

Share-based payments

The Group makes equity settled share-based payments to certain employees and other third parties. Equity settled share-based schemes are measured at fair value (excluding the effect of non market-based vesting conditions) at the date of grant, measured by use of an option valuation model. The expected life used in the model has been adjusted, based on management's best estimate, for the effects of non-transferability, exercise restrictions and behavioural considerations.

The fair value determined at the grant date of the equity settled share-based payments is expensed on a straight-line basis over the period to exercise, based on the Group's estimate of shares that will eventually vest.

The Company is liable for Employer's National Insurance on the difference between the market value at date of exercise and exercise price. This expense is accrued by reference to the share price of the Company at the balance sheet date.

Finance costs and debt

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale.

Financial costs of debt are allocated to periods over the term of the related debt at a constant rate on the carrying amount. Arrangement fees and issue costs are deducted from the debt proceeds on initial recognition of the liability and are amortised and charged to the income statement as finance costs over the term of the debt.

Derivative financial instruments

The Group has entered into swaps and call options to economically protect against exposures to variability in the price of a proportion of Okoro and Côte d'Ivoire crude oil production for 2008 to 2012. Derivative financial instruments are stated at fair value. The gains and losses arising out of changes in fair value of these derivative financial instruments together with settlements in the period are accounted for in other operating income/(expense) in the income statement in the period in which they are incurred.

Convertible bonds

Convertible bonds are regarded as compound instruments, consisting of a liability component and an equity component. At the date of issue, the fair value of the liability component is estimated using the prevailing market interest rate for similar non-convertible debt. The difference between the proceeds of issue of the convertible loan notes and the fair value assigned to the liability component, representing the embedded option to convert the liability into equity of the Group, is included in equity.

Issue costs are apportioned between the liability and equity components of the convertible loan notes based on their relative carrying amounts at the date of issue.

The portion relating to the equity component is charged directly against equity.

The interest expense on the liability component is calculated by applying the prevailing market interest rate for similar non-convertible debt to the liability component of the instrument. The difference between this amount and the interest paid is added to the carrying amount of the convertible loan note.

12. Critical accounting judgements

A description of the Group's critical accounting judgements and key sources of estimation uncertainty, which may have a significant effect on the amounts recognised in the Group's financial statements, is included in note 3 of the Group's financial statements.

13. Dividend policy

The Directors do not expect that Afren will pay any dividends in the foreseeable future, and in any event until such time as it is prudent to do so, having regard to the level of revenue generated by the Group's operations and the retained earnings to fund its operations and exploration and development programmes. For the foreseeable future, any earnings will be reinvested in developing the businesses of the Group.

14. Current trading and future prospects

Production

Gross production from Okoro for the 6 month period to 30 June 2010 was 3,229,178 bbls (average gross 17,841 bopd). Two infill wells are planned at Okoro that are expected to add gross incremental production of between 3,000 bopd and 5,000 bopd over the second half of 2010. Average gross production and NGL output from CI-11 and the associated Lion Gas Plant for the 6 month period to 30 June 2010 was 6,481 boepd.

The Lion Gas Plant also received significantly reduced third party inlet volumes over the period as a result of work on the gas compression systems at the CNR operated Espoir and Baobab facilities. Average gross daily production from the Lion Gas Plant for the 6 month period to 30 June 2010 was 654 boepd.

Development

Afren's Ebok Phase 1 development commenced in December 2009 and consists of six horizontal production wells and one water injection well. First oil is expected in the fourth quarter of 2010.

In January 2010, production, processing and storage facilities for the Ebok development were contracted. A tanker owned by Mercator, a major Indian shipping company, is being converted into a floating storage offloading vessel ("FSO"). The vessel has been designed with a storage capacity of 1.2 million barrels and will be spread-moored near a mobile offshore production unit ("MOPU"), which is currently being

refurbished and upgraded. The FSO vessel and MOPU will be leased to the Ebok development over an initial seven year period at a rate of US\$98,092 per day, with an option to extend.

Future development phases will target the West Fault Block (Phase 2, incorporating the installation of an additional dedicated wellhead platform (“**WHP**”) and six development wells tied back to the central Ebok MOPU and FSO facilities), the upside potential established in the Southern Lobe (Ebok 6), full development of the D1 reservoir in the Central Fault Block 1 and Fault Block 2 area of the field and any other commercial reserve additions from future exploration and appraisal drilling activity.

In March, a contract was signed for a jack up drilling unit to undertake planned drilling across the Company’s assets offshore in shallow water south-east Nigeria. The contract is for a duration of up to 210 days and was agreed at a day rate of US\$84,000.

Exploration and appraisal

In January 2010, the Company announced the acquisition of an interest in the OML 115 block, which surrounds the Ebok and Okwok discoveries. On 15 July 2010, Afren announced that terms have been agreed to acquire Energy Equity Resources Oil and Gas residual interest in OML 115. Following completion of this transaction, Afren’s interest in OML 115 will be 40 per cent.

One appraisal well is planned in the second half of 2010 on the Okwok discovery to confirm and define commercial development requirements of the field. An exploration well on OML 115 is also planned for the second half of 2010, subject to rig availability.

An exploration well is also planned at OPL 310, following a successful farm-out. The block is located offshore south-west Nigeria. An electro-magnetic survey is currently underway on the block.

Financial position

In March 2010, Afren entered into a debt facility agreement for up to US\$450 million, which is secured against the Ebok field reserves. The facility will provide up to US\$450 million of reserves based lending and has a maturity up to five years, is repayable semi-annually and has a margin of between 4.0 per cent. and 5.5 per cent. over LIBOR. The facility will be available to be used for development of the Ebok, Okwok and OML 115 areas, offshore south-east Nigeria.

Afren’s net debt/(cash) at 30 June 2010 was US\$12.2 million.

Current assets

As highlighted in January 2010, the Company has an intensive drilling programme for 2010, in particular on the Ebok development. Accordingly, since the start of 2010 Afren has been funding the development of the Ebok field, and exploration of the surrounding area as set out in paragraph 14 of Part 6 of the Prospectus.

Consequently, and in line with the Company's plans, as at the date of this Prospectus, this has resulted in an increase in the non-current assets of the Company from the start of 2010, principally as a result of an increase in oil and gas assets reflecting the investment in Ebok, and a corresponding decrease in current assets from the start of 2010, principally reflecting the cash contributions towards the drilling and development programmes.

PART 6

HISTORICAL FINANCIAL INFORMATION ON BLACK MARLIN ENERGY LIMITED

PART A: HISTORICAL FINANCIAL INFORMATION ON BLACK MARLIN ENERGY LIMITED

Basis of Financial Information

This section sets out the consolidated financial information of Black Marlin and its subsidiary undertakings for the financial years ending 31 December 2007, 2008, and 2009. The accountant's report on such financial information are also set out in this Part 6. The auditors reports of BDO Chartered Accountants and Advisors, who is a member of and regulated by the Federal Government of the United Arab Emirates, for each of these three years was unqualified and did not contain a statement under section 498(2) or 498(3) of the Companies Act 2006.

The financial information for the years ended 31 December 2007, 2008, and 2009 set out in this document has been extracted without material adjustment from the audited consolidated financial statements of Black Marlin for the years ended 31 December 2007, 31 December 2008, and 31 December 2009 which were prepared in accordance with IFRS.

The financial information included within this Part 6 does not constitute statutory accounts within the meaning of section 434 of the Companies Act 2006.

Consolidated statement of comprehensive income for the three years ended 31 December

		<i>For the three years ended 31 December</i>		
	<i>Note</i>	<i>2007</i>	<i>2008</i>	<i>2009</i>
		<i>(U.S. Dollars)</i>		
Revenue		21,067,730	8,022,064	6,284,624
Cost of sales		(17,191,436)	(15,493,381)	(11,886,864)
Gross (loss)/profit		3,876,294	(7,471,317)	(5,602,240)
Other income		259,862	336,857	531,361
		4,136,156	(7,134,460)	(5,070,879)
Administration, selling and general expenses	14	(2,459,482)	(3,724,241)	(4,047,520)
Finance cost		183,870	—	—
(loss)/profit for the year before tax		1,492,804	(10,858,701)	(9,118,399)
Corporate taxes		(26,974)	—	—
Total comprehensive income for the year		<u>1,465,830</u>	<u>(10,858,701)</u>	<u>(9,118,399)</u>

Consolidated statement of financial position at 31 December

	<i>Note</i>	<i>Position at 31 December</i>		
		<i>2007</i>	<i>2008</i>	<i>2009</i>
		<i>(U.S. Dollars)</i>		
Non current assets				
Property, plant and equipment	6	7,096,570	8,853,107	7,462,760
Investment in joint ventures	7	3,354,741	8,905,094	11,516,566
Total non current assets		10,451,311	17,758,201	18,979,326
Current assets				
Trade and other receivables	8	6,744,693	2,746,556	2,467,266
Due from related parties	9	67,307	—	—
Bank balances and cash	10	669,261	4,983,477	1,700,627
Total current assets		7,481,261	7,730,033	4,167,893
Current liabilities				
Trade and other payables	11	4,105,344	4,071,827	8,046,533
Due to related parties	9	15,255	32,630	113,168
Loans from related parties	9	1,767,538	150,512	2,863,790
Total current liabilities		5,888,137	4,254,969	11,023,491
Net current (liabilities)/assets		1,593,124	3,475,064	(6,855,598)
Non current liabilities				
Provision for employees' end of service gratuities		(14,629)	(12,168)	(21,030)
Net assets		12,029,806	21,221,097	12,102,698
Equity				
Share capital	12	17,766,667	26,850,492	26,850,492
Share premium	13	2,383,333	13,349,500	13,349,500
Accumulated deficit		(8,120,194)	(18,978,895)	(28,097,294)
Total equity		12,029,806	21,221,097	12,102,698

Consolidated statement of changes in equity for the three years ended 31 December 2009

Three years ended 31 December 2009

	<i>Share capital</i>	<i>Share premium (U.S. Dollars)</i>	<i>Accumulated deficit</i>	<i>Total equity</i>
Balance at 1 January 2007	13,766,667	383,324	(9,586,024)	4,563,967
Additional capital introduced	4,000,000	2,000,000	–	6,000,000
Total comprehensive income for the year	–	–	1,465,830	1,465,830
Balance at 1 January 2008	17,766,667	2,383,324	(8,120,194)	12,029,797
Additional capital introduced	9,083,825	10,966,176	–	20,050,001
Total comprehensive income for the year	–	–	(10,858,701)	(10,858,701)
Balance at 31 December 2008	26,850,492	13,349,500	(18,978,895)	21,221,097
Total comprehensive income for the year	–	–	(9,118,399)	(9,118,399)
Balance at 31 December 2009	26,850,492	13,349,500	(28,097,294)	12,102,698

Consolidated statement of cash flows for the three years ended 31 December 2009

		Three years ended 31 December 2009		
	Note	2007	2008	2009
		(U.S. Dollars)		
Cash flows from operating activities				
Net (loss)/profit for the year		1,465,830	(10,858,701)	(9,118,399)
Adjustments for:				
Depreciation	6	1,589,240	2,665,271	3,183,630
Loss on disposal of property, plant and equipment		—	5,075	27,794
Provision for employees' end of service gratuities		14,629	(2,461)	8,862
<i>Operating loss before working capital changes</i>		3,069,700	(8,190,816)	(5,898,113)
Change in trade and other receivables	8	(5,451,179)	3,998,137	279,290
Change in due from related parties		292,957	67,307	—
Change in trade and other payables	11	2,094,861	(33,517)	3,974,706
Change in due to related parties	9	(157,614)	17,375	80,538
<i>Net cash used in operating activities</i>		(151,275)	(4,141,514)	(1,563,579)
Cash flows from investing activities				
Purchase of property, plant and equipment	6	(4,995,166)	(4,578,173)	(1,904,170)
Proceeds from disposal of property, plant and equipment	6	—	151,281	83,093
Addition in investment in joint ventures		(2,022,799)	(5,550,353)	(2,611,472)
<i>Net cash used in investing activities</i>		(7,017,965)	(9,977,245)	(4,432,549)
Cash flows from financing activities				
Change in loans from related parties		1,567,538	(1,617,026)	2,713,278
Additional capital introduced		4,000,000	9,083,825	—
Share premium received		2,000,000	10,966,176	—
<i>Net cash from financing activities</i>		7,567,538	18,432,975	2,713,278
Net change in cash and cash equivalents		398,298	4,314,216	(3,282,850)
Cash and cash equivalents at beginning of the year		270,963	669,261	4,983,477
Cash and cash equivalents at end of the year	10	669,261	4,983,477	1,700,627

1. Status and activity

Black Marlin Energy Limited, British Virgin Islands (“the Company”) operates under a license issued by the Government of British Virgin Islands. The registered address of the Company is Akara Building, 24 De Castro Street, Wickhams Cay 1, Road Town, Tortola, British Virgin Islands.

The principal activities of the Company are seismic acquisition services on land, transition zone and shallow water and also acquiring petroleum exploration ventures in the East African region.

This consolidated financial information is presented in United States Dollars (“USD”) being the functional currency of the Company.

2. Basis of consolidation

The Company has investments in subsidiaries and is required to prepare consolidated financial information as per IAS 27. Details of the Company’s subsidiaries as at 31 December 2009 are as follows.

<i>Name of subsidiary</i>	<i>Place of incorporation and operation</i>	<i>Ownership interest %</i>	<i>Voting power held %</i>	<i>Principal activity</i>
Upstream Petroleum Services Limited	British Virgin Islands	100	100	Providing seismic acquisition services on land, transition zones and shallow water.
East African Exploration Limited	British Virgin Islands	100	100	Acquiring petroleum exploration ventures in the East African region.
Black Marlin Exploration Limited	British Virgin Islands	100	100	Acquiring petroleum exploration ventures in the East African region.
Black Marlin Energy DMCC	Dubai, United Arab Emirates	100	100	Providing services in oil and gas exploration, geophysics and geology.

3. Adoption of new and revised standards

In the current year, the Company has adopted the following new and revised Standards, Amendments and Interpretations issued by the International Accounting Standards Board (“the IASB”) and the International Financial Reporting Interpretations Committee (“the IFRIC”) of the IASB that are relevant to its operations and effective for annual reporting periods beginning on 1 January 2009.

- IAS 1 (revised). ‘Presentation of financial statements’ – effective 1 January 2009. The revised standard prohibits the presentation of items of income and expenses (that is, ‘non-owner changes in equity’) in the consolidated statement of changes in equity, requiring ‘non-owner changes in equity’ to be presented separately from owner changes in equity in a consolidated statement of comprehensive income. As a result the Company presents in the consolidated statement of changes in equity all owner changes in equity, whereas all non-owner changes in equity are presented in the consolidated statement of comprehensive income. Comparative information has been re-presented so that it also is in conformity with the revised standard. As the change in accounting policy only impacts presentation aspects, there is no impact on the net loss for the year.

- IFRS 7 'Financial instruments – Disclosures' (amendment) – effective 1 January 2009. The amendment requires enhanced disclosures about fair value measurement and liquidity risk. In particular, the amendment requires disclosure of fair value measurements by level of a fair value measurement hierarchy. As the change in accounting policy only results in additional disclosures, there is no impact on the net loss for the year.
- IAS 16 (Amendment), 'Property, plant and equipment' (and consequential amendment to IAS 7, 'Statement of cash flows') (effective for annual periods beginning on or after 1 January 2009). Entities whose ordinary activities comprise renting and subsequently selling assets present proceeds from the sale of those assets as revenue and should transfer the carrying amount of the asset to inventories when the asset becomes held for sale. A consequential amendment to IAS 7 states that cash flows arising from purchase, rental and sale of those assets are classified as cash flows from operating activities. The amendment will not have an impact on the Company's operations because their ordinary activities do not comprise renting and subsequently selling assets.
- IAS 36 (Amendment), 'Impairment of assets' (effective for annual periods beginning on or after 1 January 2009). Where fair value less costs to sell is calculated on the basis of discounted cash flows, disclosures equivalent to those for value-in-use calculation should be made. The Company will provide the required disclosure where applicable for impairment tests from 1 January 2009.
- IAS 19 (Amendment), 'Employee benefits' (effective for annual periods beginning on or after 1 January 2009).
- IAS 32 (Amendment), 'Financial instruments: Presentation', and IAS 1 (Amendment), 'Presentation of financial statements' – 'Puttable financial instruments and obligations arising on liquidation' (effective for annual periods beginning on or after 1 January 2009). The amended standards require entities to classify Puttable financial instruments and instruments, or components of instruments that impose on the entity an obligation to deliver to another party a *pro rata* share of the net assets of the entity only on liquidation as equity, provided the financial instruments have particular features and meet specific conditions. The amendment in this standard will not have an impact on the classification of the Company's financial statements, as the Company does not have Puttable financial instruments and instruments, or components of instruments that impose on the entity an obligation to deliver to another party a *pro rata* share of the net assets of the entity.
- IAS 39 (Amendment), 'Financial instruments: Recognition and measurement' (effective for annual periods beginning on or after 1 January 2009). The definition of financial asset or financial liability at fair value through profit or loss as it relates to items that are held for trading was amended. This clarifies that a financial asset or liability that is part of a portfolio of financial instruments managed together with evidence of an actual recent pattern of short-term profit-taking is included in such a portfolio on initial recognition. The amendment will not have an impact on the Company's financial statements.
- IAS 31 (Amendment), 'Interests in joint ventures' (and consequential amendments to IAS 32 and IFRS 7) (effective for annual periods beginning on or after 1 January 2009).
- The following Standards, Amendments and Interpretations are not yet effective and have not been adopted by the Company:
- IAS 1 (Amendment), 'Presentation of financial statements' (effective for annual periods beginning on or after 1 January 2010).
- IAS 7 (Amendment), 'Statement of cash flows' (effective for annual periods beginning on or after 1 January 2010).
- IAS 17 (Amendment), 'Leases' (effective for annual periods beginning on or after 1 January 2010).
- IAS 27 (Revised), 'Consolidated and separate financial statements', (effective for annual periods beginning on or after 1 July 2009).

- IAS 39 (Amendment), 'Financial instruments recognition and measurement' (effective for annual periods beginning on or after 30 June 2009).
- IAS 39 (Amendment), 'Financial instruments recognition and measurement' (effective for annual periods beginning on or after 1 July 2009).
- IAS 39 (Amendment), 'Financial instruments recognition and measurement' (effective for annual periods beginning on or after 1 January 2010).
- IAS 31 (Amendment), 'Interests in joint ventures' (effective for annual periods beginning on or after 1 July 2009).

4. Significant accounting policies

This consolidated financial information is prepared under the historical cost convention and in accordance with International Financial Reporting Standards. The significant accounting policies adopted are as follows:

Consolidation and Subsidiaries

Subsidiaries are entities over which the Company has the power to govern the financial and operating policies generally accompanying a shareholding of more than one half of the voting rights. The existence and effect of potential voting rights that are currently exercisable or convertible are considered when assessing whether the Company controls another entity.

The consolidated financial information incorporates the financial information of the Company and its subsidiaries. The consolidated financial information is prepared for the same reporting year as the Company, using consistent accounting policies. Inter-company transactions, balances, unrealised gains and unrealised losses on transactions between Company companies are eliminated. Subsidiaries are consolidated from the date on which control is transferred to the Company and cease to be consolidated from the date that control ceases to exist.

Accounting policies of subsidiaries have been changed where ever necessary to ensure consistency with the policies adopted by the Company.

Investment in joint ventures

Where the Company has entered into a contractual arrangement with the other ventures, which establishes joint control over the economic activity of that entity, such interest is classified as an interest in joint venture. The Company uses equity method of accounting for its interests in joint venture. Joint ventures are initially recognized in the consolidated financial position at cost.

Property, plant and equipment

Property, plant and equipment are stated at cost, less accumulated depreciation and accumulated impairment losses.

Depreciation

Depreciation is provided consistently on a straight line basis so as to write off the cost of property, plant and equipment over their estimated useful lives as follows:

Marine seismic equipment	3-8 years
Land seismic equipment	3-8 years
Furniture and fixtures	3 years
Building	5 years

Impairments

The carrying amounts of the Company's assets are reviewed annually at each date of statement of financial position to determine whether the assets have been impaired during the year. Where an asset has been impaired, the recoverable amount of the asset is determined. Where the carrying amount exceeds the

recoverable amount, the asset is written down to its recoverable amount. The resultant impairment loss is recognised as an expense in the consolidated statement of comprehensive income.

Financial assets

All financial assets are recognised and derecognised on trade date and are initially measured at fair value, plus transaction costs, except for those financial assets classified as at fair value through profit or loss, which are initially measured at fair value.

Financial assets are classified into the following specified categories: financial assets at fair value through profit or loss, held to maturity investments, loans and receivables and available for sale financial assets. The classification depends on the nature and purpose of the financial assets and is determined at the time of initial recognition.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market.

Loans and receivables comprise of trade receivables, due from related parties and other receivables that have fixed or determinable payments and are not quoted in an active market. Loans and receivables are measured at amortised cost using the effective interest method, less any impairment. Interest income is recognised in statement of comprehensive income by applying the effective interest rate.

Employees' end of service gratuities

Provision is made for employees' end of service gratuities on the basis prescribed in the UAE Labour Law, for the accumulated period of service at the date of statement of financial position.

Financial liabilities

Financial liabilities are classified as either financial liabilities at fair value through profit or loss or other financial liabilities. The Company's financial liabilities consist of trade and other payables and due to related parties. The trade and other payables and due to related parties are stated at cost.

Revenue recognition

Revenue from services is recognised when the services are rendered and are spread over the period of contract.

Interest revenue is accrued on a time basis.

Foreign currencies

Transactions in foreign currencies during the year are converted into USD at rates of exchange ruling at the transaction dates. Monetary assets and liabilities in foreign currencies are translated to USD at the rates of exchange ruling at the date of statement of financial position. All gains and losses on exchange are taken to the consolidated statement of comprehensive income.

Cash and cash equivalents

For the purposes of the consolidated statement cash flows, cash and cash equivalents include cash and bank balances.

5. Critical accounting judgments and key sources of estimation uncertainty

In the application of the Company's accounting policies, which are described in note 4, management is required to make judgments, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

Key sources of estimation uncertainty

The key assumptions concerning the future, and other key sources of estimation uncertainty at the date of statement of financial position, that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year, are discussed below.

Property, plant and equipment

Property, plant and equipment is depreciated over its estimated useful life, which is based on estimates for expected usage of the asset and expected physical wear and tear which are dependent on operational factors. Management has not considered any residual value as it is deemed immaterial.

Allowance for doubtful debts

An allowance for doubtful debts is determined using a combination of factors to ensure that the trade receivables are not overstated due to uncollectibility. The allowance for doubtful debts for all customers is based on a variety of factors, including the overall quality and aging of receivables, continuing credit evaluation of the customers' financial conditions and collateral requirements from customers in certain circumstances.

6. Property, plant and equipment

	<i>Marine seismic equipment</i>	<i>Land seismic equipment</i>	<i>Furniture and fixtures (U.S. Dollars)</i>	<i>Building</i>	<i>Total</i>
Cost					
At 1 January 2007	2,303,261	1,876,455	545	–	4,180,261
Additions	1,065,637	3,755,319	174,210	–	4,995,166
At 31 December 2007	3,368,898	5,631,774	174,755	–	9,175,427
Additions	103,725	3,944,287	51,216	478,945	4,578,173
Disposals	(40,369)	(184,560)	(12,996)	–	(237,925)
At 31 December 2008	3,432,254	9,391,501	212,975	478,945	13,515,675
Additions	–	1,858,672	44,294	1,204	1,904,170
Disposals	(19,520)	(350,357)	(7,958)	–	(377,835)
At 31 December 2009	3,412,734	10,899,816	249,311	480,149	15,042,010
Depreciation					
At 1 January 2007	292,484	197,073	60	–	489,617
Charge for the year	608,006	944,733	36,562	–	1,589,241
At 31 December, 2007	900,490	1,141,805	36,562	–	2,078,857
Charge for the year	662,824	1,928,283	67,606	6,558	2,665,271
On disposals	(16,261)	(57,535)	(7,764)	–	(81,560)
At 31 December, 2008	1,547,053	3,012,553	96,404	6,558	4,662,568
Charge for the year	621,552	2,385,376	79,719	96,983	3,183,630
On disposals	(11,872)	(253,218)	(1,858)	–	(266,948)
At 31 December 2009	2,156,733	5,144,711	174,265	103,541	7,579,250
Net Book Value					
At 31 December 2009	1,256,001	5,755,105	75,046	376,608	7,462,760
At 31 December 2008	1,885,201	6,378,948	116,571	472,387	8,853,107
At 31 December 2007	2,468,408	4,489,969	138,193	–	7,096,570

7. Investment in joint venture

These represent the investments in joint ventures and cost of acquiring seismic data. The Company's share in the joint ventures and the amounts invested are:

	Share %	2007	2008 (U.S. Dollars)	2009
Joint venture				
Ethiopia block 2,6,7 & 8	30%	—	—	1,200,000
Kenya block 17 & 18	65%	—	341,626	5,560,551
Seychelles A, B & C	75%	527,427	1,941,793	2,696,316
Madagascar Block 1101	40%	—	866,728	999,735
Kenya Block 1	50%	—	—	529,149
Kenya Block 10A	20%	—	—	530,815
Nyuni	10%	2,827,314	5,754,947	—
		<u>3,354,741</u>	<u>8,905,094</u>	<u>11,516,566</u>

Movement in the investments is as under:

	2007	2008 (U.S. Dollars)	2009
At January 1	—	3,354,741	8,905,094
Additions	3,354,741	5,550,353	8,366,419
Disposals	—	—	(5,754,947)
At 31 December	<u>3,354,741</u>	<u>8,905,094</u>	<u>11,516,567</u>

8. Trade receivables

	2007	2008 (U.S. Dollars)	2009
Trade receivables	6,098,898	1,164,477	464,669
Allowance for doubtful debts	—	—	(34,500)
Trade receivables (net)	6,098,898	1,164,477	430,169
Prepayments	204,915	437,890	58,177
Advances	111,543	768,273	1,544,112
Deposits	179,085	213,584	220,058
Other receivables	150,252	162,332	214,750
	<u>6,744,693</u>	<u>2,746,556</u>	<u>2,467,266</u>

Included in trade receivables are debtors with carrying amounts of USD 464,668 (2008: USD 345,659 and 2007: USD 200,405) which are past due at the reporting date for which the Company, based on its past default experience has partly provided as it still considers these amounts as recoverable.

The carrying amount of trade receivables approximates to its fair value, which is based on an estimate of the recoverable amount.

Ageing analysis of these trade receivables is as under:

	2007	2008 (U.S. Dollars)	2009
Amounts past due but not impaired:			
Less than 365 days	200,465	345,659	382,505
More than 365 days	—	—	82,163
	<u>200,465</u>	<u>345,659</u>	<u>464,668</u>

Movement in allowance for doubtful debts is as under:

	2007	2008 (U.S. Dollars)	2009
Beginning balance	—	—	—
Increase in allowance	—	—	34,500
Closing balance	<u>—</u>	<u>—</u>	<u>34,500</u>

9. Related party disclosures

Related parties include the ultimate parent company, the shareholders, key management personnel, associates, joint ventures and any businesses which are controlled directly or indirectly by the Company or over which they exercise significant management influence. The balances due to/from such parties, which have been disclosed separately in the consolidated financial information, are unsecured and are repayable on demand.

Related party balances are as under:

	2007	2008 (U.S. Dollars)	2009
Payable:			
– Other related parties	15,255	32,630	113,168
– Interest on loan from shareholders	166,044	150,512	150,512
– Interest free loan from shareholders	—	—	200,000
– Interest bearing loan from shareholders	1,601,494	—	2,513,278
Receivable:			
– Associates	<u>67,307</u>	<u>—</u>	<u>—</u>

Loan from related party represents an unsecured loan from a related party bearing interest at 15 per cent. per annum (2008: Nil per cent. and 2007: 7.75 per cent.).

10. Bank balances and cash

	2007	2008 (U.S. Dollars)	2009
Cash on hand	47,819	1,651	1,732
Current account with banks	612,228	4,966,059	1,661,227
Call deposits with bank	9,214	15,767	37,668
	<u>669,261</u>	<u>4,983,477</u>	<u>1,700,627</u>

11. Trade and other payables

	2007	2008 (U.S. Dollars)	2009
Trade payables	2,867,929	3,417,302	6,782,771
Accruals and other payables	1,237,415	654,525	1,263,762
	<u>4,105,344</u>	<u>4,071,827</u>	<u>8,046,533</u>

The Company has financial risk management policies in place to ensure that payables are paid within the credit time frame.

12. Share capital

	2007	2008 (U.S. Dollars)	2009
Authorised capital:			
500,000,000 shares of USD 0.20 each	<u>100,000,000</u>	<u>100,000,000</u>	<u>100,000,000</u>
Issued and paid up capital :			
88,833,331 shares of USD 0.20 each	17,766,667	—	—
134,252,458 shares of USD 0.20 each	<u>—</u>	<u>26,850,492</u>	<u>26,850,492</u>

13. Share Premium

	USD
Balance at 1 January 2007	383,333
19,999,996 shares issued at USD 0.10 premium	<u>2,000,000</u>
Balance at 1 January 2008	2,383,333
8,333,332 shares issued at USD 0.40 premium	3,333,333
1,666,666 shares of issued at USD 0.10 premium	166,667
35,419,126 shares issued at USD 0.2235 premium	7,916,174
Share issuance expense	<u>(450,007)</u>
Balance at 31 December 2008	<u>13,349,500</u>
Balance at 31 December 2009	<u>13,349,500</u>

14. Administration, selling and general expenses

	2007	2008	2009
Administration expenses	1,996,691	2,789,618	3,417,612
Selling expenses	205,606	356,337	294,828
Other general expenses	257,185	578,286	335,080
	<u>2,459,482</u>	<u>3,724,241</u>	<u>4,047,520</u>

15. Financial instruments – risk management

Capital risk management

The capital is managed by the Company in a way that it is able to continue as a going concern while maximising returns to shareholders.

The capital structure of the Company consists of borrowings, cash and cash equivalents and equity attributable to equity holders, comprising of issued capital and reserves.

As a risk management policy, the Company reviews its cost of capital and risks associated with each class of capital. The Company balances its capital structure based on the above review.

Market risk management

Credit risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation.

The company is potentially exposed to concentration of credit risk from its financial assets which comprise principally fixed deposits, bank balances, trade and other receivables and amounts due from related parties. The company's bank accounts are placed with high credit quality financial institutions. The credit risk on trade receivables and related parties is subjected to credit evaluations and an allowance has been made for estimated irrecoverable amounts. The amounts presented in the consolidated statement of financial position are net of allowances for doubtful receivables.

Liquidity risk management

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities.

The Company has built an appropriate liquidity risk management framework for the management of its short, medium and long term funding and liquidity requirements. The Company manages liquidity risk by maintaining adequate reserves, banking facilities and borrowing facilities by continuously monitoring forecast and actual cash flows.

Financial instruments by category

The carrying amounts for each class of financial instrument are listed below:

	2007	2008 (U.S. Dollars)	2009
Financial assets			
Loans and receivables			
– Trade and other receivables	6,539,778	2,308,666	2,409,089
– Due from related parties	67,307	–	–
Cash and bank balances	669,261	4,983,477	1,700,627
Financial liabilities			
Other financial liabilities			
– Trade and other payables	4,105,344	4,071,827	8,046,533
– Due to related parties	1,782,793	183,142	2,976,958

Trade and other receivables are excluding prepayments, which are not financial instruments.

16. Subsequent events

In March 2010, the Company obtained listing on the Canadian stock exchange through a reverse acquisition of Kristina Limited (subsequently name changed as Black Marlin Energy Holding Limited).

17. Comparative figures

Previous year's figures have been regrouped or reclassified wherever necessary to make them comparable to those of the current year.

**PART B: ACCOUNTANTS' REPORT IN RESPECT OF BLACK MARLIN ENERGY LIMITED
FOR THE YEARS ENDED 31 DECEMBER 2007, 2008 AND 2009**

The Directors
Afren Plc
Kinnaird House
1 Pall Mall East
London SW1Y 5AU

and

Merrill Lynch International
Bank of America Merrill Lynch Financial Centre
2 King Edward Street
London EC1A 1HQ

24 August 2010

Dear Sirs,

AFREN PLC (the "Company")

BLACK MARLIN ENERGY LIMITED

Introduction

We report on the financial information set out in Section A of Part 6. This financial information has been prepared for inclusion in the prospectus dated 24 August 2010 of Afren Plc (the "Prospectus") on the basis of the accounting policies set out in note 4 to the financial information. This report is required by item 20.1 of annex I of the Commission Regulation (EC) No. 809/2004 (the "PD Regulation") and is given for the purpose of complying with those items and for no other purpose.

Responsibilities

The directors of the Company are responsible for preparing the financial information on the basis of preparation set out in note 4 to the financial information and in accordance with International Financial Reporting Standards as adopted by the European Union ("IFRSs").

It is our responsibility to form an opinion as to whether the financial information gives a true and fair view, for the purposes of the Prospectus and to report our opinion to you.

Save for any responsibility arising under Prospectus Rule 5.5.3R(2)(f) to any person as and to the extent there provided to the fullest extent permitted by the law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such person as a result of, arising out of, or in connection with this report or our statements, required by and given solely for the purposes of complying with item 23.1 of annex I of PD Regulation consenting to its inclusion in the Prospectus.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included as assessment of evidence relevant to the amounts and disclosures in the financial information. It also included an assessment of significant estimates and judgements made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we consider necessary in order to provide us with sufficient evidence to give reasonable assurance that the financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in the United States of America or other jurisdictions and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion

In our opinion, the financial information gives, for the purposes of the Prospectus a true and fair view of the financial position of Black Marlin Energy Limited as at the dates stated and of its financial performance, cash flows and changes in equity for the years then ended in accordance with the basis of preparation set out in note 4 to the financial information and in accordance with IFRSs.

Declaration

For the purposes of Prospectus Rule 5.5.3R(2)(f) we are responsible for this report as part of the Prospectus and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of annex I of the PD Regulation.

Yours faithfully

BDO Chartered Accountants and Advisors
United Arab Emirates

PART 7

UNAUDITED INTERIM FINANCIAL INFORMATION ON BLACK MARLIN

PART A: UNAUDITED INTERIM FINANCIAL INFORMATION ON BLACK MARLIN FOR THE THREE MONTHS ENDED 31 MARCH 2010

The following is an extract of Black Marlin's interim results announcement for the three months ended 31 March 2010 as posted by Black Marlin on 31 May 2010 on SEDAR. These results have been prepared on a Canadian Gaap basis and have not been audited or reviewed by either Black Marlin's or Afren's auditors.

Afren Shareholders should read the whole of this document and the documents incorporated by reference on page 33 of this prospectus and should not just rely on the unaudited interim financial information set out in this Part 7.

Interim condensed consolidated statement of financial position as at 31 March 2010

	<i>Note</i>	<i>Unaudited 31 March 2010 USD</i>
Non current assets		
Property, plant and equipment	11, 12	17,875,610
Intangibles		1,941,793
Total non current assets		19,817,403
Current assets		
Trade and other receivables	4	4,708,221
Bank balances and cash	5	19,176,617
Total current assets		23,884,838
Current liabilities		
Trade and other payables	6	6,366,670
Due to related parties	9	98,357
Loan from shareholders	9	283,855
Total current liabilities		6,748,882
Net current assets		17,135,956
Non current liabilities		
Provision for employees' end of service gratuities		(23,007)
Provision for Abandonment Liability		(1,097,514)
Net assets		<u>35,832,838</u>
Equity		
Share capital	7	40,498,896
Share premium	8	29,759,208
Contributed Surplus		—
Accumulated deficit		(34,425,266)
Total equity		<u>35,832,838</u>

Interim condensed consolidated statement of comprehensive income for the period ended 31 March 2010

		<i>Unaudited Period ended 31 March 2010 USD</i>
	<i>Note</i>	
Revenue		123,346
Cost of revenue		(1,209,478)
Gross loss		(1,086,132)
Other income		42,190
		(1,043,942)
Administration, selling and general expenses	10	(1,107,806)
Comprehensive income for the period		(2,151,748)
Loss per share – Basic & Diluted		(0.011)
No of shares outstanding		202,494,475

Interim condensed consolidated statement of changes in equity for the period ended 31 March 2010

	<i>Share Capital USD</i>	<i>Share Capital USD</i>	<i>Contributed Surplus USD</i>	<i>Accumulated deficit USD</i>	<i>Total USD</i>
Balance at 1 January 2010	4,457,959	–	1,042,453	(6,264,542)	(764,130)
Balance c/f from Black Marlin Energy Ltd (Operating Company)	26,850,492	13,349,500	–	(28,316,191)	11,883,801
Additional share capital introduced	13,648,404	–	–	–	13,648,404
Share premium on capital introduced	–	16,409,708	–	–	16,409,708
Total comprehensive income for the period	–	–	–	(2,151,748)	(2,151,748)
Shares issued to Kristina Limited	–	–	–	(3,957,328)	(3,957,328)
Adjustment of Kristina's opening Balance	(4,457,959)	–	(1,042,453)	6,264,543	764,131
Balance at 31 March 2010	40,498,896	29,759,208	–	(34,425,266)	35,832,838

Interim condensed consolidated statement of cash flows for the period ended 31 March 2010

Unaudited Period ended
31 March 2010
USD

Cash flows from operating activities

Net loss for the period	(2,151,748)
Adjustment for:	
Depreciation B/f from Black Marlin Energy Limited	7,579,250
Depreciation During the Period	754,839
Provision for employees' end of service gratuities	23,007
Provision for Abandonment Liability	780,904
Shares issued to Kristina Limited	(3,957,328)
Operating loss before working capital changes	3,028,924
Increase in trade and other receivables	(4,691,821)
Decrease in trade and other payables	6,069,106
Increase in due to related parties	98,357
Net cash from operating activities	4,504,566

Cash flows from investing activities

Purchase of property plant and equipment – B/f from BMEL	(25,412,382)
Purchase of property plant and equipment – During the Period	(797,317)
Increase in intangible assets	(1,941,793)
Net cash used in investing activities	(28,151,492)

Cash flows from financing activities

Increase in loans from related party	82,345
Additional capital raised	36,040,937
Additional share premium on capital raised	33,352,938
Cost of raising funds	(3,593,730)
Change in Contributed Surplus	(1,042,453)
Black Marlin B/f Deficit Adjustment	(28,316,191)
Kristina's opening Deficit Adjustment	6,264,542
Net cash from financing activities	42,788,388

Net increase in cash and cash equivalents 19,141,462

Cash and cash equivalents at beginning of the period 35,155

Cash and cash equivalents at end of the period 19,176,617

1. Status and activity

Black Marlin operates under a license issued by the Government of British Virgin Islands. The registered address of Black Marlin is Akara Building, 24 De Castro Street, Wickhams Cay I, Road Town, Tortola, British Virgin Islands. The interim condensed consolidated financial statements present the results of Black Marlin and its subsidiaries.

The principal activities of Black Marlin and its subsidiaries are acquisition, exploration and development of petroleum and natural gas properties in addition to running a seismic acquisition services company.

The interim condensed consolidated financial statements for the period ended 31 March 2010 were authorised for issue by the Board of Directors on 28 May 2010.

These interim condensed consolidated financial statements are presented in US Dollars (USD).

2. Basis of preparation

These interim consolidated condensed financial statements have been prepared in accordance with Canadian generally accepted accounting principles (CGAAP). These interim condensed consolidated financial statements do not include all of the information required for full annual financial statements.

3. Basis of consolidation

Details of Black Marlin's subsidiaries as at 31 March 2010 are as follows.

<i>Name of subsidiary</i>	<i>Place of incorporation and operation</i>	<i>Ownership interest %</i>	<i>Voting power held %</i>	<i>Principal activity</i>
Black Marlin Energy Limited	British Virgin Islands	100	100	Providing services in oil and gas exploration, geophysics and geology.
Upstream Petroleum Services Limited	British Virgin Islands	100	100	Providing seismic acquisition services on land, transition zones and shallow water.
East African Exploration Limited	British Virgin Islands	100	100	Acquiring petroleum exploration ventures in the East African region.
Black Marlin Exploration Limited	British Virgin Islands	100	100	Acquiring petroleum exploration ventures in the East African region.

4. Trade and other receivables

	<i>31 March</i>
	<i>2010</i>
	<i>USD</i>
Trade receivables	355,739
Prepayments and other receivables	4,352,482
	4,708,221

5. Bank balance and cash

	<i>31 March</i>
	<i>2010</i>
	<i>USD</i>
Cash on hand	4,519
Current accounts with banks	19,121,174
Margin money under lien	50,924
	19,176,617

6. Trade and other payables

	<i>31 March</i>
	<i>2010</i>
	<i>USD</i>
Trade payables	5,583,214
Provisions, accruals and other payables	783,456
	6,366,670

7. Share capital

	<i>31 March</i>
	<i>2010</i>
	<i>USD</i>
Authorised:	
Unlimited number of common voting shares	—
Unlimited number of preferred shares	—
Issued and paid up capital:	
202,494,475 shares issued	40,498,896
(16,050,000 shares issued as on 31/12/09)	
	40,498,896

8. Share premium

	<i>31 March</i>
	<i>2010</i>
	<i>USD</i>
202,494,475 shares Issued	33,352,938
Share issuance expense	(3,593,730)
	29,759,208

9. Related party disclosure

	<i>31 March 2010 USD</i>
Payables:	
Loan from shareholders	283,855
Other related parties	98,357
	<u>382,212</u>

10. Administration, selling and general expense

	<i>31 March 2010 USD</i>
Salaries, wages and other benefits	653,760
Legal and professional fees	118,229
Rent and license fee	111,583
Advertisement and marketing	23,595
Communication	22,881
Repairs and maintenance	3,341
Travelling and conveyance	21,132
Bank charges	43,431
Exchange loss	20,356
Depreciation	27,681
Accretion expenses on asset retirement obligation	26,025
Other expenses	35,792
	<u>1,107,806</u>

11. Property, plant and equipment

	<i>Land and seismic equipment USD</i>	<i>Marine Seismic equipment USD</i>	<i>Furniture and fixtures USD</i>	<i>Building USD</i>	<i>Seismic Investments (Note No.12) USD</i>	<i>Total USD</i>
Cost						
B/f from Black Marlin	10,899,816	3,412,734	249,311	480,149	10,370,372	25,412,382
Additions for the period	19,542	–	33,693	1,202	742,880	797,317
At 31 March 2010	<u>10,919,358</u>	<u>3,412,734</u>	<u>283,004</u>	<u>481,351</u>	<u>11,113,252</u>	<u>26,209,699</u>
Depreciation						
B/f from Black Marlin	5,144,711	2,156,733	174,265	103,541	–	7,579,250
Charge for the period	129,553	579,107	21,030	25,149	–	754,839
At 31 March 2010	<u>5,274,264</u>	<u>2,735,840</u>	<u>195,295</u>	<u>128,690</u>	<u>–</u>	<u>8,334,089</u>
Net asset						
At 31 March 2010	<u>5,645,094</u>	<u>676,894</u>	<u>87,709</u>	<u>352,661</u>	<u>11,113,252</u>	<u>17,875,610</u>

12. Seismic Investments

	<i>Share</i> (%)	<i>1 Jan</i> <i>2010</i> <i>USD</i>	<i>Additions</i> <i>During the</i> <i>Year</i>	<i>31 Mar</i> <i>2010</i> <i>USD</i>
Ethiopia Block 2, 6, 7 & 8	30	1,200,000	169,815	1,369,815
Kenya L17/L18	65	5,560,551	59,942	5,620,493
Seychelles Block A, B & C	75	754,524	–	754,524
Madagascar Block 1101	40	999,735	116,848	1,116,583
Kenya Block 1	50	529,149	243,183	772,332
Kenya Block 10A	20	530,815	96,098	626,913
Total		<u>9,574,774</u>	<u>685,886</u>	<u>10,260,660</u>
Add: Abandonment Liability		<u>795,599</u>	<u>56,993</u>	<u>852,592</u>
Total Seismic Investments		<u>10,370,373</u>	<u>742,879</u>	<u>11,113,252</u>

13. Corresponding Figures

Certain Corresponding figures have been reclassified to confirm to the presentation adopted in these interim condensed consolidated financial statements.

PART B: RECONCILIATION STATEMENT FOR THE BLACK MARLIN INTERIM FINANCIAL INFORMATION FOR THE THREE MONTHS ENDED 31 MARCH 2010

BLACK MARLIN ENERGY HOLDINGS LIMITED

Reconciliation between the financial information as previously reported under Canadian Generally Accepted Accounting Practices (“GAAP”) and financial information presented under the accounting policies of Afren Plc.

USD

Net assets at 31 March 2010

As previously reported under Canadian GAAP	35,832,838
Adjustment for abandonment liability – see note below	244,922
As presented under the accounting policies of Afren plc	<u>36,077,760</u>

Net loss for the three months ended 31 March 2010

As previously reported under Canadian GAAP	(2,151,748)
Adjustment for abandonment liability – see note below	26,025
As presented under the accounting policies of Afren plc	<u>(2,125,723)</u>

Basis of preparation

The net assets at 31 March 2010 and loss for the three months period then ended have been extracted from the published unaudited financial statements for Black Marlin Energy Holdings Limited prepared under Canadian GAAP. The net assets at 31 March 2010 and the net loss for the period then ended as presented under the accounting policies of Afren plc are based on the Canadian GAAP financial statements of Black Marlin Energy Holdings Limited as adjusted for the difference between Canadian GAAP and International Financial Reporting Standards as adopted by the European Union (“IFRS”).

Note

Under Canadian GAAP a liability is recognised for the estimated costs to abandon interests in seismic investments. Under IFRS, such a liability is only recognised upon certain criteria being met. At 31 March 2010, the criteria had not been met to recognise the liability under IFRS and this represents the difference between the net assets at 31 March 2010 and for the three months period then ended as previously reported under Canadian GAAP and as presented under the accounting policies of Afren plc.

**PART C: BDO REPORT ON RECONCILIATION STATEMENT ON THE BLACK MARLIN
UNAUDITED INTERIM FINANCIALS FOR THE THREE MONTHS
ENDED 31 MARCH 2010**

The Directors
Afren Plc
Kinnaird House
1 Pall Mall East
London SW1Y 5AU

and

Merrill Lynch International
Bank of America Merrill Lynch Financial Centre
2 King Edward Street
London EC1A 1HQ

24 August 2010

Dear Sirs,

Afren PLC (the “Company”)

Proposed acquisition of Black Marlin Energy Holdings Limited (the “Transaction”)

We report on the reconciliation of the consolidated income statement for the interim period ended 31 March 2010 and of the consolidated statement of financial position as at 31 March 2010, (the “financial information”) as previously reported in the financial statements of Black Marlin Energy Holdings Limited, prepared under Canadian Generally Accepted Accounting Principles, showing the adjustments necessary to restate it on the basis of the Company’s accounting policies used in preparing its financial statements for the year ended 31 December 2009 (“the Reconciliation”) set out in Part B of Part 7 of the Prospectus.

Responsibilities

It is the responsibility of the directors of the Company (the “Directors”) to prepare the Reconciliation and it is our responsibility to form an opinion as to whether:

- (a) the Reconciliation has been properly prepared on the stated; and
- (b) the adjustments are appropriate for the purpose of presenting the financial information (as adjusted) on a basis consistent in all material respects with the Company’s accounting policies,

and report our opinion to you.

Save for any responsibility arising under prospectus Rule 5.5.3R(2)(f) to any person as and to the extent there provided, and save for any responsibility arising which we may have to those persons to whom this report is expressly addressed and which we may have to shareholders of the Company to the fullest extent permitted by the law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statements, required by and given solely for the purposes of complying with item 23.1 of annex I of the Commission Regulation (EC) No. 809/2004 (the “PD Regulation”).

The Reconciliation is based on the unaudited consolidated statement of financial position as at 31 March 2010 and consolidated income statement for the period then ended of Black Marlin Energy Holdings Limited which were the responsibility of the directors of Black Marlin Energy Holdings Limited. We do not accept responsibility for any of the historical financial statements of Black Marlin Energy Holdings Limited, nor do we express an opinion on those financial statements.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of checking whether the unadjusted financial information of Black Marlin Energy Holdings Limited has been accurately extracted from an appropriate source, assessing whether all adjustments necessary for the purpose of presenting the financial information on a basis consistent in all material respects with the Company's accounting policies have been made, examination of evidence supporting the adjustments in the Reconciliation and checking the arithmetical accuracy of the calculation within the Reconciliation.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the Reconciliation has been properly compiled on the basis stated and that the adjustments are appropriate for the purpose of presenting the financial information (as adjusted) on a basis consistent in all material respects with the Company's accounting policies.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in the United States of America or other jurisdictions and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion

In our opinion:

- (a) the Reconciliation has been properly compiled on the basis stated and
- (b) the adjustments made are appropriate for the purpose of presenting the financial information (as adjusted) on a basis consistent in all material respects with the Company's accounting policies.

Declaration

For the purposes of Prospectus Rule 5.5.3R(2)(f) we are responsible for this report as part of the Prospectus and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of annex I of the PD Regulation.

Yours faithfully

BDO Chartered Accountants and Advisors
United Arab Emirates

PART 8

UNAUDITED PRO-FORMA FINANCIAL INFORMATION FOR THE ENLARGED GROUP

PART A: UNAUDITED PRO-FORMA FINANCIAL INFORMATION

Afren plc

Pro forma financial information

The following unaudited pro forma financial information has been prepared on the basis of the notes set out below and in accordance with the requirements of item 20.2 of Annex I and items 1 to 6 of Annex II of the Prospectus Directive to illustrate the effect on the Group's consolidated balance sheet of the Acquisition and the Share Issue as if they had been completed on 31 December 2009 and on the Group's profit and loss as if the transaction had occurred on 1 January 2009. The pro forma financial information has been prepared for illustrative purposes only. Due to its nature, the pro forma financial information addresses a hypothetical situation and, therefore does not represent the Group's actual financial position or results. Actual future results may differ materially from those assumed or described herein. This unaudited pro forma financial information does not take into account trading of Afren or Black Marlin subsequent to 31 December 2009.

The unaudited pro forma financial information set out below is based on information which has been extracted without material adjustment from the audited financial statements of Afren for the year ended 31 December 2009 as incorporated by reference in this document and the audited financial statements of Black Marlin for the year ended 31 December 2009 set out in part 6 of this document. Further adjustments have been made in accordance with Annex II item 6 of Appendix 3 of the Prospectus Rules.

The accounting policies used in the preparation of the unaudited pro forma financial information are consistent with those to be used by Afren in the audited consolidated financial statements as at 31 December 2010. Such accounting policies differ from those used by Afren in the consolidated financial statements as at 31 December 2009 in respect of the adoption of IFRS3 (revised) Business Combinations.

Afren plc
Pro forma consolidated balance sheet as at 31 December 2009 (unaudited)

	Adjustments						
	Afren plc	Black Marlin Energy Ltd	Acquisition accounting	Reclassification	Placement and reverse takeover	Transaction costs	Pro forma consolidated balance sheet
			\$000's				
	Note 1	Note 2	Note 3 and Note 6	Note 4	Note 5	Note 6	
Assets							
Non-current assets							
Intangible oil and gas assets	184,161	–	89,031	11,516	–	–	284,708
Property, plant and equipment							
Oil and gas assets	486,672	–	–	–	–	–	486,672
Other	6,996	7,463	–	–	–	–	14,459
Prepayments	3,383	–	–	–	–	–	3,383
Derivative financial instruments	2,153	–	–	–	–	–	2,153
Investment in joint ventures	–	11,516	–	(11,516)	–	–	–
Investments in associates	604	–	–	–	–	–	604
	<u>683,969</u>	<u>18,979</u>	<u>89,031</u>	<u>–</u>	<u>–</u>	<u>–</u>	<u>791,979</u>
Current assets							
Inventories	34,564	–	–	–	–	–	34,564
Trade and other receivables	55,614	2,467	–	–	–	–	58,081
Derivative financial instruments	4,523	–	–	–	–	–	4,523
Cash and cash equivalents	321,312	1,701	–	–	24,858	(4,100)	343,771
	<u>416,013</u>	<u>4,168</u>	<u>–</u>	<u>–</u>	<u>24,858</u>	<u>(4,100)</u>	<u>440,939</u>
Total assets	<u>1,099,982</u>	<u>23,147</u>	<u>89,031</u>	<u>–</u>	<u>24,858</u>	<u>(4,100)</u>	<u>1,232,918</u>
Liabilities							
Current liabilities							
Trade and other payables	(134,739)	(8,046)	(23)	–	–	–	(142,808)
Borrowings	(117,634)	(2,977)	–	–	1,538	–	(119,073)
Derivative financial instruments	(5,240)	–	–	–	–	–	(5,240)
	<u>(257,613)</u>	<u>(11,023)</u>	<u>–</u>	<u>–</u>	<u>1,538</u>	<u>–</u>	<u>(267,121)</u>
Net current (liabilities)/ assets	<u>158,400</u>	<u>(6,855)</u>	<u>(23)</u>	<u>–</u>	<u>26,396</u>	<u>–</u>	<u>173,818</u>
Non-current liabilities							
Provision for decommissioning	(21,836)	–	–	–	–	–	(21,836)
Deferred tax liabilities	(12,460)	–	(22,113)	–	–	–	(34,573)
Borrowings	(149,446)	–	–	–	–	–	(149,446)
Derivative financial instruments	(379)	–	–	–	–	–	(379)
Provision for employees' gratuities	–	(21)	–	–	–	–	(21)
	<u>(184,121)</u>	<u>(21)</u>	<u>(22,113)</u>	<u>–</u>	<u>–</u>	<u>–</u>	<u>(206,255)</u>
Total liabilities	<u>(441,734)</u>	<u>(11,044)</u>	<u>(22,136)</u>	<u>–</u>	<u>1,538</u>	<u>–</u>	<u>(473,376)</u>
Net assets	658,248	12,103	66,895	–	26,396	(4,100)	759,542

		Adjustments				Pro forma consolidated balance sheet
Afren plc	Black Marlin Energy Ltd	Acquisition accounting classification	Re-	Placement and reverse takeover	Transaction costs	
		\$000's				
Note 1	Note 2	Note 3 and Note 6	Note 4	Note 5	Note 6	
Equity						
Share capital	15,702	26,850	(37,653)	–	12,043	–
Share premium	755,169	13,350	76,451	–	14,353	(1,480)
Other reserves	17,272	–	–	–	–	–
Accumulated losses	(129,895)	(28,097)	28,097	–	–	(2,620)
	658,248	12,103	66,895	–	26,396	(4,100)

Pro forma income statement for the year ended 31 December 2009 (unaudited)155

Notes to pro forma financial information as at and for the year ended 31 December 2009

1. Afren

The financial information in respect of Afren has been extracted without material adjustment from, and should be read in conjunction with, the historical financial information for the year ended 31 December 2009 as incorporated by reference in this document. No account has been taken of trading or changes in the financial position of Afren after 31 December 2009.

2. Black Marlin

The financial information in respect of Black Marlin has been extracted without material adjustments from, and should be read in conjunction with, the audited financial statements for the year ended 31 December 2009 included in part 6 of this document. No account has been taken of trading or changes in the financial position of Black Marlin after 31 December 2009.

3. Acquisition accounting

The proposed transaction between Black Marlin and Afren, if completed, will result in Afren being the acquirer of Black Marlin and accordingly, Afren will account for the transaction as a business combination under IFRS3 (revised). For the purposes of determining the accounting purchase price allocation, the share price of Afren at closing of the transaction will be used to value the issuance of 76.8 million shares of Afren to be issued to the shareholders of Black Marlin. The 76.8 million shares includes 2.9 million shares to be issued to holders of Black Marlin options which are to be cancelled but excludes 1.0 million outstanding Black Marlin options described further below. For the purposes of these pro forma financial statements it has been assumed that the transaction closed on 31 December 2009 and, accordingly, the closing share price at 31 December 2009 of 85p per share has been used. The closing exchange rate used for GBP/USD was 0.6192 giving a consideration of \$105,394,000. In addition, 1.0 million outstanding options, with a fair value of CDN0.02 per option, to acquire Black Marlin shares will be converted to acquire Afren shares on substantially equivalent terms and conditions. The value of the options that has been allocated to the consideration is \$23,000 and is treated as a financial liability and included within the trade and other payables balance of \$8,069,000 below, since the exercise price is denominated in Canadian dollar.

The estimated purchase price allocation is as follows:

	<i>\$000</i>
Intangible oil and gas assets	100,547
Property, plant and equipment – other	7,463
Trade and other receivables	2,467
Cash and cash equivalents	25,517
Trade and other payables	(8,069)
Loans from related parties	(397)
Provision for employees' gratuities	(21)
Deferred tax liability	(22,113)
	105,394
Consideration	
Issue of Afren shares	105,394 105,394

The adjustment in respect of excess purchase consideration is as follows:

	<i>\$000</i>
Assumed purchase consideration as above	105,394
Net assets of Black Marlin as at 31 December 2009	12,103
Private placement and settlement of related party loan	26,396
Provisional excess purchase consideration arising on acquisition	66,918
Deferred tax	22,113
	<u>89,031</u>

The allocation of the purchase price will be finalised after the scheme of arrangement has been completed and the fair market values of the assets and liabilities acquired have been determined at the closing of the transaction.

For the purpose of the preparation of the pro forma financial information, the Company has attributed the excess of the purchase price paid over the book value of Black Marlin's net assets, entirely to oil and gas intangible assets and allocated to the individual licences in proportion to Afren's net share of the unrisksed mean resources included in Part 1 of this document. On apportionment of the actual purchase price, fair values actually ascribed to oil and gas intangible assets, property, plant and equipment and any other assets acquired and liabilities assumed may result in material change to the amount allocated to intangible oil and gas assets and the net asset position as recorded in this pro forma financial information for the enlarged Afren group. Deferred tax has been provided on the fair value adjustments at the relevant tax rates applicable to each licence interest.

4. Reclassification to conform with Afren's balance sheet format

Afren presents intangible oil and gas assets held through joint venture arrangements as Intangible Oil and Gas Assets, whereas Black Marlin presents such items as Investment in Joint Ventures. The adjustment reclassifies the amounts reported by Black Marlin to conform with Afren's balance sheet format.

5. Private placement and reverse takeover

Subsequent to year end, Black Marlin issued 56.4 million shares at CDN0.50 raising gross proceeds of CDN28.2 million which after deducting cost of issue raised net proceeds of approximately US\$24.8 million. As part of the private placement related party borrowings amounting to CDN1.9 million (approximately US\$1.5 million) were settled by issuance of shares by Black Marlin.

Black Marlin completed a reverse takeover of Kristina subsequent to year end. Prior to closing the reverse takeover Kristina's assets and liabilities were settled and or taken over by a third party. Kristina's assets and liabilities based on the financial statements for the year ended 31 December 2009 were as follows:

	<i>CDN \$000</i>
Trade and other receivables	17
Cash and cash equivalents	37
Trade and other payables	(312)
Related party loan	(212)
Retirement asset obligation	(332)
Net liabilities	<u>(802)</u>

Kristina's financial information has been excluded from the pro forma financial information since it is a discontinued operation, prior to the closing of the reverse takeover. Kristina's 31 December 2009 financial statements were filed with the Canadian Securities regulators and with the TSX Venture Stock Exchange.

6. Transaction costs

Total transaction costs are estimated to be \$4.10 million of which \$2.62 million relates to the acquisition and will be expensed and \$1.48 million relates to issue of shares and will be offset against share premium.

PART B: ACCOUNTANT'S REPORT ON PRO-FORMA FINANCIAL INFORMATION

Deloitte LLP
2 New Street Square
London
EC4A 3BZ

The Board of Directors
on behalf of Afren plc
Kinnaird House
1 Pall Mall East
London
SW1Y 5AU

Merrill Lynch International
Bank of America Merrill Lynch Financial Centre
2 King Edward Street
London
EC1A 1HQ

24 August 2010

Dear Sirs,

Afren plc (the "Company")

We report on the pro forma financial information (the "Pro forma financial information") set out in Part 8 of the prospectus dated 24 August 2010 (the "Prospectus"), which has been prepared on the basis described in notes 1 to 6, for illustrative purposes only, to provide information about how the transaction might have affected the financial information presented on the basis of the accounting policies to be adopted by the Company in preparing the financial statements for the period ended 31 December 2010. This report is required by Annex I item 20.2 of Commission Regulation (EC) No 809/2004 (the "Prospectus Directive Regulation") and is given for the purpose of complying with that requirement and for no other purpose.

Responsibilities

It is the responsibility of the directors of the Company (the "Directors") to prepare the Pro forma financial information in accordance with Annex I item 20.2 and Annex II items 1 to 6 of the Prospectus Directive Regulation.

It is our responsibility to form an opinion, as required by Annex I item 20.2 and in accordance with item 7 of Annex II of the Prospectus Directive Regulation, as to the proper compilation of the Pro forma financial information and to report that opinion to you.

Save for any responsibility arising under Prospectus Rule 5.5.3R (2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in accordance with this report or our statement, required by and given solely for the purposes of complying with Annex I item 23.1 of the Prospectus Directive Regulation, consenting to its inclusion in the prospectus.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information used in the compilation of the Pro forma financial information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

Basis of Opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. The work that we performed for the purpose of making this report,

which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro forma financial information with the Directors.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro forma financial information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in jurisdictions outside the United Kingdom, including the United States of America, and accordingly should not be relied upon as if it had been carried out in accordance with those standards or practices.

Opinion

In our opinion:

- (a) the Pro forma financial information has been properly compiled on the basis stated; and
- (b) such basis is consistent with the accounting policies of the Company.

Declaration

For the purposes of Prospectus Rule 5.5.3R(2)(f) we are responsible for this report as part of the Prospectus and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the Prospectus in compliance with Annex I item 1.2 of the Prospectus Directive Regulation.

Yours faithfully

Deloitte LLP

Chartered Accountants

Deloitte LLP is a limited liability partnership registered in England and Wales with registered number OC303675 and its registered office at 2 New Street Square, London EC4A 3BZ, United Kingdom. Deloitte LLP is the United Kingdom member firm of Deloitte Touche Tohmatsu Limited (“DTTL”), a UK private company limited by guarantee, whose member firms are legally separate and independent entities. Please see www.deloitte.co.uk/about for a detailed description of the legal structure of DTTL and its member firms.

PART 9

MANAGEMENT AND CORPORATE GOVERNANCE

1. Directors

As at the date of this Prospectus, the members of the Board and their positions are:

<i>Name</i>	<i>Position</i>
Mr. Egbert Imomoh	Non executive Director and Chairman
Dr. Osman Shahenshah	Chief Executive, Executive Director
Mr. Darra Comyn	Group Finance Director
Mr. Shahid Ullah	Chief Operating Officer, Executive Director
Mr. Constantine Ogunbiyi	Executive Director
Mr. Ennio Sganzerla	Independent Non executive Director
Mr. Peter Bingham	Independent Non executive Director
Mr. John St. John	Independent Non executive Director
Mr. Toby Hayward	Independent Non executive Director

Mr. Egbert Imomoh, Chairman (Non Executive)

Mr. Imomoh, aged 65, was appointed as Non Executive Chairman on 18 December 2008. Prior to assuming his current position, Mr. Imomoh, a founder of Afren, was Managing Director and Executive Chairman of Afren Energy Resources Limited. He successfully led the growth of Afren's Nigerian asset base, established partnerships with indigenous companies and realised the first oil milestone at the Okoro field.

Mr. Imomoh has been a member of the Board of Directors since 16 February 2005 and has had 36 years experience with the Shell group of companies, in Nigeria, the UK and The Netherlands. Prior to his retirement, he served as Deputy Managing Director of SPDC, one of the Shell Group's largest operating companies, which is responsible for operating a joint venture that produces approximately 1,000,000 bopd. Trained in Mechanical and Petroleum Engineering, Mr. Imomoh held a wide variety of senior positions throughout the Shell Group, including Chief Petroleum Engineer in SPDC, Technical and Planning Manager to Deputy Managing Director in SPDC. He is a member of the Society of Petroleum Engineers and has served on its board as Regional Director for Africa.

Dr. Osman Shahenshah, Chief Executive

Dr. Shahenshah, aged 48, was appointed as Chief Executive on 27 February 2007. Dr. Shahenshah has been a member of the Board of Directors since 3 December 2004. Dr. Shahenshah is a founder of Afren and has over 20 years experience in oil and gas finance. His international career began with Credit Suisse First Boston and has included senior positions in the oil and gas finance groups of the IFC (private sector arm of the World Bank), and the investment banking divisions of Dresdner Kleinwort Wasserstein and Mediocredito Centrale. Dr. Shahenshah has been actively involved in the African oil and gas sector for more than 15 years, working with companies including Shell, Chevron, Total, ENI and the Nigerian National Petroleum Corporation. He holds a PhD from the University of Pennsylvania, a Master's Degree from Columbia University and a Bachelor's Degree from Brown University.

Mr. Darra Comyn, Group Finance Director

Darra Comyn, aged 48, joined Afren in December 2009 as Group Finance Director and was appointed to the Board on 23 March 2010. Prior to joining Afren, Mr. Comyn was the Group Finance Director for ITE Group plc and Expomendia Group plc (both international groups focused on emerging markets); and in the oil industry with Chevron Oil UK and Dragon Oil where he was Group Financial Controller and Company Secretary. He is a Chartered Accountant with a degree in Economics from Trinity College, University of Dublin.

Mr. Shahid Ullah, *Chief Operating Officer*

Mr. Ullah, aged 51, was appointed as Chief Operating Officer on 1 July 2008. Mr. Ullah has been a member of the Board of Directors since 1 July 2008 and has worked within the international oil and gas industry for several years. Mr. Ullah has held senior management positions at Western Atlas and Baker Hughes, where he was responsible for managing petroleum equities and assets. In particular, he brings extensive technical and commercial knowledge of the African petroleum industry. Mr. Ullah holds a degree in Petroleum Engineering from the University of Texas and received executive development training at Oxford University and the London Business School. He is a member of the Engineering Advisory Board at the University of Texas.

Mr. Constantine Ogunbiyi, *Executive Director*

Mr. Ogunbiyi, aged 38, was appointed as an Executive Director on 3 January 2008. He is responsible for business development, growth and strategy at Afren and has led Afren's negotiating teams in acquisitions and debt financings. Prior to his appointment as Executive Director, Mr. Ogunbiyi was an Associate Director and Special Assistant to the Chairman and General Counsel as well as a Director of Afren's wholly owned Nigerian subsidiary. Mr. Ogunbiyi assisted in the establishment of Afren in late 2004 and has nearly 15 years experience of private equity, acquisition, structured, trade and project finance, and public and private partnerships in the African energy and infrastructure sectors in particular.

Prior to joining Afren, Mr. Ogunbiyi was the Deputy Head of Cadwalader, Wickersham & Taft LLP's Africa Practice. Before this, Mr. Ogunbiyi spent four and a half years with Herbert Smith's International Finance and Banking Department. He has also served as a strategic adviser to the New Partnership for Africa's Development (NEPAD) Business Group and the Southern African Development Community's (SADC) Banking Association's PPP Unit. He holds a LLB with German Law from King's College, University of London, a diploma in German Public and Civil Law from the University of Passau (Germany) and Legal Practising qualifications from the Oxford Institute of Legal Practice.

Mr. Ennio Sganzerla, *Independent Non-Executive Director*

Mr. Sganzerla, aged 66, was appointed as Non Executive Director on 26 June 2009. Mr. Sganzerla, a senior industry practitioner with a wealth of African upstream oil and gas experience, has been an advisor to the Afren Board since November 2006. He was previously Senior Vice President (E&P) at ENI, having joined the group in 1971. From 1997, he was responsible for ENI's business unit encompassing the North Sea, America, Australasia and Russia, with production in excess of 500,000 boepd. Previously, he was Managing Director of ENI's North Sea Operations. Over the course of his wide ranging career at ENI, he was instrumental in establishing and building ENI's presence in Congo-Brazzaville, and played an active part in increasing ENI's position in Nigeria and Gabon. Mr. Sganzerla was also active in leading the group's M&A activities, including the acquisition of Lasmo plc and British Borneo. He currently also serves as non executive Director at Stratic Energy Corporation.

Mr. Peter Bingham, *Independent Non-Executive Director*

Mr. Bingham, aged 75, was appointed as Non Executive Director on 10 May 2005 and is a senior financial executive with over 40 years experience in international financial markets, primarily at the Barclays Bank Group. Mr. Bingham successively held directorships at the London branch level, in the Group's merchant banking division, and at BZW (now Barclays Capital). Mr. Bingham ultimately became Head of Banking at BZW where he set up the credit risk management team and served as a member of the central Barclays Group Credit Committee.

Mr. John St. John, *Independent Non-Executive Director*

Mr. St. John, aged 47, was appointed as Non Executive Director on 18 June 2007. Prior to his appointment as Non Executive Director, Mr. St John was previously Strategic Financial Adviser to the Board. He was formerly Global Head of Equity Capital Markets at Dresdner Kleinwort, Commerzbank and Lehman Brothers and European Head of Equity Capital Markets at Citigroup, formerly Salomon Brothers. He was also until most recently the Chairman of Equity Capital Markets at Nomura International plc. Mr. St. John is a founding Partner of STJ Advisors. Mr. St. John has acted as an advisor on over US\$100 billion of equity and equity linked issuance in all major markets worldwide.

Mr. Toby Hayward, Senior Independent Non-Executive Director

Mr. Hayward, aged 51, was appointed as Non Executive Director on 26 June 2009. He qualified as a Chartered Accountant with Touche Ross & Co in 1984 and subsequently held a number of senior Equity Capital Market positions in the City of London. Mr. Hayward was formerly Managing Director and Head of Corporate Broking at Jefferies International Limited, where he was responsible for all international equity and equity linked capital markets transactions together with corporate broking and Nomad responsibilities. Prior to this, Mr. Hayward was Head of Oil and Gas Equity Capital Markets at Canaccord Adams where led a number of initial public offerings, including Afren's in March 2005. Mr. Hayward is the Senior Independent Director.

2. Senior Management

As at the date of this Prospectus, in addition to the Board, members of the senior management and their positions are:

<i>Name</i>	<i>Position</i>
Shirin Johri	Group General Counsel and Company Secretary
Andrew Olleveant	Head of EHSS
Galib Virani	Acquisitions and Investor Relations Director
Jeremy Whitlock	Group Financial Controller
Iain Wright	Technical Director

Ms. Shirin Johri, Group General Counsel and Company Secretary

Ms. Johri has extensive experience advising on acquisitions and disposals, joint ventures, infrastructure projects and private equity investment. Prior to joining Afren, Ms. Johri worked with Cadwalader, Wickersham & Taft LLP's Africa practice. Ms. Johri holds a LLM from the Cornell Law School, New York, a LLB (Hons) from Delhi University India and a Bachelor's degree from Delhi University and has also been called to the New York Bar.

Andrew Olleveant, Head of EHSS

Mr. Olleveant is a qualified health and safety professional with 18 years' experience in the oil industry, over 10 of which were spent in an international role with LASMO. He has extensive experience of managing the EHSS issues associated with major oil and gas projects as well as wider risk management experience. In previous roles he has been responsible for developing and implementing management systems and providing corporate assurance that effective controls are in place. Mr. Olleveant holds a Master of Science degree in Engineering Geology from Durham University and a Bachelor of Science degree in Environmental Science from Lancaster University.

Mr. Galib Virani, Acquisitions and Investor Relations Director

Mr. Virani is Acquisitions and Investor Relations Director, having joined the Company in 2005 following a career in the City of London in Corporate Finance and Mergers & Acquisitions. Mr. Virani has played a key role in the growth of the Company's portfolio of assets, in the Company's equity financing and in diversifying the shareholder base. Mr. Virani is an East African national and a member of the Johannesburg Stock Exchange Africa Board Advisory Committee. He is a Fellow of the Securities Institute, and has a Master of Finance & Investment (with Distinction) and a Master of Philosophy in Emerging Market Finance.

Mr. Jeremy Whitlock, Group Financial Controller

Mr. Whitlock is a qualified accountant with 20 years experience in the oil industry. He spent 13 years with Enterprise Oil in a variety of roles across the finance department, including several years as Financial Planning Manager and International & Corporate Accounting Manager. Prior to joining Afren he was Planning Manager at Nexen (UK) Ltd. He is a member of the Institute of Chartered Management Accountants and holds a degree in Mathematics from Durham University.

Mr. Iain Wright, Technical Director

Mr. Wright leads Afren's technical team and is responsible for all geoscience and reservoir engineering activities associated with Afren's ongoing exploration, development and production assets together with new

business technical assessments to enhance Afren's portfolio. With over 25 years working in the industry, he has extensive international geosciences experience and has served in both development and exploration geology roles. Previously, he was a Managing Director at Jefferies. He also worked with Randall & Dewey, Baker Hughes, Qatar Petroleum, Conoco (UK) Ltd and Anadrill Schlumberger. Mr. Wright received a BSc (Hons) from the City of London Polytechnic and is a Certified Petroleum Geologist (CPG) with the AAPG, a fellow with the Geolsoc, the SPE and PESGB.

3. International Advisory Board

Following his appointment as Chairman of Afren on 2 November 2006, Dr. Rilwanu Lukman established an International Advisory Board to assist and advise the Board to grow Afren into the leading pan African independent exploration and production company. The International Advisory Board is a consultative body with a strong orientation to Africa, the oil and gas industry and the international capital markets.

The founding members of the International Advisory Board were Mr. Brian Ward and Mr. Ennio Sganzerla, two senior oil industry practitioners with significant African experience. In 2009, Mr. Hiroshi Kanematsu, Prof. Ekwere Peters and Mr. Henry Groppe joined the International Advisory Board and in June 2009, Mr. Ennio Sganzerla stepped down from the International Advisory Board to join the Board of Afren.

Mr. Brian Ward

Mr. Ward was formerly the Regional Chief Executive for Shell E&P Africa. He was responsible for Shell's Upstream African operations and relationships with host governments. Prior to managing Shell's operations in Africa, Mr. Ward's career included a number of senior positions within the Shell organisation, including Managing Director of Petroleum Development Oman, Managing Director of Shell E&P (NAM) in Holland, and Deputy Managing Director and Production Director for Shell Expro UK.

Mr. Hiroshi Kanematsu

Mr. Kanematsu is the President of the Energy and Mineral Resources Division at Sojitz Corporation and Senior Managing Executive Officer of Sojitz. He has been involved in international energy and mining projects for over 25 years. Prior to assuming his current position, his career included a number of senior positions within Sojitz, including President and Chief Executive Officer for Sojitz Asia and General Manager for Sojitz South East Asia.

Prof. Ekwere Peters

Dr. Peters is the Frank W. Jessen Professor of Petroleum Engineering at the University of Texas at Austin where he has been a faculty member since 1980. He is a former chairman of the Department of Petroleum & Geosystems Engineering at UT Austin. He has over 35 years of varied petroleum engineering experience in field operations, education and research. His petroleum industry experience was with Shell BP in Nigeria, Amoco Production Company in the USA and United Petro Laboratories in Canada.

Mr. Henry Groppe

Mr. Groppe has had 63 years of management, economic and technical experience in the energy field. He was with Dow Chemical, Monsanto, Texaco, and Arabian American Oil Company (in Saudi Arabia) before establishing his consulting firm in 1955. The firm, Groppe, Long & Littell, based in Houston, Texas, provides consulting services to government, corporate and private clients involved in the petroleum, natural gas, refining and petroleum industries. During the past 25 years the firm has earned an international reputation for accurate long range forecasts of major changes in oil and natural gas supply, consumption and prices.

Mr. Groppe is a Distinguished Graduate of The University of Texas College of Engineering, a Fellow of the American Institute of Chemical Engineers, a member of the Chancellor's Council of The University of Texas, is a member and former chairman The University of Texas Engineering Foundation Advisory Council and founder of The University of Texas Chemical Engineering Alumni Association.

4. Corporate Governance

The Directors support high standards of corporate governance. As a UK listed company, Afren plc is required to state whether it has complied with the provisions in Section 1 of the Combined Code on Corporate Governance (Combined Code) throughout the year and, where the provisions have not been complied with, to provide an explanation. Afren is also required to explain how it has applied the principles in Section 1 of the Combined Code.

The Directors consider that the Company complied with the provisions set out in Section 1 of the Combined Code since the 2009 Admission. Throughout 2009 and up to the date of this Prospectus, the Group has complied with the provisions of the Combined Code, save for the exceptions listed below. The Chairman on appointment as Chairman in December 2008 did not meet with the independence criteria set out in the Combined Code as he is a former Executive Director of the Company. The Board believes that the Chairman is in substance independent, being independent in character and judgement, however it recognises that at the time of his appointment as Chairman, he did not meet with the independence criteria set out in the Combined Code. The Board has considered this factor and remains satisfied that his role as Chairman of the Board is of considerable benefit to the Board given his wealth of knowledge and experience of the Group, of Africa and of the oil and gas industry. The Board consulted major shareholders in advance of his appointment as Chairman and the consensus was that his appointment as Chairman was focal to our strategy of utilising relationships of the Board and management to partner with indigenous companies, national oil companies and host governments, in growing an upstream portfolio of significant scale. Prior to 9 July 2009, the Nomination Committee did not comprise a majority of Non-executive Directors. Prior to 9 July 2009, the Chairman was a member of the Audit and Risk Committee. Also prior to 9 July 2009 the Remuneration Committee comprised of two independent Non-executive Directors in addition to the Non-executive Chairman instead of three independent Non-executive Directors in addition to the Non-executive Chairman. At that time the Company was an AIM Company and the composition of the Board and its committees was considered to be appropriate in the circumstances for the short period while the Board was considering candidates to appoint as Non-executive Directors. The imbalance was rectified by the appointment of two additional Non-executive Directors in June 2009 and the resignation of the Chairman from the Audit and Risk Committee and the Remuneration Committee on 9 July 2009.

The Board comprises a non executive chairman, four executive directors and four non executive directors. The Company regards all of the non-executive directors to be independent within the meaning of “independent” as defined in the Combined Code.

Between 1 January 2009 and 31 December 2009, Mr. St. John, through his consultancy company St. John Advisers Ltd, has received payments totalling approximately US\$1.1 million from the Group for providing consultancy services to the Company. Mr. St. John has also historically been granted options over Ordinary Shares in the Company, as disclosed in paragraph 7.2 of Part 10 of this Prospectus. In the opinion of the Board, these historic option grants, and these payments by the Company to Mr. St. John, do not affect the ability of Mr. St. John to be independent in character and judgement so as to prevent being considered independent for the purposes of the Combined Code.

Mr. Bingham has historically been granted options over Ordinary Shares in the Company, as disclosed in paragraph 7.2 of Part 10 of this Prospectus. No further options have been granted to any non-executive director since the 2009 Admission. In the opinion of the Board, these historic option grants do not affect the ability of these directors to be independent in character and judgement so as to prevent being considered independent for the purposes of the Combined Code.

The Board meets on at least four occasions during the course of the year to review trading performance and budgets, funding, to set and monitor strategy, examine acquisition opportunities and report to shareholders. The Board has a formal schedule of matters specifically reserved to it for decisions. The roles of Chairman and Chief Executive are separate and the responsibilities of Chairman and Chief Executive are independently defined. It is the Chairman’s responsibility to ensure that the Board is provided with accurate, timely and clear information in relation to the Group and its business.

The Combined Code recommends that the Board should appoint one of its independent non executive directors to be the senior independent director. The senior independent director should be available to

shareholders if they have concerns that contact through the normal channels of Chairman, Chief Executive or Chief Operating Officer has failed to resolve or where such contact is inappropriate. Toby Hayward is the Board's existing senior independent director and has continued in this role since the 2009 Admission.

The Board has appointed an Audit and Risk Committee, a Remuneration Committee and a Nomination Committee, each of which have defined terms of reference which are summarised below. Each committee and each Director has the authority to seek independent professional advice where necessary to discharge their respective duties in each case at Afren's expense. In addition, each Director and committee has access to the advice of the Company Secretary, Shirin Johri.

Audit and Risk Committee

The Audit and Risk Committee comprises of Peter Bingham (Chairman), John St. John, Ennio Sganzerla and Toby Hayward. It meets at least three times a year at appropriate times in the reporting and audit cycle of Afren and more frequently if required.

The purpose of the Audit and Risk Committee is to assist the Board in fulfilling its responsibilities of oversight and supervision of, among other things,:

- the integrity of the financial statements of Afren including annual and interim reports, financial returns to regulators and announcements of a price sensitive nature;
- the adequacy of Afren's internal controls and accountancy standards; assessing consistency and clarity of disclosure as well as the operating and financial review and corporate governance statement; and
- the relationship with Afren's external auditor including appointment, remuneration, terms of engagement, assessing independence and objectivity and ultimately reviewing the findings and assessing the standard and effectiveness of the external audit.

The Audit and Risk Committee considers annually how the Group's internal audit requirements shall be satisfied and makes recommendations to the Board accordingly as well as on any area it deems needs improvement or action.

Remuneration Committee

The Remuneration Committee comprises of John St. John (Chairman), Ennio Sganzerla and Peter Bingham. The Remuneration Committee is responsible for

- making recommendations to the Board on Afren's overall framework for remuneration and its cost and in consultation with the Chairman and Chief Executive determining remuneration packages of each Executive Director;
- reviewing the scale and structure of executive directors' remuneration and the terms of their service or employment contracts, including share based schemes, other employee incentive schemes adopted by Afren from time to time and pension contributions. Executive directors of the Company are not permitted to participate in discussions or decisions of the Committee regarding their own remuneration; and
- ensuring that payments made on termination are fair to the individual and Afren.

The remuneration of the non executive directors is determined by the Chairman and the other executive directors outside the framework of the Remuneration Committee.

Nomination Committee

The Nomination Committee comprises of Egbert Imomoh (Chairman), Ennio Sganzerla and Toby Hayward. The Nomination Committee meets at least once a year and more frequently if required and is responsible for reviewing and recommending to the Board suitable candidates for appointment as Directors of the Company. It regularly reviews the structure, size and composition (including the skills, knowledge and experience) required on the Board.

5. The City Code

The City Code is issued and administered by the Takeover Panel. The Company is subject to the City Code and therefore its shareholders are entitled to the protection afforded by the City Code.

Under Rule 9 of the City Code when (i) a person acquires an interest in shares which (taken together with shares he and persons acting in concert with him are interested) carry 30 per cent., or more of the voting rights of a company subject to the City Code, or (ii) an person who, together with persons acting in concert with him, is interested in shares which in the aggregate carry not less than 30 per cent., of the voting rights of a company, but does not hold shares carrying more than 50 per cent., of the voting rights of the company subject to the City Code, and such person, or any persons acting in concert with him, acquires an interest in any other shares which increases the percentage of the shares carrying voting rights in which he is interested, then in either case, that person together with the person acting in concert with him, is normally required to extend offers in cash, at the highest price paid by him (or any persons acting in concert with him) for shares in the company within the preceding 12 months, to the holders of any class of equity share capital whether voting or on voting and also to the holders of any other class or transferable securities carrying voting rights.

PART 10

ADDITIONAL INFORMATION

1. Persons responsible

- 1.1 Afren and the Directors, whose names and functions are set out in paragraph 1 of Part 9, accept responsibility for the information contained in this Prospectus. To the best of the knowledge and belief of Afren and the Directors (who have taken all reasonable care to ensure that such is the case) the information contained in this Prospectus is in accordance with the facts and there is no omission likely to affect the import of such information.
- 1.2 NSAI accepts responsibility for the NSAI Report and its letter set out in Part 11. To the best of the knowledge of NSAI (which has taken all reasonable care to ensure that such is the case) the information contained therein is in accordance with the facts and there is no omission likely to affect the import of such information.
- 1.3 GCA accepts responsibility for the GCA Report and its letter set out in Part 12. To the best of the knowledge of GCA (which has taken all reasonable care to ensure that such is the case) the information contained therein is in accordance with the facts and there is no omission likely to affect the import of such information.
- 1.4 McDaniel accepts responsibility for the McDaniel Report and its letter set out in Part 13. To the best of the knowledge of McDaniel & Associates Consultants Ltd. (which has taken all reasonable care to ensure that such is the case) the information contained therein is in accordance with the facts and there is no omission likely to affect the import of such information.
- 1.5 BDO accepts responsibility for the BDO reports set out in Part B of Part 6 and Part C of Part 7 of this Prospectus. To the best of the knowledge of BDO (which has taken all reasonable care to ensure that such is the case) the information contained therein is in accordance with the facts and there is no omission likely to affect the import of such information.
- 1.6 Deloitte accepts responsibility for the Deloitte report set out in Part B of Part 8 of this Prospectus. To the best of the knowledge of Deloitte (which has taken all reasonable care to ensure that such is the case) the information contained therein is in accordance with the facts and there is no omission likely to affect the import of such information.

2. Incorporation and share capital

- 2.1 Afren was incorporated and registered in England and Wales, as a public limited company, on 3 December 2004, under the 1985 Act, with the name Afren plc and with registered number 05304498.
- 2.2 The principal legislation under which Afren operates is the 2006 Act.
- 2.3 The liability of the members of Afren is limited. Afren's registered office is at Kinnaird House, 1 Pall Mall East, London, SW1Y 5AU, United Kingdom. Its principal business address in the UK is Kinnaird House, 1 Pall Mall East, London, SW1Y 5AU and its telephone number is +44 (0)20 7451 9700. Afren's website is located at: www.afren.com.
- 2.4 The Ordinary Shares are in registered form and their ISIN code is GB00B0672758. The Ordinary Shares were created under the 1985 Act.

- 2.5 Pursuant to the shareholder resolution passed at a general meeting of the Company on 30 November 2009, the Company's authorised share capital was abolished. The issued share capital of Afren at 31 December 2009, the date to which the latest audited financial information in this Prospectus has been prepared, was as follows:

	<i>Number of Ordinary Shares with a nominal value of 1p</i>	<i>£</i>
Issued Ordinary Shares (fully paid)	889,065,354	8,890,653.54

- 2.6 The following table sets out the issued share capital of Afren as at the date of this Prospectus and as it will be immediately following completion of the Acquisition:

	<i>Date of this Prospectus</i>		<i>Following Completion of the Acquisition</i>	
	<i>Number of Ordinary Shares of 1p</i>		<i>Number of Ordinary Shares of 1p</i>	
		<i>£</i>		<i>£</i>
Issued Ordinary Shares (fully paid)	891,125,768	8,911,257.68	967,902,332	9,679,023

- 2.7 Since incorporation of Afren, there have been the following changes to Afren's authorised and issued share capital:

- on incorporation on 3 December 2004, the authorised share capital was £1,000,000 divided into 100,000,000 ordinary shares of 1p each, one of which was issued to SDG Secretaries Limited and one of which was issued to SDG Registrars Limited;
- on 3 December 2004 the subscriber shares were transferred to Ethelbert Cooper and to Osman Shahenshah in consideration of their undertakings to pay up such shares in full;
- on 17 December 2004 the Company allotted 5,000,000 Ordinary Shares which increased the number of issued Ordinary Shares to 5,000,002;
- during the period from 1 January 2005 to 31 December 2005, a total of 144,039,494 Ordinary Shares were issued, fully paid, increasing the number of issued Ordinary Shares to 189,039,496;
- during the period from 1 January 2006 to 31 December 2006, a total of 2,500,000 Ordinary Shares were issued, fully paid, increasing the number of issued Ordinary Shares to 191,539,496;
- during the period from 1 January 2007 to 31 December 2007, a total of 81,467,067 Ordinary Shares were issued, fully paid, increasing the number of issued Ordinary Shares to 273,006,563;
- during the period from 1 January 2008 until 31 December 2008, a total of 173,985,296 Ordinary Shares were issued, fully paid, increasing the number of issued Ordinary Shares to 446,991,859;
- during the period from 1 January 2009 until 31 December 2009 a total of 442,073,495 Ordinary Shares were issued, fully paid, increasing the number of issued Ordinary Shares to 889,065,354; and
- during the period from 1 January 2010 until 30 June 2010 a total of 2,055,414 Ordinary Shares were issued, fully paid, increasing the number of issued Ordinary Shares to 891,120,768.

- 2.8 In July 2006 Afren issued convertible bonds at a value of the equivalent of US\$75 million. The bonds were issued at 100 per cent. of the principal amount and denominated in British Pounds. The bonds were at a coupon of nine per cent. per annum (payable semi annually) and were converted early into ordinary shares of Afren on 25 July 2008. 71,120,683 new Ordinary Shares were issued to holders of the bonds.
- 2.9 On 8 October 2008 Afren entered into a strategic alliance with Sojitz, a Japanese investment and industrial conglomerate, to jointly pursue acquisition opportunities in Africa. Sojitz invested US\$45 million in the form of loan notes in Afren which become convertible bonds at the time of entering into joint acquisitions. The loan notes bear a coupon based on LIBOR plus a margin of two per cent. The net proceeds from the issue of the loan notes were split between a liability component and an equity component at the date of issue. The liability component of the loan notes was US\$33.2 million as at 31 December 2008. The interest charged for the year is calculated by applying an effective interest rate of 11.7 per cent. to the liability component. The loan notes are repayable in full in October 2011.
- 2.10 On 10 November 2009, the holders of warrants under the Founders' Investment and Warrant Scheme exercised warrants in respect of 40,000,000 Ordinary Shares at an exercise price of 37.95 pence per warrant, raising approximately £15 million (US\$25 million) in net proceeds to the Company. 40,000,000 Ordinary Shares were allotted to the exercising holders on 10 November 2009, conditional on the Placing. Further details of the Founders' Investment and Warrant Scheme are set out in paragraph 10.5 of this Part 10.
- 2.11 Save as disclosed in this Part 10:
- (a) no share or loan capital of Afren has, since incorporation of Afren, been issued or agreed to be issued, or is now proposed to be issued, fully or partly paid, either for cash or for consideration other than cash, to any person;
 - (b) no commissions, discounts, brokerages, or other special terms have been granted by Afren in connection with the issue or sale of any such share or loan capital; and
 - (c) no share or loan capital of Afren is under option or agreed conditionally or unconditionally to be put under option.
- 2.12 Afren is subject to the continuing obligations of the UK Listing Authority with regard to the issue of shares for cash. The provisions of section 561 of the 2006 Act (which confer on Shareholders rights of pre-emption, in respect of the allotment of equity securities which are, or are to be, paid up in cash other than by way of allotment to employees under an employees' share scheme as defined in section 1166 of the 2006 Act) apply to the unissued share capital of Afren except to the extent such provisions have been disapplied.
- 2.13 By a series of ordinary and special resolutions duly passed by the shareholders at the annual general meeting of the Company on 7 June 2010:
- (a) the directors' standing authority under Section 551 of the 2006 Act was renewed to issue unissued ordinary share capital up to (i) an aggregate nominal value of £2,967,719.97 (representing 296,771,997 Ordinary Shares); and (ii) up to an aggregate nominal amount equal to £5,936,330.34 (representing 593,633,034 Ordinary Shares), as reduced by the nominal amount of any shares issued under (i) for the purposes of rights issues. The aggregate amount in (ii) (before any reduction) is consistent with the current guidance issued by the Association of British Insurers. Such authority will expire at the earlier of the conclusion of the date of the Company's annual general meeting in 2011 and 10 September 2011;
 - (b) the provisions of section 561 of the Act (statutory pre-emption provisions) were disapplied to renew the directors' standing authority to allot ordinary shares (or sell any ordinary shares which the Company elects to hold in treasury) for cash without first offering them to existing shareholders in proportion to their existing holdings. This authority is limited to allotments or

sales in connection with pre-emptive offers and offers to holders of other equity securities if required by the rights of those shares or as the board of directors of the Company otherwise considers necessary, or otherwise up to an aggregate nominal amount of £445,202.52 (representing 44,520,252 Ordinary Shares). Such authority will expire at the earlier of the conclusion of the date of the Company's annual general meeting in 2011 and 10 September 2011; and

- (c) authority was given for the minimum period of notice for all general meetings of the Company other than annual general meetings to be 14 days.

3. Memorandum of association

In accordance with Section 8 of the 2006 Act, the memorandum of association of Afren consists of a simple statement that the subscribers wish to form a company and subscribe for at least one share each. Pursuant to the 2006 Act, unless a company's articles provide otherwise, a company's objects are unrestricted. Accordingly, the Company removed its objects clause together with all other provisions of its memorandum of association, pursuant to a special resolution of shareholders on 30 November 2009, which, by virtue of the 2006 Act, were to be treated as forming part of the Company's Articles as of 1 October 2009.

4. Articles of association

The Articles include provisions to the following effect:

(a) *Share rights*

Subject to the provisions of the Companies Acts (as defined in Section 2 of the 2006 Act), in so far as they apply to the Company, the Regulations and every other statute or enactment for the time being in force concerning companies and affecting the Company (together the "**Statutes**"), and without prejudice to any special rights previously conferred on the holders of any shares or class of shares for the time being issued, any share may be issued with such rights or restrictions as the Company may determine by ordinary resolution or failing any such determination, as the Directors may determine.

The Company may issue any shares which are to be redeemed or are liable to be redeemed at the option of the Company or the shareholder, and the Directors may determine the terms, conditions and manner of redemption of any such share. All shares of the Company shall be at the disposal of the Directors and they may allot, grant options over, offer or otherwise deal with or dispose of such shares to such persons as the Directors think propose but so that no share shall be issued at a discount.

(b) *Voting rights and general meetings*

Subject to the provisions of the Statutes, the annual general meeting shall be held at such time and place as may be determined by the directors. The directors may whenever they think fit, and shall on requisition in accordance with the Statutes, convene a general meeting to be held at such time and place as the directors may determine.

Subject to any special rights or restrictions as to voting attached by or by virtue of the Articles to any shares or any class of shares, on a show of hands:

- (i) every member who is present in person shall have one vote, and every proxy present who has been duly appointed by a member entitled to vote shall have one vote;
- (ii) every proxy present who has been duly appointed by one or more members entitled to vote on the resolution has one vote, except that if the proxy has been duly appointed by more than one member entitled to vote on the resolution and is instructed by one or more of those members to vote for the resolution and by one or more others to vote against it, or is instructed by one or more of those members to vote in one way and is given discretion as to how to vote by one or more others (and wishes to use that discretion to vote in the other way) he has one vote for and one vote against the resolution; and

- (iii) every corporate representative present who has been duly authorised by a corporation has the same voting rights as the corporation would be entitled to; and

on a poll every member present in person or by duly appointed proxy or corporate representative has one vote for every share of which he is the holder or in respect of which his appointment of proxy or corporate representative has been made.

A member, proxy or corporate representative entitled to more than one vote need not, if he votes, use all his votes or cast all the votes he uses the same way.

If any member, or any other person appearing to be interested in shares held by such member, has been duly served with a notice under Section 793 of the 2006 Act and is in default for a period of 14 days after service of the notice in supplying to the Company the information thereby required, then (unless the directors otherwise determine) in respect of:

- (i) the shares comprising the shareholding account in the register which comprises or includes the shares in relation to which the default occurred (all or the relevant number as appropriate of such shares being the “default shares”, which expression shall include any further shares which are issued after the date of service of the notice under Section 793 of the 2006 Act in respect of such share); and
- (ii) any other shares held by the member,

the member (for so long as the default continues) shall not be entitled to attend or vote either personally or by proxy at a shareholders’ meeting.

Where the default shares represent 0.25 per cent. or more of the issued shares of the class in question, the directors may in their absolute discretion by notice (a “direction notice”) to such member, and provided that the 14 day period referred to above has elapsed, direct that:

- (i) any dividend or part thereof or other money which would otherwise be payable in respect of the default shares shall be retained by the Company, without any liability to pay interest thereon when such money is finally paid to the member, including shares to be issued in lieu of dividend; and
- (ii) no transfer of any of the default shares held by such member shall be registered unless the transfer is an approved transfer,

provided that, in the case of shares in uncertificated form, the directors may only exercise their discretion not to register a transfer if permitted to do so by the Regulations. Any direction notice may treat shares of a member in certified and uncertificated form as separate holdings and either apply only to the former or to the latter or make different provision for the former and the latter.

No member shall, unless the directors otherwise determine, be entitled to be present or to vote at any general meeting either in person or by proxy or upon any poll or to exercise any other right conferred by membership in relation to meetings of the Company in respect of any shares held by him if any call or other sum presently payable by him to the Company in respect of such shares remains unpaid.

(c) ***Alteration of share capital***

The Company may by ordinary resolution increase its capital by such sum to be divided into shares of such amounts as the resolution shall prescribe, consolidate and divide all or any of its share capital into shares of a larger amount than its existing shares, and sub divide its shares into shares of smaller amounts.

The Company may by special resolution reduce its share capital or any capital redemption reserve fund or share premium account in any manner and with and subject to any incident authorised and consent required by law.

(d) ***Variation of rights***

Whenever the share capital of the Company is divided into different classes of shares, the special rights attached to any class may, subject to the provisions of the Statutes, be varied or abrogated either with the consent in writing of the holders of three fourths in nominal amount of the issued shares of the class (excluding any shares of that class held as Treasury Shares) or with the sanction of a special resolution passed at a separate general meeting of the holders of the shares of the class (but not otherwise) and may be so varied or abrogated either whilst the Company is a going concern or during or in contemplation of a winding up.

The necessary quorum (other than at an adjourned meeting) shall be two persons holding or representing by proxy at least one third in nominal amount of the issued shares of the class (excluding any shares of that class held as Treasury Shares), and at an adjourned meeting shall be one person holding shares of the class in question or his proxy. Any holder of shares of the class present in person or by proxy may demand a poll. Any holder of shares of the class present in person or by proxy shall, on a poll, have one vote in respect of every share of the class held by him. The special rights attached to any class of shares having preferential rights shall not unless otherwise expressly provided by the terms of issue thereof be deemed to be varied or abrogated by the creation or issue of further shares ranking as regards participation in the profits or assets of the Company or voting in some or all respects *pari passu* therewith but in no respect in priority thereto, or by any reduction of the capital paid up thereon, or by any purchase by the Company of its own shares.

(e) ***Issue of share warrants***

The directors may issue warrants in respect of fully paid up shares stating that the bearer is entitled to the shares therein specified and may provide by coupons or otherwise for the payment of future dividends on the shares included in such warrants. The directors may determine and vary the conditions upon which the bearer of a share warrant shall be entitled to receive notices of and attend and vote at general meetings or to join in requisitioning general meetings and upon which a share warrant may be surrendered and the name of the bearer entered in the register in respect of the shares therein specified. The directors may determine and vary the conditions upon which share warrants shall be issued.

(f) ***Transfer of Shares***

All transfers of shares which are in uncertificated form may be effected by means of a relevant system. Transfers of shares in certificated form may be effected by transfers in writing in any usual or common form or in any other form acceptable to the directors and may be under hand only. The instrument of transfer shall be signed by or on behalf of the transferor and (except in the case of fully paid shares) by or on behalf of the transferee. The transferor shall remain the holder of the shares concerned until the name of the transferee is entered in the register in respect thereof.

The directors may, in their absolute discretion, decline to register any transfer of shares which are not fully paid provided that were any such shares are admitted to trading on the Official List or AIM, such discretion may not be exercised in such a way as to prevent dealings in the shares of that class from taking place on an open and proper basis. The directors may, in their absolute discretion decline to register any transfer of shares in favour of more than four persons jointly.

The directors may decline to recognise any instrument of transfer relating to shares in certificated form unless the instrument of transfer is deposited at the place where the registrar is situate for the time being, is in respect of one class of shares, duly stamped, accompanied by the relevant share certificate(s) (except where no certificate shall have been issued thereof) and such other evidence as the directors may reasonably require to show the right of the transferor to make the transfer and, if the instrument of transfer is executed by some other person on his behalf, the authority of that person so to do. The directors may decline to recognise any instrument of transfer relating to shares in uncertificated form in the circumstances set out in the Regulations.

If the directors refuse to register a transfer they must, within two months, send to the transferee notice of the refusal together with reasons for the refusal. The directors shall send to the transferee such further information about the reasons for the refusal as the transferee may reasonably request.

No fee will be charged by the Company in respect of the registration of any instrument of transfer or document relating to or affecting the title to any shares or otherwise for making any entry in the register affecting the title to any shares.

The directors may determine that any class of shares may be held in uncertificated form and that title to such shares may be transferred by means of a relevant system or that shares of any class should cease to be held and transferred as described in the Articles.

(g) ***Dividends***

The Company may by ordinary resolution declare dividends and fix the time for payment thereof, but no dividend shall be payable except out of profits of the Company available for distribution in accordance with the Statutes or in excess of the amount, or at any earlier date than, recommended by the Directors.

Unless and to the extent that the rights attached to any shares or the terms of issue thereof or the Statutes otherwise provide, all dividends shall (as regards any shares not fully paid throughout the period in respect of which the dividend is paid) be apportioned and paid *pro rata* according to the amounts paid on the shares during any portion or portions of the period in respect of which the dividend is paid.

If and so far as in the opinion of the directors the profits of the Company justify such payments, the directors may pay the fixed dividend on any class of shares carrying a fixed dividend expressed to be payable on fixed dates on the half yearly or other dates prescribed for the payment thereof and may also from time to time pay interim dividends of such amounts and on such dates and in respect of such periods as they think fit.

No dividend or other moneys payable on or in respect of a share shall bear interest as against the Company. All unclaimed dividends or other moneys payable on or in respect of a share may be invested or otherwise made use of by the directors for the benefit of the Company until claimed. Any dividend unclaimed for a period of 12 years from the date of declaration of such dividend or the date on which such dividend became due for payment shall be forfeited and shall revert to the Company.

(h) ***Winding up***

If the Company shall be wound up the liquidator may, with the authority of special resolution, divide amounts the members *in specie* the whole or any part of the assets of the Company and may for such purpose set such value as he deems fair upon any one or more class or classes of property and may subject to any special rights attached to any shares or the terms of issue thereof determine how such division shall be carried out as between the members or different classes of members. The liquidator may, with the like authority, vest any part of the assets in trustees upon such trusts for the benefit of members as the liquidator with the like authority shall think fit, and the liquidation of the Company may be closed and the Company dissolved, but so that no contributory shall be compelled to accept any shares or other property in respect of which there is a liability.

(i) ***Forfeiture and Lien***

The directors may from time to time make calls upon members in respect of any moneys unpaid on their shares and not by the terms of issue thereof made payable at fixed times. Each member shall, subject to receiving at least 14 days' notice specifying the time or times and place of payment, pay to or as directed by the Company at the time or times and place so specified the amount called on the shares.

If a member fails to pay in full any call or instalment of a call on the day appointed for payment thereof, the directors may at any time thereafter serve a notice on him requiring payment of so much

of the call or instalment as is unpaid together with any interest which may have accrued thereon and any expenses incurred by the Company by reason of such non payment.

A member whose shares have been forfeited or surrendered shall cease to be a member in respect of the shares but shall notwithstanding the forfeiture or surrender remain liable to pay to the Company all moneys which at the date of forfeiture or surrender were presently payable by him to the Company in respect of the shares with interest thereon at 15 per cent. Per annum from the date of forfeiture or surrender until payment.

(j) ***Purchase of own shares***

Subject to the provisions of the Statutes, the Company may purchase, or enter into a contract under which it will or may purchase, any of its own shares of any class (including redeemable shares) but so that if there shall be in issue any shares which are admitted to trading on the Official List or AIM and which are convertible into equity share capital of the Company of the class proposed to be purchased, then the Company shall not purchase, or enter into a contract under which it will or may purchase, such equity shares unless either:

- (i) the terms of the issue of such convertible shares include provisions permitting the Company to purchase its own equity shares or providing for adjustment to the conversion terms upon such a purchase; or
- (ii) the purchase, or the contract, has first been approved by a special resolution passed at a separate meeting of the holders of such convertible shares.

(k) ***Directors***

(i) ***Appointment of Directors***

The minimum number of Directors is two and the maximum is 12. The Company may by ordinary resolution from time to time vary the minimum or maximum number of directors.

No person other than a director retiring at the meeting shall, unless recommended by the directors for election, be eligible for appointment as a director at any general meeting unless not less than seven nor more than 42 clear days before the day appointed for the meeting there shall have been left at the registered office of the Company notice signed by some member (other than the person to be proposed) duly qualified to attend and vote at the meeting for which such notice is given of his intention to propose such person for election and also notice in writing signed by the person to be proposed of his willingness to be elected.

(ii) ***Retirement of Directors by rotation***

At each annual general meeting any director who was elected or last re elected a director at or before the annual general meeting held in the third calendar year before the current year shall retire by rotation and, such further directors (if any) shall retire by rotation as would bring the number retiring by rotation up to one third of the number of directors in office at the date of the notice of the annual general meeting (or if their number is not a multiple of three, the number nearest to but not greater than one third).

The directors to retire by rotation shall include (so far as necessary to obtain the number required) any director who wishes to retire and not offer himself for re election. Any further directors so to retire shall be those of the other directors subject to retirement by rotation who have been longest in office since their last re election or appointment and so that as between persons who became or were last re elected directors on the same day, those to retire shall (unless they otherwise agree among themselves) be determined by lot. A retiring director shall be eligible for re election.

(iii) *Proceedings of Directors*

The directors may meet together for the despatch of business, adjourn and otherwise regulate their meetings as they think fit. Questions arising at any meeting shall be determined by a majority of votes. In the case of an equality of votes the chairman of the meeting shall have a second or casting vote. No business shall be transacted at any meeting of the directors unless a quorum is present. The quorum necessary for the transaction of the business of the directors may be fixed by the directors and unless so fixed at any other number shall be two. A director shall not be counted in the quorum present in relation to a matter or resolution on which he is not entitled to vote but shall be counted in the quorum present in relation to all other matters or resolutions considered or voted on at the meeting.

(iv) *Remuneration of Directors*

The directors (other than alternate directors) shall be entitled to receive by way of fees for their services as directors such sums as the Board may from time to time determine (not exceeding £350,000 per annum per director or such other sum as the Company in general meeting shall from time to time determine). Such sum (unless otherwise directed by the resolution of the Company by which it is voted) shall be divided among the directors in such proportions and in such manner as the board may determine or in default of such determination, equally (except that in such event any director holding office for less than the whole of the relevant period in respect of which the fees are paid shall only rank in such division in proportion to the time during such period for which he holds office). Any fees payable pursuant to this article shall be distinct from any salary, remuneration or other amounts payable to a director pursuant to any other provisions of the Articles and shall accrue from day to day.

Each director shall be entitled to be repaid all reasonable travelling, hotel and other expenses properly incurred by him in or about the performance of his duties as director, including any expenses incurred in attending meetings of the board or any committee of the board or general meetings or separate meetings of the holders of any class of shares or of debentures of the Company.

Any director who is appointed to any executive office (including for this purpose the office of the chairman or deputy chairman whether or not such office is held in an executive capacity) or who serves on any committee or who otherwise performs services which in the opinion of the directors are outside the scope of the ordinary duties of a director may be paid extra remuneration by way of salary, commission, bonus or otherwise (whether exclusive or inclusive of his remuneration (if any) under the Articles) as the directors may determine.

A director may hold any other office or place of profit under the Company (other than the office of auditor) in conjunction with his office of director, and may act in a professional capacity to the Company, on such terms as to tenure of office, remuneration and otherwise as the directors may determine.

(v) *Permitted interests of Directors*

Subject to the provisions of the Acts to the extent in force from time to time, and provided that he has disclosed to the directors the nature and extent of any material interest of his, a director, notwithstanding his office, may be a part to or otherwise interested in any transaction or arrangement with the Company or in which the Company is otherwise interested, and he may be a director or other officer of, or employed by, or a party to an transaction or arrangement with, or otherwise interested in, any body corporate promoted by the Company or in which the Company is otherwise interested. And such a director (i) shall not, by reason of his office, be accountable to the Company for any benefit which he derives from any such office or employment or from any such transaction or arrangement or from any interest in any body corporate; (ii) shall not infringe his duty to avoid a situation in which he has, or can have, a direct or indirect interest that conflicts, or possibly may conflict, with the interests of the Company as a result of any such office or employment or any such transaction or arrangement

or any interest in any such body corporate; and (iii) no such transaction or arrangement shall be liable to be avoided on the ground of any such interest or benefit.

(vi) *Restrictions on voting*

A director shall not vote in respect of any contract or arrangement or any other proposal whatsoever in which he has an interest which is a material interest otherwise than by virtue of his interests in shares or debentures or other securities of or otherwise in or through the Company.

A Director shall (in the absence of some other material interest than is indicated below) be entitled to vote (and be counted in the quorum) in respect of any resolution concerning any of the following matters, namely:

- (a) the giving of any guarantee, security or indemnity in respect of money lent or obligations incurred by him or by any other person at the request of or for the benefit of the Company or any of its subsidiary undertakings;
- (b) the giving of any security, guarantee or indemnity in respect of a debt or obligation of the Company or any of its subsidiary undertakings for which he himself has assumed responsibility in whole or in part under a guarantee or indemnity or by the giving of security;
- (c) any proposal concerning an offer of shares or debentures or other securities of or by the Company or any of its subsidiary undertakings for subscription or purchase or in exchange in which offer he is or is to be interested as an existing holder of securities of the Company or the subsidiary undertaking concerned or as a participant in the underwriting or sub underwriting thereof;
- (d) any proposal concerning any other company in which he is interested, directly or indirectly and whether as an officer or a shareholder or otherwise howsoever, provided that he is not the holder of or beneficially interested in one per cent. Or more of the issued shares of any class of such company (or of any third company through which his interest is derived) or of the voting rights available to members of the relevant company (any such interest being deemed for the purposes of this Section to be a material interest in all circumstances);
- (e) any arrangement for the benefit of the employees and directors and/or former employees and directors of the Company or any of its subsidiary undertakings and/or the members of their families (including a spouse of civil partner and a former spouse and former civil partner) or any person who is or was dependent on such persons, including but without being limited to a retirement benefits scheme and employees' share scheme, provided that such arrangement does not accord to any director as such any privilege or advantage not generally accorded to the employees to whom such arrangement relates; or
- (f) insurance which the Company proposes to maintain or purchase for the benefit of the directors or for the benefit of persons including directors.

The Company may by ordinary resolution suspend or relax to any extent, in respect of any particular matter, any provision of the Articles prohibiting a director from voting at a meeting of the directors or of a committee of the directors.

(l) *Borrowing powers*

The directors may exercise all the powers of the Company to borrow money, and to mortgage or charge its undertaking, property and uncalled capital or any part thereof and, subject to the provision of Section 549 of the 2006 Act, to issue debentures and other securities whether outright or as collateral security for any debt, liability or obligation of the Company or of any third party.

(m) **Indemnity of officers**

Subject to the provisions of the Acts, the Company may indemnify any person who is or was a director, secretary or other officer of any Relevant Company directly or indirectly (including by funding any expenditure incurred or to be incurred by him) against any loss or liability, whether in connection with any proven or alleged negligence, default, breach of duty or breach of trust by him or otherwise, in relation to the Company or any Relevant Company; and/or subject to the provisions of the Acts the Company may indemnify to any extent any person who is or was a director of a Relevant Company that is a trustee of an occupational pension scheme, directly or indirectly (including by funding any expenditure incurred or to be incurred by him) against any liability incurred by him in connection with the Company's activities as trustee of an occupational pension scheme.

5. Subsidiary undertakings and investments

- 5.1 The Group comprises Afren and its subsidiary undertakings. Afren has the following significant subsidiaries, all of which are directly or indirectly owned by Afren and which are likely to have a significant effect on the assessment of Afren's assets and liabilities, profits and losses:

<i>Company name</i>	<i>Principal Activity</i>	<i>Country of registration</i>	<i>Country of operation</i>	<i>%</i>
Directly held				
Afren CI (UK) Ltd (formerly Afren Production and Shipping Limited)	Oil and gas exploration, development and production	England & Wales	UK	100
Afren Energy International plc	Oil and gas exploration, development and production	England & Wales	UK	100
Afren USA Inc.	Service company	USA, Delaware	USA	100
Indirectly held				
Dangote Energy Equity Resources Limited	Oil and gas exploration, development and production	Nigeria	Nigeria	49 ⁽ⁱ⁾
Afren Energy Resources Limited	Oil and gas exploration, development and production	Nigeria	Nigeria	100
Afren Global Energy Resources Limited	Oil and gas exploration, development and production	Nigeria	Nigeria	50 ⁽ⁱ⁾
Afren Onshore Limited	Oil and gas exploration, development and production	Nigeria	Nigeria	100

<i>Company name</i>	<i>Principal Activity</i>	<i>Country of registration</i>	<i>Country of operation</i>	<i>%</i>
Afren Investments Oil & Gas (Nigeria) Limited	Oil and gas exploration, development and production	Nigeria	Nigeria	100
Afren Energy Services Limited	Service company	Nigeria	Nigeria	100
Zetah Noumbi Limited	Oil and gas exploration, development and production	Bahamas	Congo-Brazzaville	14
Afren CI One Corporation	Oil and gas exploration, development and production	Cayman	Côte d'Ivoire	100
Afren Côte d'Ivoire, Ltd	Oil and gas exploration, development and production	Cayman	Côte d'Ivoire	100
Lion GPL SA	Oil and gas exploration, development and production	Côte d'Ivoire	Côte d'Ivoire	100
Afren Energy Ghana Limited	Oil and gas exploration, development and production	Bahamas	Ghana	100
Afren Resources Limited	Oil and gas exploration, development and production	Nigeria	Nigeria	100
Afren Exploration & Production Alpha Nigeria Limited	Oil and gas exploration, development and production	Nigeria	Nigeria	100
Afren Exploration & Production Beta Nigeria Limited	Oil and gas exploration, development and production	Nigeria	Nigeria	100
First Hydrocarbon Nigeria Limited	Oil and gas exploration, development and production	Nigeria	Nigeria	40

(i) Accounted for via proportional consolidation as the Group exercises joint control over its operations.

All operating companies are engaged in the exploration, development and production of oil and gas properties whilst those whose names indicate they are holding and service companies manage the operating companies.

- 5.2 The percentage interests shown opposite the names of the subsidiaries of Afren represent both ownership interests and voting rights.

6. Premises

- 6.1 The following are the principal premises owned or leased or used by the Group:

<i>Property Address</i>	<i>Use</i>	<i>Tenure</i>	<i>Term Expires</i>	<i>Yearly Rent⁽¹⁾</i>
Right Wing Of Plot 1355 (No. 30) T.Y. Danjuma Street, Cadastral Zone A4, Asokoro, Ajuba, Nigeria	Offices	Lease	29/12/2010 (with option to extend)	USD 55,955
14/13 Amanful Road, Harbour Business Area, Takoradi, Ghana	Offices	Lease	Renewable on 6 monthly basis	USD 42,000
Ground And Mezzanine Floor, The Octagon, Victoria Island Annexe, Lagos, Nigeria	Offices	Lease	30/06/2010 Lease renewal underway	USD367, 140 plus service charge
3rd Floor, Kinnaird House, 1-4 Pall Mall East, London SW1, United Kingdom	Offices	Lease	09/09/2012	GBP 664, 695 plus service charge
Office, 1st Floor, Residence Pelieu, Avenue Delafosse, Plateau, Abidjan, Ivory Coast	Offices	Lease	Annually renewable	CFA 9,000,000 plus service charge
Office, Ground Floor, Residence Pelieu, Avenue Delafosse, Plateau, Abidjan, Ivory Coast	Offices	Lease	Annually renewable	CFA 27,600,000 plus service charge
Office, Ground Floor, Residence Pelieu, Avenue Delafosse, Plateau, Abidjan, Ivory Coast	Offices	Lease	Annually renewable	CFA 18,216,000 plus service charge
Waterway Plaza Two, 10001 Woodloch Forest Dr., The Woodlands, TX 77380, USA	Offices	Lease	Annually renewable 14/11/2013 (with option to break 01/09/2011)	USD 143,232 plus service charge

(1) Excluding value added tax and local equivalents in overseas jurisdictions.

(2) Premises is subleased and not occupied by the business.

7. Interests of Directors and senior management

- 7.1 None of the Directors or senior managers has any business interests nor performs any activities outside the Group which are significant with respect to the Group. No Director or senior manager has any conflict of interest between his duties to Afren and any private interests or other duties.

7.2 *Interests in the Ordinary Shares of Afren*

As at the close of business on 23 August 2010 (being the latest practicable date prior to the publication of this Prospectus), the share ownership and any options over such shares held by the Directors and senior managers in respect of the share capital of Afren are as follows:

	<i>Number of existing Ordinary Shares</i>	<i>Options to acquire Ordinary Shares</i>	<i>Ordinary Shares held pursuant to Performance Share Plan</i>	<i>R&D Shares due 1 May 2011</i>	<i>Warrants</i>	<i>Total⁽¹⁾</i>
Egbert Imomoh	3,672,246	3,500,000	271,084	–	–	7,443,330
Osman Shahenshah	4,181,515	13,200,000	1,887,458	–	–	19,268,973
Darra Comyn	–	1,850,000	–	–	–	1,850,000
Shahid Ullah	3,268,961	3,000,000	1,322,600	–	–	7,591,561
Constantine Ogunbiyi	1,295,676	6,000,000	1,258,305	–	–	8,553,981
Peter Bingham	–	400,000	–	–	–	400,000
John St. John	50,922	400,000	–	–	–	450,922
Ennio Sganzerla	24,000	–	–	–	100,000	124,000
Toby Hayward	205,000	–	–	–	–	205,000
Iain Wright	638,727	850,000	606,936	89,674	–	2,185,337
Shirin Johri	–	925,000	542,644	–	–	1,467,644
Andrew Olleveant	10,544(2)	625,000	497,612	–	–	1,133,156
Galib Virani	1,172,754	2,421,667	646,044	–	–	4,240,465
Jeremy Whitlock	–	2,025,000	669,290	–	–	2,694,290

(1) Assuming all options and warrants are exercised and granted.

(2) Shares held by Mr. Olleveant's spouse.

7.3 *Interests in transactions*

Save for the related party transactions set out in the financial information incorporated by reference in this Prospectus (as set out on page 33) and as set out in paragraphs 7.4 and 25 of this Part 10 of this Prospectus, no Director has or has had any interest in any transaction which is or was unusual in its nature or conditions or is or was significant to the business of the Group and which was effected by Afren in the current or immediately preceding financial year of Afren or which was effected in an earlier financial year and remains in any respect outstanding or unperformed.

7.4 *Directorships and partnerships*

Set out below are the directorships and partnerships in which the Directors and members of the senior management are currently directors or partners or have been directors or partners at any time in the five years prior to the date of this Prospectus:

<i>Name</i>	<i>Current directorships</i>	<i>Former directorships held in the last five years</i>
Egbert Imomoh	Afren pic, London Afren Nigeria First Hydrocarbon Nigeria Ltd Guaranty Trust Bank, Nigeria Guaranty Trust Asset Ltd, Nigeria Dagnet Ltd, Nigeria Mts Ltd Nigeria Egpat Patetopi Enterprise, Nigeria	Presidential Insurance Limited Mts Ltd
Osman Shahenshah	Gasol plc First Hydrocarbon Nigeria Ltd	
Constantine Ogunbiyi	First Hydrocarbon Nigeria Ltd	

<i>Name</i>	<i>Current directorships</i>	<i>Former directorships held in the last five years</i>
Darra Comyn	Elmfield Services Ltd (UK) Expocentres (Poland) Limited Informedia India Pty Limited Expomedia Deutschland GmBH (termination of directorship being processed)	IEC Africa Limited Expomedia Exhibitions and Conferences Limited Expomedia Events Limited (in liquidation) HB 2009 Limited (in administration) ATS Events Limited (in administration) Expomedia Group plc (in liquidation) Expomedia Events (UK) Limited Mash Media Group Limited Informedia Group Limited (dissolved) PI Portal Limited Expomedia Events India Pty Limited Tafcon Expomedia India Pty Limited OOO Central European Exhibitions Expocentres Eastern Europe Limited CEE Exhibition Limited Expo Sports Centre Limited Expomedia Overseas Limited Expo XXI Venue Management
Shahid Ullah	Stratum Energy Kismet Family Ltd Caymus Fund RTL Fund Stiletto Real Estate	
Peter Bingham	Capital Corporate Holdings	
Ennio Sganzerla	Stratic Energy Proger	Sun Energy Ltd Tristanoil ENI Exploration & Production
John St. John	St. John Advisers Limited St. John Estates LLP St. John Estates Limited MMJ Advisers LLP STJ Advisers LLP	Burkhardt Fraess & Co Chiliogon plc Solebury Capital Group Highview Enterprises Limited Solebury International LLP
Toby Hayward	Severfield Rowen plc Sirius Petroleum plc THC Consultants Limited	Paradisii Limited eCast Limited
Andrew Olleveant	EHSS Solutions Ltd	

7.5 *Receiverships, liquidations and administrations*

- (a) Save as disclosed in this paragraph 7.5, none of the Directors or senior managers have, in the five years immediately preceding the date of this Prospectus:
- (i) received any convictions in relation to fraudulent offences;
 - (ii) been declared bankrupt or been the subject of an individual voluntary arrangement or been associated with any bankruptcy, receivership or liquidation in his capacity as a director or senior manager of another company;

- (iii) been a partner or senior manager in a partnership which has been subject to a compulsory liquidation, administration or a partnership voluntary arrangement; or
 - (iv) been subject to any official public incrimination and/or sanction by statutory or regulatory authorities (including designated professional bodies) or been disqualified by a court from acting as a director or member of the administrative, management or supervisory bodies of a company or entity or from acting in the management or conduct of the affairs of any company or entity.
- (b) Mr. Darra Comyn was appointed a director of Informedia Group Limited on 19 October 2004. This company has now been dissolved. An administrative receiver was appointed on 19 January 2009 and there was a deficit to creditors of £563,000.
 - (c) Mr. Darra Comyn was appointed a director of Expomedia Events Limited on 9 May 2003. A liquidator was appointed on 22 January 2009 and there was a deficit to creditors of £8.7 million.
 - (d) Mr. Darra Comyn was appointed a director of HB 2009 Limited and ATS Events Limited on 24 May 2007 and 4 July 2006 respectively. An administrative receiver was appointed on 22 January 2009 and there was a deficit to creditors of £5.7 million for HB 2009 Limited and £37,000 for ATS Events Limited.
 - (e) Mr. Darra Comyn was appointed a director of Expomedia Group plc on 15 December 2001. An administrative receiver was appointed on 19 January 2009 and there was a deficit of £11.7 million.
 - (f) Mr. Toby Hayward was appointed a director of Paradisii Limited in 1999. A liquidator was appointed for a creditors/members voluntary winding up on 22 February 2006 and Paradisii Limited was dissolved on 2 February 2008. There was a deficit to creditors of £133,629.
 - (g) Mr. Toby Hayward was appointed a director of Ocean Supplies Limited (a wholly owned subsidiary of International Seafood Products plc) in 1999. An administrative receiver was appointed on 12 July 1999 for Ocean Supplies Limited, which was dissolved on 1 May 2007. There was a deficit to creditors of £1,168,785.

8. Directors' service contracts and letters of appointment and advisors' consultancy agreements

8.1 *Mr. Egbert Imomoh*

Mr. Imomoh was appointed as a non executive director and as non executive chairman of Afren under a non executive director and non executive chairman agreement dated 1 January 2009. His period of appointment is deemed to have commenced on 1 January 2009. Mr. Imomoh is entitled to an annual fee of £140,000, variable by agreement from time to time. His appointment may be terminated by either party giving the other not less than three months' written notice. The agreement also contains provisions relating to confidentiality, share dealings and conflicts of interest.

8.2 *Dr. Osman Shahenshah*

Dr. Shahenshah is employed by Afren as Chief Executive under a service agreement dated 27 February 2009. His period of continuous employment is deemed to have commenced on 14 May 2005 and terminates on 27 February 2011, which termination date may be extended with approval of the Board. His employment also terminates automatically at the end of the month in which he reaches his 65th birthday. Dr. Shahenshah was also appointed as a director under the agreement. Dr. Shahenshah is entitled to an annual basic salary of £462,500, exclusive of director's remuneration, which is reviewed by the Board from time to time. His salary may also be supplemented by an annual discretionary bonus, the terms of such payment being set by Afren's Remuneration Committee. Dr. Shahenshah's employment may be terminated by either party giving the other not less than 12 months' written notice. The agreement also contains provisions relating to confidentiality, share dealings, conflicts of interest, the ownership of intellectual property created by Dr. Shahenshah during

his employment, and restrictions on the conduct of Dr. Shahenshah following the cessation of his employment with Afren.

8.3 Mr. Darra Comyn

Mr. Comyn was appointed as Group Finance Director under an agreement dated 26 March 2010. His period of appointment is deemed to have commenced on 23 March 2010 for an initial period of two (2) years, contingent on re-election to the Board. Mr. Comyn's employment also terminates automatically at the end of the month in which he reaches his 65th birthday. Mr. Comyn is currently entitled to an annual fee of £290,000 variable by agreement from time to time. His salary may also be supplemented by an annual discretionary bonus, the terms of such payment being set by Afren's Remuneration Committee. His employment may be terminated by either party giving the other not less than six (6) months' written notice. The agreement also contains provisions relating to share dealings, conflicts of interests, the ownership of intellectual property created by Mr. Comyn during his employment and confidentiality.

8.4 Mr. Shahid Ullah

Mr. Ullah is employed by Afren USA, Inc., as President under an employment agreement dated effective 16 April 2008. His period of continuous employment is deemed to have commenced on 14 April 2008. Mr. Ullah was also appointed as director of Afren USA, Inc. and Afren under the agreement. He is currently entitled to an annual basic salary of £353,500, which is reviewed by the board of directors of Afren USA, Inc. (with the approval of the Board) from time to time. Mr. Ullah was entitled to Ordinary Shares on the occurrence of the following events: 1,125,000 Ordinary Shares on joining (with vesting spread over a period to the end of 2009), 375,000 Ordinary Shares conditional on the production performance of Okoro, and 525,000 Ordinary Shares in the second quarter of 2009. His salary may also be supplemented by an annual discretionary bonus, the terms of such payment being set by the board of directors of Afren USA, Inc. Mr. Ullah's employment may be terminated by either party giving the other not less than six months' written notice. The agreement contains provisions relating to confidentiality, share dealings, non competition, conflicts of interest, the ownership of intellectual property created by Mr. Ullah during his employment, and restrictions on the conduct of Mr. Ullah following the cessation of his employment with Afren USA, Inc.

8.5 Mr. Constantine Ogunbiyi

Mr. Ogunbiyi is employed by Afren as Chief Corporate Planning and Strategy Officer under a service agreement dated 12 February 2008. His period of continuous employment is deemed to have commenced on 12 February 2008 for an initial period of two years, to be automatically extended unless terminated by either party. Mr. Ogunbiyi's employment also terminates automatically at the end of the month in which he reaches his 65th birthday. He was also appointed as a director under the agreement, with an effective date of 3 January 2008. He is currently entitled to an annual basic salary of £260,000, exclusive of any director's remuneration, which is reviewed by the Board from time to time. Mr. Ogunbiyi's salary may also be supplemented by an annual discretionary bonus, the terms of such payment being set by Afren's Remuneration Committee. His employment may be terminated by either party giving the other not less than 12 months' written notice. The agreement also contains provisions relating to confidentiality, share dealings, conflicts of interest, the ownership of intellectual property created by Mr. Ogunbiyi during his employment, and restrictions on the conduct of Mr. Ogunbiyi following the cessation of his employment with Afren.

8.6 Mr. Ennio Sganzerla

Mr. Sganzerla was appointed as a non executive director under a non executive director agreement dated 26 June 2009. His period of appointment is deemed to have commenced on 26 June 2009 for an initial period of three years, contingent on re election to the Board. Mr. Sganzerla is currently entitled to an annual fee of £47,000 variable by agreement from time to time. His appointment may be terminated by either party giving the other not less than three months' written notice. The agreement also contains provisions relating to confidentiality, share dealings and conflicts of interest.

8.7 **Mr. Peter Bingham**

Mr. Bingham was appointed as non executive director under a contract for services dated 10 May 2005. His period of appointment is deemed to have commenced on 10 May 2005 for an initial term of three years, contingent on re election to the Board. Mr. Bingham is entitled to an annual fee of £47,000, which is reviewed by the Board from time to time. His appointment may be terminated by either party giving the other not less than three months' written notice. The contract also contains provisions relating to confidentiality and conflicts of interest.

8.8 **Mr. John St. John**

(a) *Letter of appointment*

Mr. St. John was appointed as non executive director under a letter agreement dated 6 June 2007. His period of appointment is deemed to have commenced on 18 June 2007 for an initial term of three years, contingent on re election to the Board. He is entitled to an annual fee of £47,000, which is reviewed by the Board from time to time. He was also granted options on up to 400,000 Ordinary Shares. Mr. St John's appointment may be terminated by either party giving the other not less than three months' written notice. The letter agreement also contains provisions relating to confidentiality and conflicts of interest.

(b) *Consultancy contract*

St. John Advisers Ltd and Afren entered into a letter agreement effective 27 June 2008 whereby St. John Advisers Ltd is to provide Afren with financial consulting services in respect of fund raising relating to a special purpose acquisition company. Afren is to pay St. John Advisers Ltd a monthly retainer fee of £15,000, a transaction fee of £400,000 upon successful completion of the fund raising, and a completion fee of £1.5 million upon the successful acquisition of an asset or assets by the special purpose acquisition company for an amount greater than €150 million within two months of the fund raising. St. John Advisers Ltd is engaged under the terms of the agreement for an initial period of 12 months from the effective date, to automatically continue thereafter unless terminated by either party. The agreement may be terminated by either party on 30 days' written notice. Afren indemnifies St. John Advisers Ltd against costs related to litigation arising from its services, except where St. John Advisers Ltd has acted in bad faith, wilful misconduct or negligence; Afren is also prohibited from settling any related litigation without prior consent from, or a written release of claims against, St. John Advisers Ltd. The agreement contains provisions on confidentiality and standard warranties.

Pursuant to the letter agreement, St. John Advisers Ltd provided Afren with financial consulting services with both the Placing and Admission and an earlier placing conducted by Afren in April 2009 (the "**April Placing**"). Afren paid St. John Advisers Ltd a discretionary fee of £230,000 in connection with the Placing and Admission and £231,515.70 in connection with the April Placing.

8.9 **Mr. Toby Hayward**

Mr. Hayward was appointed as a non executive director under a non executive director agreement on 26 June 2009 for an initial period of three years, contingent on re election to the Board. Mr. Hayward is the Senior Independent Director and is entitled to an annual fee of £50,000, variable by agreement from time to time. His appointment may be terminated by either party giving the other not less than three months' written notice. The agreement also contains provisions relating to confidentiality, share dealings and conflicts of interest.

9. **Remuneration and benefits**

9.1 The aggregate emoluments of each of the Directors (including benefits in kind) for the financial accounting period ending 31 December 2009 were as follows:

	<i>Salary/fee US\$000's</i>	<i>Benefits in kind US\$000's</i>	<i>Pension US\$000's</i>	<i>Annual Bonuses US\$000's</i>	<i>Total US\$000's</i>
Executive					
Egbert Imomoh ⁽¹⁾	27	–	–	–	27
Dr. Osman Shahenshah	511	18	51	547	1,127
Darra Comyn ⁽²⁾	26	–	–	–	26
Shahid Ullah	513	25	–	520	1,058
Constantine Ogunbiyi	341	5	23	294	663
Non Executive					
Egbert Imomoh ⁽¹⁾	162	19	–	–	181
Peter Bingham	62	–	–	–	62
John St. John ⁽³⁾	62	–	–	–	62
Ennio Sganzerla ⁽⁴⁾⁽⁵⁾	33	–	–	–	33
Toby Hayward ⁽⁴⁾	33	–	–	–	33
Guy Pas	29	–	–	–	29
Total	1,799	67	74	1,361	3,301

(1) Egbert Imomoh was paid as an Executive Director until the end of January 2009 and then as a non-Executive Chairman. His Chairman's fee includes a housing allowance of US\$41,000 for the period.

(2) Darra Comyn joined Afren on 1 December 2009 and was appointed to the Board of Directors of Afren on 26 March 2010.

(3) John St. John received US\$1,083,000 through his contractor company, St. John Advisors, in relation to consultancy services provided to Afren as set out in the financial information incorporated by reference in this Prospectus.

(4) Appointed during the financial year ended 31 December 2009.

(5) Mr. Sganzerla received US\$24,000 in an advisory capacity during the financial year ended 31 December 2009. Mr. Sganzerla was paid \$78,738 in 2008 and \$24,000 in 2009 before his appointment to the board.

(6) Guy Pas resigned from the board on 26 June 2009.

9.2 The aggregate emoluments of each of the Senior Managers (including benefits in kind) for the financial accounting period ending 31 December 2009 were as follows:

	<i>Salary/fee US\$000's</i>	<i>Benefits in kind US\$000's</i>	<i>Pension US\$000's</i>	<i>Annual Bonuses US\$000's</i>	<i>Total US\$000's</i>
Senior Managers					
Jeremy Whitlock	240	5	24	154	423
Shirin Johri	211	4	21	93	329
Iain Wright	271	7	27	154	459
Andrew Olleveant	179	7	18	51	255
Galib Virani	232	6	23	208	469
Total	1,133	29	113	660	1,935

9.3 Afren operates a defined contribution scheme, therefore, there were no amounts set aside or accrued to provide pension, retirement or other benefits (other than the annual bonuses disclosed in paragraph 9.1 of this Part 10) to the Directors and senior managers of the Group for the year ended 31 December 2009.

9.4 Save as disclosed in this paragraph 9, there have been no changes to the emoluments or the terms of employment of the Directors or senior management within the six months prior to the date hereof.

10. Employees, Employee Share Schemes and Pensions

10.1 As at 31 December 2009, the Group employed 183 people. The table below sets out the number of full time employees employed by the Group at the end of each of the last three financial periods:

	<i>Year ended</i>		
	<i>31 December 2009</i>	<i>31 December 2008</i>	<i>31 December 2007</i>
Directors	3	4	3
Administrative and technical	86	80	41
Operational	94	89	7
Total	183	173	51

The table below sets out the number of full time employees, employed by the Group in the United Kingdom, Nigeria, Côte d'Ivoire and the USA at the end of each of the last three financial periods:

	<i>Year ended</i>		
	<i>31 December 2009</i>	<i>31 December 2008</i>	<i>31 December 2007</i>
United Kingdom	43	49	33
Nigeria	33	22	18
Côte d'Ivoire	96	96	–
USA	11	5	–
Total	183	173	51

10.2 *Share Option Scheme*

The Share Option Scheme was adopted on 28 June 2005. The Remuneration Committee has responsibility for supervising the Share Option Scheme. A summary of the rules of the Share Option Scheme is set out below:

(i) *Eligibility*

Any employee or executive director of the Group is eligible to receive options under the Share Option Scheme. Prior to the 2009 Admission, non-executive directors of the Company were also granted options, but the Share Option Scheme has been amended so that no further options may be granted to non-executive directors of the Company, although their rights to exercise options already granted are unaffected.

(ii) *Grant of Options*

An option may be granted at any time. Options are awarded at the absolute discretion of the Company, although the Group's policy is to award options to participants on appointment or completion of their probationary period and periodically thereafter as part of their annual bonus. Options are not pensionable. Options are personal and may not be transferred, assigned or charged, except on death. The exercise price per Ordinary Share is the market value of an Ordinary Share at the time of grant.

(iii) *Vesting, Performance Conditions and Exercise of Options*

Options may vest on a specific date, the occurrence of a specific event or be conditional upon an achievement of a given performance condition as determined at the time of grant. The vesting date for options already granted typically is 20 per cent. on the first anniversary of grant of the option; a further 20 per cent. on the second anniversary and the remaining 60 per cent. on the third anniversary although some options have been granted on other terms. Where options have been granted with performance conditions, the condition has related to the achievement of an increase in the Ordinary Share price above the exercise price.

It is currently intended that future options will be granted with the 20/20/60 vesting described above and with a performance condition requiring an increase in the price of an Ordinary Share so that it is 40 to 50 per cent. above the price on the day the option was granted for at least 3 months.

Options may be exercised in whole or part. To the extent that an option has not already been exercised or lapsed, an option will then lapse on the tenth anniversary of the date of grant.

In the case of an optionholder's death, the relevant option may be exercised (to the extent it has vested) by a personal representative of the deceased in the twelve months following his death, when the option will lapse if it has not been exercised. If an optionholder ceases to be employed by a Group Company by reason of, *inter alia*, ill health, injury, disability, redundancy, retirement or pregnancy or as a result of a sale out of the Group of the optionholder's employer or business in which he is employed, that optionholder may exercise his option (to the extent it has vested) during the twelve months following termination of employment, when the option will lapse if it has not been exercised.

Where an optionholder ceases to be employed by a Group Company for a reason not specified above, the Remuneration Committee may in certain circumstances allow an option to be exercised during a period of 40 days following the date of termination and the options will lapse at the end of this period, but there is discretion to allow a longer period for exercise. In other cases, an option will lapse on termination of employment.

(iv) *Issue of Shares*

Shares issued on the exercise of options will be Ordinary Shares and will rank *pari passu* with other Ordinary Shares except in respect of rights arising prior to the date of issue.

(v) *Change of Control and Exchange of Options*

In the event of a change of control of the Company or other similar event, options will vest in full but will lapse after the optionholder has had a short period to exercise the option. In certain circumstances, and with the agreement of the acquiring company, an optionholder may instead exchange his option for an equivalent option over shares in the acquiring company.

(vi) *Variation of Share Capital*

To preserve the value of an option, options may be varied in the event of any capitalisation, rights issue, consolidation, subdivision, reduction or other variation of the share capital of the Company.

(vii) *Scheme Limit*

On any date, the maximum number of Ordinary Shares which can be placed under an option to be satisfied by the issue of Ordinary Shares under the Share Option Scheme, when added to the number of Ordinary Shares issuable or issued (i.e. excluding lapsed awards) in the preceding 10 years under the Share Option Scheme or any other employee share scheme adopted by the Company, must not exceed 12 per cent. of the Company's issued ordinary share capital immediately prior to that date.

(viii) *Amendments*

The Board may amend any of the rules of the Share Option Scheme as they see fit at any time, except that any variation to the maximum number of Ordinary Shares that may be placed under option at any particular time may not be made without approval of the Company's shareholders.

(ix) *Termination*

The Share Option Scheme will terminate on 28 June 2015, but may be terminated earlier by the Company. Termination will not prejudice existing optionholder rights.

10.3 *Performance Share Plan*

The Performance Share Plan was adopted by the Board on 15 January 2008. The Remuneration Committee has responsibility for supervising the Performance Share Plan. A summary of the rules of the Performance Share Plan is set out below:

(i) *Eligibility*

Any employee or executive director of the Group is eligible to participate in the Performance Share Plan.

(ii) *Making of Awards*

Awards are granted at the absolute discretion of the Company, although, in practice, the number of Ordinary Shares over which an award is made is based on a multiple of the recipient's salary. Awards are not pensionable.

Awards are personal and may not be transferred, assigned or charged except with the consent of the Company or on death.

Awards may be granted in the form of a conditional award, or a nominal value option or in such other form as has a similar purpose or effect so that substantially free Ordinary Shares are received. The Performance Share Plan further permits that at the date of grant a conditional award or an option shall be expressed as a right of the participant to acquire a cash sum at the Company's discretion. The cash sum is calculated by reference to the number of Ordinary Shares in respect of which the relevant award has vested or, in the case of an option, has been exercised.

(iii) *Vesting of Awards and Performance Conditions*

Awards may contain a performance target and/or such other conditions on the vesting of the awards. Awards will ordinarily vest on the third anniversary of the date of grant, subject to the achievement of performance targets set at the date of grant. Any such target imposed must be assessed over a period of at least three financial years unless determined otherwise on grant.

The performance criteria which have been set and which are currently intended to apply to future grants require the Company to outperform a comparator group of similarly focused oil and gas exploration and production companies in terms of shareholder return over a three year period. The full number of Ordinary Shares is received only if the Company has performed in the top quartile when compared against a selected peer group of upstream oil and gas companies focused on Africa: Bowleven, Gulf Keystone Petroleum, Gulfsands Petroleum, Hardy Oil & Gas, Mart Resources, Petroceltic International, Roc Oil Company, Serica Energy, Soco International, Sterling Energy, Stratic Energy, Tullow Oil, Vaalco Energy and, in respect of 2008 grants only, White Nile. White Nile was removed from the peer group in 2009. If the Company does not achieve at least median performance in the peer group, no Ordinary Shares will be received. At the median level, 30 per cent. of the Ordinary Shares will vest and there is a sliding scale between median and top quartile performance where only a percentage of the total award will vest.

Where Ordinary Shares vest, a payment may be made of an amount equal to the dividends paid on the relevant number of Ordinary Shares between the grant of the award and the receipt of Ordinary Shares.

(iv) *Exercise of Options*

If the award is in the form of an option, it may be exercised in whole or in part.

(v) *Lapse of Awards*

Options lapse on the tenth anniversary of the date of grant or such other date as is specified on grant. Other awards lapse on the vesting date to the extent to which they have not then vested.

If an awardholder ceases to be an employee of the Group because of death, illness, injury or disability, redundancy, retirement by agreement or the sale of the business in which he works or other reason decided by the Remuneration Committee, Ordinary Shares can be received but vesting will be scaled back taking into account the achievement of the performance condition and (unless the Remuneration Committee decides otherwise) the period since the awards were granted. Options already vested can be held for up to 12 months.

If an awardholder leaves for other reasons, his award will usually lapse, although options may be exercised for up to 40 days following the termination of his employment.

(vi) *Issue of Shares*

Shares issued on the exercise of options will be Ordinary Shares and will rank *pari passu* with other Ordinary Shares except in respect of rights arising prior to the date of issue.

(vii) *Change of Control and Exchange of Awards*

In the event of a change of control of the Company or other similar event, awards will can be received but vesting will be scaled back taking into account the achievement of the performance condition and (unless the Remuneration Committee decides otherwise) the period since the awards were granted. Options will similarly vest and may be exercised for a short period following the change of control.

In certain circumstances, and with the agreement of the acquiring company, an awardholder may instead exchange his award for an equivalent award over shares in the acquiring company.

(viii) *Variation of Share Capital*

To preserve the value of an award, awards can be adjusted in the event of any capitalisation issue, demerger, any offer or invitation made by way of rights issue, subdivision, consolidation, reduction, other variation in the share capital of the Company, or other such reason as the Company may consider justifies an adjustment.

(ix) *Plan Limits*

No participant may be granted awards which would, at the time of grant, cause the market value of Ordinary Shares which the participant may acquire as a result of the award to exceed 200 per cent. of his base salary (or such other percentage as may be determined by the Remuneration Committee from time to time).

Further, an award may not be made if it would result in the number of Ordinary Shares issued or issuable during a period of ten years (i.e. excluding lapsed awards), under the Performance Share Plan or any other employee share scheme adopted by the Company, to exceed 12 per cent. of the Company's issued ordinary share capital at that time.

(x) *Amendments*

The Board may amend the rules of the Performance Share Plan as they see fit at any time.

Amendments to the material advantage of participants cannot be made without the approval of the Company's shareholders. Amendments to the disadvantage of awardholders cannot be imposed without the agreement of awardholders holding at least 75 per cent. of the Ordinary Shares under outstanding awards.

(xi) *Termination*

The Performance Share Plan will terminate on 15 January 2018, but may be terminated earlier by the Company. Termination will not prejudice existing awardholder rights.

10.4 ***Jefferies, Randall & Dewey Employee Share Plan***

As part of the incentive to attract the Jefferies, Randall & Dewey technical team, a number of Ordinary Shares were awarded to the team under arrangements known as the Jefferies, Randall & Dewey Employee Share Plan. None of the team was eligible to receive an award under the Performance Share Plan in 2008. The rules of the plan are, in all material respects, the same as the rules of the Performance Share Plan, as described in paragraph 10.3, above, subject to the differences described below:

(i) *Performance Conditions*

The receipt of Ordinary Shares is not subject to the achievement of any performance targets.

(ii) *Vesting*

Awards will generally vest in equal instalments each year after grant over a consecutive period of three years, and in most cases is subject to being in Group employment at the relevant vesting date.

10.5 ***Pension scheme***

Afren operates a defined contribution scheme and the Company contributes 10 per cent. of base salary subject to the participant contributing at least five per cent. of their salary. Details of the Group's contributions to pension accounts for its employees are set out in Part 9.

11. **Significant shareholders**

- 11.1 As at 23 August 2010 (being the latest practicable date prior to publication of this Prospectus), and in addition to the interests of certain Directors, as set out in paragraph 7 of this Part 10, Afren is aware of the following persons who, directly or indirectly, had a notifiable interest in three per cent., or more of Afren's issued Ordinary Shares:

<i>Name</i>	<i>Number of Shares</i>	<i>% of issued Ordinary Shares</i>
BlackRock Investment Management (UK) Ltd	44,395,506	4.98%
AXA S.A.	55,587,067	6.24%
Vidacos Nominees (Standard Life)	80,598,411	9.04%
JP Morgan Asset Management Holdings Inc	44,425,333	4.997%
HSBC Client Holdings UK Limited	43,806,532	4.92%
GLG Partners LP	34,962,762	3.92%
Investec Asset Management Ltd	39,993,467	4.498%
Deutsche Bank AG	21,619,962	2.43%

- 11.2 As at 23 August 2010 (being the latest practicable date prior to publication of this Prospectus), and in addition to the interests of certain Directors, as set out in paragraph 7 of this Part 10, assuming a maximum of 76,776,564 Ordinary Shares are issued pursuant to the Acquisition and that no other Ordinary Shares are issued in the period from the publication of this Prospectus to the Effective Date, Afren is aware of the following persons who will have a notifiable interest in three per cent. or more of Afren's issued Ordinary Shares immediately following completion of the Acquisition.

<i>Name</i>	<i>Number of Shares</i>	<i>% of issued Ordinary Shares</i>
BlackRock Investment Management (UK) Ltd	44,395,506	4.59%
AXA S.A.	55,587,067	5.74%

Vidacos Nominees (Standard Life)	80,598,411	8.33%
JP Morgan Asset Management Holdings Inc	44,425,333	4.59%
HSBC Client Holdings UK Limited	43,806,532	4.53%
GLG Partners LP	34,962,762	3.61%
Investec Asset Management Ltd	39,993,467	4.13%
Deutsche Bank AG	21,619,962	2.23%

- 11.3 None of Afren's major holders of Ordinary Shares listed in Paragraph 11.1 have, and those listed in Paragraph 11.2 above have on completion of the Acquisition, voting rights different from other holders of Ordinary Shares.
- 11.4 As far as Afren is aware, as at 23 August 2010 (being the last practicable date prior to the publication of this Prospectus) there are no arrangements the operation of which may at a later date result in a change of control of Afren.
- 11.5 Afren is not aware of any person who either as at the date of this Prospectus or immediately following New Share Admission exercises, or could exercise, directly or indirectly, control over Afren.

12. Legal and arbitration proceedings

No member of the Group is, or has been during the 12 months preceding the date of this Prospectus, involved in any governmental, legal or arbitration proceedings which may have, or have had in the recent past a significant effect on the Group's financial position or profitability, nor, so far as Afren is aware, are any such proceedings pending or threatened.

Black Marlin is not, nor has been during the 12 months preceding the date of this Prospectus, involved in any governmental, legal or arbitration proceedings which may have, or have had in the recent past a significant effect on the Group's financial position or profitability, nor, so far as Afren is aware, are any such proceedings pending or threatened.

13. Material contracts of the Group

The following contracts are all the material contracts (not being contracts entered into in the ordinary course of business) which have been entered into within the two years prior to the date of this Prospectus by members of the Group and the contracts (not being contracts entered into in the ordinary course of business) entered into at any time by members of the Group which contain provisions under which any member of the Group has an obligation or entitlement which is or may be material to the Group as at the date of this Prospectus:

- 13.1 On 8 October 2008, Sojitz Corporation, Afren Energy International plc and Afren entered into a bond subscription agreement under which Sojitz Corporation agreed to make a direct investment into Afren in the form of floating rate guaranteed bonds issued by Afren Energy International plc, with a nominal value of US\$45 million; with Afren guaranteeing Afren Energy International plc's payment obligations. The terms and conditions of the bonds are set out in an individual bond certificate issued by Afren Energy International plc on 29 October 2008. No convertible bonds have been issued to date. The bonds are exchangeable for convertible bonds at the time of entering into, or announcing, a joint acquisition between Afren and Sojitz Corporation, and the convertible bonds are convertible into fully paid ordinary shares in Afren. Afren Energy International plc is to pay to Sojitz Corporation an annual fee of 0.5 per cent. of the available bond commitment less the drawdown amount. Bonds are exchangeable for convertible bonds for each joint acquisition in a proportion *pro rata* to the aggregate joint acquisition investment by Sojitz Corporation available to Afren, assuming a notional US\$500 million of available aggregate joint acquisition investment, including funds committed and/or advanced directly or indirectly by or on behalf of Sojitz Corporation in respect of joint acquisitions. If US\$300 million or more is committed, all of the bonds will be exchanged for convertible bonds. Interest on the bonds and the convertible bonds is six month US\$ LIBOR plus two per cent. per annum. The bonds and convertible bonds are redeemable at the option of Afren Energy International plc from six months following the first utilisation date, upon payment of a 2.5 per cent. early

redemption fee, and mature on 8 October 2011. If Afren declares a cash dividend, each bondholder is entitled to receive an amount per bond to be calculated with reference to several factors, including the cash dividend amount, the 30 day volume weighted average price of an ordinary share in Afren and the principal amount of the bonds. The conversion price of the bonds is calculated by reference to the 30 day volume weighted average price of Afren ordinary shares ending on the earlier of the time of entering into, or announcing, a joint acquisition. The bonds and convertible bonds are redeemable in whole (but not in part only) at the option of Sojitz Corporation upon notification within the first 20 days following each of the first and second anniversaries of the agreement if, during the 365 days prior to the anniversary, the parties have not entered into a joint acquisition and, in addition, Afren has not submitted to Sojitz Corporation at least five proposals for joint acquisitions (excluding exploration opportunities).

- 13.2 A strategic alliance agreement was entered into between Afren and Sojitz Corporation on 8 October 2008 under which the parties agreed to act jointly with the aim of acquiring rights or property interests in Africa relating to the exploration or extraction of oil or gas and/or the production of oil and gas related or derived products, including assets already in development and/or production. Under the terms of the agreement, the alliance will terminate on the earlier of 8 October 2011 or the date upon which Sojitz Corporation has invested a total of US\$500 million in joint acquisitions. Sojitz Corporation is to provide financial support to the alliance for the purpose of funding material joint acquisitions, among other things, including by securing funding and credit support from the Japanese Government. Afren is to be appointed as operator in respect of any joint acquisitions. Afren is required to attempt to locate assets which are materially and strategically appropriate for a direct or indirect joint acquisition and provide information in relation to such assets to Sojitz Corporation. Subject to such assets fulfilling certain criteria, Afren is required to submit a proposal to Sojitz Corporation offering participation in acquisitions of such new assets. Afren and its affiliated companies cannot transfer or sell any interest in any asset of the type referred to above already held by Afren without offering Sojitz Corporation the opportunity to purchase the interest on the same terms that Afren has offered such interest to a third party.
- 13.3 A placing agreement was entered into between Afren and Merrill Lynch International, Jefferies International Limited and Morgan Stanley Securities Limited on 15 April 2009 relating to the cash placing of 265 million new Ordinary Shares at 32 pence per Ordinary Share to institutional investors. Afren paid commission of two per cent. of the aggregate value at the placing price of the placing shares to Merrill Lynch International, Jefferies International Limited and Morgan Stanley Securities Limited. Afren gave representations and warranties customary for an agreement of this nature in favour of Merrill Lynch International, Jefferies International Limited and Morgan Stanley Securities Limited, unlimited in time and amount.
- 13.4 The Company and the Directors entered into the Placing and Sponsor's Agreement on 10 November 2009 with Merrill Lynch International, Morgan Stanley, Evolution, Nomura and Jefferies relating to the issue of up to 129.5 million Ordinary Shares (the "**New Shares**") and the sale of 24.5 million Ordinary Shares by certain shareholders, including certain Directors (the "**Founder Shares**" and together with the New Shares, the "**Placing Shares**") and the admission of the Ordinary Shares (issued and to be issued) to the Official List and to trading on the London Stock Exchange.

The Company appointed Merrill Lynch International as sponsor, global coordinator and joint bookrunner, in respect of the 2009 Admission and the Placing and appointed Morgan Stanley as joint bookrunner and Evolution, Nomura and Jefferies as co-managers in respect of the Placing. Merrill Lynch International, Morgan Stanley, Jefferies, Nomura and Evolution agreed to procure subscribers for the Placing Shares and the Underwriters have agreed to underwrite settlement of the Placing Shares at the Placing Price.

In consideration of the services being provided under the Placing and Sponsor's Agreement the Company agreed to pay to Merrill Lynch International a fee of US\$750,000 in connection with its role as sponsor and the Underwriters a commission at a rate of 1.25 per cent. of the amount equal to the product of the Placing Price and the aggregate number of Placing Shares. An additional

commission of up to one per cent. of the amount equal to the product of the Placing Price and the aggregate number of Placing Shares is payable to the Underwriters at the absolute discretion of the Company. The Company also agreed to pay all reasonable costs and expenses of, or in connection with, the Placing, the 2009 Admission, the Placing and Sponsor's Agreement and the allotment and issue of the New Shares (including, without limitation, any stamp duty or stamp duty reserve tax) and all stock exchange listing fees, admission fees, registrar's fees, legal fees and expenses of the Company and the Underwriters, the Company's accountancy fees and expenses, costs of printing, advertising and circulating documentation and the out-of-pocket expenses of the Underwriters.

The Company and the Directors gave certain customary representations, warranties and indemnities to the Underwriters under the Placing and Sponsor's Agreement. The liabilities of the Company are unlimited as to time and amount.

- 13.5 Afren Resources entered into Contract Number C-1680 for the provision of a jack up drilling unit "GSF High Island VII" and drilling rig services with Sedco Forex International, Inc. in association with Transocean Support Services Nigeria Limited (together with Sedco Forex International, the "**Contractor**") on 11 March 2010. The Contractor is to provide the drilling unit together with certain other equipment, material, supplies, services and personnel necessary to carry out drilling operations. Afren Resources is required to pay the contractor an operating rate of US\$84,000 per day during the operating period, subject to reductions in certain situations such as *force majeure*, repair and re-drilling with such rates calculated as a percentage (either 80 per cent., 90 per cent. or 100 per cent.) of the applicable term rate. In addition, the Contractor is entitled to certain lump sums in relation to mobilisation and other fees and is entitled to mark up reimbursable items on a sliding scale linked to cost, ranging from 15 per cent. to 5 per cent. The contract continues in force until the date that drilling operations are deemed to be complete under the contract, subject to a firm term of no less than 181 calendar days and no more than 210 calendar days, beginning on the date of acceptance of the drilling unit by Afren Resources or unless earlier terminated.

Afren Resources shall not commence any work that extends this term for more than 30 days without the Contractor's approval. Afren Resources may terminate at any time without reason on 10 days' notice in which case liquidated damages for early termination will apply. Afren Resources may also terminate the contract at any time if the Contractor is in breach of any material obligations under the agreement, if the Contractor becomes insolvent or bankrupt, if a *force majeure* event prevails for a continuous uninterrupted period of 30 days, if the Contractor is unable to perform its obligations or if the drilling unit is damaged or unsafe or lost. In these circumstances, the Contractor shall be entitled to payment from Afren Resources up to the date of termination. Afren Resources may terminate the contract immediately with no compensation to the Contractor if the drilling unit fails to arrive at the mobilisation point by the requisite date. The indemnities under the agreement may be enforced by the Contractor against Afren Resources for the benefit of the Contractor and extend to any and all liabilities (including death of personnel and loss or damage to physical property and down-hole equipment) in connection with or in consequence of the claim. The indemnity covers claims caused by negligence of any degree, tort, breach of contract and breach of duty. Afren Resources is required to indemnify the Contractor against claims relating to loss of or damage to physical property, down-hole equipment and the Well (as defined in the agreement) or loss of products from the Well. The indemnities also extend to all claims relating to pollution, containment or waste matter from the Contractor group equipment in relation to Well damage. If the Well has to be plugged and abandoned due to the Contractor's negligence, Afren may require the Contractor to drill a new Well in replacement. If either party becomes aware of any incident likely to give rise to a claim, it shall notify the other party as soon as practicable. Under the agreement the Contractor shall not assent to liens over the operations, property or equipment of Afren Resources and the Contractor shall indemnify Afren Resources against any claims in respect of liens, charges or other encumbrances in connection with this agreement (and shall procure discharge of such liens where it materially affects the Contractor's obligations). In any case, if either party becomes aware of any potential claim, it shall notify the other party as soon as possible. This agreement is not enforceable by any third party. The reliance on any term of the contract by a third party must be notified in writing to each party to the contract.

- 13.6 A services contract for the provision of a Floating Production Storage and Offloading Unit (“FPU”) was entered into between Afren Resources and Mercator Offshore (Nigeria) Pte Ltd (the “Contractor”) on 13 January 2010. The Contractor is responsible for the provision, operation and maintenance of the FPU which, according to the FPU specifications, should be capable of receiving, processing, storing and exporting processed stabilised crude oil to an offloading tanker and gas to a gas lift/gas injection pipeline. The Contractor shall provide such personnel as are required to properly execute the contract and shall take all responsibility for the health and safety risks in connection with the FPU. Afren Resources shall secure at its expense any and all authorisations and permits required for the FPU and all ancillary materials. The term of the contract is 7 years from the issuance of the provisional acceptance certificate with an option for Afren Resources Limited to extend the term for a period of one year. If such extension option has been exercised, Afren Resources is entitled to further extend the period for one year, provided that it provides at least six months’ prior written notice. Rates are applied daily for the FPU hire in the amount of US\$65,120 per day and the operation and maintenance services in the amount of US\$25,409 per day, subject to review. The Contractor shall be entitled to an early installation fee of US\$20,000 for each day that the FPU has been installed in advance of the stipulated target date (15 September 2010, or such other date as may be adjusted in accordance with the contract), up to a maximum early installation fee of US\$1,200,000. If the FPU is not installed in accordance with the agreement, the Contractor shall pay to Afren Resources as liquidated damages for such delay an amount of 50 per cent. of the operating rate per day (or *pro-rata* per hour) until the notice of readiness has been issued, up to a maximum of 120 days. Under the agreement, if Afren fails to pay the Contractor within 60 days of receipt of an invoice, the Contractor may present a demand to the issuer of the standby letter of credit for payment of the outstanding sum. Within 20 days from such payment, Afren Resources shall replenish the standby letter of credit up to the amount of US\$6,000,000. Mercator International Limited of Singapore is appointed as the guarantor for the Contractor under this agreement, who will then be replaced by Mercator Lines Limited within a period of no more than 6 months. Afren Resources shall also provide a standby letter of credit until 31 December 2017 from BNP Paribas to guarantee timely payment which shall be extended if the contract extends beyond that date.

Afren Resources may terminate the contract on not less than three months’ written notice to the Contractor provided that if termination occurs before the end of the primary term of the contract, an early termination payment is payable by Afren Resources. An early termination payment is not incurred in the case of termination as a result of certain conditions including *force majeure* events or material breach of the Contractor’s material obligations. The Contractor is also entitled to terminate the contract under certain circumstances, including failure to provide the letter of credit and material breach of Afren Resources’ material obligations. Prior written consent is required for either party to assign their obligations under this agreement. The Contractor shall indemnify Afren Resources from any claim resulting from pollution damage in respect of leaks from the facilities or property of the Contractor. Each party agrees to indemnify the other against loss of or damage to property, personal injury and loss of or damage to any wells, formation and/or reservoir arising from its negligence, breach of duty, breach of contract, warranty or indemnity. Under the agreement, Afren Resources has the option to purchase the FPU provided that six months’ written notice is given to the Contractor. In the event of early termination, the Contractor shall sell the FPU to Afren Resources in exchange for the early termination payment. If the Company purchases the FPU while the Contract continues, the contract will terminate on the purchase of the FPU. The Contractor may grant security over the FPU property and assign its rights under the contract for the benefit of its financiers. Each party may assign its obligations with the prior written consent of the other party which shall not be unreasonably withheld or delayed.

- 13.7 Afren (the “Purchaser”) and Black Marlin entered into the Arrangement Agreement to set out the terms on which they have agreed to cooperate with each other to implement the Acquisition (including the Scheme). Black Marlin and the Purchaser agree that the Scheme shall result in the acquisition of all the Black Marlin Shares on the basis of the issue of 1 New Ordinary Share for 0.3647 Black Marlin Shares (the “Exchange Ratio”).

Under the Arrangement Agreement, Black Marlin is required to prepare a management information circular, which must comply with all applicable laws and include the unanimous recommendation of the Black Marlin directors that the Black Marlin Shareholders vote in favour of the Acquisition. The representations and warranties of the Purchaser include receipt of the aforementioned requisite approvals, authority to enter into the Arrangement Agreement without violating any laws, as well as compliance with all the listing requirements and U.K. Securities Laws (as defined in the Arrangement Agreement).

The Arrangement Agreement sets out the covenants of both parties including those relating to Black Marlin's conduct of business and its performance of certain actions in connection with the Scheme and to the performance by the Purchaser of other general obligations, such as applications for requisite regulatory consents. The Acquisition is conditional on certain conditions which are customary for a transaction of this nature, including the sanction of the Scheme by Court Order and obtaining the Requisite Approval at the Shareholder Meeting and the approval of the Afren Shareholders.

The Arrangement Agreement also contains certain non-solicitation provisions, pursuant to which Black Marlin provides to Afren covenants not to solicit any offer, proposal or inquiry relating to a merger or take-over of Black Marlin or any of its subsidiaries. However, under the Arrangement Agreement, in the event that Black Marlin receives an unsolicited superior offer, Afren has the right to amend the terms of the Arrangement Agreement and the board of Black Marlin is obliged to review such proposed amendments in good faith, to determine whether the superior offer is still preferable to the proposed amended Arrangement Agreement. The Arrangement Agreement contains various provisions which govern the options available to Black Marlin in such an event, which include, but are not limited to, termination, subject to payment of a break fee (as discussed below).

The Arrangement Agreement may be terminated in certain circumstances such as breach of the Arrangement Agreement by either party, failure to receive the required approvals or by the written agreement of both parties. The Arrangement Agreement may not be assigned by either party without the prior written consent of the other.

The Arrangement Agreement also contains the break fee provisions set out in paragraph 6.3 of Part 3 of this Prospectus.

14. Material Contracts of Black Marlin

The following contracts are all the material contracts which have been entered into within the two years prior to the date of this Prospectus by Black Marlin which contain provisions under which Black Marlin has an obligation or entitlement which is or may be material to Black Marlin as at the date of this Prospectus:

14.1 Kenya

- (a) Black Marlin has interests in the following Production Sharing Contracts in Kenya for the exploration and development of the contractually stipulated and as exclusive operator:
 - (i) a Production Sharing Contract entered into between the Government of the Republic of Kenya and Lundin Kenya B.V. (as the contractor), relating to Anza Basin – Block 10A on 4 October 2007. Lundin Petroleum AB sold its wholly owned subsidiary Lundin Kenya B.V. to Africa Oil Corporation and by way of assignment Africa Oil Kenya B.V. (a subsidiary of Africa Oil Corporation) assigned certain rights under the Production Sharing Contract to East Africa Exploration Limited (a subsidiary of Black Marlin);
 - (ii) a Production Sharing Contract entered into between the Government of the Republic of Kenya and Aminex Kenya Limited, East African Exploration (Kenya) Limited (a subsidiary of Black Marlin) and Somken Upstream Kenya Limited (as the contractors), relating to Block L17/18 on 24 October 2007; and
 - (iii) a Production Sharing Contract entered into between the Government of the Republic of Kenya and Lion Petroleum (as the contractor), relating to Block 01 on 19 November

2007. By way of assignment Lion Petroleum assigned certain rights under the Production Sharing Contract to East African Exploration (Kenya) Limited (a subsidiary of Black Marlin).

The contractor is to provide all capital, machinery, equipment, technology and personnel necessary for the conduct of the petroleum operations, and will bear the associated costs. In addition it shall carry out minimum exploration work and expenditure obligations and pay bonuses and surface fees as stipulated in the Production Sharing Contracts. The Production Sharing Contracts stipulate an initial exploration period and permit extensions. If a commercial discovery has been made before the expiration of the initial exploration period or its extension, the Production Sharing Contracts shall continue as to such development area for a term of twenty-five (25) years. If control over one of the entities constituting contractor has changed, the continuation of the contract shall be subject to the consent of the Minister responsible for energy. In addition, the contractor shall report to the Minister any material changes in the corporate structure, ownership and financial position of the contractor and its parent company.

These Production Sharing Contracts have varying initial exploration periods although extensions can be granted.

- (i) The Production Sharing Contract relating to Block 10A has a four year initial exploration period.
 - (ii) The Production Sharing Contract relating to Block L17/18 has a two year initial exploration period. The initial exploration period expired on 23 January 2010. The Ministry of Energy of the Republic of Kenya approved a nine months extension effective from 24 January 2010 and thus the extended exploration period will expire on 24 October 2010.
 - (iii) The Production Sharing Contract relating to Block 01 has a three year initial exploration period.
- (b) Black Marlin has also entered into following Joint Operating Agreements in Kenya in relation to operations under the respective Production Sharing Contracts, including the joint exploration, appraisal, development, production and disposition of petroleum covered by the Production Sharing Contracts.
- (i) a Joint Operating Agreement was entered into between Aminex Kenya Limited, East African Exploration (Kenya) Limited (a subsidiary of Black Marlin) and Somken Upstream Kenya Limited relating to Block L17/18 in Kenya dated 23 October 2007;
 - (ii) a Joint Operating Agreement was entered into between East African Exploration (Kenya) Limited (a subsidiary of Black Marlin) and Lion Petroleum Corporation relating to Block 01 in Kenya dated 12 February 2009.

The Joint Operation Agreements terminate on termination of the related Production Sharing Contracts and upon final settlement and removal or disposal of all materials, equipment and personal property used in connection with joint operations. The Joint Operating Agreements contain provisions, which need to be satisfied in the event of change of control of a party or transfer of rights under the Joint Operating Agreements.

Except in relation to Block 01, change of control is defined as including both direct and indirect change of control. In the event of a change of control, the Joint Operating Agreements impose an obligation on the party who suffers the change of control to provide evidence reasonably satisfactory to the other parties that it will continue to have the financial capability to satisfy its payment obligations and entitles the other parties to a “right of first refusal” relating to the participating interest of the party suffering the change of control.

Certain differences between these Joint Operating Agreements are summarized below:

(i) Division of the participating interest of the respective parties

The Joint Operating Agreement relating to Block L17/18 divides the participating interest of the parties as follows: (i) Aminex Kenya Limited – 25 per cent., (ii) East African Exploration (Kenya) Limited – 40 per cent. and (iii) Somken Upstream Kenya Limited – 35 per cent. Aminex Kenya Limited is designated as an operator under the Joint Operating Agreement.

The Joint Operating Agreement relating to Block 01 divides the participating interest of the parties as follows: (i) Lion Petroleum Corporation – 50 per cent.; and (ii) East African Exploration (Kenya) Limited – 50 per cent. East African Exploration (Kenya) Limited is designated as an operator under the Joint Operating Agreement.

(ii) Change of control and limitation of the right of first refusal

The change of control provision in the Joint Operating Agreement relating to Block 01 excludes any direct or indirect change of control which takes place on a recognised stock exchange. It also states that the right of first refusal (i) does not apply to change of control of East African Exploration (Kenya) Limited and (ii) it applies only prior to a discovery being declared commercial.

A Farm in Agreement was entered into between Lion Petroleum Corporation and East African Exploration (Kenya) Limited (“**EAEL**”) (a subsidiary of Black Marlin) relating to Block 01 in Kenya (effective date 11 November 2009) under which EAEL has agreed to acquire from Lion Petroleum Corporation a 50 per cent. interest in the rights and obligations of the contractor under the Production Sharing Contract in respect of the onshore Block 01 in Kenya entered into by the Government of the Republic of Kenya and Lion Petroleum Corporation dated 19 November 2007. The 50 per cent. interest was assigned to EAEL by the Deed of Assignment dated 31 October 2008, which is required to pay all costs relating to the acquisition of the first 600 km of 2D seismic in the initial work program, capped at USD6,000,000. EAEL is entitled to acquire an additional interest up to 30 per cent. from Lion Petroleum Corporation. The Production Sharing Contract requires the prior consent of the Ministry of Energy of the Republic of Kenya for the assignment of rights and obligations.

- (c) In addition, a Farm out Agreement was entered into between Lundin East Africa B.V., Lundin Kenya B.V. and Black Marlin Energy Limited on 22 May 2009. The rights and obligations under the Farmout Agreement are described in relation to Black Marlin’s matured contracts in Ethiopia below.

14.2 *Seychelles*

- (a) A Petroleum Agreement was entered into between the Government of the Republic of Seychelles, Seychelles Petroleum Company Limited and East African Exploration (Seychelles) Limited (a subsidiary of Black Marlin) and Avana Petroleum Limited, together, (the “**Exploration Company**”) relating to Area A, B, and C on 28 November 2008 under which the Government of the Republic of Seychelles granted to the Exploration Company exclusive rights for exploring and mining for petroleum in the contractually agreed land, subject to the provisions of the Petroleum Agreement and Petroleum Mining Act 1976. The Exploration Company is required to carry out minimum program of work and pay to the Government of the Republic of Seychelles annual rental and, during petroleum production, pay a royalty in accordance with the Petroleum Agreement. The term of the Petroleum Agreement is thirty-two (32) years. However, if before the end of the seventh year no commercial discovery is made, the Petroleum Agreement shall terminate automatically. The Exploration Company is required to report to the Minister responsible for petroleum mining promptly particulars of any material changes in its own, its affiliates on which it closely depends or its parent company’s financial, technical or legal standing which may materially affect the Company’s ability to perform its

obligations. In addition, the assignment of rights is subject to the consent of the Minister responsible for petroleum mining.

- (b) In addition, a Joint Operation Agreement was entered into between East African Exploration (Seychelles) Limited (a subsidiary of Black Marlin) and Avana Petroleum Limited relating to Area A, B and C in February 2009, pursuant to which the parties further define their respective rights and obligations with regard to operations under the Petroleum Agreement entered into between the Government of the Republic of Seychelles, Seychelles Petroleum Company Limited, East African Exploration (Seychelles) Limited and Avana Petroleum Limited on 28 November 2008. These rights include the joint exploration, appraisal, development, production and disposition of crude oil and natural gas and other substances. The participating interest of the respective parties is divided as follows: (i) East Africa Exploration (Seychelles) Limited – 75 per cent.; and (ii) Avana Petroleum Limited – 25 per cent. East Africa Exploration (Seychelles) Limited is designated as an operator under the Joint Operation Agreement. The Joint Operation Agreement terminates on the termination of the related Petroleum Agreement and upon final settlement and removal or disposal of all materials, equipment and personal property used in connection with joint operation. The Joint Operation Agreement also contains certain provisions which need to be satisfied in the event of change of control of a party or transfer of rights under the Joint Operation Agreement. Change of control is defined broadly to include both a direct and indirect change of control (which excludes any direct or indirect change of control which takes place on a recognised stock exchange). In the event of a change of control, the Joint Operating Agreement imposes an obligation on the party who suffers the change of control to provide evidence reasonably satisfactory to the other parties that it will continue to have the financial capability to satisfy its payment obligations and entitles the other parties to a “right of first refusal” relating to the participating interest of the party suffering the change of control.

14.3 *Madagascar*

- (a) An Onshore Production Sharing Contract was entered into between the Office of National Mines and Strategic Industries (“OMNIS”), Candax Madagascar Limited and East African Exploration Limited (a subsidiary of Black Marlin) relating to Block 11/01 on 2 November 2006 under which the terms and conditions of exploration, exploitation, transportation, and any other activity connected with these operations, including planning and preparations of such activities shall be carried out. Candax has been appointed as an operator and has the exclusive responsibility of managing and conducting operation activities. The Onshore Production Sharing Contract includes a six year “Exploration Period” divided into three (3) two year phases. In the event of commercial discovery (discovery of petroleum) OMNIS shall ensure that the “Exploitation Period” will be 25 years or, if the commercial discovery is predominantly of natural gas, then for 25 years. The contractors are required to carry out minimum exploration work and expenditure obligations as stipulated in the Onshore Production Sharing Contract. The contractors shall also pay a royalty on all extracted liquid petroleum and natural gas to OMNIS. Under the Onshore Production Sharing Contract any sale, assignment or transfer of a participating interest, rights or obligations relating to such participating interest may not take place without prior notification or consent of OMNIS, which shall not be unreasonably withheld or delayed.
- (b) In addition, a Joint Operating Agreement was entered into between Candax Madagascar Limited and East African Exploration Limited (a subsidiary of Black Marlin) relating to Block 11/01 in Madagascar, pursuant to which the parties further define their respective rights and obligations with regard to operations under the Onshore Production Sharing Contract entered into between the Office of National Mines and Strategic Industries (OMNIS), Candax Madagascar Limited and East African Exploration Limited on 2 November 2006. These rights include the joint exploration, appraisal, development, production and disposition of petroleum covered by the Onshore Production Sharing Agreement. The participating interest of the respective parties is divided in the following manner: (i) Candax Madagascar Limited –

60 per cent. and (ii) East African Exploration Limited – 40 per cent. Candax Madagascar Limited is designated as an operator under the Joint Operating Agreement. The Joint Operating Agreement terminates on the termination of the related Onshore Production Sharing Contract and upon final settlement and removal or disposal of all materials, equipment and personal property used in connection with joint operation. The Joint Operating Agreement restricts the transfer of a participating interest if it results in the transferor or the transferee holding less than five (5 per cent.) per cent. of the participating interest. The transfer of a participating interest is subject to any necessary Government approval and, other than transfer to an affiliate, requires a prior written consent of the other parties.

- (c) Further, a Joint Venture Agreement for Block 11/01, Onshore Madagascar, was entered into between Candax Energy Limited and East Africa Exploration Limited (a subsidiary of Black Marlin) on 21 September 2006 which relates to the exploration and production of Block 1101, onshore Madagascar. The interest in the joint venture is shared as follows: Candax Energy Limited 60 per cent. and East Africa Exploration Limited 40 per cent. Candax Energy Limited, the nominated operator in Block 1101, is required to pay USD2,000,000 of the agreed budget and shall furthermore provide a financial security acceptable to the Government in the amount of USD1,500,000 for the first exploration phase. Any amount above USD2,000,000 shall be paid by each party in proportion in their participating interest. The Joint Venture Agreement shall remain in full force until both parties mutually agree to terminate it or either party is no longer participant of the intended production sharing contract.

14.4 *Ethiopia*

- (a) Black Marlin has interests in the following two Petroleum Production Sharing Agreements in Ethiopia for the exploration and development of petroleum resources in the contractually stipulated area as exclusive operator:
 - (i) a Petroleum Production Sharing Agreement entered into between the Government of the Republic of Ethiopia and Lundin East Africa B.V. (as the contractor) relating to the Ethiopia Ogaden Basin, Blocks 2 & 6 dated 7 November 2006; and
 - (ii) a Petroleum Production Sharing Agreement entered into between the Government of the Republic of Ethiopia and Lundin East Africa B.V. (as the contractor) relating to the Ethiopia Ogaden Basin, Blocks 7 & 8 dated 11 July 2007.

Lundin Petroleum AB sold its wholly owned subsidiary Lundin East Africa B.V. to Africa Oil Corporation and by way of assignment Africa Oil Ethiopia B.V. (a subsidiary of Africa Oil Corporation) assigned certain rights under the Production Sharing Contracts to East African Exploration (Ethiopia) Limited (a subsidiary of Black Marlin).

The contractor is required to provide all capital, machinery, equipment, technology and personnel necessary for the conduct of the petroleum operations, and it bears the associated costs. The contractor shall carry out minimum exploration work and expenditure obligations and pay bonuses, rentals and royalties as stipulated in the Petroleum Production Sharing Agreements. The Petroleum Production Sharing Agreements shall expire automatically at the end of the initial exploration period of four years or any extension granted. If, however, a commercial discovery has been made before the expiration of the initial exploration period or its extension, the Petroleum Production Sharing Contracts shall continue as to such development area for a term of 25 years. Prior consent from the Government of Ethiopia will be required for the transfer of interests under the Petroleum Production Sharing Contracts.

- (b) In addition, the following two Joint Operating Agreements have been signed in Ethiopia:
 - (i) a Joint Operation Agreement was entered between Lundin East Africa B.V. and New Age (African Global Energy) Limited relating to Ogaden Blocks 2 & 6 dated 1 October 2008 (effective date 15 July 2008); and

- (ii) a Joint Operation Agreement was entered between Lundin East Africa B.V. and New Age (African Global Energy) Limited dated 1 October 2008 (effective date 15 July 2008).

Black Marlin Energy Limited agreed to be bound by the terms of the Joint Operation Agreements in the Farm-out Agreement.

Under the Joint Operation Agreements Lundin, East Africa B.V. has assigned a 15 per cent. interest in the rights and obligations to New Age (African Global Energy) Limited. Under these Joint Operation Agreements, the parties further define their respective rights and obligations with respect to their operations under the Petroleum Production Sharing Agreements, including the joint exploration, appraisal, development, production and disposition of crude oil and natural gas and other substances. The participating interest of the respective parties under both Joint Operating Agreements is as follows: (i) Lundin East Africa B.V. – 85 per cent.; and (ii) New Age (African Global Energy) Limited – 15 per cent. Lundin East Africa B.V. is designated as an operator under the Joint Operation Agreements. The Joint Operation Agreements terminate on the termination of the related Petroleum Production Sharing Agreements and upon final settlement and removal or disposal of all materials, equipment and personal property used in connection with joint operation. The Joint Operation Agreements provide that in the event of change of control (both direct and indirect) of a party or transfer of a participating interest the party who suffers the change of control is required to provide evidence reasonably satisfactory to the other parties that it will continue to have the financial capability to satisfy its payment obligations and the other parties have a “right of first refusal” relating to the participating interest of the party suffering such change of control.

- (c) In addition, a Farm out Agreement was entered into between Lundin East Africa B.V., Lundin Kenya B.V. and Black Marlin Energy Limited on 22 May 2009. The parties agreed that Lundin East Africa B.V. and Lundin Kenya B.V. transfer and assign parts of their respective interests in Ogaden Basin Blocks 2 & 6, Ogaden Basin Blocks 7 & 8 (Ethiopia) and Block 10A (Kenya) to Black Marlin Energy Limited. Upon execution of this Agreement, the parties are required to also execute deeds of assignment. The assignment is subject to, *inter alia*, the execution of a seismic contracts between Lundin East Africa B.V. respectively Lundin Kenya B.V. on one hand and Upstream Petroleum Services Limited on the other hand. As consideration for the transfers and assignments, Lundin East Africa B.V. and Lundin Kenya B.V. are paid past costs in respect of the related Petroleum Production Sharing Agreements governing the blocks and costs for the seismic programmes. After 31 December 2009, Black Marlin Energy Limited shall require the prior written consent of the other parties to the Farm-out Agreement for any transfer of participating interest under all three Petroleum Production Sharing Agreements and to any change of control. A deed of assignment was entered into between Africa Oil Ethiopia B.V. and East African Exploration (Ethiopia) Limited on 22 July 2009 pursuant to which Africa Oil Ethiopia B.V. transferred and assigned to East African Exploration Ethiopia Limited 30 per cent. of the rights and obligations under the Petroleum Production Sharing Agreement dated 7 November 2006 relating to Ogaden Basin Blocks 2 & 6 (Ethiopia) and 30 per cent. of the rights and obligations under the Petroleum Production Sharing Agreement dated 11 July 2007 relating to Ogaden Basin Blocks 7 & 8 in Ethiopia. East African Exploration (Ethiopia) Limited shall observe, perform and discharge all and any past, present or future obligation or liabilities of Africa Oil Ethiopia B.V. the mentioned Petroleum Sharing Agreements to the extent of the assigned interests.

15. Financing arrangements

Afren has entered into financing arrangements which are summarised below.

15.1 US\$200,000,000 Facility Agreement (as amended and restated from time to time)

On 20 March 2007, Afren Okoro as borrower entered into a US\$200,000,000 revolving loan facility arranged by BNP. Afren and AERL act as guarantors under the terms of the agreement (as amended

and restated on 14 May 2007, and as further amended on 11 August 2008 and 8 October 2009) (the “**Okoro Facility**”). The aggregate commitments as at 30 December 2008 consisted of US\$ 127,500,000 “Tranche A” commitments and US\$22,500,000 “Tranche B” commitments.

Afren Okoro is permitted to draw the funds available under the Okoro Facility only for the purposes of (i) funding budgeted capital and operating expenditure relating to the Okoro field; (ii) funding fees, expenses and interest accruing under the Okoro Facility; (iii) funding up to 50 per cent. of cost overruns in relation to the development of the Okoro field or any other borrowing base asset to the extent taken into account in a projection; and (iv) on and from completion of the Okoro project, for the lawful general corporate purposes of Afren Okoro. Notwithstanding this, no amounts borrowed by Afren Okoro under the Okoro Facility shall be used for anything other than to finance or refinance (or to provide credit support in respect of the financing or refinancing of) the ownership, acquisition, construction, development and/or operation of an asset or portfolio of assets.

The total aggregate commitments under the Okoro Facility reduce at a rate of US\$30,000,000 per six month period from US\$200,000,000 on 30 December 2008 to the higher of (i) the borrowing base amount (which is readjusted every six months) and (ii) US\$20,000,000 on 30 December 2011, with the total commitment falling to zero on the final maturity date, being the earlier of five years from the closing date (as defined in the agreement) and the projected date on which the specified assets subject to the agreement fall below 25 per cent. of their initial reserves. The rate of interest payable is calculated on the basis of a formula which incorporates the aggregate of the applicable margin, LIBOR, and the mandatory cost specified.

The Okoro Facility includes representations, covenants and events of default which are standard for facilities of this nature. The events of default comprise a cross default in an aggregate amount of more than US\$1,000,000, an adverse change in the political situation in Nigeria, and a change of control in any Obligor other than Afren.

Fixed and floating security over all of the shares and assets of Afren Okoro and AERL has been granted in relation to the Okoro Facility. Charges over the shares of Afren Okoro and Afren Block One Limited, and pledges over the bank accounts of, Afren Okoro, AERL and the AERL-Amni joint bank account and of Afren Block One Limited, have also been granted in relation to the Okoro Facility.

15.2 ***US\$150,000,000 Senior Secured Revolving Reducing Facility Agreement (as amended and restated from time to time)***

On 5 March 2008, Afren CI (UK) Limited (“**ACL (I)**”) as borrower, Afren and Afren CI (II) Limited (“**ACL (II)**”) as guarantors and BNP (in various capacities including “Facility Agent”, “Original Lenders” and “Security Agent”) entered into the US\$150,000,000 Senior Secured Revolving Reducing Facility Agreement (the “**CI Facility**”) to provide financing for, amongst others things, the acquisition of Devon CI One Corporation, Devon Côte d’Ivoire Limited and Lion G.P.L. S.A. The CI Facility was amended and restated on 23 September 2008 and Afren CI One Corporation and Afren Côte d’Ivoire acceded as guarantors on 20 October 2008.

Under the CI Facility, the lenders make available to ACL (I) a revolving credit facility comprising of a “Facility A Commitment” (in two tranches) totalling US\$120,000,000, and a “Facility B Commitment” (in two tranches) totalling US\$30,000,000.

ACL (I) is permitted to draw the funds available under Facility A for the purposes of (i) on lending to ACL (II) to fund the remainder of the acquisition costs relating to the acquisition of Devon Côte d’Ivoire Limited and Devon CI One Corporation and the related fees and expenses; (ii) to pay fees and expenses related to any of the finance documents relating to the CI Facility; and (iii) for lawful general corporate purposes.

ACL (I) is permitted to draw the funds available under Facility B for the purposes of (i) on lending to ACL (II) to fund the remainder of the acquisition costs relating to the acquisition of Lion G.P.L. S.A., and to pay the related fees and expenses; and (ii) for lawful general corporate purposes.

The total aggregate commitments under Facility A of the CI Facility reduce at a rate of US\$ 11,200,000 (rounded to three significant figures) per six month period from US\$112,430,000 on 30 June 2008 to US\$11,240,000 on 31 December 2012. The total aggregate commitments under Facility B of the CI Facility reduce at a rate of US\$3,760,000 (rounded to three significant figures) per six month period from US\$37,570,000 on 30 June 2008 to US\$3,760,000 on 31 December 2012. Each of the total commitments of Facility A and Facility B fall to zero on the final maturity date, being the earlier of 30 June 2013 and the projected date on which the specified assets subject to the agreement fall below 25 per cent. of their initial reserves. The rate of interest payable is calculated on the basis of a formula which incorporates the aggregate of the applicable margin, LIBOR, and the mandatory cost specified.

The CI Facility includes representations, covenants and events of default which are standard for facilities of this nature. There are a number of negative pledges and restrictions set out in the CI Facility which protect the interests of the lenders, such as restrictions on transfers of assets, restrictions on granting security over assets, among others.

Fixed and floating security over all of the shares and assets of Afren CI One Corporation, Afren Côte d'Ivoire, ACL (II) and ACL (I) has been granted in relation to the CI Facility. In addition, charges over the shares of Afren CI One Corporation, Afren Côte d'Ivoire and ACL (I), and pledges over the bank accounts of ACL (I), Afren Côte d'Ivoire, Afren CI One Corporation and Lion G.P.L. S.A., have also been granted in relation to the CI Facility.

15.3 *US\$66,666,636 Subordinated Facility Agreement*

On 5 March 2008, ACL (I) as borrower, Afren and ACL (II) as guarantors, BNP ("as Arranger") and FCMB ("as Subordinated Agent") entered into a "Facility A" term loan and "Facility B" term loan, for the total aggregate amount of US\$66,666,636. ACL (I) shall apply the Facility A loan towards (i) on lending to ACL (II) to fund (i) acquisition costs relating to the acquisition of Devon Côte d'Ivoire Limited and Devon CI One Corporation and related fees and expenses, (ii) paying fees and expense in relation to any finance documents; and (iii) for general corporate purposes. ACL (I) shall apply the Facility B loan towards (i) on lending to ACL (II) to fund the remainder of the acquisition costs relating to the acquisition of Lion G.P.L. S.A and related fees and expenses; and (ii) for general corporate purposes. The facility agreement includes representations, covenants and events of default which are standard for facilities of this nature. The events of default comprise a cross default in an aggregate amount of more than US\$1,000,000, and a change of control provision triggered in the event that Afren ceases to wholly own any obligor or the target companies, or any persons acting in concert gain control of Afren.

With the exception of the French law bank account pledge over the proceeds of a treasury account, the security package provided in respect of the CI Facility is also for the benefit of the Subordinated Lenders.

15.4 *US\$50,000,000 Facility Agreement*

On 17 August 2007, Afren Nigeria and Afren entered into a US\$50,000,000 Facility Agreement with FCMB, under which FCMB granted Afren Nigeria an amortising facility over five years with an interest rate of LIBOR plus 4.45 per cent. per annum solely for the use by Afren Nigeria for its general corporate purposes and those of Afren and their subsidiaries. The loan principal (together with interest and fees) is repayable in six equal semi annual instalments commencing 30 months from the drawdown date. Payment of interest and fees is also payable during the initial 30 month period. In return for the grant of the facility, Afren (as guarantor of Afren Nigeria's obligations) issued a detachable warrant to FCMB to subscribe for 12,000,000 ordinary shares. The agreement includes representations, covenants and events of default which are standard for facilities of this nature. There are a number of negative pledges and restrictions set out in the agreement which protect the interests of FCMB, such as restrictions on transfers of assets, restrictions on granting security over assets, including an undertaking from each of Afren Nigeria and Afren not to dispose of, and that no substantial subsidiary will dispose of, a substantial part of its assets.

15.5 **US\$450,000,000 Facility Agreement**

On 24 March 2010, Afren Resources Limited (“**ARL**”) as borrower entered into an up to US\$ 450,000,000 revolving reserve based lending facility arranged by BNP, Crédit Agricole Corporate Investment Bank and Natixis as mandated lead arrangers. Afren acts as guarantor under the terms of the agreement (the “**Ebok Facility**”).

ARL is permitted to draw the funds available under the Ebok Facility only for the purposes of: (i) funding budgeted capital expenditure relating to the Ebok field or any other borrowing base asset to the extent taken into account in a projection; (ii) funding fees, expenses and interest accruing under the Ebok Facility; (iii) funding cost overruns (up to a cap to be agreed) in relation to the development of the Ebok field or any other borrowing base asset to the extent taken into account in a projection; (iv) issuing letters of credit; and (v) refund overfunded equity in relation to the Project with unused debt. Provided the DSRA and CSRA funding requirements are met, on and from completion of Phase 1A of the Ebok project (i.e. the development of the Central Area), the funds generated by the Ebok development may be used for the lawful general corporate purposes of Afren. If a further phase of the Ebok Project is included as a borrowing base asset, then up to 50 per cent. of the net proceeds from Phase 1A production may be used to fund exploration and appraisal work in the Ebok area or up to 100 per cent. of the net proceeds from Phase 1A production may be used to fund development work in relation to subsequent phases of the Ebok Project which are not yet borrowing base assets.

The total aggregate commitments under the Ebok Facility reduce at a rate of approximately US\$ 55,000,000 per six month period from US\$450,000,000 on 30 June 2012 to the higher of (i) the borrowing base amount (which is readjusted every six months) and (ii) US\$56,250,000 on 30 June 2015, with the total commitment falling to zero on the final maturity date, being the earlier of five years from the closing date (as defined in the agreement) and the projected date on which the specified assets subject to the agreement fall below 25 per cent. of their initial reserves. The rate of interest payable is calculated on the basis of a formula which incorporates the aggregate of the applicable margin, LIBOR, and the mandatory cost specified.

The Ebok Facility includes representations, covenants and events of default which are standard for facilities of this nature. The events of default comprise a cross default in an aggregate amount of more than US\$5,000,000, an adverse change in the political situation in Nigeria, and a change of control in any Obligor other than Afren.

The security package in relation to the Ebok Facility which has been granted includes (i) fixed and floating security over all of the shares and assets of ARL; (ii) pledge by Afren Nigeria Holdings (Nigeria) Limited of the shares in ARL; (iii) account pledges over ARL’s bank account, and (iv) assignment of insurances, reinsurance rights and major contracts.

- 15.6 On 8 May 2007, Afren Okoro and BNP entered into an International Swaps and Derivatives Association (“**ISDA**”) master agreement. On 1 June 2007 and 11 July 2007, respectively, Afren Okoro and BNP entered into a swap and a cap transaction pursuant to such agreement. The purpose of these transactions is to protect Afren Okoro from volatility in the price of dated Brent oil. Each transaction is effective on 1 May 2008 and is in respect of the price of a total notional quantity of 1,571,982 barrels of dated Brent oil, with 32 monthly determination periods terminating on 31 December 2010.
- 15.7 On 8 May 2007, Afren Okoro and BNP entered into an International Swaps and Derivatives Association (“**ISDA**”) master agreement. On 23 June 2009, Afren Okoro and BNP entered into a swap and a cap transaction pursuant to the agreement. The purpose of these transactions is to protect Afren Okoro from volatility in the price of dated Brent oil. The transaction is effective on 1 July 2009 and is in respect of the price of a total notional quantity of 1,004,646 barrels of dated Brent oil, with 32 monthly determination periods terminating on 31 December 2011.
- 15.8 On 12 May 2008, Afren CI (UK) Limited and BNP entered into an ISDA master agreement in respect of the hedging policy set out in the US\$150,000,000 Senior Secured Revolving Reducing Facility Agreement and the US\$66,670,000 Subordinated Facility Agreement, each dated 5 March 2008. A transaction was entered into pursuant to such agreement on 29 September 2008, effective 1 October

2008, under the terms of which Afren CI (UK) Ltd and BNP entered into a synthetic put option in respect of the price of a total notional quantity of 1,576,611 barrels of dated Brent oil. The aim of this transaction is to hedge against volatility in the movement in the price of oil by guaranteeing that Afren CI (UK) Ltd will always receive at least a minimum price in the case of a reduction in the market price of crude oil. The arrangement has 15 quarterly determination periods and terminates on 30 June 2012.

- 15.9 On 23 September 2008, Afren CI (UK) Limited and, one of its indirect subsidiaries, Afren Côte d'Ivoire, entered into an ISDA master agreement which follows from the agreement between Afren CI (UK) Limited and BNP referred to above. A transaction was entered into pursuant to a confirmation dated 23 September 2008, effective 1 October 2008, whereby Afren Côte d'Ivoire and Afren CI (UK) Limited entered into a synthetic put option in respect of the price of a total notional quantity of 1,576,611 barrels of dated Brent oil. The aim of the transaction is to hedge against volatility in the movement in the price of oil by guaranteeing that Afren Côte d'Ivoire will always receive at least a minimum price in the event of a reduction in the market price of crude oil. The arrangement has 15 quarterly determination periods and terminates on 30 June 2012.

16. Agreements relating to Afren's assets

Afren has entered into agreements relating to its assets which are summarised below.

16.1 *Okoro and Setu Fields*

Production Sharing and Technical Services Agreement

A Production Sharing and Technical Services Agreement was entered into between Amni, Afren and AERL on 24 March 2006 (as amended) with respect to the Okoro and Setu fields. Afren's rights and obligations were novated to Afren Okoro pursuant to a novation deed dated 1 March 2007. Under the agreement, AERL is appointed as the contractor and technical operator. Afren Okoro is obligated to lend to AERL and Amni the initial field development costs. Afren Okoro is entitled to recover such costs (plus interest of eight per cent. per annum) from 90 per cent. of the sales proceeds of crude oil (net of royalties and taxes). Thereafter, proceeds are to be shared equally between Amni and AERL (unless a separate OML has been issued in respect of the Okoro and Setu fields). Until such amount is repaid, Amni and AERL have granted a bank account charge, an asset charge and a share option agreement (in respect of shares in Amni) as security for the repayment of the amounts loaned by Afren Okoro. To the extent the development does not result in sales proceeds being generated, Afren Okoro is not entitled to recoup any amounts from Amni or AERL. The agreement remains in effect until terminated in accordance with its terms.

Marketing Services and Sale and Purchase Agreement for Crude Oil

AERL and Shell Western Supply and Trading Limited (the "**Buyer**") entered into an agreement for the purchase of Okoro Crude Oil on 14 April 2010. The term of the agreement is from 1st May 2010 to 31st May 2011, unless previously terminated by either party. AERL has the option to extend the contract by 12 months which must be declared by 31st January 2011. Termination of the agreement must be provided in writing, by either party to the other, not less than three months before such termination becomes effective. Under the agreement, AERL shall sell 100 per cent. of its entitlement to Okoro Crude Oil to the Buyer, which shall be of normal export quality. AERL shall provide one safe berth for loading the crude oil at the FSO which must at all times conform to standards not less than those set out in the International Chamber of Shipping/Oil Companies International Marine Forum (ICS/OCIMF) "ship-to-ship transfer guide for Tandem Moorings". The price for the crude oil shall be determined as set out in the agreement to which a premium of US\$1.41 per barrel shall be applied. If the Okoro terminal is used for export, the price will be determined under a different formula and a premium of US\$0.19 per barrel shall be applied. There are two different payment options under the agreement which involve the Buyer paying in full, without discount, within 30 calendar days after the bill of lading date or not later than 5 days after the bill of lading date. Any loss or damage to the oil during loading shall be for the account of the Buyer. The quality and quantity of oil shall be determined in accordance with the usual practice at the terminal. The Buyer shall procure that its vessel shall comply with the requirements of the International Ship and Port Facility

Security Code. AERL's liability under the agreement for any costs, losses or expenses incurred by the vessel shall be limited to the payment of demurrage. Either party may terminate the contract should the other party fail to perform its obligations and such failure is not remedied within 15 days following receipt of written notice of such failure to perform.

Contract for the Provision of Floating Production Storage and Offloading Unit

A Contract for the Provision of Floating Production Storage and Offloading Unit was entered into between AERL (on behalf of itself and its co-venturers) and Bumi Armada Berhad on 3 April 2007. This contract was then novated and split pursuant to a novation agreement dated 8 February 2008 between AERL, Bumi Armada Berhad (as guarantor of the contractor), Armada Floating Solutions Limited (as contractor) and Bumi Armada (Singapore) PTE. Limited into (i) the Bareboat Charter Contract (entered into between AERL and Armada Floating Solutions Limited); and (ii) the Operation and Maintenance Contract (entered into between AERL and Bumi Armada (Singapore) PTE. Limited). Bumi Armada (Singapore) PTE. Limited is responsible for the operation and maintenance of the FPSO and Armada Floating Solutions Limited is to provide the FPSO. The term for both contracts is five years from the issuance of the provisional acceptance certificate on the first flow of oil into the FPSO with an option for AERL to extend the term for at least one year to a maximum of five years. The provisional acceptance certificate was issued on 1 July 2009. Rates are applied daily for the FPSO hire at US\$42,426 per day and the operation and maintenance services at US\$26,000 per day, subject to review. The technical fee in the Operation and Maintenance Contract is US\$1.88 million per annum. Under the Bareboat Contract, AERL has an exclusive option to purchase the FPSO at its sole discretion. AERL may terminate the Bareboat Contract and the Operation and Maintenance Contract on 180 days' notice provided that if termination occurs before the end of the primary term of the contracts, an early termination payment is payable by AERL. An early termination payment is not incurred in the case of termination as a result of certain conditions including *force majeure* events or the actual or constructive loss of the FPSO. The contracts also provide each party with the right to terminate upon a default by the other party. Events of default are linked between the two contracts. Parent company guarantees are to be provided by Armada Floating Solutions Limited and Bumi Armada (Singapore) PTE. Limited from Bumi Armada Berhad and by AERL from Afren and are to be valid until the expiry of 180 days after the demobilisation of the FPSO, or in the case of a total loss of requisition of the FPSO, the date of termination of the contracts. In addition, AERL is obliged to provide Armada Floating Solutions Limited and Bumi Armada (Singapore) PTE. Limited with a bank guarantee or letter of credit for a sum not exceeding US\$6 million.

16.2 Ebok

Farm Out Agreement

The ExxonMobil/NNPC Joint Venture holds participating interests in several oil mining licences, including OML 67, in which the Ebok field is situated. The ExxonMobil/NNPC Joint Venture entered into a Farm Out Agreement with Oriental on 25 May 2007 under which Oriental was granted a 100 per cent. working interest in an area within OML 67 for the purpose of conducting petroleum operations for a period of 60 months in consideration for Oriental making monthly payments to the ExxonMobil/NNPC Joint Venture of 30 per cent. of the profit oil and profit gas arising from the farm-out area and certain other payments and complying with a number of obligations in relation to OML 67. Subject to obtaining approval from the Department of Petroleum Resources of Nigeria and to Oriental complying with its obligations under the Farm Out Agreement, the Farm Out Agreement continues for so long as the ExxonMobil/NNPC Joint Venture continue to have the right to conduct petroleum operations within the relevant area of OML 67.

Farm In Agreement

Oriental entered into a Farm In Agreement with Afren Resources on 31 March 2008. This agreement sets out the terms upon which Afren Resources accepts the assignment and transfer of a 40 per cent. participatory interest in the rights and obligations of Oriental in respect of the Farm Out Agreement (including those referred to above), the farm out area and the Joint Operating Agreement. In consideration for such participating interest Afren Resources was to pay US\$11.5 million to Oriental

and US\$1 million to Sovereign Oil & Gas Company II, LLC following satisfaction of certain conditions precedent, and US\$11.5 million to Oriental and US\$1 million to Sovereign Oil & Gas Company II, LLC following any development plan submitted to the Government of the Federal Republic of Nigeria being approved. Oriental has the right to require such payment to be satisfied in whole or in part by the issue of shares in Afren at a number of shares to be agreed between the parties. The conditions precedent were satisfied in respect of the agreement on 22 August 2008 and Afren Resources paid the initial payments referred to above within 15 business days of that date. The field development program was approved by the Department of Petroleum Resources on 5 October 2009 and payment was made within 15 business days. Under the agreement, Afren Resources also agreed to bear and pay all capital costs and all operating costs (until Afren Resources has recovered all capital costs) as well as 40 per cent. of the payment obligations of Oriental and the provision of abandonment security under the Farm Out Agreement referred to above, Afren has provided a parent company guarantee in favour of Oriental and the ExxonMobil/NNPC to guarantee Afren Resources' obligations in respect of the farm-in.

Joint Operating Agreement

Oriental and Afren Resources entered into a Joint Operating Agreement on 31 March 2008 to set out the parties' obligations with respect to the conduct of petroleum operations in the farm out area, with Oriental as operator and Afren Resources as technical adviser. Afren Resources is liable to fund all costs to drill of one exploration well and (unless Afren decides to relinquish its rights in the interest at that time) one exploration, appraisal or development well and other work program costs. Available crude oil from the farm-out area (after deducting royalty amounts due to the Federal Government of Nigeria, overriding royalty amounts due to the ExxonMobil/NNPC Joint Venture and Sovereign Oil and Gas Company II, LLC and amounts due for taxes) will be allocated 100 per cent. to Afren Resources until Afren Resources has recovered its capital and operating costs. Thereafter, available crude oil will be shared between Afren Resources and Oriental equally. The Joint Operating Agreement is effective for so long as both the parties retain an interest in the Farm out Agreement referred to above and farm out area.

Contract C 1527 (Rig Contract)

Afren Resources (on behalf of itself and its co-venturers) entered into Contract Number C 1527 for the provision of jack up drilling unit "GSF Adriatic IX" and drilling rig services with GlobalSantaFe International Drilling Corporation in association with Global Offshore Drilling Limited (collectively with GlobalSantaFe International Drilling Corporation, the contractor) on 7 August 2009. The contractor is to provide the drilling unit together with certain other equipment, material, supplies, services and personnel necessary to carry out drilling operations. Afren Resources is to pay the contractor varying defined rates during the different operating terms of drilling operations which range from US\$85,000 per day to US\$97,000 per day. Certain other rates are also applicable for various situations such as *force majeure*, repair and re drilling with such rates calculated as a percentage (either 80 per cent. or 100 per cent.) of the applicable term rate. In addition, the contractor is entitled to certain lump sums in relation to mobilisation and other fees and is entitled to mark up reimbursable items on a sliding scale linked to cost, ranging from 10 per cent. to five per cent. The contract continues in force until the date that drilling operations are deemed to be complete under the contract, initially for a period of 250 days beginning on the date of acceptance of the drilling unit by Afren Resources or unless earlier terminated. Afren Resources may extend the term for another 175, 250 or 425 days. Afren Resources may terminate at any time without reason on 10 days' notice in which case liquidated damages for early termination will apply.

16.3 Okwok

Addax Farm Out Agreement

On 7 July 2009, Afren Exploration and Addax entered into a farm out agreement whereby Addax agreed to assign 70 per cent. of the rights, entitlements and obligations of Addax a joint venture agreement dated 14 September 2005 between Oriental and Addax, a technical services agreement

dated 16 September 2006 between Oriental and Addax, a joint operating agreement dated 9 May 2006 between Oriental and Addax, a deed of assignment dated 6 June 2006, a crude oil sales and agency agreement dated 16 November 2005 and a conveyance of overriding royalty interest dated 14 September 2005 between Oriental, Addax and Sovereign, in consideration for Afren Exploration agreeing to drill one appraisal well in the farm-out area and paying all costs associated therewith. Afren Exploration was also granted an option, exercisable within six months after the drilling of the well is complete (and, if Afren Exploration elects, the production testing of one or more of the crude oil bearing sections of that well), to purchase Addax's residual interest in the project. In consideration for such option, Afren Exploration is to pay US\$55 million together with an amount equal to the sum of all expenditure and liabilities incurred by Addax in respect of its residual interest on or after such completion of the drilling of the first well (and production testing if applicable). The agreement is conditional on a number of matters, including consent to the assignment from Oriental, NNPC, Mobil and the Minister, which Afren is still awaiting to receive. The assignment under the agreement of Addax's interests is not effective until Afren Exploration completes the drilling of the well. Afren Exploration is required to have completed the drilling of the well by 31 March 2011 (subject only to delays caused by *force majeure*).

Joint Operating Agreement

On 19 August 2009, Oriental, Addax and Afren Exploration entered into a joint operating agreement to determine how the Okwok oil field is to be managed. Under the agreement, Oriental is appointed as operator and Afren Exploration is appointed as its technical adviser. The parties can elect to take part in proposed site projects. Oriental may propose and conduct site projects where neither of the other parties is willing to approve a work programme containing a firm well, or a development plan within a fixed period of time. If parties elect not to participate in such a project, they have an option to reinstate such rights and participate within a specified timeframe and subject to certain conditions and payments. No exclusive operations shall conflict with projects in which all three parties have agreed to participate. Each party shall have the right to own, take in kind and separately dispose of its share of total production in such quantities and in accordance with such procedures as set out in an offtake agreement.

16.4 **OPL 310**

Participation Agreement and Production and Revenue Sharing Agreement

A participation agreement was entered into by Optimum and Afren Investments on 8 September 2008 and was amended by a Production and Revenue Sharing Agreement on 19 December 2008. Optimum, as holder of 100 per cent. of the participating interest in OPL 310, agreed to assign 40 per cent. of such interest to Afren Investments. Under the agreement, Afren Investments agreed to pay US\$ 10 million to the Government of Nigeria as initial payment for revalidation of the OPL 310 licence being allocated to Optimum and to take on certain liabilities and obligations in relation to operations pursuant to the OPL 310 licence. These include the obligation to make a payment to Optimum of (i) US\$3 million following governmental approval being given to Optimum's proposed assignment to Afren Investments, (ii) US\$10 million after the issue of the oil mining lease with respect to the area the subject of the OPL 310 licence in the joint names of Optimum and Afren Investments, (iii) US\$4 million after the date on which production of petroleum commences pursuant to the first development plan with respect to the area the subject of the OPL 310 licence which receives all necessary governmental consents ("**Production Date**"), and (iv) subject to an independent third party having certified there is at least 100 mmboe of recoverable reserves in the area of the subject of the OPL 310 licence, US\$8 million after the date on which the cumulative production of petroleum from such area reaches 50 mmboe. If the first well drilled after 8 September 2008 results in the discovery of petroleum and an independent third party certifies that the discovery will produce at least 10,000 boe per day, then Afren Investments is to pay Optimum US\$5 million, with the amount to be paid pursuant to (ii) above reduced to US\$9 million and the amount to be paid pursuant to (iii) above reduced to zero. Afren Investments must also pay the Government of Nigeria US\$10 million after the issue of the oil mining lease in the joint names of Optimum and Afren Investments and the same amount again once the Production Date is achieved. Afren Investments is required to pay all capital

and operating expenditures from 8 September 2008 until the Production Date. After the Production Date and until Afren Investments recovers certain costs incurred as a result of carrying Optimum's capital and operating expenditure obligations until the Production Date, Afren Investments will bear all capital expenditures. After Afren Investments has recovered its costs, Optimum and Afren Investments will bear 70 per cent. and 30 per cent. of capital expenditure respectively. After the Production Date, operating expenditures will be apportioned between the parties in proportion to each party's share of net available production. Optimum is to pay the royalty and concession rental on behalf of the parties and liability for such payments will be shared in proportion to each party's share of net available production. Until Afren Investments recovers certain costs, it is entitled to 91 per cent. of net available production. Optimum then has an entitlement to 79 per cent. of net available production until it recovers certain costs, then the parties are to share in net available production with Optimum being entitled to 30 per cent. and Afren Investments being entitled to 70 per cent. The agreement is effective from 8 September 2008 and continues for a term of the OPL 310 licence or such replacement licence, including any extension thereof, unless otherwise terminated. The Department of Petroleum Resources transmitted the ministerial approval for the assignment of 40 per cent. equity to Afren on 26 May 2009.

16.5 **Anambra Basin – OPL 907 and OPL 917**

Master Loan and Production Sharing Agreement

AGER, Afren, GEC and AERL entered into a Master Loan and Production Sharing agreement on 22 December 2005 to set out the basis on which Afren, GEC and AERL are to lend monies to AGER. The agreement provides that for each of OPL 907 and OPL 917, the lending parties are to enter into a loan memorandum with AGER in respect of the purpose of the loan, the interest rate, the default interest rate and repayment obligations. AGER, Afren, GEC and AERL entered into a loan memorandum for each of OPL 907 and OPL 917 on 1 February 2006. Under the loan memorandum in respect of OPL 907, Afren agreed to loan to AGER amounts not exceeding 47.3 per cent. of the work commitment for OPL 907 (or such further amounts as Afren may in its absolute discretion make available to AGER) at an interest rate of 10 per cent. accruing daily. Afren is entitled to 60 per cent. of allocated profit oil and AGER is entitled to 40 per cent. of allocated profit oil. Under the loan memorandum in respect of OPL 917, Afren agrees to loan to AGER an amount equal to 70 per cent. of the US\$13 million work commitment for OPL 917 at an interest rate of 10 per cent. accruing daily. Afren is entitled to 60 per cent. of allocated profit oil and AGER is entitled to 40 per cent. of allocated profit oil.

Production Sharing Contract

AGER entered into a production sharing contract on 20 February 2008 with a term of 30 years in relation to OPL 907 with NNPC, Buston Energy Resources Limited, Allenne Exploration and Production Limited, Kaztek Engineering Limited, VP Energy Limited, De Atai Oil Services International Limited and Bepta Oil and Gas Limited. The current parties to the agreement and their respective participating interests are: AGER (41 per cent.), Buston Energy Resources Limited (25 per cent.), Allenne Exploration and Production Limited (14 per cent.), Kaztek Engineering Limited (5 per cent.), Bepta Oil and Gas Limited (10 per cent.) VP Energy Limited (3 per cent.) and De Atai Oil Services International Limited (2 per cent.).

AGER entered into a production sharing contract on 20 February 2008 with a term of 25 years in relation to OPL 917 with NNPC, VP Energy Limited, Petrolog Oil and Gas Limited, De Atai Oil Services International Limited, and Goland Petroleum Development Company Limited. The current parties to the agreement and their respective participating interests are: AGER (42 per cent.), Petrolog Oil and Gas Limited (18 per cent.), VP Energy Limited (17 per cent.), De Atai Oil Services International Limited (10 per cent.) and Goland Petroleum Development Company Limited (13 per cent.).

Under the production sharing contracts the parties other than NNPC were appointed as contractor for OPL 907 and OPL 917 respectively and such parties are required to ensure minimum work

programmes (including minimum financial commitments) are complied with and pay NNPC a production bonus once certain levels of production have been attained. Subject to the contractor fulfilling its obligations, each of the production sharing contracts are for a term of 30 years, being a 10 year exploration period and a 20 year oil mining licence period. Upon the discovery of a commercial quantity of hydrocarbons NNPC may apply for a conversion of the oil prospecting licence into an oil mining licence and on expiry of the 20 year mining period, NNPC is to seek the maximum allowed renewal period of the oil mining licence.

16.6 ***Block CI-11***

Share Purchase Agreement

The share purchase agreement between Devon Energy, Devon International Holdings Ltd, Afren CI (II) Limited and Afren dated 5 March 2008 summarised at paragraph 3 of Part 1 of this Prospectus.

Petroleum Production Sharing Contract

A Petroleum Production Sharing Contract was entered into by The Republic of Côte d'Ivoire, UMIC Côte d'Ivoire Corporation and Petroci on 27 June 1992 (the “**Petroleum Production Sharing Contract**”). Under the contract, Petroci and UMIC Côte d'Ivoire Corporation were appointed as contractor in respect of carrying out crude oil and natural gas operations in Block CI-11. The term of the contract is expressed to be until the expiry, surrender or withdrawal of the last existing exclusive exploitation licence granted to the contractor. The contractor was granted an exclusive exploration authorisation for an initial period of 18 months from 4 January 1993. Such right is extendable at the contractor's request provided it fulfils its exploration work commitments under the contract for renewals of further exploration periods to an aggregate further term of 5.5 to 6.5 years. The contract requires the contractor to surrender parts of the initial area of Block CI-11 in stages except to the extent any appraisal or exploitation perimeters have been granted. If the contractor conducts an appraisal and considers the field to be commercial it may apply to the Government for an exclusive exploitation authorisation, which shall be for a period of 25 years from the date of issue and may be extended for a further 10 years. The grant of an exclusive exploitation authorisation obligates the contractor to undertake all petroleum operations necessary for the exploitation at its sole costs and risk. Exploration decrees for the Lion and Panthère fields were granted for 25 years on 12 September 1994. The contractor is entitled to no greater than 63 per cent. of production of crude oil and natural gas, or such lesser percentage which would be sufficient to recover costs. Any other crude oil or natural gas produced is to be shared between The Republic of Côte d'Ivoire and the contractor on a tiered basis linked to daily total production of crude oil or natural gas (as applicable). The contractor is also required to pay bonuses to the Directorate General of Taxes of Côte d'Ivoire linked to production rates of crude oil. Petroci retained a greater participating interest in respect of two wells drilled in Block CI-11 which were developed prior to the effective date. Except for such area, Petroci's initial participating interest in Block CI-11 is 10 per cent. with an option to increase up to a maximum of 20 per cent. for a particular exploitation area provided Petroci notifies the other contractor parties within four months of a grant of an exclusive exploitation authorisation for such area. Any additional participation is assigned from each of the other contractor parties in proportion to their participating interests. There have been three subsequent amendments to the contract and the current parties to the contract are The Republic of Côte d'Ivoire, Afren Côte d'Ivoire, Petroci, the IFC and SK Energy. UMIC Côte d'Ivoire Corporation changed its name to Ocean International Limited and then to Devon Côte d'Ivoire, Ltd., and the shares in Devon Côte d'Ivoire, Ltd. were subsequently acquired by Afren CI (II) Limited on 24 September 2008 pursuant to a share purchase agreement dated 5 March 2008. On 10 June 2010, the IFC sold its interest in Block CI-11 to Compagnie Ivoirienne du Pétrole et des Mines S.A. (“CIPEM”).

Joint Operating Agreement

A Joint Operating Agreement was entered into by UMIC Côte d'Ivoire Corporation and Petroci on 27 June 1992, with an effective date of 4 January 1993. There have been eight amendments to the agreement. The current parties to the agreement are Afren Côte d'Ivoire, Petroci, IFC and SK Energy. Under the Petroleum Production Sharing Contract, Petroci retained a greater interest in a special area

of Block CI-11 encompassing two previously drilled wells. The parties now hold the following percentage participating interests in Block CI-11: Afren Côte d'Ivoire (47.9592 per cent.), Petroci (20.1360 per cent.), CIPEM (18.9456 per cent.) and SK Energy Co Ltd (12.9592 per cent.). The parties can elect whether or not to take part in proposed projects which are in addition to the minimum exploration work commitments set out in the Petroleum Production Sharing Contract. Parties have the right, but not the obligation, to assume any non consenting parties' participating interest in such case. If parties elect not to participate in such a project, they have an option to reinstate such rights and participate within a specified timeframe and subject to certain conditions and payments. The agreement continues until only one party holds 100 per cent. of the interest in Block CI-11 or when the Petroleum Production Sharing Contract terminates, whichever is the earlier.

Unitization Agreement

Petroci, UMIC Côte d'Ivoire Corporation, IFC, Pluspetrol Côte d'Ivoire CI-11 Corporation (which later transferred its interest to Yukong Limited) and GNR (Côte d'Ivoire) Limited entered into a Unitization Agreement on 1 July 1996. The Petroleum Production Sharing Contract covers two areas (being Block CI-11 and the special areas inside Block CI-11 in which Petroci is entitled to enhanced participating interest) and both the Lion field and the Panthère field are covered by the contract and are each partly located within and without the special areas. As the participating interests of the parties in the special area differ from that of the parties in Block CI-11 excluding the special area, the parties agreed to unitise the Lion field and the Panthère field to obtain an equitable allocation of production and cost for the two areas. The Unitization Agreement provides for the formation of a unit area for the purposes of unitising the reserves in the two areas, the ownership of all joint property used for petrol operations and reserves in any future exploitation perimeter within the two areas. For that purpose, unit interests over the area are determined and calculated by a selected engineering firm first on 1 July 1996, and subsequently recalculated on a yearly basis on 1 July; the amount of reserves determined, however, takes into account reserves that were produced and sold between the Petroleum Production Sharing Contract effective date (4 January 1993) and the date of the Unitisation Agreement.

Gas Sale and Purchase Agreements

- (a) An agreement for the Sale and Purchase of Natural Gas in Block CI-11 was entered into between Société Ivoirienne de Raffinage (as buyer) and Afren Côte D'Ivoire Ltd., International Finance Corporation, SK Energy Co. Ltd., Petroci Holding and Republic of Côte D'Ivoire (together as sellers) on 18 December 2009. Under the agreement from 1 January 2010, the Sellers are required to deliver a daily quantity of up to 7,000,000 cubic feet of natural gas and a minimal annual quantity of 2.6 billion cubic feet of natural gas, with pricing determined pursuant to a specific formula in accordance with the agreement. If the quality of the natural gas is not in accordance with the prescribed specifications, the Buyer is entitled to refuse to accept the non-conforming gas until the deficiency in quality is remedied or to pay the Sellers 80 per cent. of the contract price. The agreement is due to expire on the earlier of: (i) on 31 December 2012 or (ii) on the date of expiration of the latest exclusive development and production permit as defined in the agreement. Each Seller is required to assign its interest in this agreement as a consequence of any assignment of its interest in the production sharing contract dated 27 June 1992 between Afren Côte D'Ivoire Limited, Petroci Holding and the Republic of Côte D'Ivoire. The Buyer is also entitled to assign the rights and obligations under this agreement to a third party capable of performing the contractual obligations. IFC's interest in the agreement was duly assigned to CIPEM.
- (b) An agreement for the Sale and Purchase of Natural Gas in Block CI-11 was entered into between La Caisse Autonome d'Amortissement (as buyer) (now SOGEPE), UMIC Côte d'Ivoire Corporation, IFC, G.N.R. (Côte d'Ivoire) Ltd, Pluspetrol S.A. (collectively as sellers) and Petroci and The Republic of Côte d'Ivoire (collectively as delivering parties) on 30 September 1994 (as amended on 1 August 2003). The seller's obligation to deliver a set annual quantity and buyer's obligation to take or pay have expired in accordance with the terms of the agreement. Afren Côte d'Ivoire terminated the purchase price provisions of the

amendment (setting natural gas price of US\$2.35 per million btu for all natural gas received up to an annual base quantity, and thereafter of US\$2.15 per million btu) in accordance with the terms of the amendment. The parties are currently negotiating a new gas price; in the interim, it has been agreed to use a provisional price of US\$4 per million btu. The agreement expires (if not earlier terminated) on the expiry of the last exclusive exploration authorisation issued by The Republic of Côte d'Ivoire to the contractor under the Petroleum Production Sharing Contract.

- (c) On 17 April 1998, Lion GPL, S.A. ("**Lion**") and SIR entered into an LPG Sales Contract whereby Lion agrees to sell, and SIR agrees to purchase, commercial butane received in SIR's storage facility. The quantities which SIR agrees to purchase are determined by a formula set out in the agreement. Lion has the exclusive right to supply to SIR any shortage of commercial butane which SIR needs to supply the Ivorian market. The price for the commercial butane is determined by governmental decree. Such price was determined by decree of The Republic of Côte D'Ivoire on 7 July 1997, which specified that the sale price would be US\$244 per metric ton from the date that the volume of sales by Lion reaches 5000 tons or following the expiry of the period of the first 18 months of production. The agreement is renewable annually. Lion has the right to close down the LPG plant if it is no longer economically viable (thereby terminating the agreement).

Gas Transportation Agreement

On 25 October 2005, a Block CI-26 and Block CI-40 Gas Transportation Agreement was entered into between CNR International (Côte d'Ivoire) SARL, Svenska Petroleum CI AB, Petroci Holding, Petroci Overseas Limited and The Republic of Côte d'Ivoire (collectively, as charterer for CI-40), CNR International (Côte d'Ivoire) SARL, Tullow Côte d'Ivoire Limited, Petroci Holding, and The Republic of Côte d'Ivoire (collectively, as charterer for CI-26), Ocean Energy Côte d'Ivoire Corporation, IFC, SK Energy Co Ltd and Petroci Holding (collectively, as transporter). Under the agreement, the transporter is required, subject to minimum and maximum specified quantity requirements, to receive, transport and deliver natural gas (and certain other associated liquids and gases) on behalf of the charterers at a price of US\$0.13 per thousand cubic feet for actual volumes of gas delivered by the charterer to the transporter less any unaccounted for line losses. The transporter is required to maintain the CI-11 pipeline and the Azito pipeline as part of its obligations under the agreement. The agreement expires (unless earlier terminated) on the date of expiration of any exclusive exploitation authorisation to be issued by The Republic of Côte d'Ivoire to the contractor under the production sharing contract (such contract is not defined but it may be referring to the Petroleum Production Sharing Contract).

16.7 Block CI-01

Production Sharing Contract

A production sharing contract was entered into by The Republic of Côte d'Ivoire, UMIC Côte d'Ivoire Corporation and Petroci on 5 December 1994 (as amended), with UMIC Côte d'Ivoire Corporation and Petroci as contractor and UMIC Côte d'Ivoire Corporation appointed as operator. The contract provides that the duration of any exclusive exploration authorisation together with an approved appraisal work programme is for a total of eight years and nine months and the duration of any exclusive exploitation authorisation is 25 years from the date of issue, which may be extended for a further period of 10 years. A commercial petroleum discovery entitles the parties to an exploitation authorisation and several such discoveries in respect of the relevant area. Afren is currently in the process of obtaining an exclusive exploitation authorisation. The contractor is entitled to take no more than 60 per cent. of total production of crude oil (or 40 per cent. in the case of natural gas) or such lesser percentage as would be sufficient for it to recover its costs. Any other crude oil or natural gas produced is to be shared between The Republic of Côte d'Ivoire and the contractor on a tiered basis linked to daily total production. The contractor is also required to pay bonuses to the Directorate General of Taxes of Côte d'Ivoire linked to production rates of crude oil. Under the agreement, Petroci had an initial participating interest of 10 per cent. Petroci elected to take a 40 per cent. participating interest on 14 February 1996, but reduced such interest effective on 31 December 1997 so that it holds

a 20 per cent. carried interest in exploration and appraisal. Petroci has an option to convert the 20 per cent. carried interest into a total exploitation participation of 20 per cent. or less in respect of each area where exploitation is being conducted. UMIC Côte d'Ivoire Corporation assigned its interest under the contract to UMIC (CI 01) Corporation which assigned a portion of its interest to Yukong Limited on 19 January 2006. UMIC (CI-01) Corporation changed its name to Ocean (CI 01) Corporation and then to Devon CI One Corporation, and the shares in Devon CI One Corporation were subsequently acquired by Afren CI (II) Limited pursuant to a share purchase agreement dated 5 March 2008. Currently the parties have the following participating interests: Devon CI One Corporation (65 per cent.); Petroci (20 per cent.) and SK Energy Co Ltd (which acquired Yukong Limited's interest) (15 per cent.).

16.8 **Keta Block**

Petroleum Agreement

Under a Petroleum Agreement between the Republic of Ghana, GNPC, Devon Energy Ghana Limited and EnCana International (Ghana) Limited dated 29 July 2002 (as amended), Afren Energy Ghana Limited ("**Afren Ghana**") (formerly Devon Energy Ghana Limited) is designated as the contractor in respect of the Keta Block. Under the agreement, Afren Ghana and GNPC have 90 per cent. and 10 per cent. initial participating interests respectively, with the option for GNPC to acquire an additional 15 per cent. participating interest subject to GNPC contributing a proportionate share of development and production costs within designated commercial discovery areas. Afren Ghana assigned a two per cent. participating interest to Gulf and entered into a joint operating agreement with Gulf on 18 June 2008, although this two per cent. participating interest has since been bought back. The agreement was to expire on 31 January 2008 but could be extended for two additional periods up to 31 December 2009 for each well drilled beyond the minimum work requirements. On 29 July 2009 the Ministry of Energy of Ghana confirmed such extension to 31 December 2009. Afren Ghana also had the option under the agreement to require the Ministry of Energy and GNPC to enter into a new petroleum agreement, covering 4,400 km² of the contract area as selected by Afren Ghana. The new petroleum agreement, which received parliamentary approval on 19 February 2010, contains substantially the same terms and conditions as the Petroleum Agreement, except that the term shall be six years divided into three periods of two years each with one exploration well work obligation and a minimum expenditure of US\$45 million for each period.

Farm Out Agreement

On 24 October 2008 Afren Ghana and Mitsui Ghana entered into a Farm Out Agreement and this agreement completed on 20 November 2008. Under the agreement, Mitsui Ghana acquired a 20 per cent. participating interest in the Petroleum Agreement together with a 22.2 per cent. interest in a joint operating agreement with Gulf. Mitsui Ghana agreed to pay 50 per cent. of all costs and claims incurred in the drilling programme in respect of the exploration well (subject to a cap), certain well costs incurred prior to the date of the agreement, and to fund 20 per cent. of cash calls in funding any costs relating to the exploration well exceeding the approved budget.

16.9 **La Noumbi Permit**

Production Sharing Agreement

A Production Sharing Agreement was entered into between the Republic of Congo-Brazzaville (the "**Government**"), Les Établissements Maurel & Prom, Tacoma Resources Ltd and Heritage Congo Ltd (in which Afren acquired the entire issued share capital of in November 2006) (together the contractor) with an effective date of 9 February 2004. The agreement terminates on expiry or termination of the research permit or exploration permit. The research permit, granted by the Presidential Decree to Zetah Maurel & Prom Congo dated 10 February 2003 enters into force on the date that the Production Sharing Agreement is approved by law and is granted for a period of four years. The Production Sharing Agreement was approved by law on 19 June 2006. Such permit can be renewed twice for a three year period each. The first period will be expiring in June 2010. The contractor is represented by the company Zetah Maurel & Prom Congo. Les Établissements Maurel & Prom was appointed operator. The operator is currently seeking a renewal of the permit. Oil costs

may be recovered in the following priority; exploration costs, development costs, research costs and last, the deposit agreed for the purpose of the rehabilitation works. Such oil costs may be recovered up to a limit of 60 per cent. of the net oil production and certain other limits determined by a sliding scale formula relating to the oil price. If the determined price (the parties are to meet every quarter to agree the price applicable for each month of the quarter) of oil is less than US\$22 then the contractor is entitled to 45 per cent. of the oil produced and the Government is entitled to 55 per cent. If the determined price is more than US\$22 then 25 per cent. of the oil production will be shared as if the determined price was less than US\$22 and the contractor will be entitled to 40 per cent. and the Government will be entitled to 60 per cent. of the remainder. Excess oil will be shared between the contractor and the Government in shares of 40 per cent. and 60 per cent. respectively. The Government may request the contractor sell up to 30 per cent. of its oil entitlement to Congolese industries.

17. Market quotations

The Ordinary Shares are currently quoted on main market for listed securities on the London Stock Exchange. The closing middle market quotations for the Ordinary Shares as derived from the Daily Official List of the London Stock Exchange for the first dealing day in each of the six months before the date of this Prospectus and on 23 August 2010 (the last practicable date prior to the publication of this Prospectus) are as follows:

<i>Dates</i>	<i>Price per Share (p)</i>
01-March-10	80.75
01-April-10	103.50
04-May-10	89.75
01-June-10	94.70
01-July-10	79.15
02-August-10	95.90
23-August-10	99.35

18. No significant change

Save as set out under the heading “Current Assets” in section 14 of Part 5 of this Prospectus, there has been no significant change in the financial or trading position of the Group since 31 December 2009, being the date to which the latest audited financial information that is incorporated by reference in this Prospectus has been compiled. The changes arise in connection with the Company’s intensive drilling programme for 2010, which is highlighted in January 2010, in particular on the Ebok development. This has contributed to a decrease in current assets and an increase in the non-current assets of the Company from the start of 2010 to the date of this Prospectus, as set out in more detail under the heading “Current Assets” in Section 14 of Part 5 of the Prospectus.

19. Working capital

It is the opinion of the Directors that, after taking into account the available bank facilities of the Group, the Group has sufficient working capital for its present requirements, that is for at least the next 12 months from the date of this Prospectus.

20. United Kingdom taxation

20.1 General

The following comments are intended only as a general guide to the position under current United Kingdom tax law and what is understood to be the current practice of the United Kingdom HM Revenue & Customs and may not apply to certain classes of investors, such as dealers in securities, any person holding Ordinary Shares by reason of an opportunity associated with employment or holding of any office, or persons connected with the Group. Any person who is in doubt as to his tax position or is subject to tax in another jurisdiction is strongly recommended to consult his own professional tax adviser. The tax rates set out below apply for the year to 5 April 2011, subject to particular changes introduced mid-year by the recent Emergency UK Budget of 22 June 2010.

Although these changes have come into force, they will not become law until the enactment of the Finance Act 2010.

20.2 *Taxation of dividends*

(a) *Afren*

Afren will not be required to withhold tax at source on any dividends it pays to its shareholders in respect of the Ordinary Shares.

(b) *UK resident shareholders*

Individuals resident in the UK for taxation purposes are generally liable to income tax on the aggregate amount of any dividend received and a tax credit equal to 10 per cent. of the gross dividend (or one ninth of the dividend received). For example, on a dividend received of £90, the tax credit would be £10, and an individual would be liable to income tax on £100.

No further income tax is payable in respect of the dividend by UK resident individuals who are liable to income tax at the lower and basic rates of tax. UK resident individuals who are liable to income tax at the higher rates are subject to tax on dividends at the rate applicable to dividends (currently 32.5 or 42.5 per cent.) but are entitled to offset the 10 per cent. notional tax credit against such liability. For example, on a dividend received of £90, such taxpayers would have to pay additional tax of £22.50 (representing 32.5 per cent. of the gross dividend less the 10 per cent. tax credit) or £32.50 (representing 42.5 per cent. of the gross dividend less the 10 per cent. tax credit). For this purpose, dividends are treated as the top slice of an individual's income.

No repayment of the tax credit in respect of dividends paid by Afren (including in respect of any dividend paid where the Ordinary Shares are held in a personal equity plan or in an individual savings account) can be claimed by a United Kingdom resident shareholder (including pension funds and charities).

Subject to certain exceptions for traders in securities and insurance companies, a corporate shareholder resident in the United Kingdom for tax purposes will generally not be subject to corporation tax or income tax on dividends received from Afren.

(c) *Non UK resident shareholders*

Non UK resident shareholders are not entitled to claim a repayment of the 10 per cent. tax credit in the UK. Non UK resident Shareholders may be subject to tax on UK dividend income under any law to which they are subject outside the UK, although in certain circumstances, they may be able to claim a reduction for the UK tax credit against any foreign tax liability, depending on the Double Taxation Treaty between the UK and their relevant jurisdiction. Such shareholders should consult their own tax advisers concerning their tax liabilities.

UK resident trustees of discretionary or accumulation trusts are liable to income tax on UK company dividends at 42.5 per cent. of the gross dividend, which after setting off the tax credit equal to 10 per cent. of the gross dividend, will result in additional income tax equal to 32.5 per cent. of the gross dividend.

20.3 *Stamp duty and stamp duty reserve tax*

The statements below summarise the current position and are only intended as a general guide to stamp duty and SDRT. Special rules apply, for example, to agreements made by broker dealers and market makers in the ordinary course of their business and to certain categories of person (such as depositories and clearance service providers) who may be liable to stamp duty or SDRT at a higher rate or may, although not primarily liable for SDRT, be required to notify and account for it. Investors are strongly advised to consult their own professional tax advisers.

New Share Admission on completion of the Acquisition will not be subject to any stamp duty or SDRT.

A transfer for value of the Ordinary Shares will generally be subject to stamp duty or SDRT. Stamp duty will arise on the execution of an instrument to transfer the Ordinary Shares and SDRT will arise on the entry into an unconditional agreement to sell the Ordinary Shares. Transfers to certain categories of person are not liable to stamp duty or SDRT and transfers to others, for example, depositories and clearance service providers may give rise to a charge at a higher rate. Where Ordinary Shares are to be issued or transferred to a provider of depository receipts or clearance service arrangements specialist advice should be sought.

Stamp duty and SDRT are normally a liability of the purchaser or transferee (although where such purchase is effected through a stockbroker or other financial intermediary, that person should normally account for the liability to SDRT and should indicate this has been done in any contract note issued to a buyer).

The amount of stamp duty or SDRT payable on the transfer is generally calculated at the rate of 0.5 per cent. of the value or amount of the consideration paid (with stamp duty rounded up to the nearest £5) subject to an exemption for certain low value transactions. A liability to SDRT will be cancelled and any SDRT already paid will be repaid, generally with interest, where an instrument of transfer is executed and duly stamped within six years of the date on which the liability to SDRT arises.

Paperless transfers of the Ordinary Shares within the CREST system are generally liable to SDRT, rather than stamp duty, at the rate of 0.5 per cent. of the amount or value of the consideration payable. SDRT on relevant transactions is generally settled within the CREST system, collected and accounted for by Euroclear. Deposits of shares into CREST will generally not be subject to SDRT, unless the transfer into CREST is itself for money or money's worth.

20.4 *Taxation of chargeable gains*

(a) *UK resident shareholders*

A disposal of the Ordinary Shares by a shareholder who is (at any time in the relevant United Kingdom tax year) resident or, in the case of an individual, ordinarily resident in the United Kingdom for tax purposes, may give rise to a chargeable gain or an allowable loss for the purposes of United Kingdom taxation of chargeable gains, depending on the shareholder's circumstances and subject to any available exemption or relief.

As of 23 June 2010, the UK capital gains tax rate for higher rate taxpayers and trustees has increased from 18 per cent. to 28 per cent., as a result of the Emergency UK Budget of 22 June. Individuals whose total taxable income and gains are below the upper limit of the prevailing income tax basic rate band will, however, continue to pay capital gains tax at 18 per cent. Gains will continue to be calculated net of available capital losses and the annual exemption.

For individuals, Entrepreneurs' Relief may be available in respect of capital gains arising on 'material disposals of business assets', subject to various conditions being satisfied, including *inter alia* a minimum holdings requirement. Gains which qualify for Entrepreneurs' Relief are taxed at an effective rate of 10 per cent., subject to a 'lifetime' limit, which increased from £2 million to £5 million in the recent Budget, of gains that qualify for Entrepreneurs' Relief. The new lifetime limit of £5 million has taken effect from 23 June 2010. Complex rules will apply if the relief has previously been claimed. Individuals should seek specialist tax advice for further information.

For a shareholder within the charge to corporation tax, indexation allowance on the cost apportioned to the shares should be available to reduce the amount of chargeable gain realised on a subsequent disposal.

(b) *Non resident Shareholders*

A shareholder who is not resident in the United Kingdom for tax purposes but who carries on a trade, profession or vocation in the United Kingdom through a branch or agency (or, in the case of a non UK resident corporate shareholder, a permanent establishment) to which the Ordinary Shares are attributable will be subject to the same rules which apply to United Kingdom resident shareholders.

A shareholder who is an individual and who has, on or after 17 March 1998, ceased to be resident or ordinarily resident for tax purposes in the United Kingdom for a period of less than five complete years of assessment and who disposes of the Ordinary Shares during that period may also be liable, on his return, to United Kingdom taxation of chargeable gains (subject to any available exemption or relief).

For a shareholder within the charge to corporation tax, indexation allowance on the cost apportioned to the shares should be available to reduce the amount of chargeable gain realised on a subsequent disposal.

20.5 ***Inheritance tax***

The Ordinary Shares are assets situated in the UK for the purposes of UK inheritance tax. A gift of Ordinary Shares by, or on the death of, an individual Shareholder may (subject to certain exemptions and reliefs) give rise to a liability to UK inheritance tax even if the Shareholder is neither domiciled nor deemed to be domiciled in the UK. Residence status also has no relevance for UK inheritance tax purposes.

For inheritance tax purposes, a transfer of assets at less than full market value may be treated as a gift and particular rules apply to gifts where the donor reserves or retains some benefit. Special rules also apply to close companies and to trustees of settlements who hold shares, bringing them within the charge to inheritance tax. Shareholders should consult an appropriate tax adviser if they make a gift or transfer at less than market value or intend to hold any shares through trust arrangements.

21. General

- 21.1 The expenses of Acquisition are estimated at approximately US\$4.10 million and are payable by Afren.
- 21.2 The Group is dependent upon the exploration and production licences and agreements summarised in Part 1 of this Prospectus. The Directors believe that there are no patents, contracts or new manufacturing processes which are of fundamental importance to the Group's business or profitability.
- 21.3 The financial information contained in this Prospectus does not amount to statutory accounts within the meaning of Section 240 of the 1985 Act or Section 434 of the 2006 Act (as applicable).
- 21.4 Other than as disclosed in the financial statements incorporated by reference in this Prospectus and 14.1 and 14.3 of Part 10 of this Prospectus, Afren has no major encumbrances over any existing or planned material tangible, fixed assets.
- 21.5 Afren is a public limited company and is therefore subject to the City Code and in particular the mandatory takeover provisions in rule 9 of the City Code. In the event of takeover, the squeeze out provisions in Part 2, Chapter 3 of the 2006 Act would be applicable, subject to the offerer acquiring the requisite percentage of the share capital to which the offer relates.
- 21.6 Merrill Lynch International, of 2 King Edward Street, London EC1A 1HQ, United Kingdom is Afren's sponsor and broker and is authorised and regulated in the UK by the FSA.

22. Authorisations and consents

- 22.1 NSAI has given and not withdrawn its written consent to the issue of this Prospectus with the inclusion of the NSAI Report, and the mineral reserves and resources estimates set out in this Prospectus, in the form and context in which they appear, and has authorised the contents of the NSAI Report and the mineral reserves and resources estimates set out in this Prospectus, for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules and for the purpose of paragraph 23.1 of Annex I of the Prospectus Directive Regulation.
- 22.2 GCA has given and not withdrawn its written consent to the issue of this Prospectus with the inclusion of the GCA Report, and the mineral reserves and resources estimates set out in this Prospectus, in the form and context in which they appear, and has authorised the contents of the GCA Report and the mineral reserves and resources estimates set out in this Prospectus, for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules and for the purpose of paragraph 23.1 of Annex I of the Prospectus Directive Regulation.
- 22.3 McDaniel has given and not withdrawn its written consent to the issue of this Prospectus with the inclusion of the McDaniel Report, and the mineral reserves and resources estimates set out in this Prospectus, in the form and context in which they appear, and has authorised the contents of the McDaniel Report and the mineral reserves and resources estimates set out in this Prospectus, for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules and for the purpose of paragraph 23.1 of Annex I of the Prospectus Directive Regulation.
- 22.4 BDO has given and not withdrawn its written consent to the inclusion in the Prospectus of the BDO reports set out in Part B of Part 6 and Part C of Part 7 of this Prospectus in the form and context in which they appear, and has authorised the contents of such reports in this Prospectus, for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules and for the purpose of paragraph 23.1 of Annex I of the Prospectus Directive Regulation.
- 22.5 Deloitte has given and not withdrawn its written consent to the inclusion in this Prospectus of its Report on the Unaudited Pro Forma Financial Information set out in Part B of Part 8 of this Prospectus in the form and context in which it appears, and has authorised the contents of such report set out in this Prospectus, for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules and for the purpose of paragraph 23.1 of Annex I of the Prospectus Directive Regulation.

23. Auditors

Afren's auditors for the year ended 31 December 2009 were Deloitte LLP, a member of the Institute of Chartered Accountants in England and Wales, of 2 New Street Square, London EC4A 3BZ.

24. Competent Persons

NSAI, whose registered office is at 1601 Elm Street, Suite 4500, Dallas, Texas 75201-4754, United States, are petroleum consultants who provide a complete range of geological, geophysical and engineering services.

GCA, whose registered office is at Bentley Hall, Blacknest, Alton, Hampshire. GU34 4PU, United Kingdom, is a technical, commercial and management advisory firm which has provided advice to the international petroleum since 1962. The firm specializes in independent petroleum advice on resource evaluation and economic analysis.

McDaniel, whose registered office is at Suite 2200, 255 5th Avenue S.W., Calgary, AB T2P 3G6, Canada, are petroleum consultants who provide a complete range of geological, and petroleum engineering services.

25. Related party transactions

A summary of certain related party transactions is set out below:

Related Party Transactions

Trading Transactions

	<i>Purchase of goods/services</i>		<i>Amounts owed/(from) to related parties</i>	
	<i>Period ended</i>	<i>Year ended</i>	<i>Period ended</i>	<i>Year ended</i>
	<i>30.06.10</i>	<i>2009</i>	<i>30.06.10</i>	<i>2009</i>
	<i>US\$000's</i>	<i>US\$000's</i>	<i>US\$000's</i>	<i>US\$000's</i>
Energy Investment Holdings Ltd	244	3,092	(97)	–
St John Advisors	150	1,083	–	28
Tzell Travel Group	143	367	16	22
H' Art of Africa	–	69	–	–

In other respects, save as disclosed in paragraph 4 of Part 4, note 34 of the financial statements for the year ended 31 December 2008 incorporated by reference, note 35 (in relation to remuneration of key management personnel only and not relating to trading transactions that are as set out above) of the financial statements for the year ended 31 December 2009 incorporated by reference and paragraphs 7 and 8 of this Part 10, there were no related party transactions entered into during the period covered by the historical financial information in this Prospectus and up to the date of this Prospectus.

26. Sources of information

Certain information has been obtained from external publications and is sourced in this Prospectus where the information is included. Where information has been sourced from a third party, the Company confirms that this information has been accurately reproduced and that as far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading. Unless otherwise stated, such information has not been audited.

27. Documents available for inspection

Copies of the following documents may be inspected at the head office of Afren at Kinnaird House, 1 Pall Mall East, London SW1Y 5AU, during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) from the date of publication of this Prospectus until completion of the Acquisition:

- 27.1 the memorandum of association and Articles of Afren;
- 27.2 the audited consolidated accounts of the Group for the three financial years ended 31 December 2009, 31 December 2008, and 31 December 2007;
- 27.3 the audited consolidated accounts of Black Marlin Energy for the three financial years ended 31 December 2009, 31 December 2008 and 31 December 2007;
- 27.4 the unaudited interim financial information for Black Marlin for the three months ended 31 March 2010 and the reconciliation statement and the accountants' report in respect thereof;
- 27.5 the unaudited pro-forma financial information for the Enlarged Group;
- 27.6 the consent letters referred to in paragraph 22 above;
- 27.7 the accountants' reports in relation to the financial statements referred to in paragraph 27.2, 27.3 and 27.4 above;
- 27.8 the NSAI Report;
- 27.9 the GCA Report;

- 27.10 the McDaniel Report;
- 27.11 the Arrangement Agreement;
- 27.12 the Scheme Document; and
- 27.13 this Prospectus.

Date 24 August 2010

PART 11

NSAI REPORT ON AFREN

**ESTIMATE OF
RESERVES AND FUTURE REVENUE**

to the

AFREN PLC INTEREST

and

**ASSESSMENT OF
GROSS (100 PERCENT)
CONTINGENT AND UNRISKED
PROSPECTIVE RESOURCES**

in

CERTAIN OIL AND GAS PROPERTIES

located

**OFFSHORE NIGERIA, OFFSHORE CÔTE D'IVOIRE,
ONSHORE CONGO, OFFSHORE GABON,
OFFSHORE GHANA, AND IN
THE JDZ, OFFSHORE NIGERIA AND
SÃO TOMÉ AND PRÍNCIPE**

as of

JUNE 30, 2010

BASED ON PRICE AND COST PARAMETERS

specified by

AFREN PLC

NSAI
**NETHERLAND, SEWELL
& ASSOCIATES, INC.**

**WORLDWIDE PETROLEUM
CONSULTANTS
ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS**

August 24, 2010

Afren plc
Kinnaird House
1, Pall Mall East
London SW1Y 5AU
United Kingdom

Merrill Lynch International
Merrill Lynch Financial Centre
2 King Edward Street
London EC1A 1HQ
United Kingdom

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of June 30, 2010, to the Afren plc (Afren) interest in certain oil and gas properties located in Okoro and Ebok Fields, offshore Nigeria, and in Lion and Panthère Fields, offshore Côte d'Ivoire. Also as requested, we have assessed the gross (100 percent) contingent and unrisked prospective resources for discoveries and prospects located offshore Nigeria, offshore Côte d'Ivoire, onshore Congo, offshore Gabon, offshore Ghana, and in the Joint Development Zone (JDZ), offshore Nigeria and São Tomé and Príncipe. Monetary values shown in this report are expressed in United States dollars (\$) or millions of United States dollars (MM\$). This report is an update of our report dated March 31, 2010, which set forth our estimates as of December 31, 2009. The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE); definitions are presented immediately following this letter. Following the definitions is a list of abbreviations used in this report.

RESERVES

We have estimated the proved, probable, and possible reserves and future revenue, as of June 30, 2010, to the Afren interest in Okoro Field located in Oil Mining Lease (OML) 112 and Ebok Field located in OML 67, Gulf of Guinea, offshore Nigeria, and in Lion and Panthère Fields located in Block CI-11, offshore Côte d'Ivoire. The estimates of reserves and revenue in this report have been prepared using price and cost parameters specified by Afren, as discussed in subsequent paragraphs of this letter.

We estimate the oil and gas reserves and future net revenue to the Afren interest in these properties, as of June 30, 2010, to be:

Area/Field/Category	Afren Effective Working Interest Reserves Before Royalty		Net Entitlement Reserves ⁽¹⁾		Future Net Revenue (MM\$)	
	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Total	Present Worth at 10%
Offshore Nigeria						
Okoro Field						
Proved (1P)	9.3	(2)	7.6	(2)	214.4	191.6
Proved + Probable (2P)	13.5	(2)	11.0	(2)	330.1	283.1
Proved + Probable + Possible (3P)	16.9	(2)	13.8	(2)	419.7	348.9
Ebok Field						
Proved (1P)	43.5	(2)	38.0	(2)	863.7	673.7
Proved + Probable (2P)	62.0	(2)	53.8	(2)	1,209.1	878.9
Proved + Probable + Possible (3P)	76.7	(2)	66.4	(2)	1,540.8	1,039.1

Area/Field/Category	Afren Effective Working Interest Reserves Before Royalty		Net Entitlement Reserves ⁽¹⁾		Future Net Revenue (MM\$)	
	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Total	Present Worth at 10%
Offshore Côte d'Ivoire						
Lion and Panthère Fields						
Proved (1P)	0.4	10.4	0.3	5.7	22.9	23.6
Proved + Probable (2P)	0.7	17.0	0.4	10.0	34.5	34.0
Proved + Probable + Possible (3P)	0.9	25.0	0.5	14.5	61.2	51.9

⁽¹⁾ Net reserves are after deductions for royalty burdens.

⁽²⁾ Gas reserves are not included because there is currently no viable market for produced gas.

The oil reserves for offshore Nigeria include crude oil only; the oil reserves for offshore Côte d'Ivoire include crude oil and condensate. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved, probable, and possible reserves. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. The reserves shown in this report have been estimated using a combination of deterministic and probabilistic methods. The probability that the quantities of oil actually recovered will equal or exceed the estimated amounts is at least 90 percent for the proved (1P) reserves, at least 50 percent for the proved plus probable (2P) reserves, and at least 10 percent for the proved plus probable plus possible (3P) reserves. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

The estimates of reserves and future net revenue presented in this report have been calculated using spreadsheet economic models provided by Afren. Future net revenue is after deductions for all royalties and production sharing oil revenue, Petroleum Profit Tax, Education Tax, future capital costs, operating expenses, domestic market obligations, abandonment costs, and payments to net profits interests but before consideration of any income taxes. Estimates of pipeline revenue have been provided by Afren. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using oil and gas price parameters specified by Afren. The oil prices are based on the following Brent crude price schedule and are adjusted for crude handling, transportation fees, quality, and a regional price differential:

Period Ending	Oil Price (\$/Barrel)
12-31-2010	80.00
Thereafter	85.00

Gas produced from Block CI-11 is sold under two contracts, the Societe de Gestion du Patrimoine du Secteur de l'Electricite (SOGEP) Contract and the Societe Ivoirienne de Raffinage (SIR) Refinery Contract. Gas prices are based on a weighted average of the SOGEP contract price of \$4.00 per MMBTU and the calculated SIR refinery contract price that is based on the adjusted oil price. Gas prices are adjusted for energy content.

Operating costs used in this report are based on operating expense records of Afren for Lion and Panthère Fields and are based on estimates provided by Afren for Okoro and Ebok Fields. These costs include the overhead expenses allowed under joint operating agreements and production sharing contracts along with estimates of costs to be incurred at and below the field level. Headquarters general and administrative overhead expenses of

Afren are included to the extent that they are covered under joint operating agreements and production sharing contracts. As requested, operating costs are held constant throughout the lives of the properties.

Future capital costs used in this report are also based on estimates provided by Afren. These estimated capital costs have been reviewed and found to be reasonable based on our experience in the region. The capital cost estimates have been adjusted to model the 1P, 2P, and 3P development scenarios. Capital costs are included as required for new development wells, injection wells, production equipment, the acquisition of seismic data, and, with the exception of Ebok Field, field abandonment; Afren's economic model incorporates abandonment costs as part of the operating costs for Ebok Field. The future capital costs are held constant to the date of expenditure.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the Afren interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Afren receiving its net revenue interest share of estimated future gross gas production.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. Contingent resources estimates in this report are for discoveries located in Kudu, Eland, and Ibex Fields located in Block CI-01, offshore Côte d'Ivoire; the Obo Discovery, offshore Nigeria and São Tomé and Príncipe in JDZ Block 1; and Setu Field located in OML 112, Gulf of Guinea, offshore Nigeria, and are contingent upon (1) approval of a project that has yet to be sanctioned, (2) commitment of the license partners to develop the resources, (3) a submitted development plan approved by the appropriate authorities, and (4) demonstration of the economic viability of the project. If these contingencies are resolved, some portion of the contingent resources estimated in this report may be reclassified as reserves. This report does not include economic analysis for these discoveries. Based on analogous field developments, it appears that the best estimate contingent resources in this report have a reasonable chance of being commercial.

We estimate the gross (100 percent) original oil-in-place (OOIP) and contingent oil resources for these properties, as of June 30, 2010, to be:

Area	Gross (100 Percent) Volumes (MMBBL)					
	OOIP			Contingent Oil Resources		
	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Offshore Côte d'Ivoire	59.2	81.1	104.8	13.5	19.8	27.9
JDZ Block 1	80.8	123.4	173.8	24.4	42.5	67.0
Offshore Nigeria	5.1	6.3	8.0	1.1	1.5	2.0

We estimate the gross (100 percent) original gas-in-place (OGIP) and contingent gas resources for these properties, as of June 30, 2010, to be:

Area	Gross (100 Percent) Volumes (BCF)					
	OGIP			Contingent Gas Resources		
	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Offshore Côte d'Ivoire	105.7	160.1	237.0	66.2	101.5	152.4
JDZ Block 1 ⁽¹⁾	-	-	-	-	-	-
Offshore Nigeria ⁽¹⁾	-	-	-	-	-	-

⁽¹⁾ Gas resources are not included because there is currently no viable market for produced gas.

The oil resources shown include crude oil only. Oil volumes are expressed in MMBBL. Gas volumes are expressed in BCF at standard temperature and pressure bases. Gross resources in this report are 100 percent of the resources expected to be produced from the wells.

The contingent resources shown in this report have been estimated using a combination of deterministic and probabilistic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 90 percent for the low estimate, at least 50 percent for the best estimate, and at least 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively. The resources included herein have not been adjusted for commercial risk.

PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report indicate exploration opportunities and development potential in the event a petroleum discovery is made and should not be construed as reserves or contingent resources. Prospective resources are dependent upon successful exploration for petroleum and are assessed according to their chance of discovery. Prospective resources estimates in this report are for prospects located in La Noumbi Permit, onshore Congo; Kudu and Ibex Fields located in Block CI-01, offshore Côte d'Ivoire; Iris Marin and Ibekelia Licenses, offshore Gabon; Keta Block, offshore Ghana; JDZ Block 1; in Ebok Field, offshore Nigeria; OML 115, offshore Nigeria; and Oil Prospecting License (OPL) 310, offshore Nigeria. The PRMS defines a prospect as a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target and a lead as a project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. Our estimates of prospective resources are presented as unrisks resources volumes only. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisks best estimate prospective resources in this report have a reasonable chance of being commercial.

We estimate the gross (100 percent) OOIP and unrisks prospective oil resources for these properties, as of June 30, 2010, to be:

Area	Gross (100 Percent) Volumes (MMBBL)					
	OOIP			Unrisks Prospective Oil Resources		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Onshore Congo	521.5	1,025.9	1,744.0	114.6	251.6	481.9
Offshore Côte d'Ivoire	17.4	48.6	93.3	4.2	12.0	24.2
Offshore Gabon	282.0	390.3	513.2	52.5	97.3	159.4
Offshore Ghana	722.4	2,416.7	8,061.2	153.9	604.2	2,299.5
JDZ Block 1	734.1	1,003.0	1,348.5	229.4	350.1	518.4
Offshore Nigeria	812.2	1,552.1	2,516.6	304.4 ⁽¹⁾	584.5 ⁽¹⁾	972.4 ⁽¹⁾

⁽¹⁾ These prospective resources volumes include condensate associated with the OPL 310 prospective gas resources.

We estimate the gross (100 percent) OGIP and unrisks prospective gas resources for these properties, as of June 30, 2010, to be:

Area	Gross (100 Percent) Volumes (BCF)					
	OGIP			Unrisks Prospective Gas Resources		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Offshore Côte d'Ivoire	197.4	544.9	949.6	157.5	436.1	763.6
Offshore Nigeria	1,358.0	2,115.8	3,129.3	991.1	1,565.3	2,373.5

The oil resources shown include crude oil and condensate. Oil volumes are expressed in MMBBL. Gas volumes are expressed in BCF at standard temperature and pressure bases.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made, the probability that the unrisks quantities of oil and gas discovered will equal or exceed the estimated amounts is at least 90 percent for the low estimate, at least 50 percent for the best estimate, and at least 10 percent for the high estimate.

As requested, a geologic risk assessment was not conducted for these properties. Geologic risk of prospective resources addresses the probability of success for the discovery of petroleum; this risk analysis is conducted independently of probabilistic estimations of petroleum volumes and without regard to the chance of development. Principal risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Geologic risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revisions with further data acquisition or interpretation. Unrisks prospective resources are estimated ranges of recoverable oil and gas volumes assuming a petroleum discovery is made and are based on estimated ranges of undiscovered in-place volumes.

Each prospect, lead, or prospective reservoir was evaluated to determine probabilistic ranges of in-place and recoverable petroleum. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both prospect risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisks prospective resources are those volumes that could reasonably be expected to be recovered in the event of the successful exploration and development of these prospects or leads.

GENERAL INFORMATION

This report is an update of our previous detailed report as of December 31, 2009, dated March 31, 2010. As shown in the Table of Contents, we have included a Technical Discussion with an Executive Summary. The Technical Discussion section includes an overview of the new data available since our March 31, 2010, report, and a brief discussion of the impact these new data have had on the reserves and resources estimates. Included in the Figures section are pertinent maps, seismic lines, tables, and exhibits. Only major changes in the analysis and results since our March 31, 2010, report are detailed in this report.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Our estimates of future revenue do not include any salvage value for the lease and well equipment but do include Afren's estimates of the costs to abandon the wells, platforms, and production facilities.

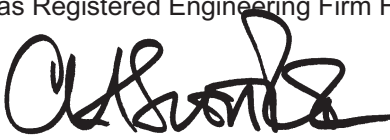
The reserves and resources shown in this report are estimates only and should not be construed as exact quantities. The reserves may or may not be recovered; if they are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, costs incurred, and actual production rates may vary from assumptions made while preparing this report. Estimates of reserves and resources may increase or decrease as a result of future operations, market conditions, or changes in regulations.

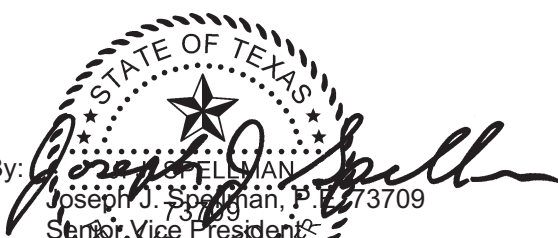
For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves and resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles. We used standard engineering and geoscience methods, or a combination of methods, such as performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to establish reserves and resources quantities and reserves and resources categorization that conform to the 2007 PRMS definitions and guidelines. A substantial portion of the offshore Nigeria reserves are for undeveloped locations and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; the contingent and prospective resources are for undeveloped locations. Therefore, these reserves and resources are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics; it may be necessary to revise these estimates as additional data become available. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be political, socioeconomic, legal or accounting, rather than engineering and geoscience. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

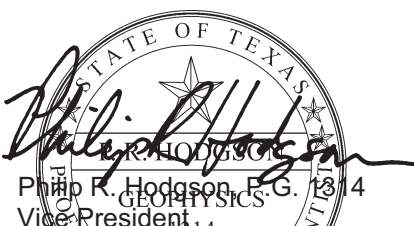
The contractual rights to the properties have not been examined by Netherland, Sewell & Associates, Inc. (NSAI), nor has the actual degree or type of interest owned been independently confirmed. The data used in our estimates were obtained from Afren and the nonconfidential files of NSAI and were accepted as accurate. Supporting geoscience, field performance, and work data are on file in our office. The technical persons responsible for preparing the reserves and resources estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties and are not employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-002699

By: 
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: 
Joseph J. Spelman, P.E. 73709
Senior Vice President
PROFESSIONAL ENGINEER
Date Signed: August 24, 2010

By: 
Philip R. Hodgson, P.G. 1314
Vice President
PROFESSIONAL GEOSCIENTIST
Date Signed: August 24, 2010

JJS:ABB

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of

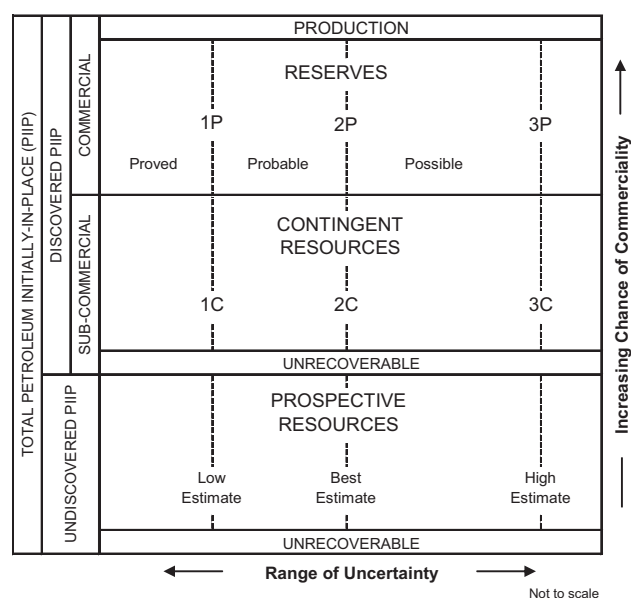


Figure 1-1: Resources Classification Framework.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

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

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

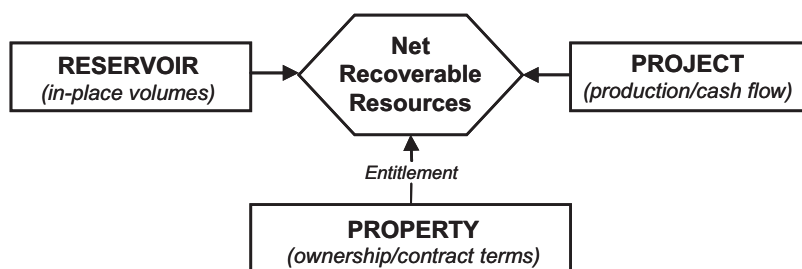


Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.
- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.
- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see

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Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

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For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

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Class/Sub-Class	Definition	Guidelines
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclassified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

The 2007 Petroleum Resources Management System can be viewed in its entirety at
<http://www.spe.org/spe-app/spe/industry/reserves/prms.htm>.

ABBREVIATIONS

\$	United States dollars
°F	degrees Fahrenheit
1C	low estimate scenario of contingent resources
1P	proved
1-S _w	hydrocarbon saturation
2C	best estimate scenario of contingent resources
2P	proved plus probable
3C	high estimate scenario of contingent resources
3P	proved plus probable plus possible
Afren	Afren plc
API	American Petroleum Institute
BBL/MMCF	barrels per million cubic feet
BCF	billions of cubic feet
B _g	gas formation volume factor
B _o	oil formation volume factor
BOPD	barrels of oil per day
CGR	condensate-gas ratio
cm ³	cubic centimeters
cp	centipoise
DHI	direct hydrocarbon indicator
DST	drillstem test
FB	Fault Block
FPSO	floating production, storage, and offloading
FSO	floating storage and offloading
ft	feet
FTT	formation testing tool
FVF	formation volume factor
GOC	gas-oil contact
GOR	gas-oil ratio
GRV	gross rock volume
GWC	gas-water contact
HKG	highest known gas
HKW	highest known water
JDZ	Joint Development Zone
km	kilometers
km ²	square kilometers
LKO	lowest known oil
m	meters
MBBL	thousands of barrels
MCFD	thousands of cubic feet per day
MD	measured depth
MDT	modular dynamic test
MM\$	millions of United States dollars
Mm ³	thousands of cubic meters
MMBBL	millions of barrels
MMCF	millions of cubic feet
MMCFD	millions of cubic feet of gas per day
MOPU	mobile production unit
MPN	Mobil Producing Nigeria

ABBREVIATIONS

ms	milliseconds
NNPC	Nigerian National Petroleum Corporation
NRV	net rock volume
NSAI	Netherland, Sewell & Associates, Inc.
NTG	net-to-gross ratio
OBM	oil-based mud
OGIP	original gas-in-place
OML	Oil Mining Lease
OOIP	original oil-in-place
OPL	Oil Prospecting License
Optimum	Optimum Petroleum Development Limited
Oriental	Oriental Energy Resources Limited
OWC	oil-water contact
PreSTM	pre-stack time migration
PRMS	Petroleum Resources Management System
Profit Oil	total volume of oil less the Cost Oil
psia	pounds per square inch absolute
PVT	pressure-volume-temperature
RB/STB	reservoir barrels per stock tank barrel
RCF/SCF	reservoir cubic feet per standard cubic foot
RMS	root mean square
SCF/STB	standard cubic feet per stock tank barrel
SIR	Societe Ivoirienne de Raffinage
S _o	oil saturation
SOGEP	Societe de Gestion du Patrimoine du Secteur de l'Electricite
SPE	Society of Petroleum Engineers
S _w	water saturation
TVD	true vertical depth
TVDSS	true vertical depth subsea
V _{sh}	shale volume
VSP	vertical seismic profile

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**TECHNICAL DISCUSSION
OFFSHORE NIGERIA, OFFSHORE CÔTE D'IVOIRE,
ONSHORE CONGO, OFFSHORE GABON, OFFSHORE GHANA, AND IN
THE JDZ, OFFSHORE NIGERIA AND SÃO TOMÉ AND PRÍNCIPE**

1.0 EXECUTIVE SUMMARY

We have estimated the proved, probable, and possible reserves and future net revenue, as of June 30, 2010, to the Afren plc (Afren) interest in certain oil and gas properties located in Okoro and Ebok Fields, offshore Nigeria, and in Lion and Panthère Fields, offshore Côte d'Ivoire. We have also assessed the gross (100 percent) contingent and unrisks prospective resources for certain discoveries and prospects located offshore Nigeria, offshore Côte d'Ivoire, onshore Congo, offshore Gabon, offshore Ghana, and in the Joint Development Zone (JDZ), offshore Nigeria and São Tomé and Príncipe (Figure 1). This report is an update of our report dated March 31, 2010, which set forth our estimates as of December 31, 2009. Please refer to the March 31, 2010, report for details on the properties with no new data; this report contains discussion and figures for the areas where new data were provided. The estimated reserves, contingent resources, and prospective resources for Afren's asset base are shown on Figures 2 and 3.

Afren's main producing assets are Okoro Field Oil Mining Lease (OML) 112, offshore Nigeria, and Lion and Panthère Fields, Block CI-11, offshore Côte d'Ivoire. As of June 30, 2010, Okoro Field had cumulative production of 11.4 million barrels (MMBBL) of oil and was producing at a rate of approximately 19,400 barrels of oil per day (BOPD) from 7 development wells. Lion and Panthère Fields had cumulative production of 33.0 MMBBL of oil and 339 billion cubic feet (BCF) of gas, as of June 30, 2010, and were producing at rates of 1,000 BOPD and 31 million cubic feet of gas per day (MMCFD) from 11 completions in 9 development wells.

Other key Afren assets include Ebok Field, OML 67, offshore Nigeria, and Ibex Field, Block CI-01, offshore Côte d'Ivoire. Ebok Field is currently undergoing advanced appraisal and development and is planned to be Afren's next producing asset. Ibex Field potentially contains a large volume of oil that will likely attract exploration/appraisal drilling by Afren in the near term.

Additional discovered fields owned by Afren include Setu Field, OML 112, offshore Nigeria; Kudu Field, Block CI-01, offshore Côte d'Ivoire; and Eland Field, Block CI-01, offshore Côte d'Ivoire. Afren also has a small working interest in the Obo Discovery, JDZ Block 1, offshore Nigeria and São Tomé and Príncipe that has potential in an emerging deepwater play area.

Afren's remaining assets are a mix of operated and nonoperated interests in large exploration license areas offshore Nigeria (OML 15), offshore Ghana, offshore Gabon, and onshore Congo.

Netherlands, Sewell & Associates, Inc. (NSAI) has been evaluating Afren's offshore West Africa properties since 2006, with numerous updates and new reports issued as Afren has drilled exploration, development, and appraisal wells and acquired new properties through acquisitions and farm-ins. We have always had complete and open access to Afren's technical databases and open interaction with its technical staff as we conduct our independent evaluations. Our independent evaluations of Afren's properties typically include, but are not limited to (1) interpretation of 2-D and 3-D seismic data in both the time and depth domain; (2) interpretation of well log data to confirm reservoir tops and to define reservoir zonation; (3) petrophysical modeling and analysis using NSAI-developed models and algorithms; (4) time-to-depth conversion (often with multiple realizations); (5) mapping and 3-D structural model building; (6) review and analysis of production data, production test information, reservoir pressure data, and fluid property data; (7) review and analysis of reservoir simulation models; (8) construction of deterministic-

probabilistic volumetric spreadsheets with Monte Carlo simulation; (9) economic evaluations of product flowstreams and development costs for reserves; and (10) screening economic analysis for selected contingent resources.

The estimates of reserves and resources presented in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). Contingent and prospective resources shown in this report should not be construed as reserves.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from discovered accumulations but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

The reserves and resources shown in this report have been estimated using a combination of deterministic and probabilistic methods; prospective resources are dependent on a petroleum discovery being made. For the reserves shown in this report, the probability that the quantities of oil actually recovered will equal or exceed the estimated amounts is at least 90 percent for the proved (1P) reserves, at least 50 percent for the proved plus probable (2P) reserves, and at least 10 percent for the proved plus probable plus possible (3P) reserves. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

For the contingent resources shown in this report, once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 90 percent for the low estimate, at least 50 percent for the best estimate, and at least 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as low estimate (1C), best estimate (2C), and high estimate (3C), respectively. The contingent resources included herein have not been adjusted for commercial risk.

For the prospective resources shown in this report, if a discovery is made, the probability that the unrisks quantities of oil and gas discovered will equal or exceed the estimated amounts is at least 90 percent for the low estimate, at least 50 percent for the best estimate, and at least 10 percent for the high estimate. Prospective resources are dependent upon successful exploration for petroleum and are assessed according to their chance of discovery and, assuming a discovery, are the estimated quantities, as of a given date, that would be recoverable under appropriate development projects. Unrisks prospective resources are estimated ranges of recoverable oil and gas volumes assuming a petroleum discovery is made and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of petroleum; this risk analysis is conducted independently of probabilistic estimations of petroleum volumes and without regard to the chance of development. Principal risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and architecture; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. As requested, a geologic risk assessment was not conducted for these properties.

**TECHNICAL DISCUSSION
OKORO, EBOK, AND SETU FIELDS
OML 115 AND OPL 310
NIGER DELTA, OFFSHORE NIGERIA AND
JDZ BLOCK 1, OFFSHORE NIGERIA AND SÃO TOMÉ AND PRÍNCIPE**

2.0 NIGERIA

2.1 NIGERIA OVERVIEW

We have estimated the proved, probable, and possible reserves and future revenue, to the Afren interest in certain properties in Okoro Field, located in OML 112, and Ebok Field located in OML 67, Gulf of Guinea, offshore Nigeria, as of June 30, 2010. We have also assessed the gross (100 percent) contingent and unrisked prospective resources for discoveries and prospects in Ebok Field, located in OML 67, Gulf of Guinea, offshore Nigeria; OML 115, offshore Nigeria; Oil Prospecting License (OPL) 310, offshore Nigeria; Setu Field, located in OML 112, Gulf of Guinea, offshore Nigeria; and JDZ Block 1, Gulf of Guinea, offshore Nigeria and São Tomé and Príncipe. Figure 4 shows the location of Ebok, Okoro, and Setu Fields and their respective lease areas, OML 115 and OPL 310 within the Gulf of Guinea, offshore Nigeria, and JDZ Block 1, offshore Nigeria and São Tomé and Príncipe. This report does not include economic analysis for the properties for which contingent and prospective resources have been assessed. As requested, a geologic risk assessment was not conducted for these properties. The estimates of reserves and resources presented in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 PRMS approved by the SPE. Contingent and prospective resources shown in this report should not be construed as reserves.

2.1.1 Data Sources

For our evaluation, Afren provided complete and open access to its current technical data for the fields and prospective areas as well as open interaction with its technical staff. The data provided included 2-D and 3-D seismic data; seismic horizon and fault interpretations in Seismic Micro-Technology, Inc. Kingdom format or Schlumberger Petrel format; well logs; drilling and test reports; volumetric estimates; development plans; and extensive reports and presentations by Afren, Afren's technical consultants, and Afren's joint venture partners. The raw and interpreted data provided us an extensive database with which to conduct our independent studies.

2.1.2 Geologic Setting

The Late Cretaceous and Early Tertiary history of the Niger Delta is characterized by tide- and river-dominated deltaic sediments deposited, respectively, during transgressive and regressive cycles on a now largely passive continental margin. After a major Paleocene transgression, the delta became dominantly a regressive system of southward- and southeastward-prograding deltaic sediments in a wave-dominated system.

The Niger Delta Tertiary section is divided into three main prograding formations: the marine-origin Akata Formation, the deltaic Agbada Formation, and the continental Benin Formation (Figure 5). The Akata Formation ranges in age from Paleocene to Early Miocene and is dominantly marine shales with some deepwater turbidite sands. The Agbada Formation ranges in age from Miocene to present in the Niger Delta and consists of delta-front to fluviodeltaic sandstones and shales characterized by generally strong,

parallel continuous reflectors on seismic data. The Benin Formation is found only onshore and in limited shallow marine regions of the Niger Delta. The reservoir ages for Ebok, Okoro, and Setu Fields and JDZ Block 1 are indicated on Figure 5.

2.1.3 General Technical Procedures

Our studies of these Nigeria fields and license areas and JDZ Block 1 were conducted in the following phases: (1) gather and review data and incorporate into new or existing NSAI databases; (2) review Afren-supplied interpretations, presentations, and reports; (3) independently interpret well logs and establish reservoir zoning; (4) conduct independent petrophysical analysis using NSAI models; (5) perform independent 2-D and 3-D seismic interpretation, mapping, and time-to-depth conversion; (6) as appropriate, construct Schlumberger Petrel format structural models; (7) review and analyze production information and production test, drillstem test (DST), and pressure-volume-temperature (PVT) data; (8) review any Afren-supplied ECLIPSE reservoir simulation models; (9) construct a deterministic-probabilistic volumetric spreadsheet using inputs from petrophysical analysis, mapping, and structural models; and (10) perform an economic evaluation of product flowstreams and development costs for reserves.

Reserves and resources have been estimated by interpreting a combination of 2-D and 3-D seismic data, well data, regional geologic data, and well performance and test data for key productive or potential reservoirs in each field or prospective area. As applicable, gross rock volume (GRV) data were derived in depth-volume format from Petrel 3-D structural models or from 2-D mapping in Landmark's Z-MAP Plus. In certain cases, GRV or net rock volume (NRV) was derived from manual reservoir mapping and planimetry. GRV and NRV are inputs into a Microsoft Excel spreadsheet with the Crystal Ball software add-in for Monte Carlo simulation. Other reservoir parameters include net-to-gross ratio (NTG), average reservoir porosity and hydrocarbon saturation ($1-S_w$), oil formation volume factor (B_o), gas formation volume factor (B_g), gas-oil ratio (GOR), condensate-gas ratio (CGR), and hydrocarbon recovery factor.

2.2 OKORO FIELD

We have assessed the gross (100 percent) original oil-in-place (OOIP) and proved, probable, and possible oil reserves, as of June 30, 2010, to the Afren interest for certain properties located in Okoro Field, OML 112, offshore Nigeria. Please refer to our March 31, 2010, report for the detailed discussion. Updated production performance data were provided and used to update our decline curve analysis. The results are summarized in the discussion below and on Figure 2.

2.2.1 Field Development

2.2.1.1 Development Plan

Afren and Amni International Petroleum Development Company Limited started producing from 7 development wells in Okoro Field by the end of 2008. For the purposes of this report, we have based development costs and flowstreams on the following development plan:

- Seven existing horizontal production wells from a single wellhead platform for the 1P and 2P scenarios.
 - Three wells in the Upper A Reservoir
 - One well in the Upper B Reservoir

- Two wells in the Lower B Reservoir
- One well in the Lower C Reservoir
- Two additional horizontal production wells from the same wellhead platform in the Lower B Reservoir scheduled to be drilled in the second half of 2010.
- Three-phase subsea flowlines run from the wellhead platform to a floating production, storage, and offloading (FPSO) vessel for processing; water injection and gas lift lines also run from the FPSO vessel to the wellhead platform. (Note that water injection well costs are not included in the capital cost estimates. The potential need for water injection will be evaluated once significant reservoir performance data are available.)
- Oil exported via shuttle tanker.
- Produced gas used for gas lift or consumed in operations.

2.2.1.2 Development Costs

Total sunk capital costs for the development plan through June 30, 2010, are \$320.5 million. Total remaining capital costs for the development plan based on the activities described in Section 2.2.1.1, as of June 30, 2010, are summarized in the following table:

<u>Capital Cost Item</u>	<u>Cost (MM\$)</u>
Sunk cost	320.5
FPSO vessel purchase	23.8
Two wells to Lower B Reservoir	49.4
Abandonment	25.0
Miscellaneous	0.6
Total	419.3

Average operating costs are summarized in the following table:

<u>Item</u>	<u>Cost (MM\$/Month)</u>
Total Expenses	5.4

Operating costs and capital costs used in this report are based on estimates provided by Afren. These estimated costs have been reviewed and found to be reasonable based on actual data provided by Afren and based on our experience in the region.

2.2.1.3 Flowstreams

Gross oil production flowstreams for the 1P, 2P, and 3P cases have been estimated based on the production scenario described in Section 2.2.1.1. Decline curve analysis based on individual well production performance data through May 2010, analog data from nearby fields, and the Afren Okoro simulation models were used as the basis for the flowstreams. The productivity of the reservoirs is estimated to be good, and the field has peaked at a rate of over 21,000 BOPD. The estimated total field production rate versus time is shown graphically and in tabulated form on Figures 6 and 7, respectively.

2.2.1.4 Cash Flow

The gross flowstreams described in Section 2.2.1.3 were loaded into the spreadsheet economic model provided by Afren. The economic model incorporates the development and operating costs, the Afren farmin provisions, and the Production Sharing and Technical Services Agreement terms. The spreadsheet calculates the estimated net barrels, future net revenue, and discounted future net revenue in Okoro Field. The Okoro cash flow results are based on economic parameters using oil prices specified by Afren. The oil prices are based on the following Brent crude price schedule and are adjusted for crude handling, transportation fees, quality, and a regional price differential:

Period Ending	Oil (\$/Barrel)
12-31-2010	80.00
Thereafter	85.00

Summary projections of reserves and revenue for the 1P, 2P, and 3P cases are shown on Figures 8, 9, and 10, respectively. The following table summarizes gross (100 percent) OOIP, cumulative production through June 30, 2010, total recovery, and remaining recovery; net oil reserves; and corresponding future net revenue for the developed sand units as of June 30, 2010:

Category	Gross (100 Percent) (MMBBL)				Net Oil Reserves (MMBBL)	Future Net Revenue (MM\$)	
	OOIP	Cumulative Production	Total Recovery	Remaining Recovery		Total	Present Worth at 10%
Proved (1P)	72.8	11.4	26.6	15.2	7.6	214.4	191.6
Proved + Probable (2P)	80.4	11.4	33.4	21.9	11.0	330.1	283.1
Proved + Probable + Possible (3P)	89.0	11.4	39.0	27.6	13.8	419.7	348.9

2.3 EBOK FIELD

We have estimated the proved, probable, and possible reserves, as of June 30, 2010, to the Afren interest in certain reservoirs in Ebok Field, located in OML 67, offshore Nigeria. We have also assessed the gross (100 percent) OOIP and unrisks prospective oil resources for eight reservoirs in certain undrilled fault blocks in Ebok Field. A map showing the location of OML 67 and Ebok Field is shown on Figure 4.

2.3.1 Overview

Ebok Field is located in OML 67, approximately 55 kilometers (km) offshore Nigeria in approximately 41 meters (m) of water (Figure 4). The field is delineated by 16 well penetrations and a 3-D seismic survey as a series of faulted, upthrown three-way closures on a large down-to-the-north normal fault (Figure 11). Sediments of the Upper Agbada Formation, shown on the stratigraphic column on Figure 5, are sourced from progradation of the Niger Delta and consist of a series of generally coarsening-upward, Pliocene age deltaic sandstones. The hydrocarbon source is the organic marine sediments of the underlying Akata Formation. Fault block nomenclature for Ebok Field is summarized on Figure 12. The Ebok-1 discovery well established the presence of oil in the Central E-1 Fault Block (FB) in the D-1, LD-1A, LD-1B, and D-2 Reservoirs. The Ebok-2 discovery well confirmed the presence of oil in the Central E-2/4 FB in the D-1 and LD-1A Reservoirs. The Ebok-3 well was an unsuccessful test for hydrocarbons along a small fault in the northern part of Ebok Field. The Ebok-4 appraisal/development well confirmed the presence of oil and gas in the D-1, LD-1A, LD-1B, and D-2 intervals and flowed significant oil to the surface during two

DSTs. The Ebok-5-ST2 well tested the West FB in a crestal position and confirmed the presence of oil in the amplitude-supported D-1 interval and discovered oil in the LD-1E and LD-1F intervals that had previously been found wet in Ebok Field. The Ebok-6 well drilled a strong seismic amplitude in the D-2 interval south of the main D-2 accumulation in the Central E-2/4 FB and discovered gas on oil in the D-2 in a pressure-separated compartment. Ebok-6 also contained oil in the LD-1A Reservoir; based on modular dynamic test (MDT) pressure interpretation, the LD-1A Reservoir may be in communication with the Central E-2/4 FB to the north. Five additional pilot wells, Ebok-9P, Ebok-10P2, Ebok-11P, Ebok-12P, and Ebok-13P, tested the main area of accumulations in the Central E-2/4 and Central E-1 FBs and generally confirmed hydrocarbon presence, fluid contacts, and reservoir thicknesses in the D-1, LD-1A, LD-1B, and D-2 intervals. Two deep exploration wells, Ebok-6-ST1 and Ebok-6-ST2, unsuccessfully targeted Biafra age reservoirs below and east of Ebok Central E-2/4 FB.

Figure 13 is a north-to-south well cross section linking the Ebok-5-ST2, Ebok-1, Ebok-4, and Ebok-6 wells and showing the D-1 through D-2 reservoir intervals and the D-1 oil-water contact (OWC) in the Central E-1 FB and Central E-2/4 FB. The development plan for Ebok Field develops all the discovered hydrocarbons through direct development drilling. Additional exploration and appraisal drilling at Ebok Field could also confirm significant prospective resources potential in adjacent amplitude-supported fault blocks, in updip but seismically dim areas of the field where reservoir presence is an uncertainty, or in deeper exploration potential for Qua Iboe or Biafra channel sandstones.

2.3.2 Lease Terms

In April 2008, Afren signed a farmout agreement with Oriental Energy Resources Limited (Oriental) for the development of Ebok Field. Oriental was awarded a 100 percent interest and operation of Ebok Field in May 2007 by the joint venture of ExxonMobil and Nigerian National Petroleum Corporation (NNPC). The farmout has been structured such that the field development benefits from the Nigerian Marginal Field Fiscal and Tax Regime. Under the terms of the agreement, Afren will be responsible for funding all capital and operating costs for the development of the field, and it will recover its costs from 100 percent of revenues, net of royalties, taxes, and operating costs. Following cost recovery, the ExxonMobil/NNPC joint venture will receive a net profits interest, with Afren and Oriental equally sharing in net production revenues.

2.3.3 Data

For our assessment, Afren provided complete and open access to its current technical data on Ebok Field as well as open interaction with its technical staff and outside consultants. The data provided included 3-D seismic data, time- and depth-domain interpreted horizons and faults, depth conversion models, well logs, drilling and test reports, technical reports and presentations by Afren and Weinman GeoScience, and development plans.

2.3.3.1 Well and Test Data

There are data from 16 Ebok Field wells, drilled by Mobil Producing Nigeria (MPN) and Afren, available for this study. The results of well tests and reservoir parameters are discussed in detail in subsequent sections of this report. Well drilling history, including total depth in feet (ft) true vertical depth subsea (TVDSS), and available test data are shown in the following table:

Well Name	Operator	Year of Completion	Total Depth (ft TVDSS)	Test Data
Ebok-1	MPN	1968	5,300	One open-hole formation testing tool (FTT) test and six cased-hole tests. At 3,717 ft measured depth (MD), recovered 8,300 cubic centimeters (cm ³) of 23.0° API gravity oil and 13.7 cubic ft of gas with a GOR of 260 standard cubic feet per stock tank barrel (SCF/STB); no DSTs.
Ebok-2	MPN	1970	4,234	No tests.
Ebok-3	MPN	1970	4,829	No tests.
Ebok-4	Afren	2008	3,838	One cased-hole and one open-hole DST. DST 2 in D-1 interval (2,580 to 2,690 ft MD) tested 96 BOPD of 20.0° API gravity oil with 1 percent water. DST 1 in D-2 interval (3,685 to 3,718 ft MD) tested over 1,400 BOPD of 25.0° API gravity oil with 1 percent water.
Ebok-5-ST2	Afren	2009	3,647	MDT.
Ebok-6	Afren	2009	4,213	MDT.
Ebok-6-ST1	Afren	2010	8,855	(Deep exploration well.) No tests.
Ebok-6-ST2	Afren	2010	9,955	(Deep exploration well.) No tests.
Ebok-8	Afren	2010	3,974	LD-1E well test.
Ebok-9P	Afren	2010	3,738	No tests.
Ebok-10P2	Afren	2010	3,758	No tests.
Ebok-11P	Afren	2010	3,716	No tests.
Ebok-12P	Afren	2010	3,695	No tests.
Ebok-12H	Afren	2010	3,592	No tests.
Ebok-13P	Afren	2010	3,850	No tests.
Ebok-15	Afren	2010	3,934	No tests.

2.3.3.2 Seismic Data

The 3-D seismic data for Ebok Field consist of approximately 75 square kilometers (km²) of generally good-quality, 1992-vintage post-stack time-migrated data, including near and far angle stacks for amplitude variation with offset analysis. Afren also provided several seismic volumes enhanced for interpretability using Schlumberger Petrel processing algorithms. Time-to-depth calibration of seismic data to wells is provided by a combination of modern vertical seismic profiles (VSPs) from the Ebok-4, Ebok-5-ST2, Ebok-6, Ebok-8, and Ebok-15 wells.

2.3.3.3 Reservoirs and Fluid Contacts

Ebok Field reservoir tops and bases are shown in the cross section on Figure 13. Fluid contacts are defined from well log interpretation and MDT pressure data. The reservoir and fluid contact data for each hydrocarbon reservoir interval, including lowest known oil (LKO), highest known water (HKW), gas-oil contact (GOC), and OWC, are shown in the table on Figure 14.

2.3.4 Volumetric Assessments

Our independent reservoir volumetric assessments for Ebok Field are based on integration of the well log data correlated for top and base reservoir depths (Figure 14) with the 3-D seismic data over the field. A relatively simple single-layer time-to-depth conversion method using the time-depth data from the Ebok-4, Ebok-5-ST2, Ebok-6, Ebok-8, and Ebok-15 wells was applied to convert our interpreted time structure horizons (D-1, LD-1A, LD-1E, D-2, Qua Iboe, and Biafra) into the depth domain. The resultant depth maps were integrated with seismic amplitude extractions to delineate and confirm areas of hydrocarbon

presence defined by the discovery, appraisal, and development well drilling and to identify prospective resources potential.

For the D-1, LD-1A, LD-1B, and LD-1F Reservoirs, GRV was determined by interpolating depth-volume curves derived from our Petrel structural model of the field in our probabilistic spreadsheet. For the more complex and amplitude-driven LD-1E and D-2 intervals, we used manual NRV mapping techniques followed by planimetry. For deeper prospects in the Qua Iboe and Biafra Reservoirs, amplitude areas defining prospect limits were planimetryed and combined with net reservoir thickness and a wedge or shape factor to create NRV.

Hydrocarbon contact ranges for the D-1 through D-2 Reservoirs in the Central, West, and surrounding fault blocks were estimated using GOC, OWC, and LKO information from the well log and MDT pressure data combined with seismic amplitude mapping.

Ranges of reservoir parameters of NTG, porosity, and water saturation (S_w) were determined from independent well log analysis (Figure 15) and Afren-provided well log analysis. Formation volume factor (FVF) estimates were based on the fluid analysis of samples taken from the Ebok-4 DSTs in the D-1 and D-2 Reservoirs and from the Ebok-5-ST2 MDTs in the LD-1E and LD-1F Reservoirs. Recovery factor estimates were based on a range of potential drive mechanisms using a combination of reservoir simulation modeling and regional field analogs. These parameters were combined with the GRV/NRV ranges in a probabilistic Monte Carlo spreadsheet to determine OOIP and reserves or prospective oil resources for each reservoir zone.

2.3.4.1 PVT Analysis

An MDT fluid sample was collected from the Ebok-4 well in the D-1 Reservoir at a depth of 2,597 ft TVDSS. This sample was contaminated, estimated at 4 percent, with oil-based mud (OBM). In addition, the sample bottle was not fully pressurized, indicating probable loss of vapor. Laboratory studies were conducted and results were adjusted to compensate for the difficulties with the sample. Increased uncertainty in the quality and applicability of the fluid properties of the D-1 Reservoir is a consequence of these difficulties even though appropriate compensation techniques were applied and results appear reasonable. The sample API gravity was measured at 18.3°.

	Measurements from MDT Sample	Corrected MDT Sample Data ⁽¹⁾
Saturation pressure (psia) ⁽²⁾	638	1,085
GOR (SCF/STB)	70	120
Oil viscosity (cp)	41	32
FVF (RB/STB)	1.082	1.098

⁽¹⁾ Correlation and extrapolation were used to extend saturation pressure to pressure measured at the GOC from that measured for assumed partially depleted sample.

⁽²⁾ Saturation pressure is at reservoir temperature.

Samples collected during DST 2 in the recent Ebok-4 well were found to be contaminated with diesel. Fluid samples were collected during the 1968 FTT test at a depth of 3,643 ft TVDSS in the D-2 Reservoir of the Ebok-1 well. No PVT analysis was provided for the 8,300-cm³ sample collected during this test. The GOR was estimated to be 260 SCF/STB with an API gravity of 24.2° at 82°F or 23.0° API gravity at 60°F. Initial results showed an estimated GOR of 315 SCF/STB and an API gravity of 24.4° at 79°F. These results led to characterizing the D-2 fluid with the nearby Okoro Field fluid that shows similar properties. Correlations were used to adjust the Okoro Field properties to the Ebok D-2 pressure and temperature. Uncertainty in the GOR increases uncertainty in the initial FVF and is reflected in the OOIP

estimates. Uncertainty in the viscosity, with an estimated range of 4 to 8 centipoise (cp), is reflected in the recovery factor ranges.

Two samples were collected from the LD-1E sand in the Ebok-5-ST2 well. Both contained OBM contamination. A fluid sample was also obtained from the LD-1F sand in the Ebok-5-ST2 well. While also exhibiting some OBM contamination, measurements showed it to be a lighter fluid, with higher API gravity, GOR, and bubblepoint pressure than other Ebok sand oils. Measured properties are summarized in the following table:

	LD-1E Sample 1	LD-1E Sample 2	LD-1F Sample 1
Sample depth (ft TVDSS)	2,995	3,057	3,326
Saturation pressure (psia) ⁽¹⁾	1,190	1,250	2,010
GOR (SCF/STB)	285	287	804
Oil viscosity (cp)	1.71	1.92	0.48
FVF (RB/STB)	1.16	1.16	1.41
API gravity (°)	32.4	29.9	41.0
OBM contamination (weight percent)	7.85	3.93	3.12

⁽¹⁾ Saturation pressure is at reservoir temperature.

2.3.4.2 Petrophysical Summary

Afren provided a comprehensive well log database ranging from wireline logs to logging while drilling data. We integrated the core and well log data and performed an independent petrophysical evaluation of all available Ebok Field wells using our proprietary three-component resistivity model, as shown on Figure 16 for the Ebok-4 D-1 interval. Our base case net pay cutoffs for porosity, shale volume (V_{sh}), and S_w are as follows:

Petrophysical Property	Excluded Range (decimal)
Porosity	<0.10
V_{sh}	>0.40
S_w	>0.60

Average reservoir characteristics for the sequences penetrated by wells, including thickness, are shown in the table on Figure 15.

2.3.4.3 Reserves Evaluation

We calibrated the Ebok-1, Ebok-4, Ebok-5-ST2, and Ebok-6 wells to seismic data using a 30-hertz reverse polarity Ricker wavelet, as shown on Figure 17. We interpreted the D-1, LD-1A, LD-1E, and D-2 horizons on a 10-inline-by-10-crossline grid, with associated normal faults interpreted at the same grid interval. Outside the Ebok Field area, a coarser 20-inline-by-20-crossline grid was used to complete the mapped area. Seismic lines on Figures 17 through 20 illustrate our independent horizon and fault interpretation of the field. We interpret the D-1 horizon to be a moderately continuous peak event (black on seismic), the LD-1A to be a strong and very continuous peak event (black on seismic), the LD-1E to be a discontinuous and variable trough or peak event (red or black on seismic), and the D-2 to be a moderately continuous peak-to-trough (black-to-red on seismic) zero crossing event. The resultant time and depth structure maps for the D-1, LD-1A, LD-1E, and D-2 Reservoirs at Ebok Field are shown on Figures 11 and 21 through 27. For time-to-depth conversion, we utilized a simple single-layer method

using a depth model that triangulated the time-depth data derived from the Ebok-4, Ebok-5-ST2, Ebok-6, Ebok-8, and Ebok-15 VSPs (Figure 28).

Our depth structure grids for the D-1, LD-1A, LD-1E, and D-2 Reservoirs were imported into Petrel along with depth-domain fault sticks and horizon picks to construct a structural model of the field (Figure 29). Depth-volume curves for Ebok Field were exported from Petrel and imported into our volumetric spreadsheet where GRV was interpolated from these curves using appropriate ranges of GOCs and OWCs.

2.3.4.3.1 *Seismic Amplitude Analysis*

The gas and oil columns in Ebok Field appear to be strongly supported by seismic amplitudes in the D-1 Reservoir, with reservoir sandstone presence strongly supported by seismic amplitudes in the LD-1E and D-2 Reservoirs, as shown on Figures 11, 25, and 27. We believe there is inconclusive or no amplitude support for known accumulations in the thinner LD-1A, LD-1B, and LD-1F Reservoirs. On Figure 11, the strongest amplitudes in the D-1 Reservoir are adjacent to and updip of the Ebok-4 well in the Central E-2/4 FB and appear to represent the thin gas zone encountered in the well. The D-1 Reservoir OWC at 2,640 ft TVDSS is also moderately well supported by amplitudes in the Central E-2/4 FB, while there is no apparent amplitude support in the West FB for the OWC at 2,490 ft TVDSS in the Ebok-5-ST2 well. On Figure 25, strong amplitude support is indicated in the West FB for the LD-1E oil accumulation discovered in the Ebok-5-ST2 well and confirmed downstructure by the Ebok-15 well. On Figure 27, the D-2 sand in the Central E-2/4 FB has been penetrated several times, with the presence of reservoir quality sandstone highly correlative with strong amplitudes.

2.3.4.3.2 *NRV Mapping*

Because of apparent, more complex stratigraphic variability in the LD-1E and D-2 Reservoirs in Ebok Field, we have mapped NRV deterministically using well thickness and amplitude as a guide, as shown on Figures 30 and 31. Figure 30 shows our low case NRV map for the LD-1E that terminates at the LKO in the Ebok-15 well at 3,361 ft TVDSS. For the high case, our NRV map (Figure 30) extends to the deep amplitude limit at 3,480 ft TVDSS that is coincident with the MDT pressure-defined OWC. Also, the Ebok-8 well encountered a thick LD-1E Reservoir downstructure from the Central E-4/2 FB in what appears to be an amplitude-supported stratigraphic trap, as shown on Figure 30.

Figure 31 shows our low case NRV map for the D-2 Reservoir, both for the main accumulation in the Central E-4/2 FB defined by the Ebok-2, Ebok-4, Ebok 8, Ebok-9P, Ebok-11P, Ebok-12P, Ebok-12H, and Ebok-13P wells and for the downdip, pressure-separated accumulation in the Central E-1 FB defined by the Ebok-1 and Ebok-10P2 wells. The Ebok-10P2 well established an OWC based on log analysis at 3,688 ft TVDSS that is shallower than the OWC range in the Central E-4/2 FB (see Figure 14), and the Ebok-12H suggests a shallower GOC than was seen in either the Ebok-11P or Ebok-4 wells (Figure 14). Figure 13 shows the downdip, pressure-separated accumulation discovered in the Ebok-6 well. Figure 31 also shows the associated high case NRV map for the D-2 Reservoir, and Figure 32 shows the gas caps for both accumulations. For the Ebok-6 downdip accumulation in the D-2 Reservoir, oil is not extended updip of the strong amplitudes, though this potential volume is classified as prospective resources and is discussed in subsequent sections.

2.3.4.3.3 *Probabilistic Reserves Estimations*

Probability ranges for recovery factors are based on expected drive mechanisms, fluid type, vertical hydrocarbon column height, depositional environments, reservoir simulation sensitivity studies, analogy to known fields with similar geologic and fluid characteristics, and development options. Ranges of input to our probabilistic spreadsheet for GRV or NRV, NTG, porosity, $1-S_w$, B_o , and recovery factor are shown in

the table on Figure 33 for the D-1, LD-1A, LD-1B, LD-1E, LD-1F, D-2, Qua Iboe, and Biafra Reservoirs of Ebok Field.

2.3.4.3.4 Reserves

The volumetric input parameters were combined in a probabilistic spreadsheet to derive our estimates of OOIP. The 1P, 2P, and 3P reserves have been estimated by defining a range of recovery factors based on our analysis of the approved field development plan and our knowledge of the Niger Delta region. Our estimates of the gross (100 percent) OOIP and 1P, 2P, and 3P reserves for the D-1, LD-1A, LD-1B, LD-1E, LD-1F, and D-2 Reservoirs in Ebok Field are shown in the table on Figure 34.

2.3.4.4 Prospective Resources Assessment

Our seismic interpretation, mapping, and time-to-depth conversion were described earlier in Section 2.3.4.3. Generally, deeper seismic horizons representing potential Qua Iboe and Biafra Reservoirs were interpreted locally and at a fairly coarse grid spacing (25-inline-by-25-crossline or coarser grid) on the Ebok 3-D seismic volumes. As with our assessment of reserves at Ebok Field, seismic amplitudes are used to identify and constrain the potential size of prospects as shown on D-1, LD-1A, LD-1E, and D-2 depth structure maps with root mean square (RMS) amplitude presented on Figures 11, 23, 25, and 27, respectively.

Significant prospective resources potential exists in several fault blocks and satellite structures adjacent to Ebok Field, as shown on Figures 11, 23, 25, and 27. The East FB is prospective for the D-1, LD-1A, LD-1B, LD-1E, and D-2 in structural and combination structural-stratigraphic traps downthrown from the main Ebok Field and the Ebok-3 well. The Southwest FB contains prospective resources potential primarily in the LD-1A, while the West FB (downdip) indicates prospective resources potential in an apparently unpenetrated lobe of LD-1E Reservoir sandstone. In the E-3 FB updip from the Ebok-3 well, we recognize prospective resources potential in the LD-1A and LD-1E Reservoirs, with additional LD-1E potential indicated in the North FB (Figure 25).

Deeper potential shown on Figure 35 was recently tested by the Ebok-6ST1 and Ebok-6ST2 exploration wells. Afren is still evaluating this potential, but based on our review of the exploration well results, we have removed the prospective resources volumes for Biafra Lead 1, Biafra Lead 2, Biafra Lead 3, and Biafra Lead 4 from this report. The only remaining Biafra prospective resources are in the East FB. Prospective resources potential for the Qua Iboe-aged sandstone is also indicated in the West and Southwest FBs (Figure 35).

2.3.4.4.1 Probabilistic Resources Estimations

Ranges of input to our probabilistic spreadsheet for GRV or NRV, NTG, porosity, $1-S_w$, B_o , and recovery factor are shown in the table on Figure 33 for the D-1, LD-1A, LD-1B, LD-1E, LD-1F, D-2, Qua Iboe, and Biafra Reservoirs of Ebok Field.

2.3.4.4.2 Prospective Resources

The volumetric input parameters were combined in a probabilistic spreadsheet to derive our estimates of OOIP. The prospective resources have been estimated by defining a range of recovery factors based on our analysis of the proposed field development plans and our knowledge of the Niger Delta region. Our estimates of the gross (100 percent) OOIP and prospective oil resources for the D-1, LD-1A, LD-1B, LD-1E, LD-1F, D-2, Qua Iboe, and Biafra Reservoirs in Ebok Field are shown in the table on Figure 34.

2.3.5 Field Development

Afren and its partners are in the process of executing the following development plan for Ebok Field reserves:

- Two 12-well wellhead platforms in the Central E-1 FB and Central E-2/4 FB.
- One 12-well wellhead platform in the West FB.
- Production through a mobile production unit (MOPU) with the following capacities:
 - 50,000 BOPD
 - 15 MMCFD
 - 25,000 barrels of water injection
- Floating storage and offloading (FSO) unit with 1 MMBBL of storage capacity.
- Eight horizontal producing wells in the Central FB D-1 Reservoir.
- Five horizontal producing wells in the West FB D-1 Reservoir.
- Five horizontal producing wells and two water injectors in the Central FB LD-1A Reservoir.
- Three horizontal producing wells in the Central FB LD-1B Reservoir.
- Five horizontal producing wells and one water injector in the West FB LD-1E Reservoir.
- Four horizontal producing wells and two water injectors in the Central FB D-2 Reservoir.
- One horizontal producing well in the West FB D-2 Reservoir.
- Two additional producing wells targeting the West FB LD-1F Reservoir and the central Ebok-6 area D-2 Reservoir (requires additional well slot capability in the West FB platform).
- One additional producing well targeting the Southwest FB LD-1E Reservoir that is not included in 1P development (requires additional well slot capability in the West FB platform).
- One additional producing well targeting the Central (Ebok-4/2) FB LD-1E Reservoir (requires additional well slot capability in the Central FB platform).
- One additional producing well targeting the Central (Ebok-1) FB LD-1E Reservoir that is not included in 1P development (requires additional well slot capability in the Central FB platform).

2.3.5.1 Development Costs

Total capital costs, including contingencies for the development, are summarized in the following table:

Item	MM\$
Sunk costs	239.4
Well costs (36 producing wells and 5 water injectors)	698.5 ⁽¹⁾
Three 12-well wellhead platforms	95.6
Flowlines and umbilicals	19.0
FSO/MOPU	21.0

Item	MM\$
Security and Environment, Health & Safety and Social Other (insurance, geologic, and geoscience)	8.0 6.8
Subtotal Capital Costs	1,088.3
Less sunk cost through June 30, 2010	239.4
Total Remaining Capital Costs as of June 30, 2010	848.9

⁽¹⁾ 34 producing wells and 5 water injectors for 1P well cost of MM\$658.5.

Average annual operating costs, including contingencies for the development plan, are summarized in the following table:

Item	MM\$/Year
MOPU and FSO vessel lease	38.0
Field operations	25.7
Security and community	3.5
Other	8.0
Total Expenses	75.2

Operating costs and capital costs used in this report are based on estimates provided by Afren. These estimated costs have been reviewed and found to be reasonable based on our experience in the region. Operating costs are held constant throughout the lives of the properties. Capital costs are held constant to the date of expenditure.

2.3.5.2 Flowstreams

Gross oil production flowstreams for the 1P, 2P, and 3P cases have been estimated based on the production scenarios described in Section 2.3.5. Reservoir simulation well productivity results and probabilistically determined ultimate recoveries, as well as analog data from nearby fields, were used as the basis for the flowstreams. The productivity of the reservoirs is estimated to be good; however, the D-1 has heavier 18° API oil. The table on Figure 34 summarizes, by reservoir and fault block, volumes in the 1P, 2P, and 3P cases. The estimated total field production rate versus time is shown graphically and in tabulated form on Figures 36 and 37, respectively. The volumetric recoverable estimates are adjusted in the cash flow analysis by the removal of uneconomic volumes.

2.3.5.3 Cash Flow

The gross flowstreams described in Section 2.3.5.2 were loaded into the spreadsheet economic model provided by Afren. The economic model incorporates the development and operating costs, the Afren farmin provisions, and the Production Sharing and Technical Services Agreement terms. The spreadsheet calculates the estimated net barrels, future net revenue, and discounted future net revenue in Ebok Field. The Ebok future net revenue results are based on economic parameters using an oil price specified by Afren. The oil prices are based on the following Brent crude price schedule and are adjusted for crude handling, transportation fees, quality, and a regional price differential:

Period Ending	Oil (\$/Barrel)
12-31-2010	80.00
Thereafter	85.00

The following table summarizes gross (100 percent) OOIP and total recovery, net oil reserves, and corresponding future net revenue for the developed sand units as of June 30, 2010:

Category	Gross (100 Percent) (MMBBL)		Net Oil Reserves (MMBBL)	Future Net Revenue (MM\$)	
	OOIP	Total Recovery		Total	Present Worth at 10%
Proved (1P)	269.8	65.9	38.0	863.7	673.7
Proved + Probable (2P)	370.7	101.5	53.8	1,209.1	878.9
Proved + Probable + Possible (3P)	461.5	136.6	66.4	1,540.8	1,039.1

As shown in the table above, the volumetric recoverable estimates are adjusted in the cash flow analysis. The unadjusted volumes are shown in the tables on Figures 34 and 37. Summary projections of reserves and revenue for 1P, 2P, and 3P cases are shown on Figures 38, 39, and 40, respectively.

2.4 OML 115

We have assessed the gross (100 percent) OOIP and unrisks prospective oil resources, as of June 30, 2010, for OML 115, located in the Niger Delta, offshore Nigeria, for Afren. Since there are no new data, please refer to the March 31, 2010, report for the detailed discussion. The results are summarized on Figure 3.

2.5 OPL 310

We have assessed the gross (100 percent) OOIP, original gas-in-place (OGIP), and unrisks prospective oil, gas, and condensate resources, as of June 30, 2010, for OPL 310 located in the Niger Delta, offshore Nigeria, for Afren. Since there are no new data, please refer to the March 31, 2010, report for the detailed discussion. The results are summarized on Figure 3.

2.6 SETU FIELD

We have assessed the gross (100 percent) OOIP and contingent oil resources, as of June 30, 2010, for certain properties located in Setu Field, OML 112, offshore Nigeria, for Afren. Since there are no new data, please refer to the March 31, 2010, report for the detailed discussion. The results are summarized on Figure 3.

2.7 JDZ BLOCK 1

We have assessed the gross (100 percent) OOIP, contingent oil resources, and unrisks prospective oil resources, as June 30, 2010, for JDZ Block 1, located in the Niger Delta, offshore Nigeria and São Tomé and Príncipe (Figure 4). Since there are no new data, please refer to the March 31, 2010, report for the detailed discussion. The results are summarized on Figure 3.

**TECHNICAL DISCUSSION
LION AND PANTHÈRE FIELDS, BLOCK CI-11 AND
KUDU, ELAND, AND IBEX FIELDS, BLOCK CI-01, OFFSHORE CÔTE D'IVOIRE**

3.0 OFFSHORE CÔTE D'IVOIRE

3.1 LION AND PANTHÈRE FIELDS

We have estimated the proved, probable, and possible reserves and future revenue, as of June 30, 2010, to the Afren interest in certain oil and gas properties located in Lion and Panthère Fields, Block CI-11, offshore Côte d'Ivoire. Please refer to the March 31, 2010, report for the detailed discussion. Updated production performance data were provided and used to update our decline curve analysis. The results discussed below are summarized on Figure 2.

3.1.1 Reserves and Future Net Revenue

3.1.1.1 Gross (100 Percent) Reserves

Volumetric and decline curve analysis and Petroleum Experts Limited's MBAL software predictions were used as the basis for the gross reserves. The productivity of the reservoirs is estimated to be very good. Summary graphs of gross historical and projected production are shown on Figures 41 and 42.

3.1.1.2 Net Reserves and Future Net Revenue

The gross reserves were loaded into the spreadsheet economic model provided by Afren. The economic model incorporates the future capital costs, operating costs, and the production sharing contract terms. The spreadsheet calculates the estimated net reserves, future net revenue, and discounted future net revenue in Block CI-11. The Block CI-11 net revenue results are based on economic parameters using oil and gas prices specified by Afren.

Summary projections of reserves and revenue for Block CI-11 are shown on Figures 43 through 45. We estimate the net reserves and future net revenue to the Afren interest in Block CI-11, as of June 30, 2010, to be:

Category	Net Reserves		Future Net Revenue (MM\$)	
	Oil (MMBBL)	Gas (BCF)	Total	Present Worth at 10%
Proved (1P)	0.3	5.7	22.9	23.6
Proved + Probable (2P)	0.4	10.0	34.5	34.0
Proved + Probable + Possible (3P)	0.5	14.5	61.2	51.9

As requested, this report has been prepared using oil and gas prices specified by Afren. The oil prices are based on the following Brent crude price schedule and are adjusted for crude handling, transportation fees, quality, and a regional price differential:

<u>Period Ending</u>	<u>Oil (\$/Barrel)</u>
12-31-2010	80.00
Thereafter	85.00

Gas produced from Block CI-11 is sold under two contracts, the Societe de Gestion du Patrimoine du Secteur de l'Electricite (SOGPE) Contract and the Societe Ivoirienne de Raffinage (SIR) Refinery Contract. Gas prices are based on a weighted average of the SOGPE contract price of \$4.00 per MMBTU and the calculated SIR refinery contract price that is based on the adjusted oil price. Gas prices are adjusted for energy content.

Operating costs used in this report are based on operating expense records of Afren. These costs include the overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the field level. Headquarters general and administrative overhead expenses of Afren are included to the extent that they are covered under joint operating agreements. As requested, operating costs are held constant throughout the lives of the properties. Capital costs are included as required for workovers and production equipment. The future capital costs are held constant to the date of expenditure.

3.2 KUDU, ELAND, AND IBEX FIELDS

We have assessed the gross (100 percent) original hydrocarbons-in-place and contingent resources, as of June 30, 2010, to the Afren interest in certain properties located in Kudu, Eland, and Ibex Fields, Block CI-01, offshore Côte d'Ivoire. Since there are no new data, please refer to the March 31, 2010, report for the detailed discussion. The results are summarized on Figure 3.

**TECHNICAL DISCUSSION
AFREN EXPLORATION LICENSES
OFFSHORE WEST AFRICA**

4.0 EXPLORATION LICENSES

4.1 LA NOUMBI PERMIT, ONSHORE CONGO

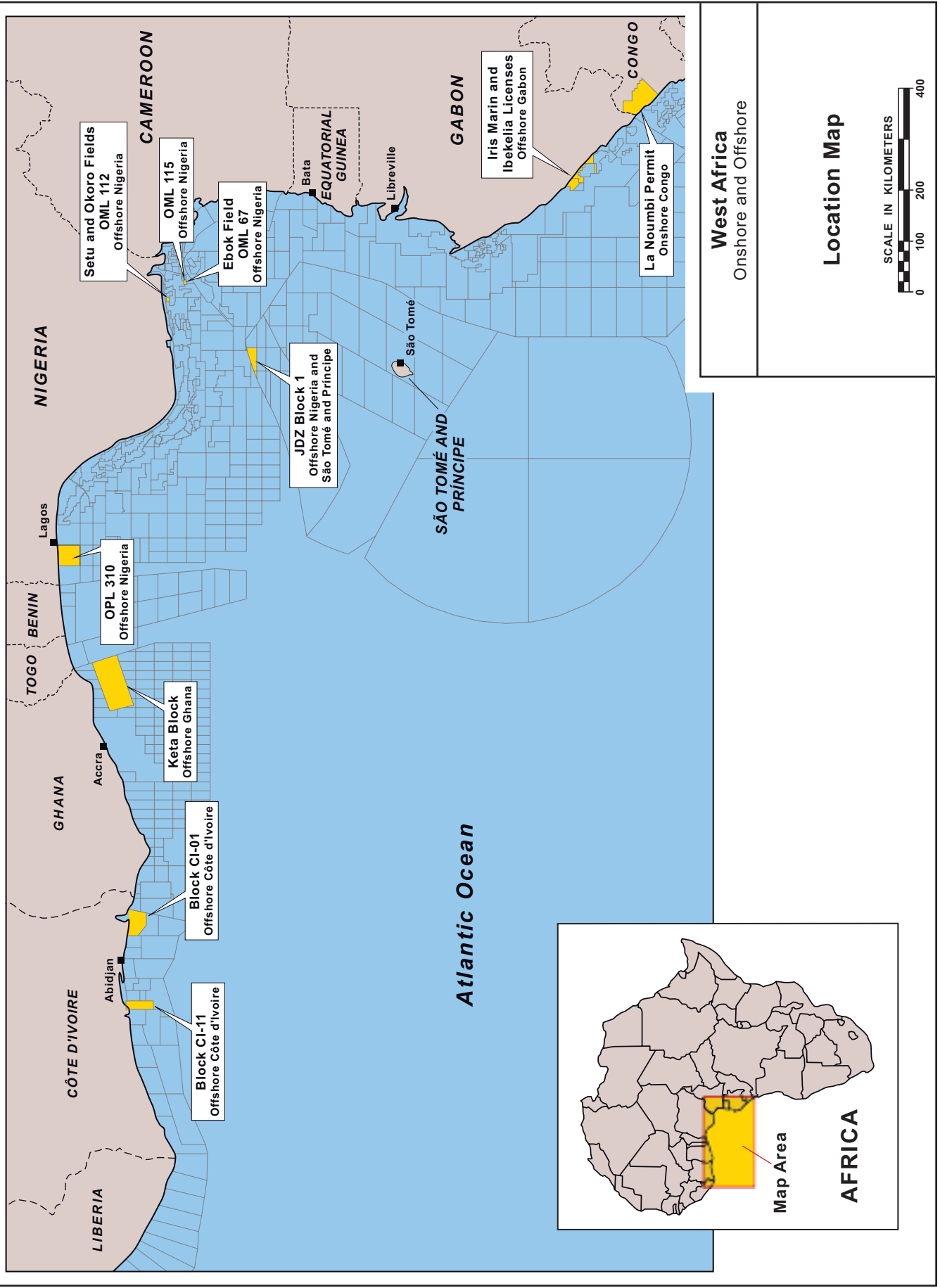
We have assessed the gross (100 percent) OOIP and unrisks prospective oil resources, as of June 30, 2010, for the La Noumbi Permit, located in the Congo Basin, onshore Congo (Brazzaville). The only revision to estimates shown in the March 31, 2010, report is the removal of the Tie-Tie Updip Prospect that was drilled unsuccessfully. Please refer to the March 31, 2010, report for the detailed discussion. The results are summarized on Figure 3.

4.2 IRIS MARIN AND IBEKELIA LICENSES, OFFSHORE GABON

We have assessed the gross (100 percent) OOIP and unrisks prospective oil resources, as of June 30, 2010, for the Iris Marin and Ibekelia Licenses, located in the Southern Gabon Subbasin, offshore Gabon. Since there are no new data, please refer to the March 31, 2010, report for the detailed discussion. The results are summarized on Figure 3.

4.3 KETA BLOCK, OFFSHORE GHANA

We have assessed the gross (100 percent) OOIP and unrisks prospective oil resources, as of June 30, 2010, for the Keta Block located offshore Ghana. Since there are no new data, please refer to the March 31, 2010, report for the detailed discussion. The results are summarized on Figure 3.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 1

SUMMARY OF OIL AND GAS RESERVES AND FUTURE NET REVENUE TO THE AFREN PLC INTEREST
OFFSHORE NIGERIA AND OFFSHORE CÔTE D'IVOIRE
AS OF JUNE 30, 2010

Area/Category	Gross (100 Percent) Reserves			Royalty Deduction (Percent)	Royalty Reserves		Gross (100 Percent) Reserves		After Effective Working Interest After Royalty (Percent)	After Effective Working Interest Reserves		After Effective Working Interest Reserves		Net Entitlement Reserves		Future Net Revenue (MM\$)	
	Oil (MMBBL)	Gas (BCF)	After Royalty (BCF)		Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)		Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Total	Present Worth at 10%		
Offshore Nigeria																	
Okoro Field																	
Proved (1P)	15.2	(1)		18.5	2.8	(1)	12.3	(1)	61	9.3	(1)	7.6	(1)	7.6	(1)	214.4	191.6
Proved + Probable (2P)	21.9	(1)		18.5	4.1	(1)	17.9	(1)	61	13.5	(1)	11.0	(1)	11.0	(1)	330.1	283.1
Proved + Probable + Possible (3P)	27.6	(1)		18.5	5.1	(1)	22.5	(1)	61	16.9	(1)	13.8	(1)	13.8	(1)	419.7	348.9
Ebok Field ⁽²⁾																	
Proved (1P)	65.9	(1)		12.4	8.2	(1)	57.7	(1)	66	43.5	(1)	38.0	(1)	38.0	(1)	863.7	673.7
Proved + Probable (2P)	101.5	(1)		12.9	13.1	(1)	88.4	(1)	61	62.0	(1)	53.8	(1)	53.8	(1)	1,209.1	878.9
Proved + Probable + Possible (3P)	136.6	(1)		13.0	17.7	(1)	118.9	(1)	56	76.7	(1)	68.4	(1)	68.4	(1)	1,540.8	1,039.1
Subtotal Offshore Nigeria																	
Proved (1P)	81.1	(1)		-	11.0	(1)	70.1	(1)	65	52.8	(1)	45.5	(1)	45.5	(1)	1,076.1	865.3
Proved + Probable (2P)	123.4	(1)		-	17.2	(1)	106.2	(1)	61	75.4	(1)	64.8	(1)	64.8	(1)	1,539.2	1,162.1
Proved + Probable + Possible (3P)	164.2	(1)		-	22.8	(1)	141.4	(1)	57	93.6	(1)	80.1	(1)	80.1	(1)	1,960.5	1,388.1
Offshore Côte d'Ivoire																	
Proved (1P)	0.9	21.7	0.0	0.0	0.0	0.0	0.9	21.7	48	0.4	10.4	0.4	10.4	0.3	5.7	22.9	23.6
Proved + Probable (2P)	1.4	35.5	0.0	0.0	0.0	0.0	1.4	35.5	48	0.7	17.0	0.7	17.0	0.4	10.0	34.5	34.0
Proved + Probable + Possible (3P)	1.9	52.1	0.0	0.0	0.0	0.0	1.9	52.1	48	0.9	25.0	0.9	25.0	0.5	14.5	61.2	51.9
Total All Properties																	
Proved (1P)	82.0	21.7	-	-	11.0	0.0	71.0	21.7	65	53.3	10.4	46.0	10.4	45.8	5.7	1,100.9	888.9
Proved + Probable (2P)	124.8	35.5	-	-	17.2	0.0	107.6	35.5	61	76.1	17.0	65.5	20.3	65.2	10.0	1,573.7	1,196.1
Proved + Probable + Possible (3P)	166.1	52.1	-	-	22.8	0.0	143.3	52.1	57	94.6	25.0	81.1	28.6	80.7	14.5	2,021.7	1,440.0

Totals may not add because of rounding.

⁽¹⁾ Gas reserves are not included because there is currently no viable market for produced gas.

⁽²⁾ Ebok Field volumetric 1P, 2P, and 3P estimates of 66.3, 103.1, and 139.8 MMBBL, respectively shown on Figure 34 are adjusted for economics.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2

*Rounds may not add because of rounding.

Figure 3
Page 1 of 4

- i) Totals are the sum of multiple arithmetic summations.
- ii) These prospective resources volumes include condensate associated with the OPL 310 prospective gas resources.
- iii) Resources estimates for the current Sels development include only Zone 1, Zone 3, and Zone 4.
- iv) Grand total is the combined arithmetic sum of multiple arithmetic summations.

Figure 3
Page 2 of 4

SUMMARY OF GROSS (100 PERCENT) OGP, OGIP, AND CONTINGENT AND UNRISKED PROSPECTIVE OIL AND GAS RESOURCES:
OFFSHORE NIGERIA, OFFSHORE COTE D'IVOIRE, ONSHORE GHANA, AND IN THE JOZ OFFSHORE NIGERIA AND SAO TOMÉ AND PRÍNCIPE
AS OF JUNE 30, 2010

Country/Area	Fault Block	Prospect/Lead	Reservoir	Discovered OGP (BCF)						Contingent Gas Resources (BCF)						Undiscovered OGP (MMBBL)						Unrisked Prospective Oil Resources (MMBBL)						Unrisked Prospective Gas Resources (BCF)																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																															
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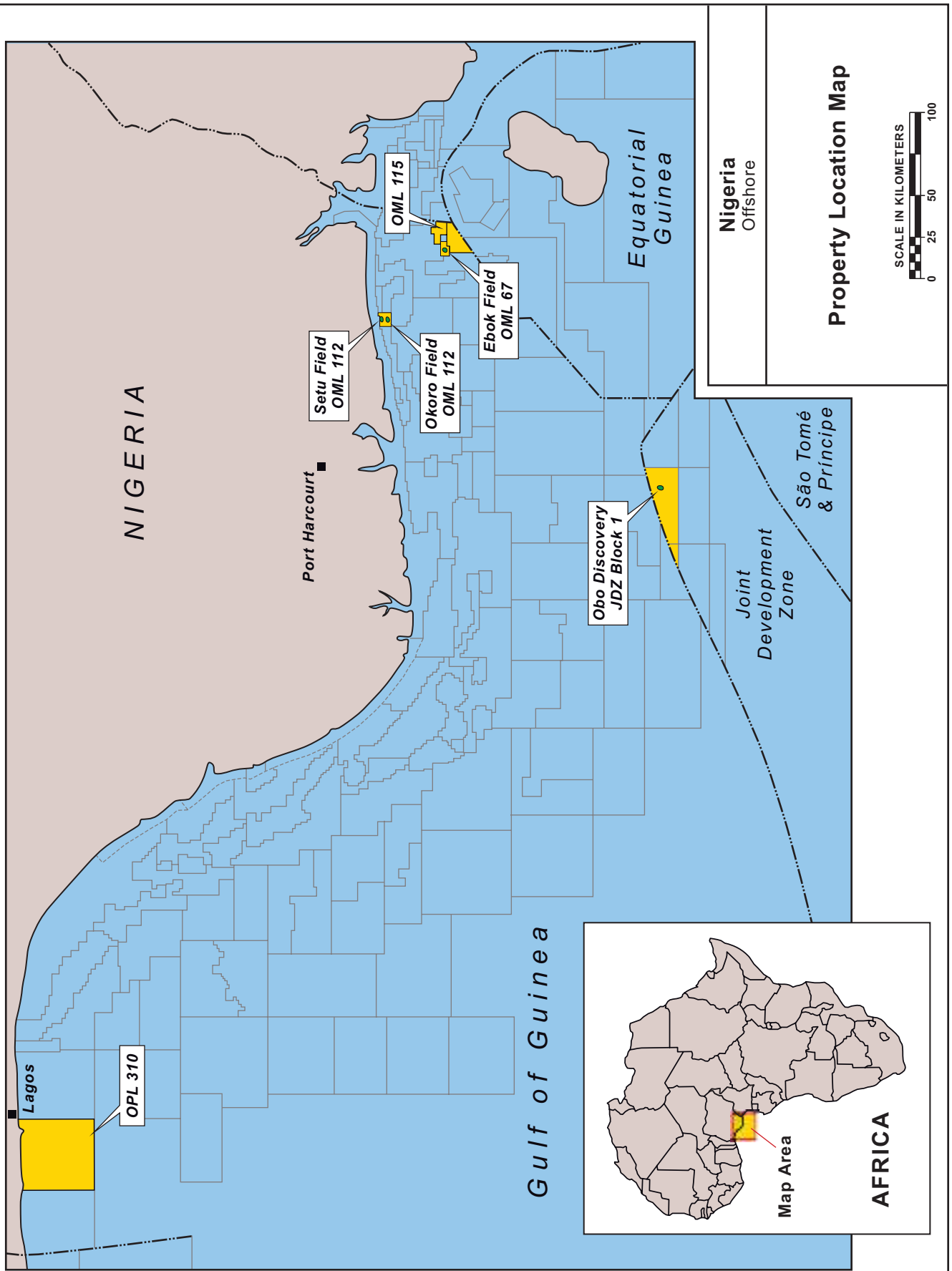
3. Totals are the sum of multiple arithmetic summations.

4. These prospective resources volumes include condensate associated with the OPL 310 prospective gas reservoir.

5. Resource estimates for the current Setu development include only Zone 1, Zone 3, and Zone 4.

6. Grand total is the combined arithmetic sum of multiple arithmetic summations.

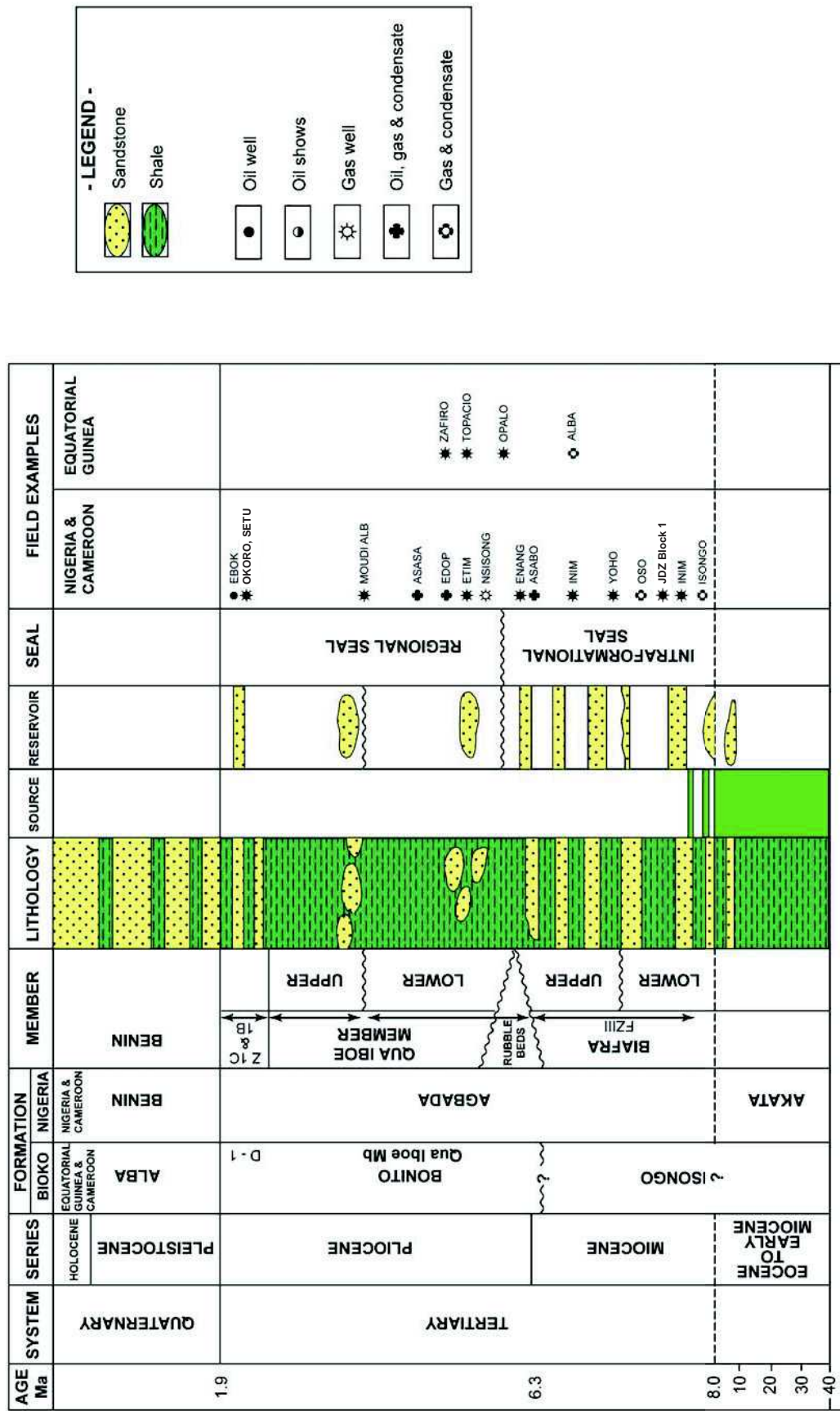
Figure 3
Page 4 of 4



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 4

Stratigraphic Column East Niger Delta Basin, Onshore and Offshore Nigeria



Adapted from a figure provided by Afren plc.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 5

GROSS (100 PERCENT) HISTORICAL AND PROJECTED OIL PRODUCTION
OKORO FIELD, OML 112, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

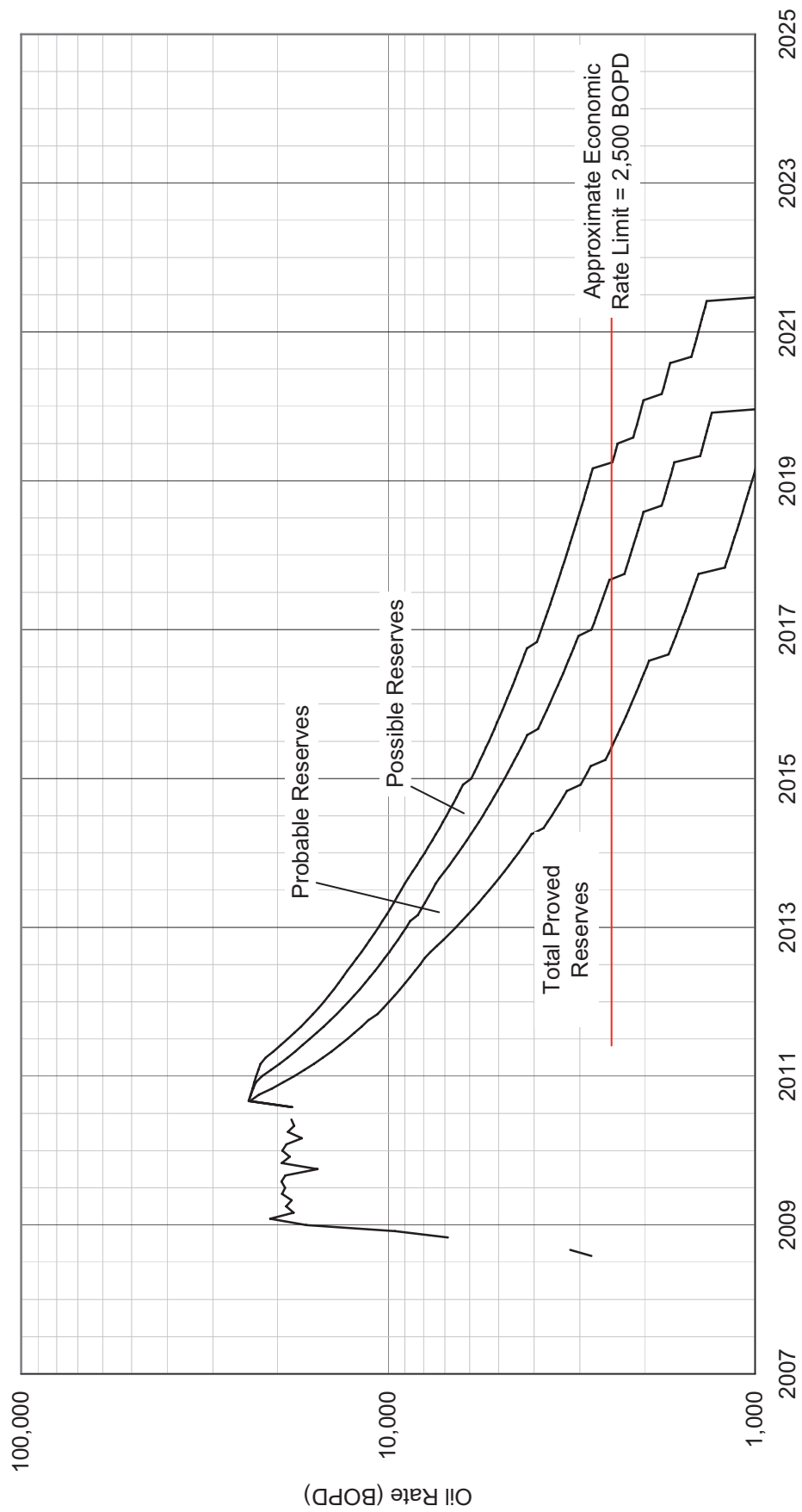


Figure 6 All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

ESTIMATED GROSS (100 PERCENT) OIL PRODUCTION
OKORO FIELD, OML 112, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

Year	Gross (100 Percent) Oil Production (Average Barrels Per Day)		
	1P	2P	3P
2010 ⁽¹⁾	20,437	22,376	22,571
2011	12,918	16,308	18,636
2012	8,049	10,482	12,432
2013	5,271	7,496	9,121
2014	3,581	5,489	6,875
2015	2,438	4,156	5,286
2016	1,885	3,246	4,306
2017	1,429	2,489	3,510
2018	1,090	1,948	3,024
2019	781	1,392	2,311
2020	575	738	1,650
2021	442	649	1,030
2022	269	571	703
2023	236	503	619
2024	192	258	545
2025	0	227	479
2026	0	136	422
2027	0	0	0
Remaining Recovery (MBBL)	18,022	24,556	30,016
Cumulative Production (MBBL)	11,424	11,424	11,424
Total Recovery ⁽²⁾ (MBBL)	29,446	35,980	41,440

⁽¹⁾ 2010 includes only estimated production from the as-of date of this report.

⁽²⁾ Total recovery is prior to economic analysis.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2010

AFREN PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN OKORO FIELD
OML 112, OFFSHORE NIGERIA

PROVED (1P) RESERVES

Period Ending	Gross Reserves		Effective Working Interest Before Royalties		Net Entitlement Reserves ⁽¹⁾		Gross Revenue to Net Interest		Gross Capital Cost ⁽³⁾ (MM\$)	Gross Operating Expense (MM\$)	Future Net Revenue (MM\$)	Cum P.W. at 10% (MM\$)
	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MM\$)	Gas ⁽²⁾ (MM\$)				
12-31-2010	3.7	-	2.3	-	1.9	-	103.8	-	49.8	43.2	57.8	56.1
12-31-2011	4.7	-	2.9	-	2.4	-	131.8	-	24.0	72.5	74.4	124.2
12-31-2012	2.9	-	1.8	-	1.5	-	70.8	-	0.0	67.1	50.3	166.1
12-31-2013	1.9	-	1.2	-	1.0	-	36.2	-	0.0	59.1	28.9	188.0
12-31-2014	1.3	-	0.8	-	0.7	-	14.6	-	0.0	59.1	14.3	197.8
12-31-2015	0.5	-	0.3	-	0.3	-	1.2	-	0.0	34.3	1.2	198.6
12-31-2016	0.0	-	0.0	-	0.0	-	0.0	-	25.0	0.0	(12.5)	191.6
12-31-2017	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	191.6
12-31-2018	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	191.6
12-31-2019	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	191.6
Total	15.2	-	9.3	-	7.6	-	358.3	-	98.8	335.2	214.4	191.6
Cum Prod	11.4											
Ultimate	26.6											

BASED ON AFREN PLC PRICE AND COST PARAMETERS

Totals may not add because of rounding.

⁽¹⁾ Net reserves include Afren plc's portion of cost and profit oil and gas.

⁽²⁾ These properties are not modeled in this report to have a commercial market for gas; produced gas will be consumed in operations or reinjected.

⁽³⁾ Abandonment costs are included as capital costs.

Figure 8

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2010

AFREN PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN OKORO FIELD
OML 112, OFFSHORE NIGERIA

PROVED + PROBABLE (2P) RESERVES

Period Ending	Gross Reserves		Effective Working Interest Before Royalties		Net Entitlement Reserves ⁽¹⁾		Gross Revenue to Net Interest		Gross Capital Cost ⁽³⁾ (MM\$)	Gross Operating Expense (MM\$)	Future Net Revenue (MM\$)	Cum P.W. at 10% (MM\$)
	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MM\$)	Gas ⁽²⁾ (MM\$)				
12-31-2010	4.1	-	2.5	-	2.0	-	115.9	-	49.8	43.2	67.6	65.6
12-31-2011	5.9	-	3.6	-	3.0	-	176.5	-	24.0	72.5	102.1	158.9
12-31-2012	3.8	-	2.3	-	1.9	-	102.9	-	0.0	67.1	70.1	217.2
12-31-2013	2.7	-	1.7	-	1.4	-	64.7	-	0.0	59.1	46.5	252.3
12-31-2014	2.0	-	1.2	-	1.0	-	39.0	-	0.0	59.1	30.3	273.1
12-31-2015	1.5	-	0.9	-	0.8	-	22.0	-	0.0	59.1	17.2	283.9
12-31-2016	1.2	-	0.7	-	0.6	-	10.3	-	0.0	59.1	7.9	288.4
12-31-2017	0.6	-	0.4	-	0.3	-	1.6	-	0.0	39.4	1.0	288.9
12-31-2018	0.0	-	0.0	-	0.0	-	0.0	-	25.0	0.0	(12.5)	283.1
12-31-2019	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	283.1
Total	21.9	-	13.5	-	11.0	-	532.8	-	98.8	458.5	330.1	283.1
Cum Prod	11.4											
Ultimate	33.4											

BASED ON AFREN PLC PRICE AND COST PARAMETERS

Totals may not add because of rounding.

⁽¹⁾ Net reserves include Afren plc's portion of cost and profit oil and gas.

⁽²⁾ These properties are not modeled in this report to have a commercial market for gas; produced gas will be consumed in operations or reinjected.

⁽³⁾ Abandonment costs are included as capital costs.

Figure 9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2010

AFREN PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN OKORO FIELD
OML 112, OFFSHORE NIGERIA

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

Period Ending	Gross Reserves		Effective Working Interest Before Royalties		Net Entitlement Reserves ⁽¹⁾		Gross Revenue to Net Interest		Gross Capital Cost ⁽³⁾ (MM\$)	Gross Operating Expense (MM\$)	Future Net Revenue (MM\$)	Cum P.W. at 10% (MM\$)
	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MM\$)	Gas ⁽²⁾ (MM\$)				
12-31-2010	4.1	-	2.5	-	2.1	-	117.2	-	49.8	43.2	68.6	66.5
12-31-2011	6.8	-	4.2	-	3.4	-	207.3	-	24.0	72.5	121.1	177.1
12-31-2012	4.5	-	2.8	-	2.3	-	128.6	-	0.0	67.1	86.0	248.6
12-31-2013	3.3	-	2.0	-	1.7	-	85.4	-	0.0	59.1	59.3	293.4
12-31-2014	2.5	-	1.5	-	1.3	-	56.7	-	0.0	59.1	41.2	321.7
12-31-2015	1.9	-	1.2	-	1.0	-	36.4	-	0.0	59.1	26.1	338.0
12-31-2016	1.6	-	1.0	-	0.8	-	23.9	-	0.0	59.1	16.2	347.2
12-31-2017	1.3	-	0.8	-	0.6	-	13.7	-	0.0	59.1	8.5	351.6
12-31-2018	1.1	-	0.7	-	0.6	-	7.5	-	0.0	59.1	4.6	353.8
12-31-2019	0.4	-	0.2	-	0.2	-	0.8	-	25.0	24.5	(12.0)	348.9
Total	27.6	-	16.9	-	13.8	-	677.6	-	98.8	561.8	419.7	348.9
Cum Prod	11.4	-	-	-	-	-	-	-	-	-	-	-
Ultimate	39.0	-	-	-	-	-	-	-	-	-	-	-

BASED ON AFREN PLC PRICE AND COST PARAMETERS

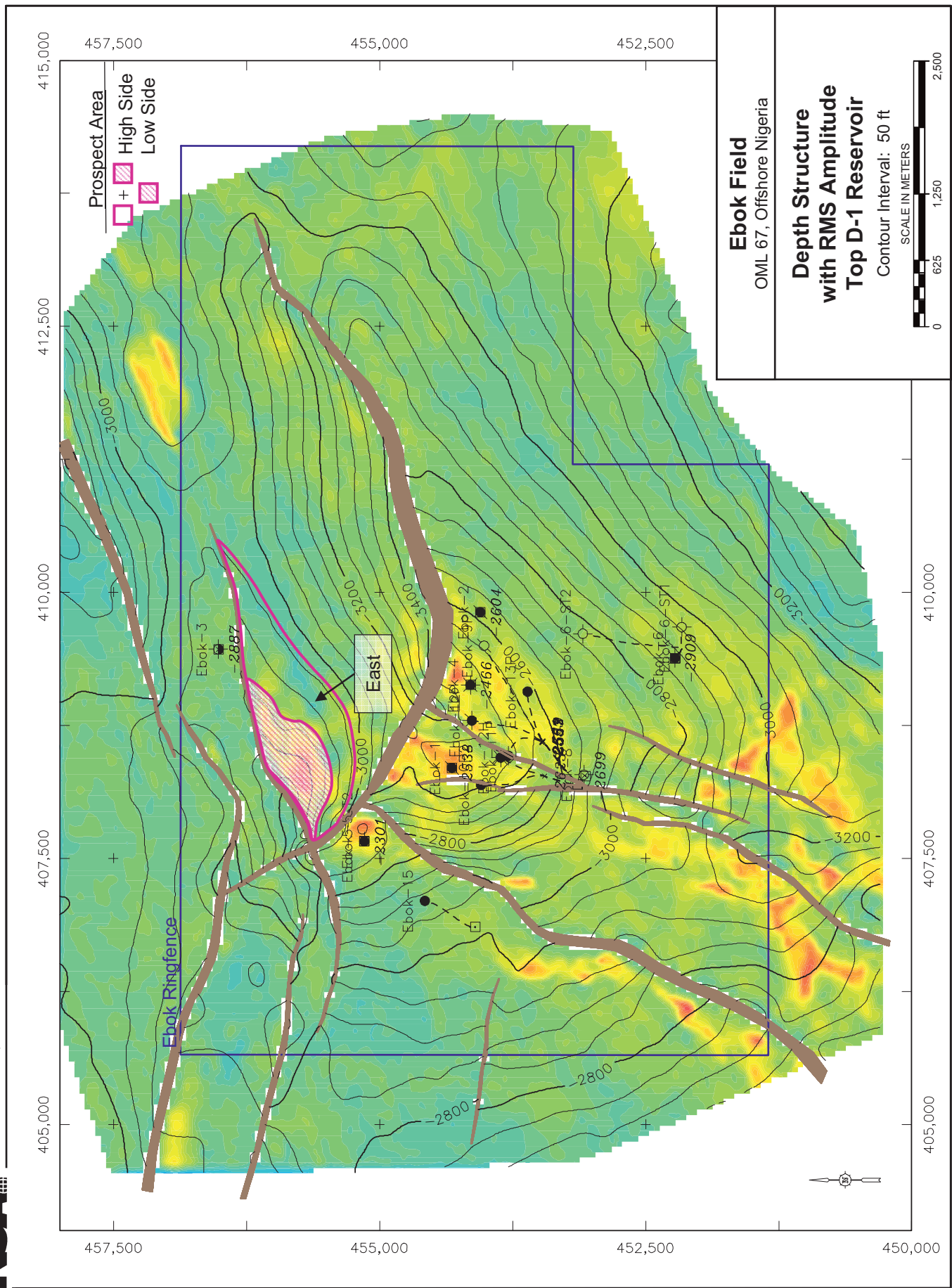
Totals may not add because of rounding.

⁽¹⁾ Net reserves include Afren plc's portion of cost and profit oil and gas.

⁽²⁾ These properties are not modeled in this report to have a commercial market for gas; produced gas will be consumed in operations or reinjected.

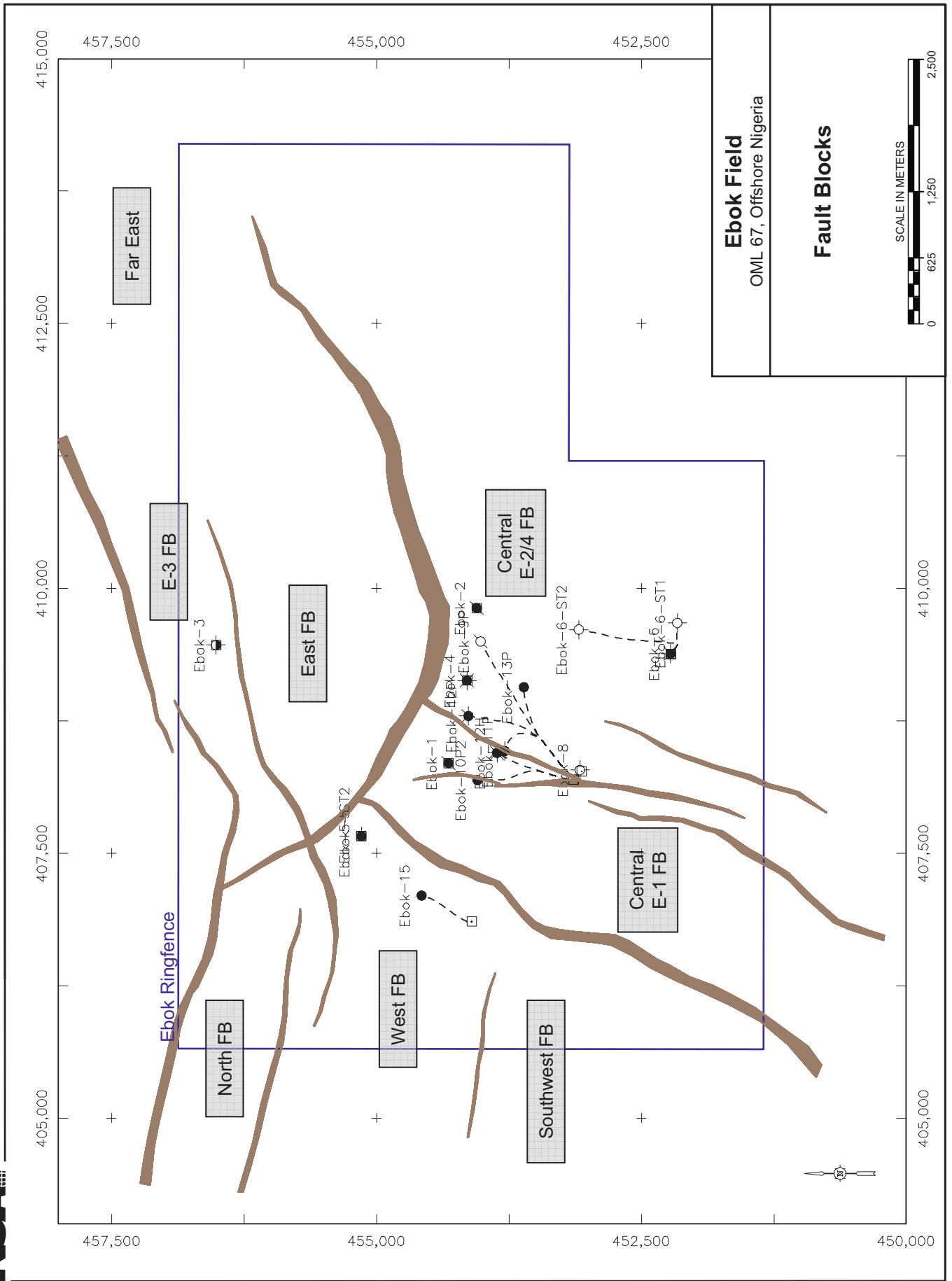
⁽³⁾ Abandonment costs are included as capital costs.

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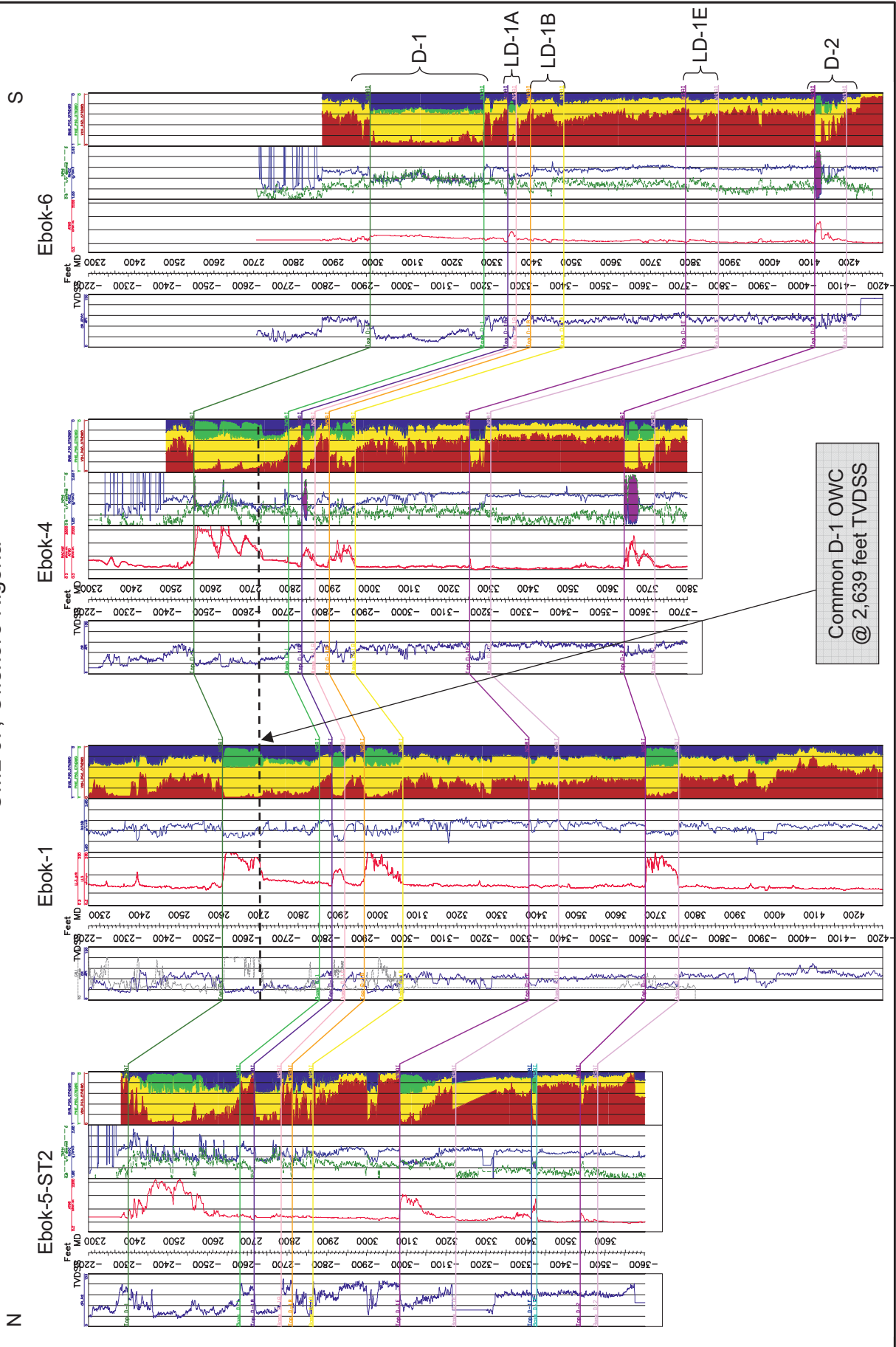
Figure 11



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 12

Well Cross Section
Ebok Field
OML 67, Offshore Nigeria



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 13

RESERVOIR AND FLUID CONTACTS
EBOK FIELD, OML 67, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

Reservoir/ Well Name	Fluid Type	Depth (ft TVDSS)		Fluid Contact (ft TVDSS)			
		Top	Base	LKO	HKW	GOC	OWC
D-1							
Ebok-1	Oil, Water	2,538	2,731				2,639
Ebok-2	Oil, Water	2,604	2,851				2,646
Ebok-3	Water	2,887	3,189		2,887		
Ebok-4	Gas, Oil, Water	2,466	2,704			2,470	2,640
Ebok-5-ST2	Oil, Water	2,301	2,583				2,490
Ebok-6	Water	2,909	3,196		2,909		
Ebok-8	Water	2,699	2,924		2,699		
Ebok-9P	Oil, Water	2,549	2,774				2,635
Ebok-10P2	Water	2,624	2,857		2,624		
Ebok-11P	Oil, Water	2,553	2,778				2,641
Ebok-12P	Oil, Water	2,551	2,769				2,636
Ebok-13P	Oil, Water	2,557	2,792				2,641
Ebok-15	Water	2,602	2,862		2,602		
LD-1A							
Ebok-1	Oil	2,815	2,846	2,846			
Ebok-2	Oil	2,920	2,951	2,951			
Ebok-3	Water	3,320	3,414		3,320		
Ebok-4	Gas, Oil	2,738	2,771	2,771		2,751	
Ebok-5-ST2	Water	2,619	2,686		2,619		
Ebok-6	Oil	3,256	3,278	3,278			
Ebok-8	Unknown ⁽¹⁾	2,961	2,974				
Ebok-9P	Oil	2,820	2,847	2,847			
Ebok-10P2	Water	2,902	2,928		2,902		
Ebok-11P	Oil	2,822	2,848	2,848			
Ebok-12P	Oil	2,811	2,834	2,834			
Ebok-13P	Unknown ⁽¹⁾	2,841	2,870				
Ebok-15	Water	2,906	2,974		2,906		
LD-1B							
Ebok-1	Oil	2,895	2,992	2,992			
Ebok-2	Water	2,988	3,047		2,988		
Ebok-3	Water	3,482	3,564				
Ebok-4	Oil	2,807	2,873	2,873			
Ebok-5-ST2	Water	2,715	2,766		2,715		
Ebok-6	Water	3,314	3,398		3,314		
Ebok-8	Water	2,999	3,037		2,999		
Ebok-9P	Water	2,879	2,952		2,887		
Ebok-10P2	Oil, Water	2,952	3,031				3,012
Ebok-11P	Water	2,887	2,966		2,887		
Ebok-12P	Oil, Water	2,874	2,952				2,885
Ebok-13P	Water	2,914	2,992		2,914		
Ebok-15	Water	3,012	3,072		3,012		

⁽¹⁾ Unknown means interval is too poorly developed to discern fluid type.

⁽²⁾ The lowest logged pay in Ebok-2 well is used in low estimate.

⁽³⁾ The lowest oil pay in Ebok-2 well is used in high estimate.

⁽⁴⁾ F/O stands for faulted out.

⁽⁵⁾ NP stands for not penetrated.

Figure 14
Page 1 of 2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

RESERVOIR AND FLUID CONTACTS
EBOK FIELD, OML 67, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

Reservoir/ Well Name	Fluid Type	Depth (ft TVDSS)		Fluid Contact (ft TVDSS)			
		Top	Base	LKO	HKW	GOC	OWC
LD-1E							
Ebok-1	Water	3,309	3,384		3,317		
Ebok-2	Water	3,453	3,530		3,453		
Ebok-3	Water	3,798	3,919		3,798		
Ebok-4	Water	3,161	3,214		3,161		
Ebok-5-ST2	Oil	2,985	3,126	3,075			
Ebok-6	Water	3,704	3,788		3,704		
Ebok-8	Oil	3,297	3,367	3,367			
Ebok-9P	Water	3,240	3,303		3,240		
Ebok-10P2	Water	3,295	3,365		3,295		
Ebok-11P	Water	3,187	3,218		3,187		
Ebok-12P	Water	3,148	3,210		3,148		
Ebok-13P	Water	3,214	3,290		3,214		
Ebok-15	Oil	3,284	3,398	3,361			
LD-1F							
Ebok-5ST2	Oil	3,317	3,330	3,330			
Ebok-15	Oil	3,545	3,608	3,608			
D-2							
Ebok-1	Oil	3,604	3,688	3,686			
Ebok-2	Oil	3,760	3,850	3,766 ⁽²⁾ /3,795 ⁽³⁾			
Ebok-3	Water	4,069	4,158				
Ebok-4	Gas, Oil	3,550	3,628	3,628		3,584	
Ebok-5-ST2	Oil	3,439	3,482	3,450			
Ebok-6	Gas, Oil	4,030	4,110	4,073		4,046	
Ebok-8	Water	3,769	3,813		3,769		
Ebok-9P	Oil	3,655	3,726	3,681			
Ebok-10P2	Oil, Water	3,604	3,699				3,688
Ebok-11P	Gas, Oil	3,553	3,649	3,649		3,577	
Ebok-12P	Gas	3,564	3,574			F/O ⁽⁴⁾	
Ebok-12H	Gas, Oil	3,539	NP ⁽⁵⁾			3,568	
Ebok-13P	Oil	3,682	3,721	3,721			
Ebok-15	Unknown ⁽¹⁾	3,733	3,776				

⁽¹⁾ Unknown means interval is too poorly developed to discern fluid type.

⁽²⁾ The lowest logged pay in Ebok-2 well is used in low estimate.

⁽³⁾ The lowest oil pay in Ebok-2 well is used in high estimate.

⁽⁴⁾ F/O stands for faulted out.

⁽⁵⁾ NP stands for not penetrated.

PETROPHYSICAL SUMMARY BY WELL
EBOK FIELD, OML 67, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

Reservoir/ Well	Fluid Type	Depth (ft TVDSS)		Thickness (ft TVD)		NTG ⁽¹⁾ (decimal)	Average Porosity (decimal)	Average V_{sh} (decimal)	Average S_w (decimal)
		Top	Base	Gross	Net Pay				
D-1									
Ebok-1	Oil, Water	2,538	2,731	192.7	101.0	192.7	0.38	0.04	0.16
Ebok-2	Oil, Water	2,604	2,851	246.7	93.0	166.1	0.38	0.11	0.46
Ebok-4	Gas, Oil, Water	2,466	2,704	237.9	168.5	236.9	0.33	0.08	0.17
Ebok-5-ST2	Oil, Water	2,301	2,583	281.5	145.5	245.2	0.31	0.10	0.14
Ebok-6	Water	2,909	3,196	287.0	0.0	287.0	—	—	—
Ebok-8	Water	2,699	2,924	224.8	0.0	224.8	—	—	—
Ebok-9P	Oil, Water	2,549	2,774	225.2	83.3	225.2	0.39	0.06	0.18
Ebok-10P2	Water	2,623	2,857	234.4	0.0	234.4	—	—	—
Ebok-11P	Oil, Water	2,553	2,778	224.4	85.1	224.4	0.39	0.06	0.17
Ebok-12P	Oil, Water	2,551	2,769	217.8	82.2	217.8	0.39	0.06	0.18
Ebok-13P	Oil, Water	2,557	2,793	235.9	111.3	225.4	0.39	0.05	0.25
Ebok-15	Water	2,602	2,862	260.0	0.0	259.3	—	—	—
LD-1A									
Ebok-1	Oil	2,815	2,846	31.4	28.0	31.4	0.39	0.07	0.33
Ebok-2	Oil	2,920	2,951	30.6	—	—	—	—	—
Ebok-4	Gas, Oil	2,738	2,771	33.3	27.5	33.3	0.34	0.12	0.32
Ebok-5-ST2	Water	2,619	2,686	67.1	0.0	64.7	—	—	—
Ebok-6	Oil	3,256	3,278	22.0	12.5	22.0	0.35	0.11	0.45
Ebok-8	Unknown ⁽²⁾	2,961	2,974	12.7	0.0	0.0	—	—	—
Ebok-9P	Oil	2,820	2,847	26.9	4.3	7.5	0.25	0.34	0.54
Ebok-10P2	Water	2,901	2,927	26.2	0.0	17.0	—	—	—
Ebok-11P	Oil	2,822	2,847	25.6	0.0	5.3	—	—	—
Ebok-12P	Oil	2,810	2,834	23.1	0.5	6.8	0.27	0.32	0.60
Ebok-13P	Unknown ⁽²⁾	2,841	2,870	29.4	0.0	0.0	—	—	—
Ebok-15	Water	2,905	2,974	68.8	0.0	67.0	—	—	—
LD-1B									
Ebok-1	Oil	2,895	2,992	97.4	87.0	97.4	0.35	0.08	0.22
Ebok-2	Water	2,988	3,047	59.6	—	—	—	—	—
Ebok-4	Oil	2,807	2,873	65.9	53.0	65.4	0.32	0.18	0.26
Ebok-5-ST2	Water	2,714	2,766	52.1	—	33.5	—	—	—
Ebok-6	Water	3,314	3,398	83.4	0.0	9.0	—	—	—
Ebok-8	Water	2,998	3,037	39.0	0.0	22.3	—	—	—
Ebok-9P	Water	2,879	2,952	72.6	0.0	38.6	—	—	—
Ebok-10P2	Oil, Water	2,952	3,030	78.5	37.6	78.5	0.35	0.09	0.24
Ebok-11P	Water	2,887	2,966	79.1	0.0	56.8	—	—	—
Ebok-12P	Oil, Water	2,874	2,952	78.1	3.4	39.5	0.38	0.11	0.47
Ebok-13P	Water	2,914	2,992	77.9	0.0	51.2	—	—	—
Ebok-15	Water	3,012	3,071	59.1	0.0	59.1	—	—	—

⁽¹⁾ NTG is net pay divided by gross in fully hydrocarbon-bearing intervals and net sand divided by gross in partially hydrocarbon-bearing intervals and water-bearing intervals.

⁽²⁾ Unknown means interval is too poorly developed to discern fluid type.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 15
Page 1 of 2

PETROPHYSICAL SUMMARY BY WELL
EBOK FIELD, OML 67, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

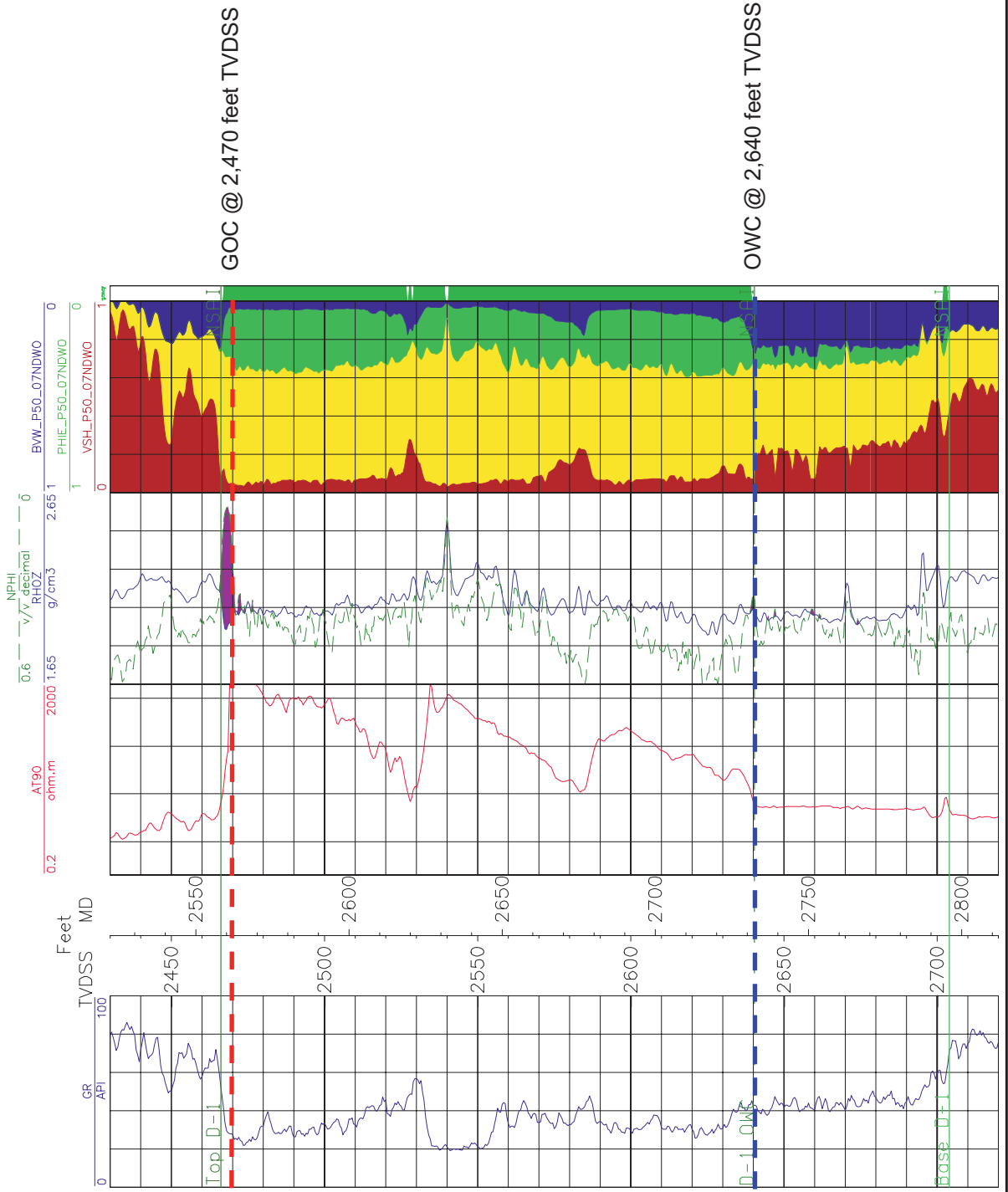
Reservoir/ Well	Fluid Type	Depth (ft TVDSS)		Thickness (ft TVD)		NTG ⁽¹⁾ (decimal)	Average Porosity (decimal)	Average V_{sh} (decimal)	Average S_w (decimal)
		Top	Base	Gross	Net Pay				
LD-1E									
Ebok-1	Water	3,309	3,384	74.7	0.0	74.7	1.00	-	-
Ebok-2	Water	3,453	3,530	76.6	-	-	-	-	-
Ebok-4	Water	3,161	3,214	52.7	0.0	36.5	0.69	-	-
Ebok-5-ST2	Oil	2,985	3,126	140.9	72.1	84.6	0.51	0.16	0.19
Ebok-6	Water	3,704	3,788	83.7	0.0	0.0	0.00	-	-
Ebok-8	Oil	3,267	3,366	99.6	85.0	98.8	0.85	0.11	0.16
Ebok-9P	Water	3,240	3,303	62.8	0.0	56.4	0.90	-	-
Ebok-10P2	Water	3,295	3,365	69.8	0.0	31.4	0.45	-	-
Ebok-11P	Water	3,187	3,218	30.2	0.0	30.1	1.00	-	-
Ebok-12P	Water	3,148	3,210	61.7	0.0	14.6	0.24	-	-
Ebok-13P	Water	3,214	3,290	76.5	0.0	30.2	0.39	-	-
Ebok-15	Oil	3,284	3,398	113.4	65.2	106.8	0.51	0.08	0.46
LD-1F									
Ebok-5-ST2	Oil	3,316	3,330	13.9	11.0	12.0	0.79	0.13	0.18
Ebok-15	Oil	3,545	3,608	63.2	62.3	63.2	0.99	0.15	0.23
D-2									
Ebok-1	Oil	3,604	3,686	84.0	81.8	84.0	0.97	0.08	0.14
Ebok-2	Oil	3,760	3,850	90.2	-	-	-	-	-
Ebok-4	Gas, Oil	3,550	3,628	77.3	68.0	74.9	0.88	0.09	0.23
Ebok-5-ST2	Oil	3,439	3,483	43.3	3.0	5.0	0.07	0.37	0.49
Ebok-6	Gas, Oil	4,030	4,110	80.0	30.6	48.1	0.38	0.10	0.28
Ebok-8	Water	3,768	3,814	45.7	0.0	0.0	0.00	-	-
Ebok-9P	Oil	3,655	3,726	70.8	19.3	19.3	0.27	0.17	0.17
Ebok-10P2	Oil, Water	3,603	3,698	94.9	83.5	94.9	1.00	0.08	0.13
Ebok-11P	Gas, Oil	3,553	3,649	96.2	95.1	95.9	0.99	0.08	0.12
Ebok-12P	Gas	3,564	3,574	9.9	8.4	8.8	0.84	0.07	0.28
Ebok-13P	Oil	3,683	3,721	38.3	36.8	37.8	0.96	0.12	0.19
Ebok-15	Unknown ⁽²⁾	3,733	3,776	43.0	-	-	-	-	-

⁽¹⁾ NTG is net pay divided by gross in fully hydrocarbon-bearing intervals and net sand divided by gross in partially hydrocarbon-bearing intervals and water-bearing intervals.

⁽²⁾ Unknown means interval is too poorly developed to discern fluid type.

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Ebok-4 Well Petrophysical Analysis of D-1 Reservoir Ebok Field OML 67, Offshore Nigeria



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 16

Seismic Calibration – Arbitrary Line through Ebok-5-ST2, Ebok-1, Ebok-4, and Ebok-6 Wells
Ebok Field
OML 67, Offshore Nigeria

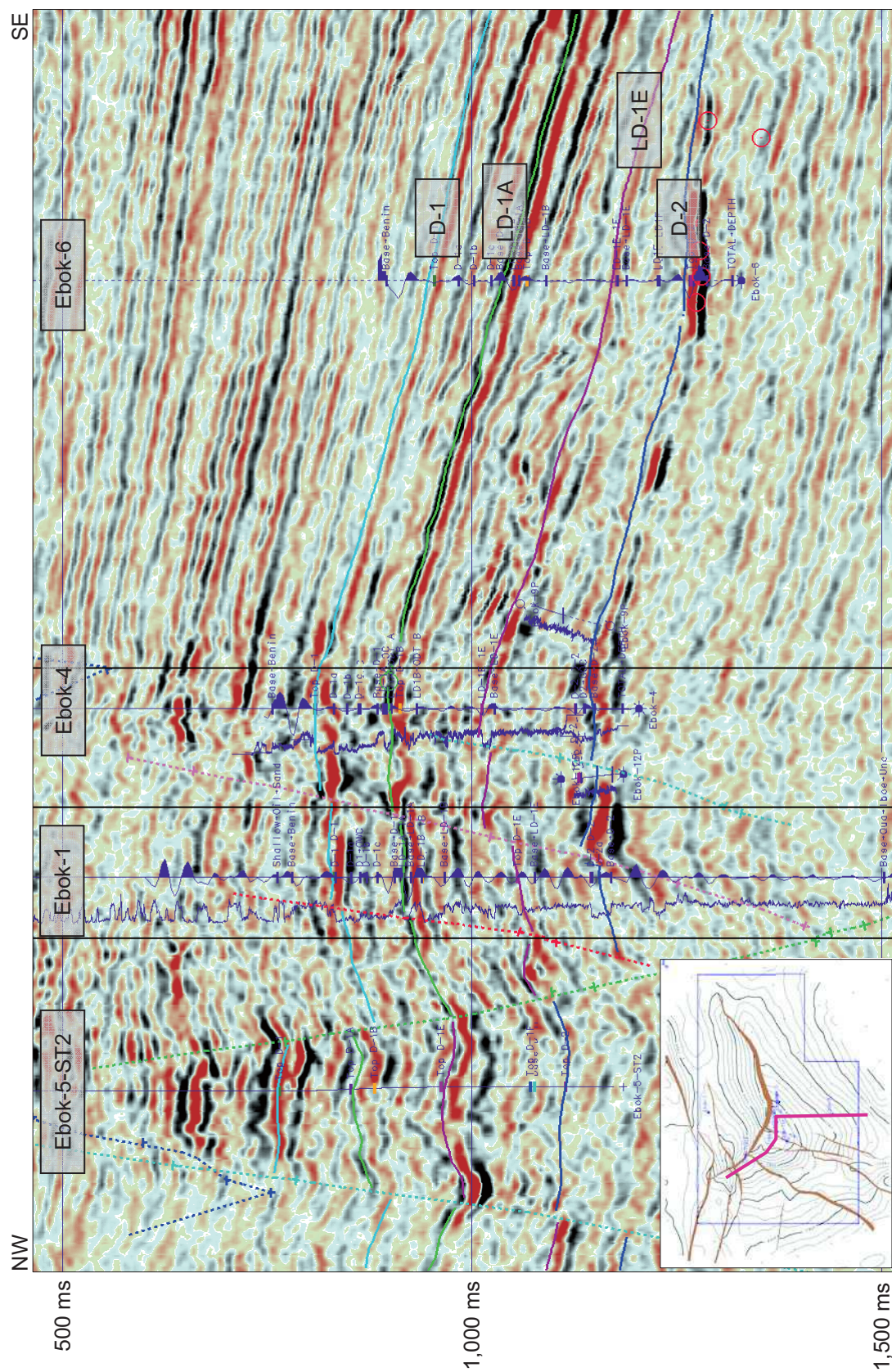
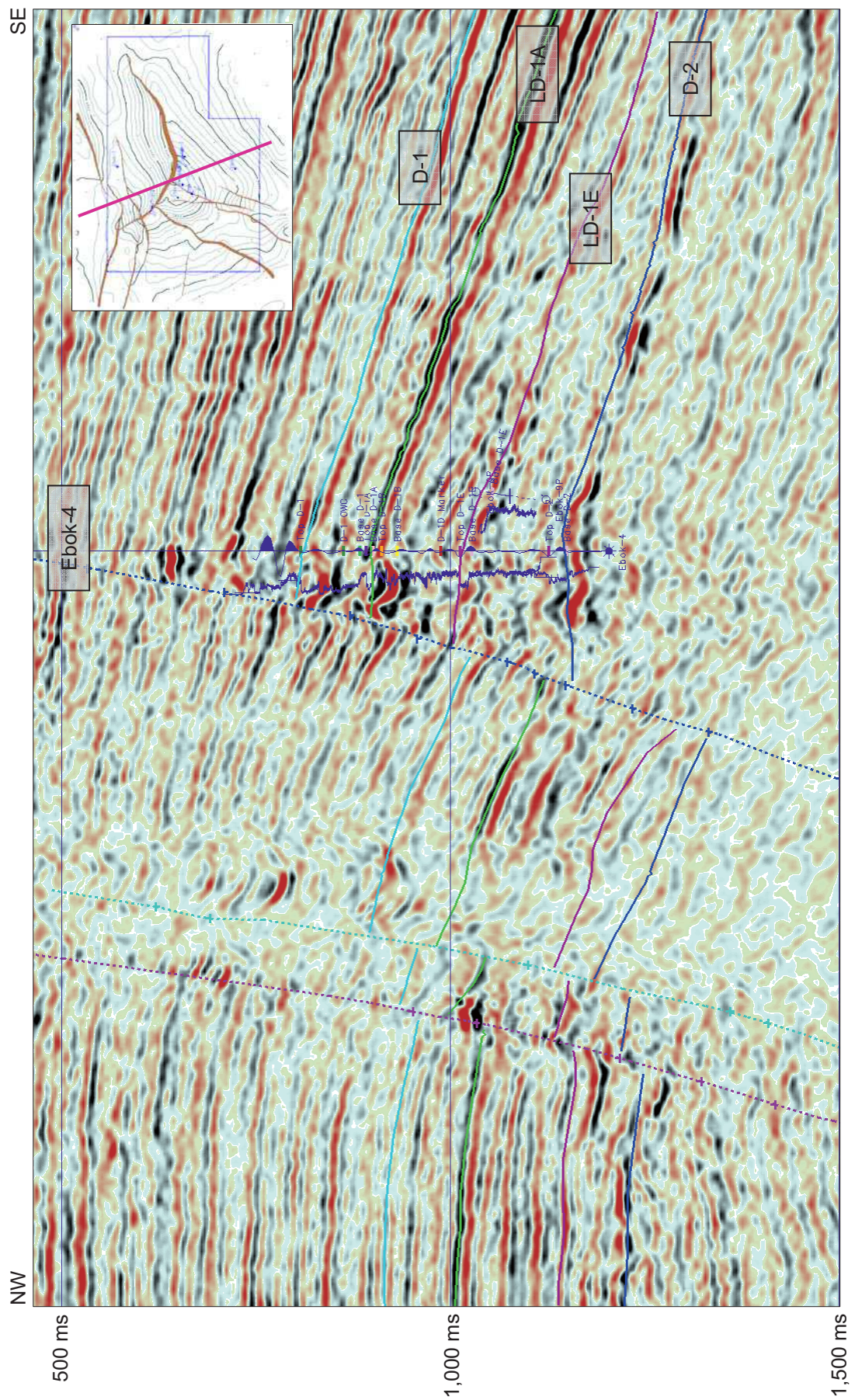


Figure 17

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

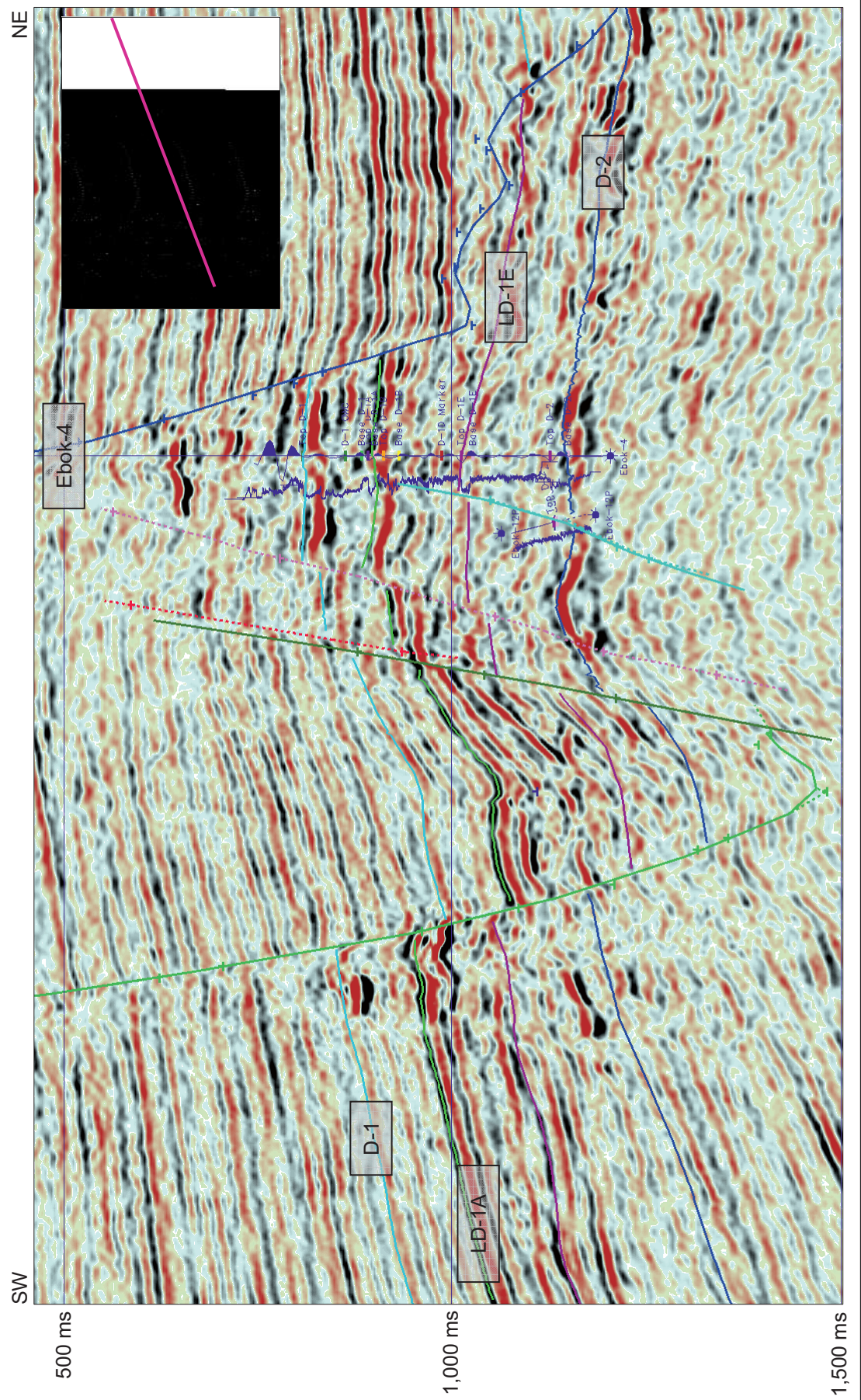
Seismic Interpretation – Trace 7145 through Ebok-4 Well
Ebok Field
OML 67, Offshore Nigeria



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 18

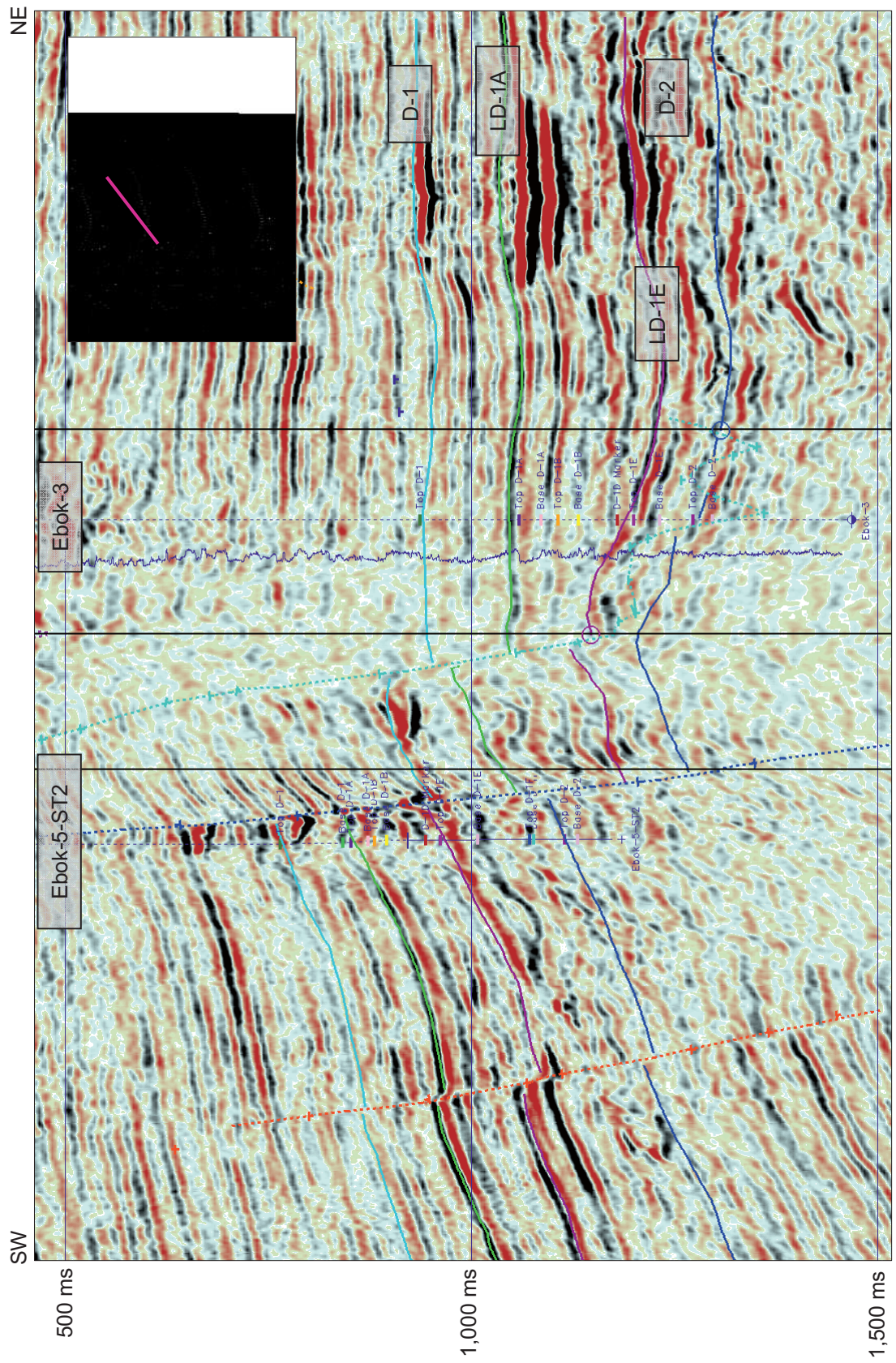
Seismic Interpretation – Line 1825 through Ebok-4 Well
Ebok Field
OML 67, Offshore Nigeria



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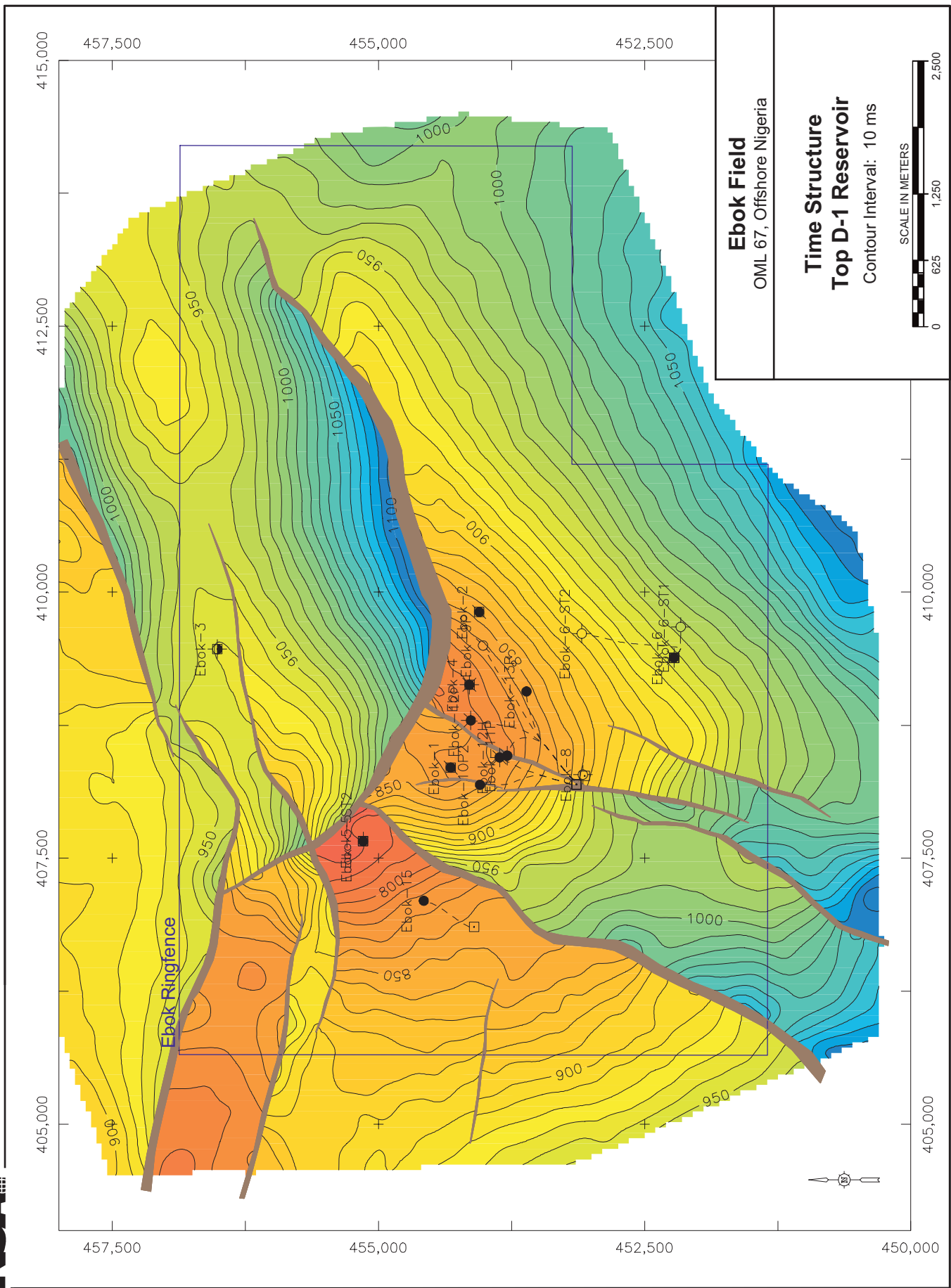
Figure 19

Seismic Interpretation – Arbitrary Line through Ebok-5-ST2 and Ebok-3 Wells
Ebok Field
OML 67, Offshore Nigeria



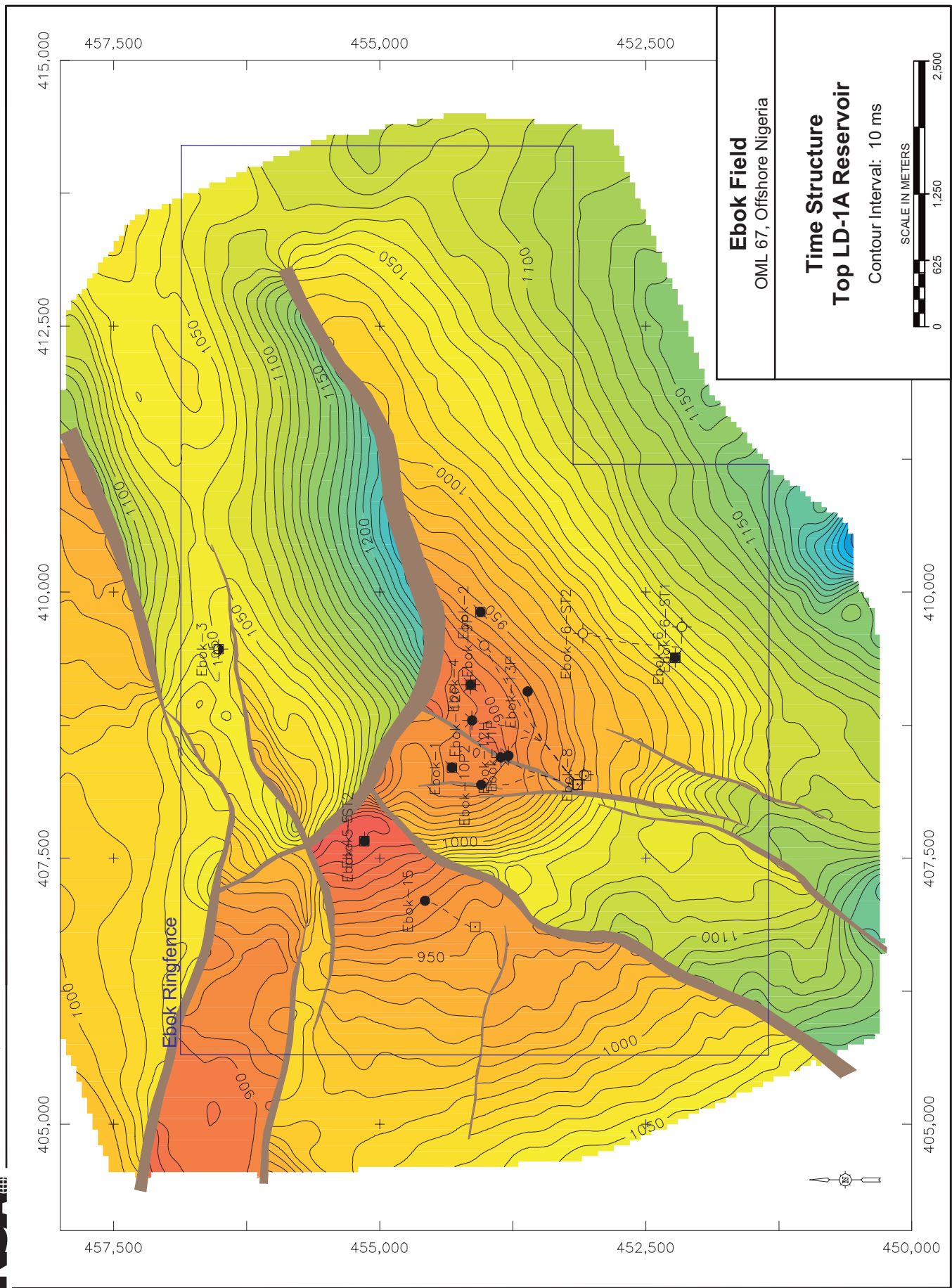
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 20



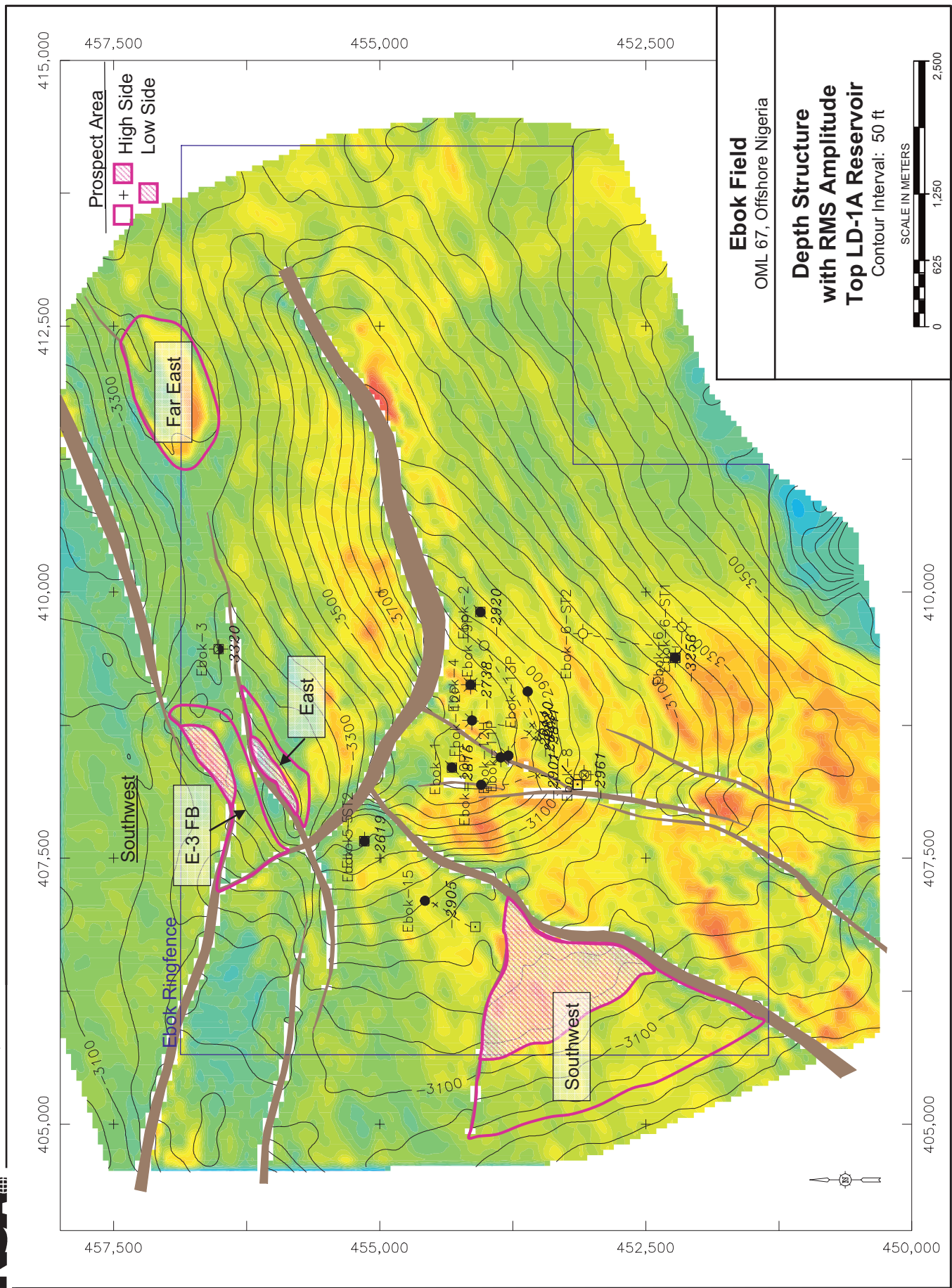
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 21



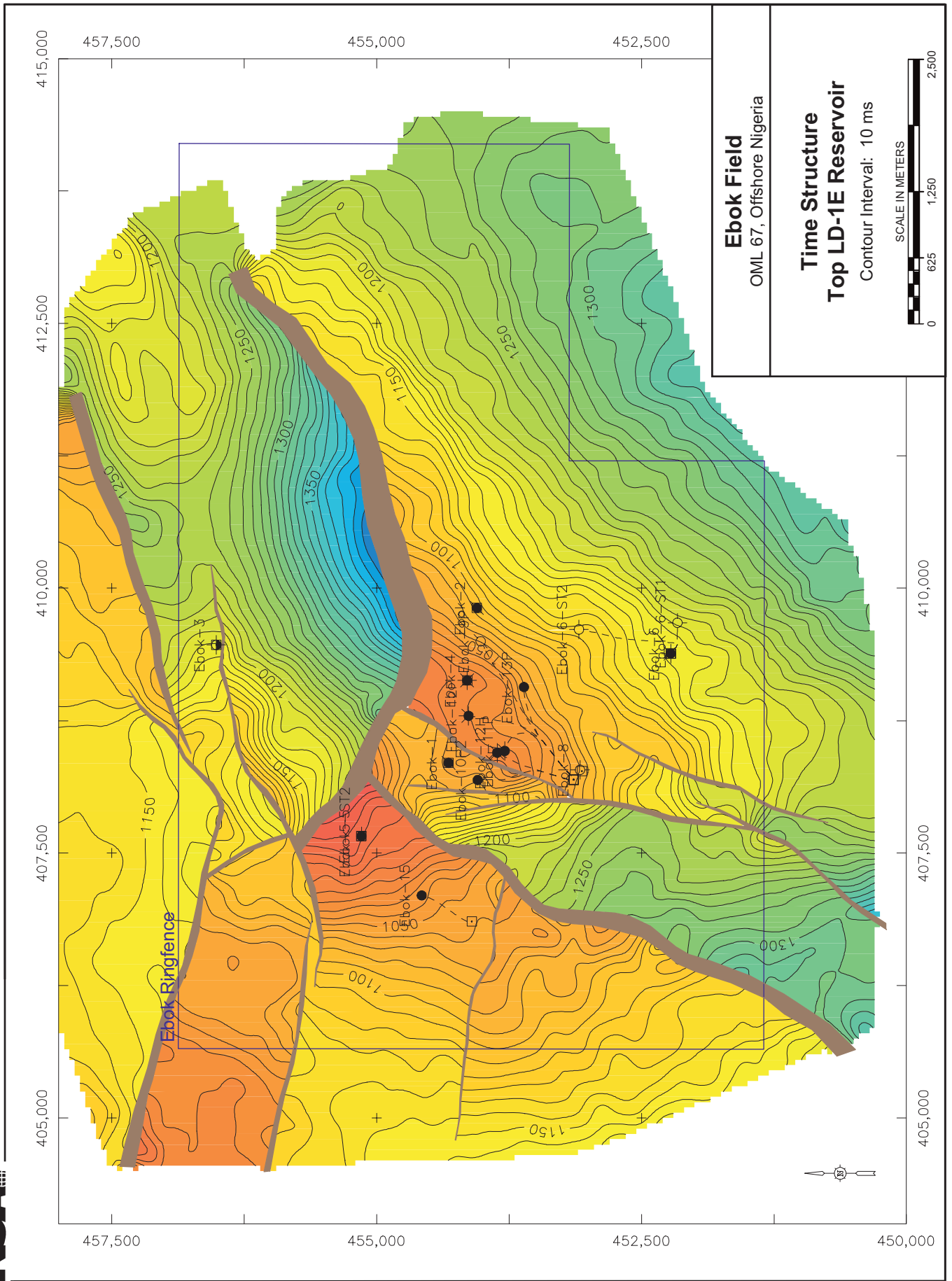
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 22



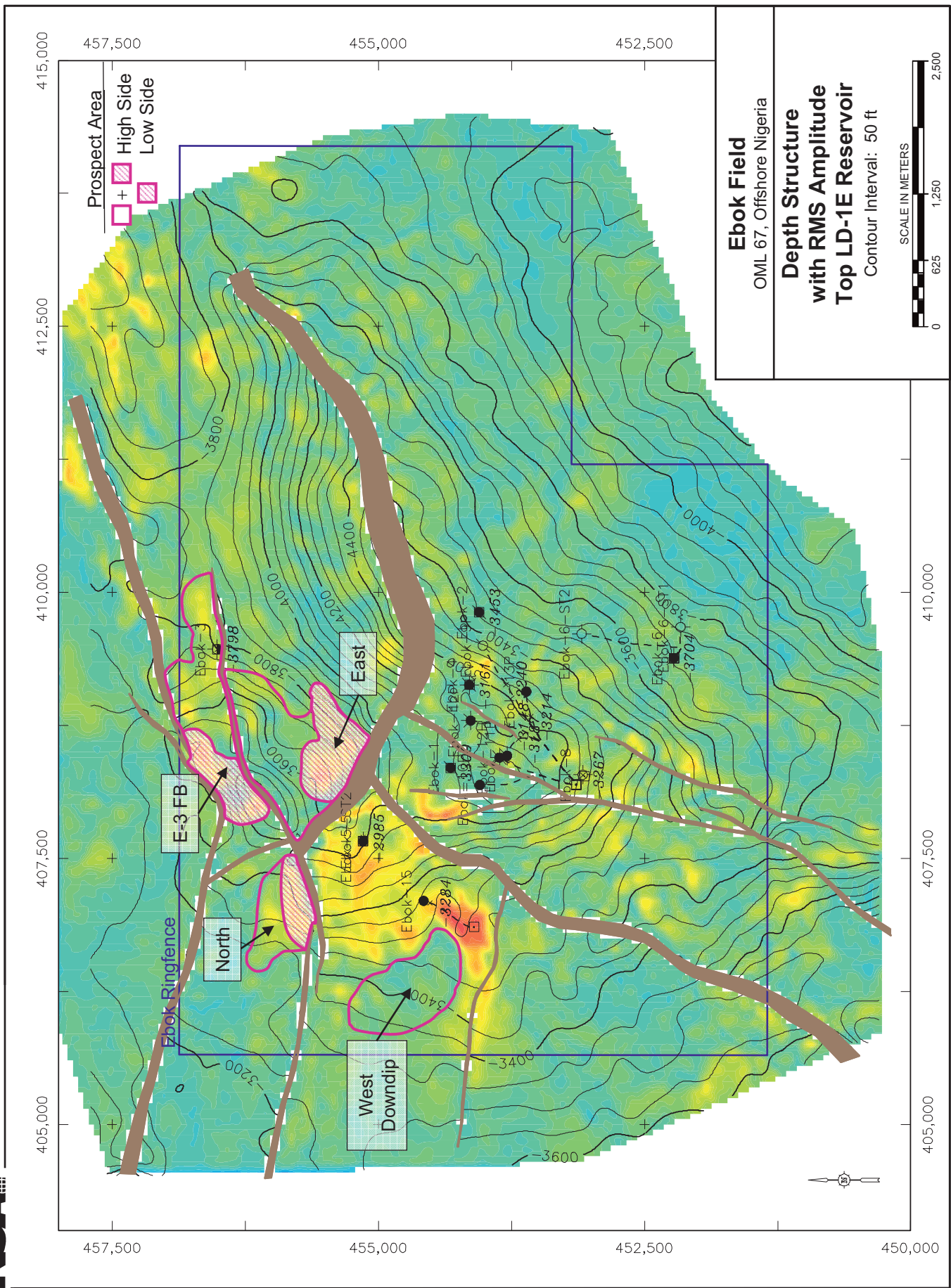
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 23



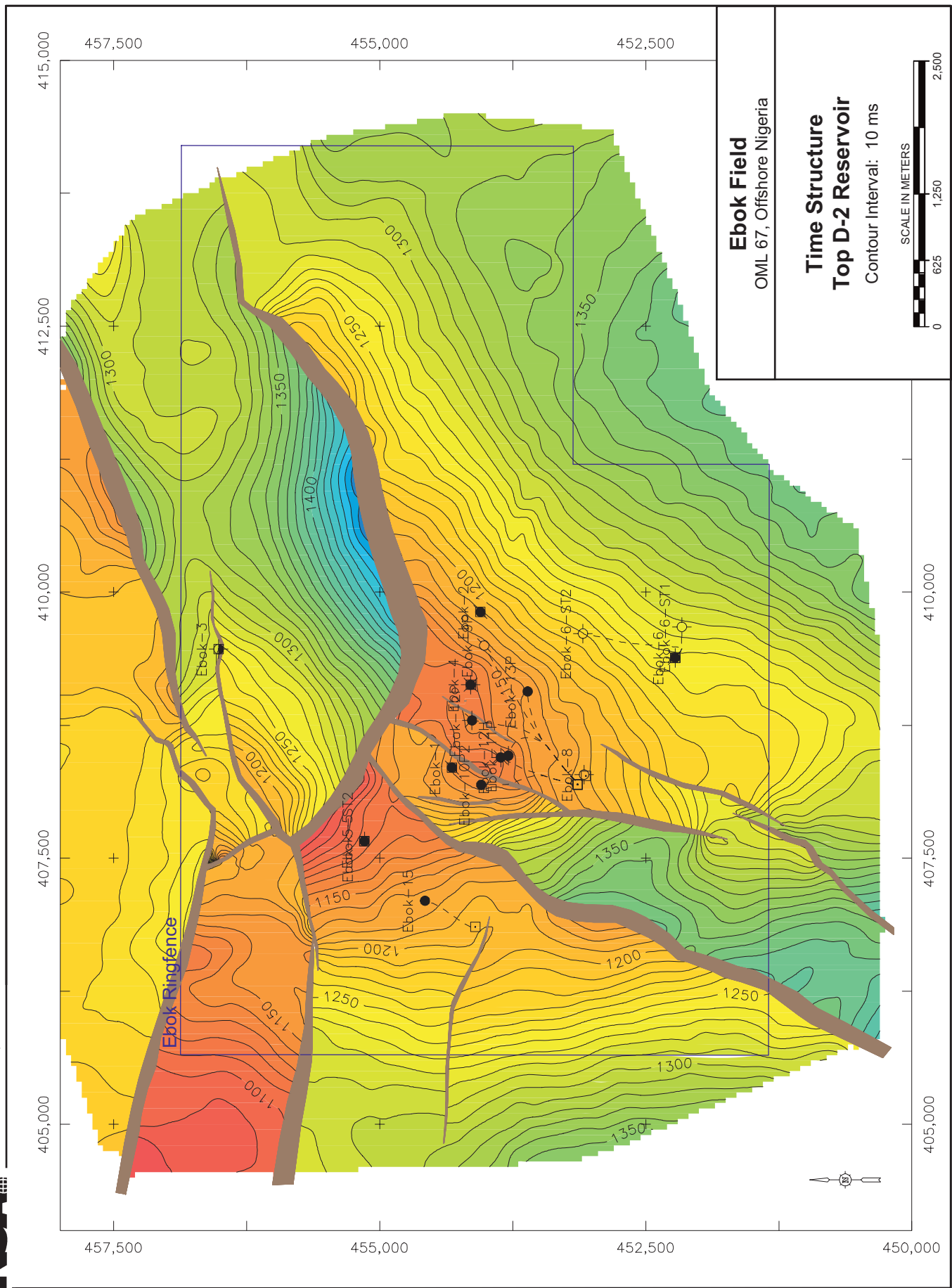
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 24



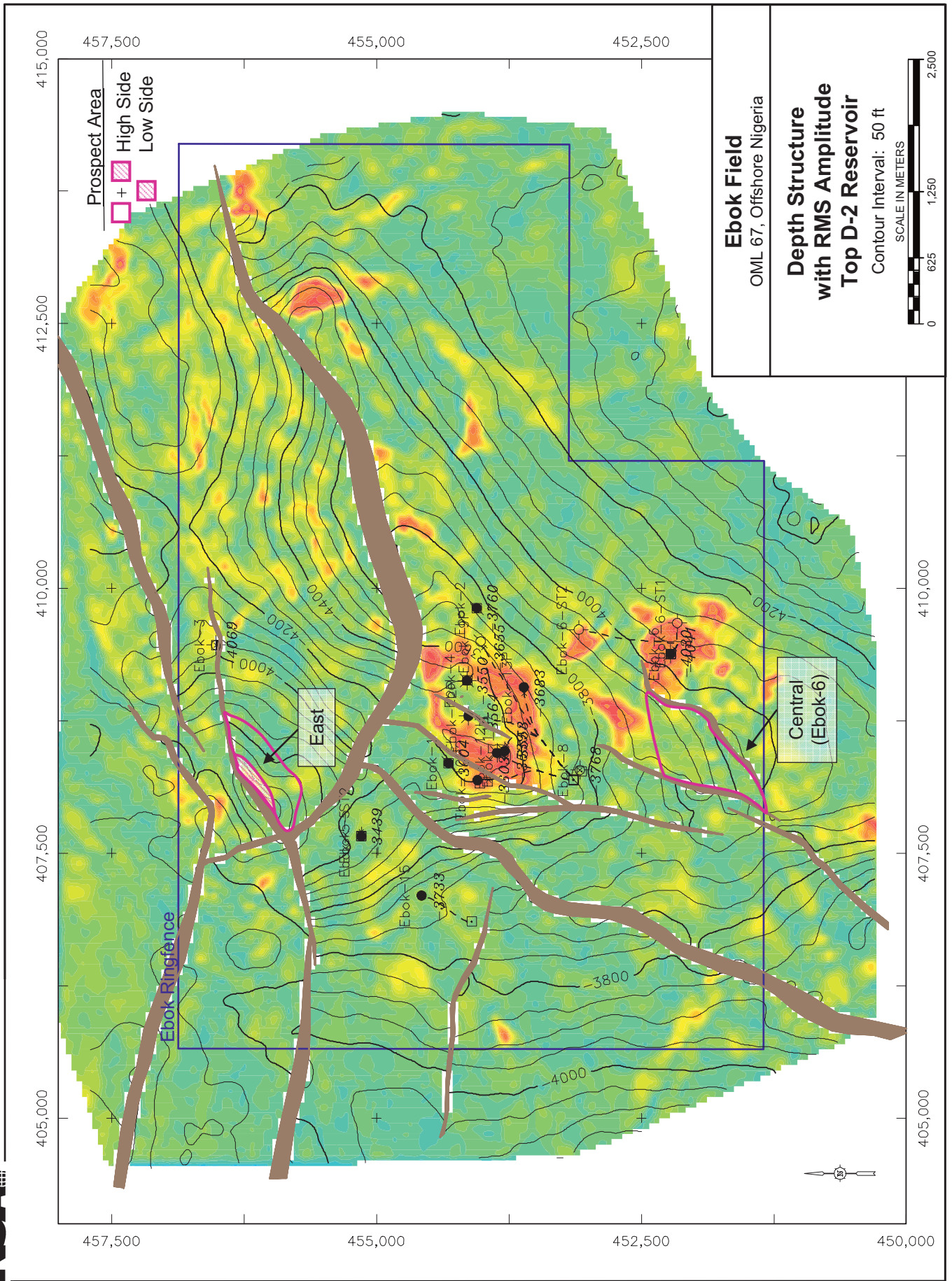
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 25



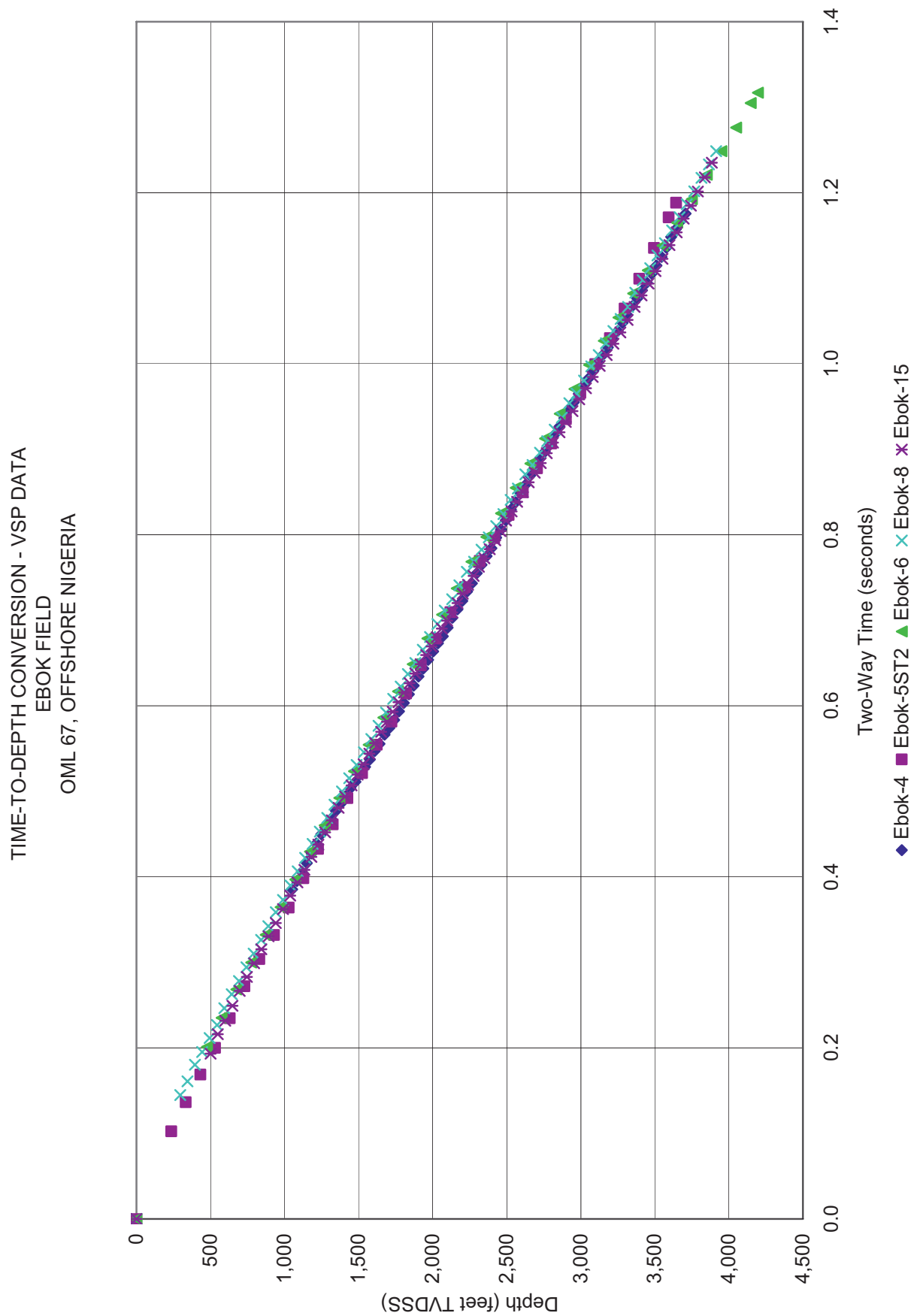
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 26



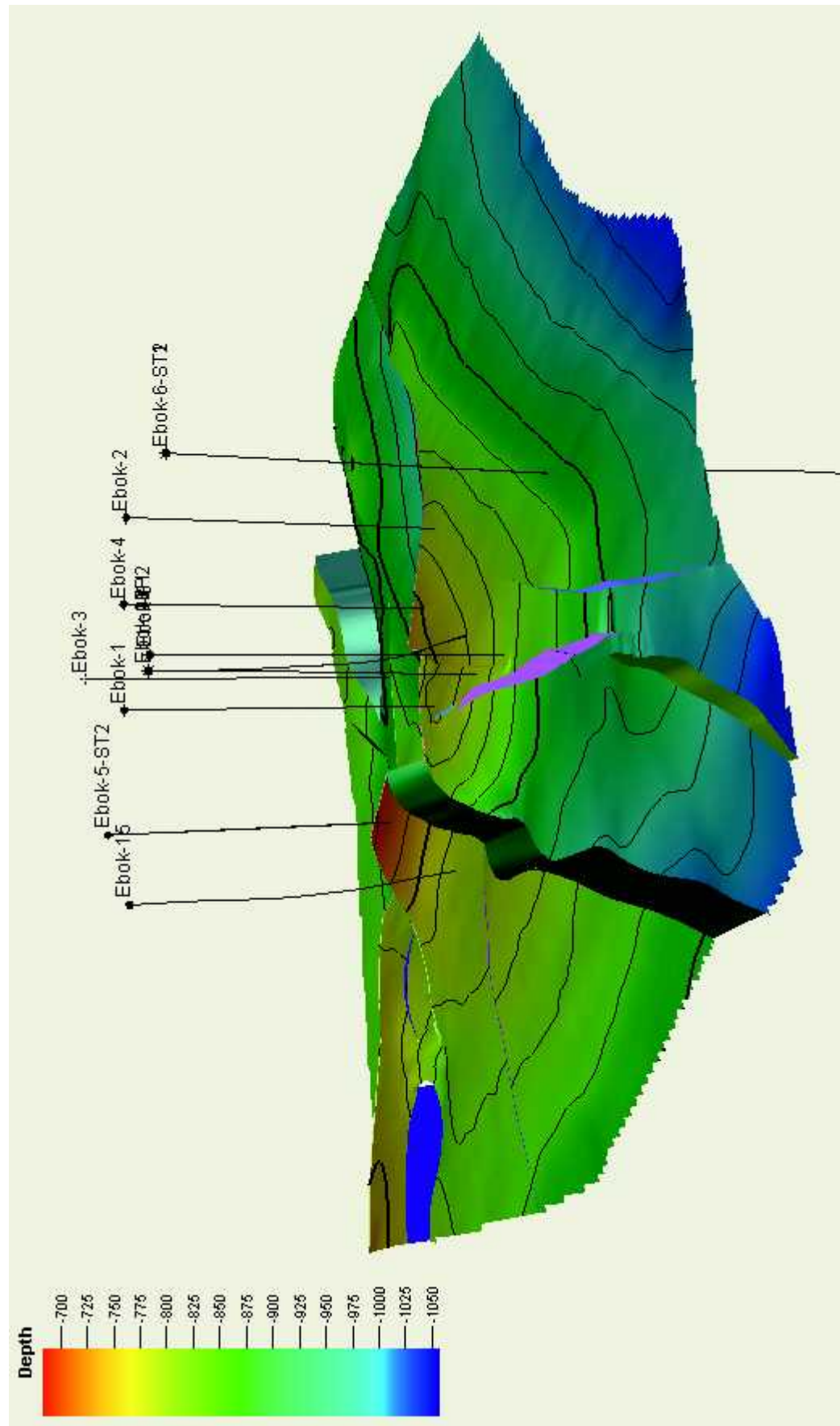
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 27



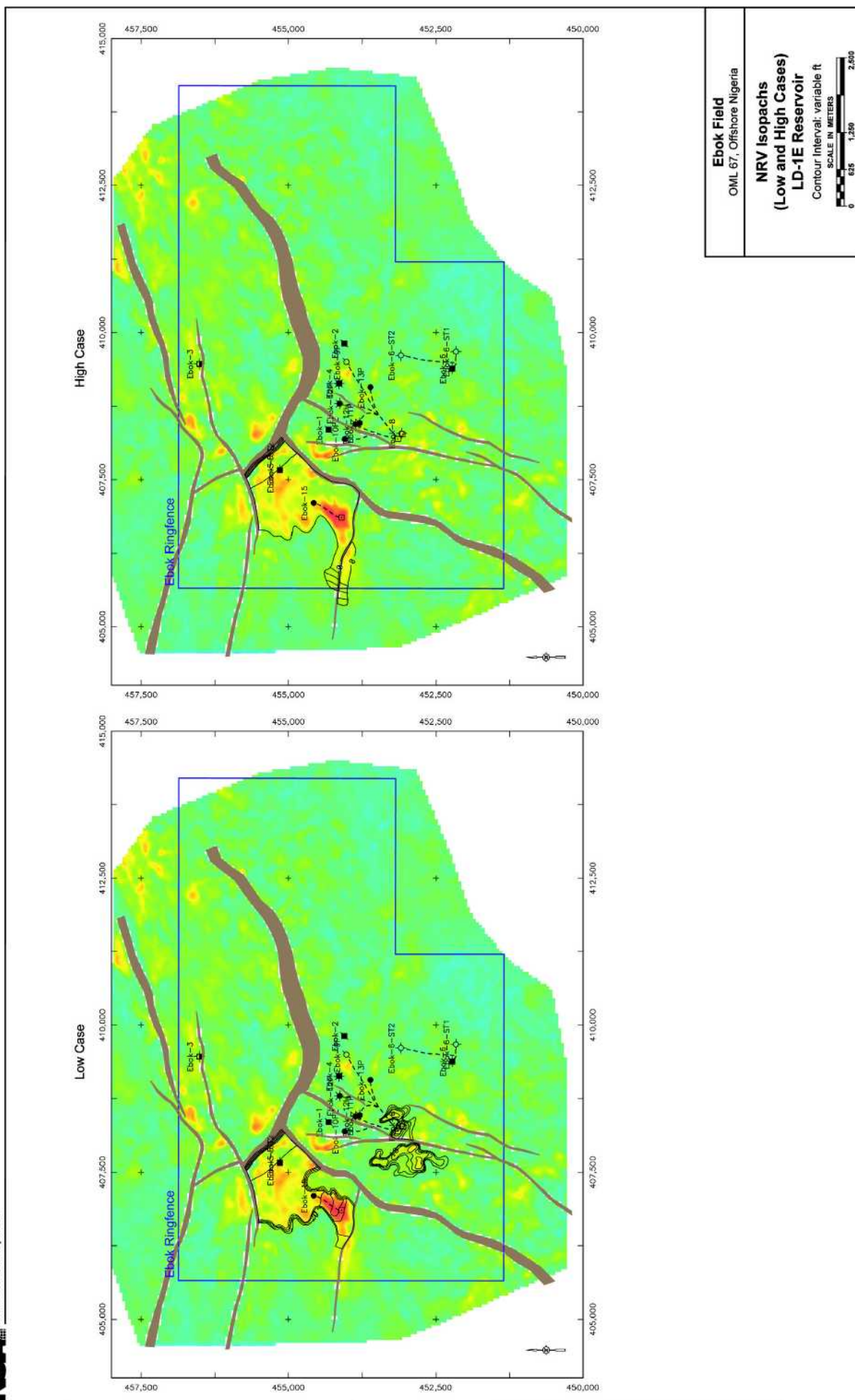
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Petrel Structural Model – D-1 Horizon
Ebok Field
OML 67, Offshore Nigeria



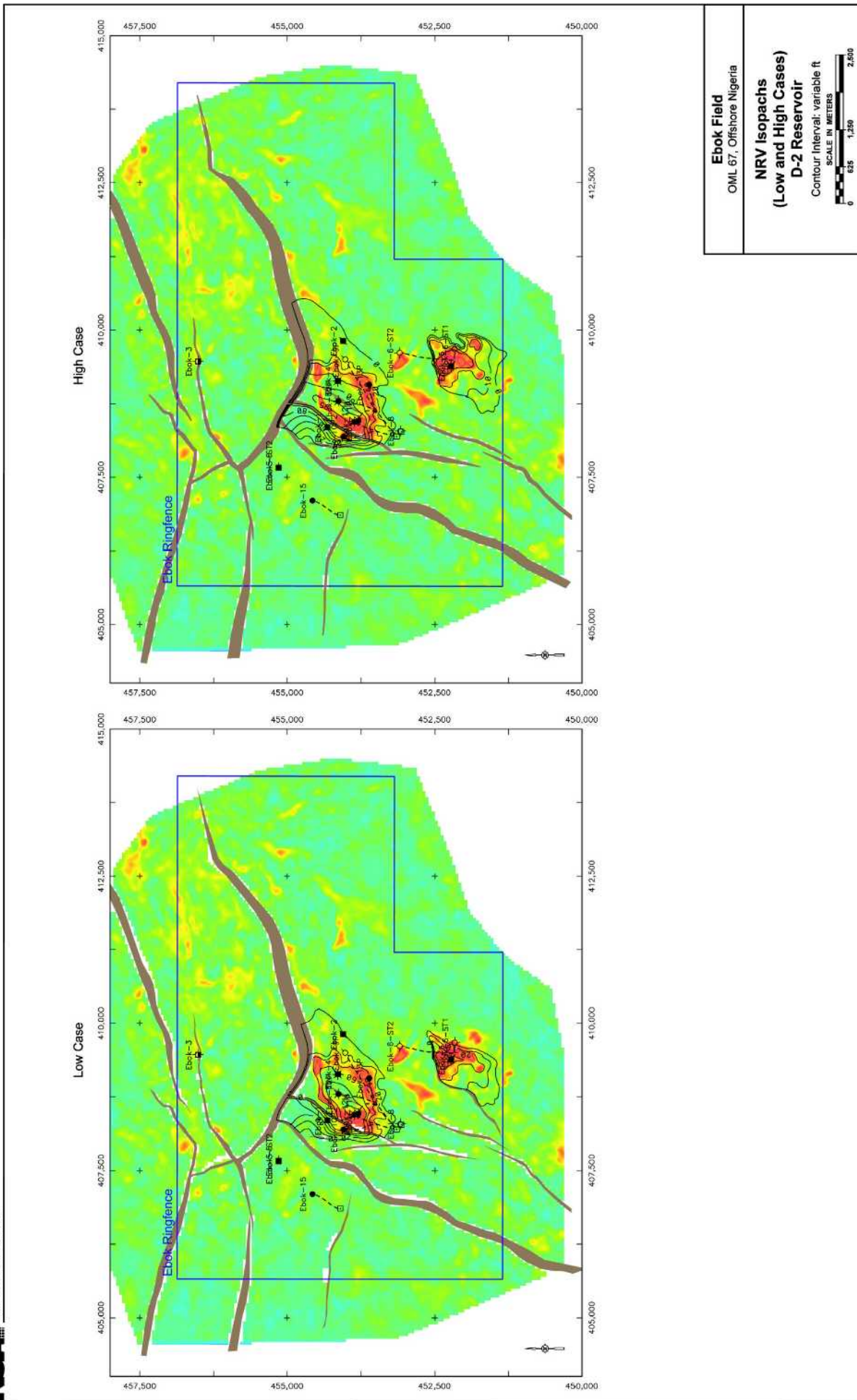
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 29



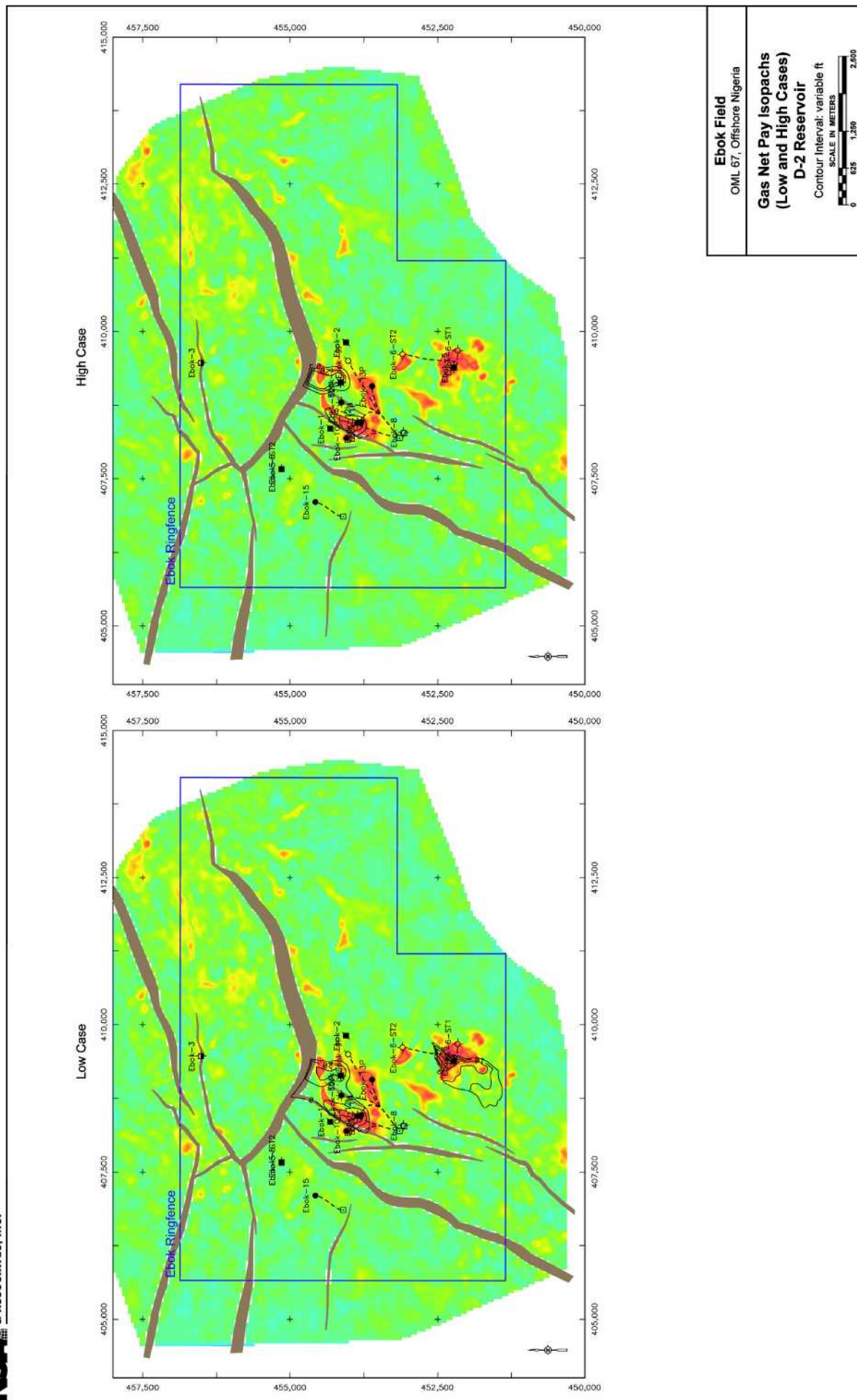
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 30



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 31



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 32

INPUT PARAMETERS
EBOK FIELD, OML 67, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

Reservoir	Fault Block	Category	Rock Volumes (sc-ft)				Net ⁽¹⁾		NTG _p ⁽¹⁾ (decimal)		Porosity (decimal)		1-S _w (decimal)		B _o (RB/STB)		Recovery Factor (decimal)	
			Gross		Max		P90	P10	Min	ML	Max	Min	ML	Max	Min	ML	Max	Min
			Min	ML														
D-1	Central	Reserves	54,016	56,859	59,702	-	-	-	0.92	0.96	1.00	0.32	0.35	0.35	0.83	0.85	0.87	0.15
D-1	West	Reserves	26,876	28,290	29,705	-	-	-	0.84	0.87	0.91	0.28	0.33	0.35	0.83	0.85	0.87	0.15
D-1	East	Prospective Resources	17,140	18,042	18,944	-	-	-	0.92	0.96	1.00	0.32	0.35	0.35	0.83	0.85	0.87	0.15
LD-1A	Central	Reserves	54,028	56,872	59,716	-	-	-	0.96	0.98	1.00	0.32	0.35	0.37	0.58	0.63	0.65	0.15
LD-1A	East	Prospective Resources	14,643	15,414	16,164	-	-	-	0.96	0.98	1.00	0.32	0.35	0.37	0.58	0.63	0.65	0.15
LD-1A	E-3	Prospective Resources	-	-	-	1,207	-	14,818	-	-	-	0.32	0.35	0.37	0.58	0.63	0.65	0.15
LD-1A	Southwest	Prospective Resources	-	-	-	3,261	-	58,662	-	-	-	0.32	0.35	0.37	0.58	0.63	0.65	0.15
LD-1A	Far East	Prospective Resources	-	-	-	8,560	-	15,833	-	-	-	0.32	0.35	0.37	0.58	0.63	0.65	0.15
LD-1B	Central (Ebok-4/2)	Reserves	9,716	10,228	10,739	9,716	10,739	10,739	0.11	0.64	1.00	0.28	0.32	0.34	0.74	0.76	0.83	0.15
LD-1B	Central (Ebok-1)	Reserves	28,399	29,893	31,388	28,399	31,388	31,388	0.11	0.64	1.00	0.28	0.32	0.34	0.74	0.76	0.83	0.15
LD-1B	East	Prospective Resources	12,666	13,332	13,999	12,666	13,999	13,999	0.11	0.64	1.00	0.28	0.32	0.34	0.74	0.76	0.83	0.15
LD-1E	Central (Ebok-4/2)	Reserves	-	-	-	2,709	-	4,937	-	-	-	0.32	0.35	0.38	0.77	0.80	0.83	0.20
LD-1E	Central (Ebok-1)	2P and 3P Reserves	-	-	-	5,106	-	5,644	-	-	-	0.32	0.35	0.38	0.77	0.80	0.83	0.20
LD-1E	West ⁽²⁾	1P Reserves	-	-	-	7,645	-	8,864	-	-	-	0.32	0.35	0.38	0.77	0.80	0.83	0.20
LD-1E	West ⁽²⁾	2P and 3P Reserves	-	-	-	45,036	-	51,946	-	-	-	0.32	0.35	0.38	0.77	0.80	0.83	0.20
LD-1E	Southwest	Reserves	-	-	-	3,182	-	3,889	-	-	-	0.32	0.35	0.38	0.77	0.80	0.83	0.20
LD-1E	West - Downdip	Prospective Resources	-	-	-	6,366	-	14,927	-	-	-	0.32	0.35	0.38	0.77	0.80	0.83	0.20
LD-1E	East	Prospective Resources	-	-	-	6,146	-	26,336	-	-	-	0.32	0.35	0.38	0.77	0.80	0.83	0.20
LD-1E	E-3	Prospective Resources	-	-	-	6,585	-	22,517	-	-	-	0.32	0.35	0.38	0.77	0.80	0.83	0.20
LD-1E	North	Prospective Resources	-	-	-	3,293	-	9,867	-	-	-	0.32	0.35	0.38	0.77	0.80	0.83	0.20
LD-1F	West	Reserves	3,200	3,368	3,536	3,200	3,536	3,536	0.83	0.86	0.89	0.34	0.34	0.35	0.77	0.82	0.91	0.15
LD-1F	Southwest	Prospective Resources	4,904	5,162	5,420	4,904	5,420	5,420	0.83	0.86	0.89	0.34	0.34	0.35	0.77	0.82	0.91	0.15
D-2	Central	Reserves	-	-	-	26,528	-	34,648	-	-	-	0.33	0.36	0.38	0.80	0.83	0.86	0.20
D-2	Central (Ebok-6) ⁽³⁾	Reserves	-	-	-	790	-	3,190	-	-	-	0.33	0.36	0.38	0.80	0.83	0.86	0.20
D-2	West	Reserves	-	-	-	327	-	1,862	-	-	-	0.33	0.36	0.38	0.80	0.83	0.86	0.20
D-2	East	Prospective Resources	18,175	19,132	20,088	-	-	-	0.26	0.74	0.98	0.33	0.36	0.38	0.80	0.83	0.86	0.20
D-2	Central (Ebok-6) ⁽³⁾	Prospective Resources	-	-	-	10,494	-	13,988	-	-	-	0.33	0.36	0.38	0.80	0.83	0.86	0.20
Que Iboe Footwall	West and Southwest	Prospective Resources	-	-	-	16,736	-	224,257	-	-	-	0.27	0.30	0.33	0.70	0.75	0.80	0.20
Biafra 1 (E-3)	East	Prospective Resources	-	-	-	6,476	-	55,474	-	-	-	0.27	0.30	0.33	0.70	0.75	0.80	0.20

⁽¹⁾ Net rock volumes shown include NTG parameter in calculation and exclude gas cap net rock volumes.

⁽²⁾ This polygon has been subdivided to reflect different volumetric parameters and categorization.

⁽³⁾ This polygon has been subdivided to reflect different volumetric parameters and classification.

Figure 33

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

ESTIMATES OF GROSS (100 PERCENT) OOIP AND OIL RESERVES AND UNDISCOVERED OOIP AND UNRISKED PROSPECTIVE OIL RESOURCES
EBOK FIELD, OML 67, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

Reservoir	Fault Block	Gross (100 Percent) Volumes					Prospective Volumes				
		OOIP (MMBBL)			Oil Reserves ⁽¹⁾ (MMBBL)		Undiscovered OOIP (MMBBL)		Prospective Oil Resources (MMBBL)		
		1P	2P	3P	1P	2P	Low Estimate	Best Estimate	Low Estimate	Best Estimate	High Estimate
D-1	Central	82.6	87.5	92.1	17.0	21.8	-	-	-	-	-
D-1	West	35.4	38.6	41.6	7.4	9.6	-	-	-	-	-
D-1	East	-	-	-	-	-	10.1	27.4	64.6	6.9	16.3
Subtotal D-1		118.0	126.1	133.7	24.4	31.4	10.1	27.4	64.6	6.9	16.3
LD-1A	Central	32.0	73.5	117.3	7.7	18.0	-	-	-	-	-
LD-1A	East	-	-	-	-	-	6.1	16.2	39.1	1.5	4.0
LD-1A	E-3	-	-	-	-	-	3.9	10.0	16.4	0.9	2.4
LD-1A	Southwest	-	-	-	-	-	14.5	38.4	64.7	3.5	9.3
LD-1A	Far East	-	-	-	-	-	11.3	14.9	18.5	2.6	5.0
Subtotal LD-1A		32.0	73.5	117.3	7.7	18.0	35.9	79.5	138.8	8.5	19.4
LD-1B	Central (Ebok-4/2)	4.6	8.5	11.8	1.1	2.1	-	-	-	-	-
LD-1B	Central (Ebok-1)	12.4	23.7	35.2	3.0	5.8	-	-	-	-	-
LD-1B	East	-	-	-	-	-	4.8	10.8	23.4	1.2	2.6
Subtotal LD-1B		17.0	32.2	47.0	4.1	7.8	4.8	10.8	23.4	1.2	2.6
LD-1E	Central (Ebok-4/2)	4.4	5.8	7.2	1.4	1.9	-	-	-	-	-
LD-1E	West	49.7	58.9	68.4	14.5	19.6	-	-	-	-	-
LD-1E	Southwest	-	5.4	6.0	-	1.8	-	-	-	-	-
LD-1E	Central (Ebok-1)	-	8.2	8.8	-	2.7	-	-	-	-	-
LD-1E	West - Downdip	-	-	-	-	-	9.4	16.1	22.6	3.0	5.3
LD-1E	East	-	-	-	-	-	9.4	26.3	43.5	2.9	8.5
LD-1E	E-3	-	-	-	-	-	10.2	22.0	34.1	3.2	7.2
LD-1E	North	-	-	-	-	-	4.8	10.0	15.2	1.5	3.2
Subtotal LD-1E		54.1	78.2	90.4	15.9	26.0	33.7	74.4	115.4	10.7	24.2
LD-1F	West	2.4	3.7	5.0	0.6	0.9	-	-	-	-	-
LD-1F	Southwest	-	-	-	-	-	2.8	5.7	9.5	0.7	1.4
Subtotal LD-1F		2.4	3.7	5.0	0.6	0.9	2.8	5.7	9.5	0.7	1.4
D-2	Central	44.4	51.8	59.5	12.9	17.3	-	-	-	-	-
D-2	Central (Ebok-6)	1.4	3.4	5.4	0.5	1.1	-	-	-	-	-
D-2	West	0.6	1.8	3.2	0.2	0.6	-	-	-	-	-
D-2	East	-	-	-	-	-	14.8	25.2	47.8	4.7	8.3
D-2	Central (Ebok-6)	-	-	-	-	-	17.6	20.7	24.0	5.2	6.9
Subtotal D-2		46.3	57.0	68.1	13.6	19.0	32.3	45.9	71.8	9.9	15.2
Qua Iboe Footwall Biafra 1 (E-3)	West & Southwest	-	-	-	-	-	47.3	142.9	260.6	15.6	46.5
Subtotal Other		0.0	0.0	0.0	0.0	0.0	59.9	179.6	324.3	19.7	58.6
Total Ebok Field		269.8	370.7	461.5	66.3	103.1	179.6	423.2	747.8	53.1	128.3

Totals may not add because of rounding.

⁽¹⁾ Gross (100 percent) reserves are before deductions for royalty burdens.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 34

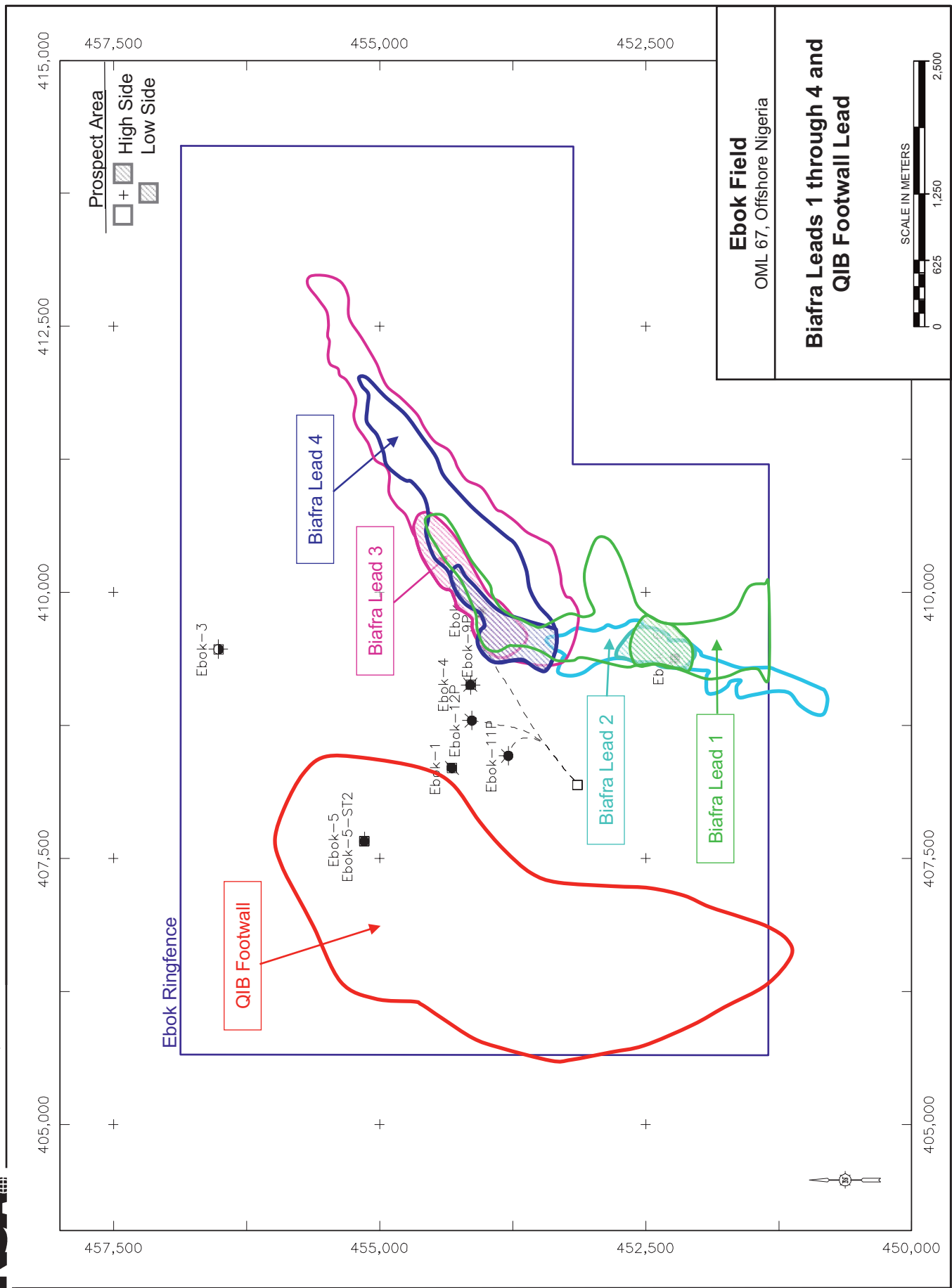


Figure 35

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

GROSS (100 PERCENT) PROJECTED OIL PRODUCTION
EBOK FIELD, OML 67, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

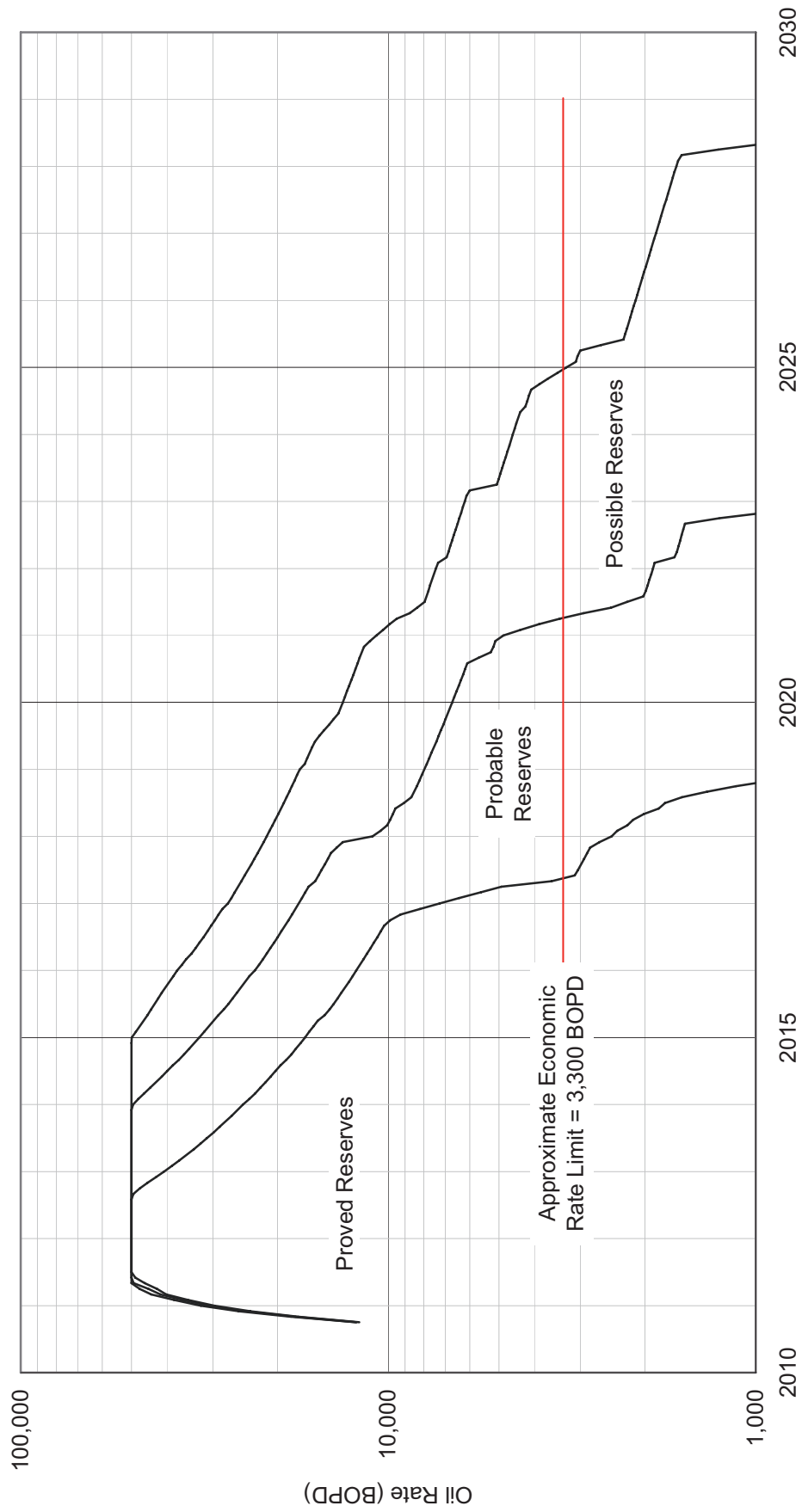


Figure 36
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

ESTIMATED GROSS (100 PERCENT) OIL PRODUCTION
EBOK FIELD, OML 67, OFFSHORE NIGERIA
AS OF JUNE 30, 2010

Project Year	Gross (100 Percent) Oil Production (Average Barrels Per Day)		
	1P	2P	3P
1	37,132	38,125	39,020
2	49,949	50,000	50,000
3	36,941	50,000	50,000
4	22,943	44,812	50,000
5	15,738	30,498	46,529
6	11,598	21,865	35,095
7	5,596	16,559	26,084
8	1,726	10,699	20,529
9	0	7,696	16,492
10	0	6,454	12,898
11	0	3,645	9,654
12	0	1,740	7,038
13	0	400	5,572
14	0	0	4,423
15	0	0	3,097
16	0	0	2,505
17	0	0	2,170
18	0	0	2,000
19	0	0	0
20	0	0	0
Total Recovery ⁽¹⁾ (MBBL)	66,293	103,110	139,834

⁽¹⁾ Total Recovery is prior to economic analysis.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2010

AFREN PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN EBOK FIELD
OML 67, OFFSHORE NIGERIA

PROVED (1P) RESERVES

Period Ending	Gross Reserves		Effective Working Interest Before Royalties		Net Entitlement Reserves ⁽¹⁾		Gross Revenue to Net Interest		Gross Capital Cost (MM\$)	Gross Operating Expense ⁽³⁾ (MM\$)	Future Net Revenue (MM\$)	Cum P.W. at 10% (MM\$)
	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MM\$)	Gas ⁽²⁾ (MM\$)				
12-31-2010	1.6	-	1.6	-	1.5	-	122.0	-	268.9	18.3	(89.2)	(87.1)
12-31-2011	16.5	-	16.5	-	14.0	-	1,192.3	-	480.0	75.2	439.6	303.1
12-31-2012	17.8	-	10.5	-	8.9	-	757.6	-	60.0	75.2	195.8	461.1
12-31-2013	11.8	-	5.9	-	5.1	-	434.3	-	0.0	75.2	133.8	559.3
12-31-2014	7.6	-	3.8	-	3.4	-	287.7	-	0.0	75.2	90.4	619.5
12-31-2015	5.3	-	2.6	-	2.4	-	207.7	-	0.0	75.2	54.6	652.6
12-31-2016	3.9	-	2.0	-	1.8	-	156.9	-	0.0	85.9	33.9	671.3
12-31-2017	1.5	-	0.7	-	0.7	-	60.7	-	0.0	85.9	4.9	673.7
12-31-2018	0.0	-	0.0	-	0.0	-	0.0	-	0.0	10.7	0.0	673.7
12-31-2019	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	673.7
12-31-2020	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	673.7
12-31-2021	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	673.7
12-31-2022	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	673.7
12-31-2023	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	673.7
12-31-2024	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	673.7
Total	65.9	-	43.5	-	38.0	-	3,219.3	-	808.9	576.7	863.7	673.7
Cum Prod Ultimate	65.9											

BASED ON AFREN PLC PRICE AND COST PARAMETERS

Totals may not add because of rounding.

- (1) Net reserves include Afren plc's portion of cost and profit oil and gas.
(2) These properties are not modeled in this report to have a commercial market for gas; produced gas will be consumed in operations or reinjected.
(3) Abandonment costs are included as operating expenses.

Figure 38

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2010

AFREN PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN EBOK FIELD
OML 67, OFFSHORE NIGERIA

PROVED + PROBABLE (2P) RESERVES

Period Ending	Gross Reserves		Effective Working Interest Before Royalties		Net Entitlement Reserves ⁽¹⁾		Gross Revenue to Net Interest		Gross Capital Cost (MM\$)	Gross Operating Expense ⁽³⁾ (MM\$)	Future Net Revenue (MM\$)	Cum P.W. at 10% (MM\$)
	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MM\$)	Gas ⁽²⁾ (MM\$)				
12-31-2010	1.7	-	1.6	-	1.6	-	125.1	-	268.9	18.3	(86.0)	(84.0)
12-31-2011	16.8	-	16.8	-	14.3	-	1,214.5	-	480.0	75.2	447.6	313.4
12-31-2012	18.3	-	11.2	-	9.5	-	808.0	-	100.0	75.2	185.2	462.8
12-31-2013	18.3	-	9.1	-	7.7	-	657.7	-	0.0	75.2	200.4	609.8
12-31-2014	15.0	-	7.5	-	6.4	-	544.1	-	0.0	75.2	166.7	721.0
12-31-2015	10.2	-	5.1	-	4.4	-	377.8	-	0.0	75.2	105.4	784.9
12-31-2016	7.4	-	3.7	-	3.3	-	283.0	-	0.0	75.2	73.2	825.2
12-31-2017	5.6	-	2.8	-	2.6	-	220.8	-	0.0	75.2	54.2	852.4
12-31-2018	3.4	-	1.7	-	1.6	-	137.4	-	0.0	75.2	29.4	865.8
12-31-2019	2.7	-	1.3	-	1.3	-	109.3	-	0.0	85.9	19.4	873.8
12-31-2020	2.2	-	1.1	-	1.1	-	90.6	-	0.0	85.9	13.7	878.9
12-31-2021	0.0	-	0.0	-	0.0	-	0.0	-	0.0	10.7	0.0	878.9
12-31-2022	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	878.9
12-31-2023	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	878.9
12-31-2024	0.0	-	0.0	-	0.0	-	0.0	-	0.0	0.0	0.0	878.9
Total	101.5	-	62.0	-	53.8	-	4,568.2	-	848.9	802.3	1,209.1	878.9
Cum Prod Ultimate	0.0	-	-	-	-	-	-	-	-	-	-	-
101.5												

BASED ON AFREN PLC PRICE AND COST PARAMETERS

Totals may not add because of rounding.

⁽¹⁾ Net reserves include Afren plc's portion of cost and profit oil and gas.

⁽²⁾ These properties are not modeled in this report to have a commercial market for gas; produced gas will be consumed in operations or reinjected.

⁽³⁾ Abandonment costs are included as operating expenses.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2010

AFREN PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN EBOK FIELD
OML 67, OFFSHORE NIGERIA

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

Period Ending	Gross Reserves		Effective Working Interest Before Royalties		Net Entitlement Reserves ⁽¹⁾		Gross Revenue to Net Interest		Gross Capital Cost (MM\$)	Gross Operating Expense ⁽³⁾ (MM\$)	Future Net Revenue (MM\$)	Cum P.W. at 10% (MM\$)
	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MMBBL)	Gas ⁽²⁾ (BCF)	Oil (MM\$)	Gas ⁽²⁾ (MM\$)				
12-31-2010	1.7	-	1.6	-	1.6	-	128.6	-	268.9	18.3	(82.4)	(80.5)
12-31-2011	17.1	-	17.1	-	14.5	-	1,233.9	-	480.0	75.2	448.6	317.7
12-31-2012	18.3	-	11.2	-	9.5	-	804.5	-	100.0	75.2	176.4	460.1
12-31-2013	18.3	-	9.1	-	7.7	-	657.7	-	0.0	75.2	200.4	607.1
12-31-2014	18.2	-	9.1	-	7.7	-	657.7	-	0.0	75.2	200.4	740.8
12-31-2015	16.0	-	8.0	-	6.8	-	579.1	-	0.0	75.2	165.2	840.9
12-31-2016	11.9	-	5.9	-	5.1	-	437.1	-	0.0	75.2	118.8	906.4
12-31-2017	8.9	-	4.5	-	3.9	-	334.2	-	0.0	75.2	87.8	950.4
12-31-2018	7.1	-	3.6	-	3.2	-	271.7	-	0.0	75.2	69.2	981.9
12-31-2019	5.6	-	2.8	-	2.6	-	220.3	-	0.0	75.2	54.1	1,004.3
12-31-2020	4.5	-	2.3	-	2.1	-	179.6	-	0.0	75.2	41.8	1,020.1
12-31-2021	3.2	-	1.6	-	1.5	-	128.2	-	0.0	75.2	26.6	1,029.2
12-31-2022	2.5	-	0.0	-	0.0	-	0.0	-	0.0	75.2	18.3	1,034.9
12-31-2023	1.9	-	0.0	-	0.0	-	0.0	-	0.0	85.9	10.0	1,037.7
12-31-2024	1.5	-	0.0	-	0.0	-	0.0	-	0.0	85.9	5.6	1,039.1
Total	136.6	-	76.7	-	66.4	-	5,632.8	-	848.9	1,092.4	1,540.8	1,039.1
Cum Prod	0.0	-	-	-	-	-	-	-	-	-	-	-
Ultimate	136.6	-	-	-	-	-	-	-	-	-	-	-

BASED ON AFREN PLC PRICE AND COST PARAMETERS

Totals may not add because of rounding.

⁽¹⁾ Net reserves include Afren plc's portion of cost and profit oil and gas.

⁽²⁾ These properties are not modeled in this report to have a commercial market for gas; produced gas will be consumed in operations or reinjected.

⁽³⁾ Abandonment costs are included as operating expenses.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 40

GROSS (100 PERCENT) HISTORICAL AND PROJECTED OIL PRODUCTION
LION AND PANTHÈRE FIELDS, BLOCK CI-11, OFFSHORE CÔTE D'IVOIRE
AS OF JUNE 30, 2010

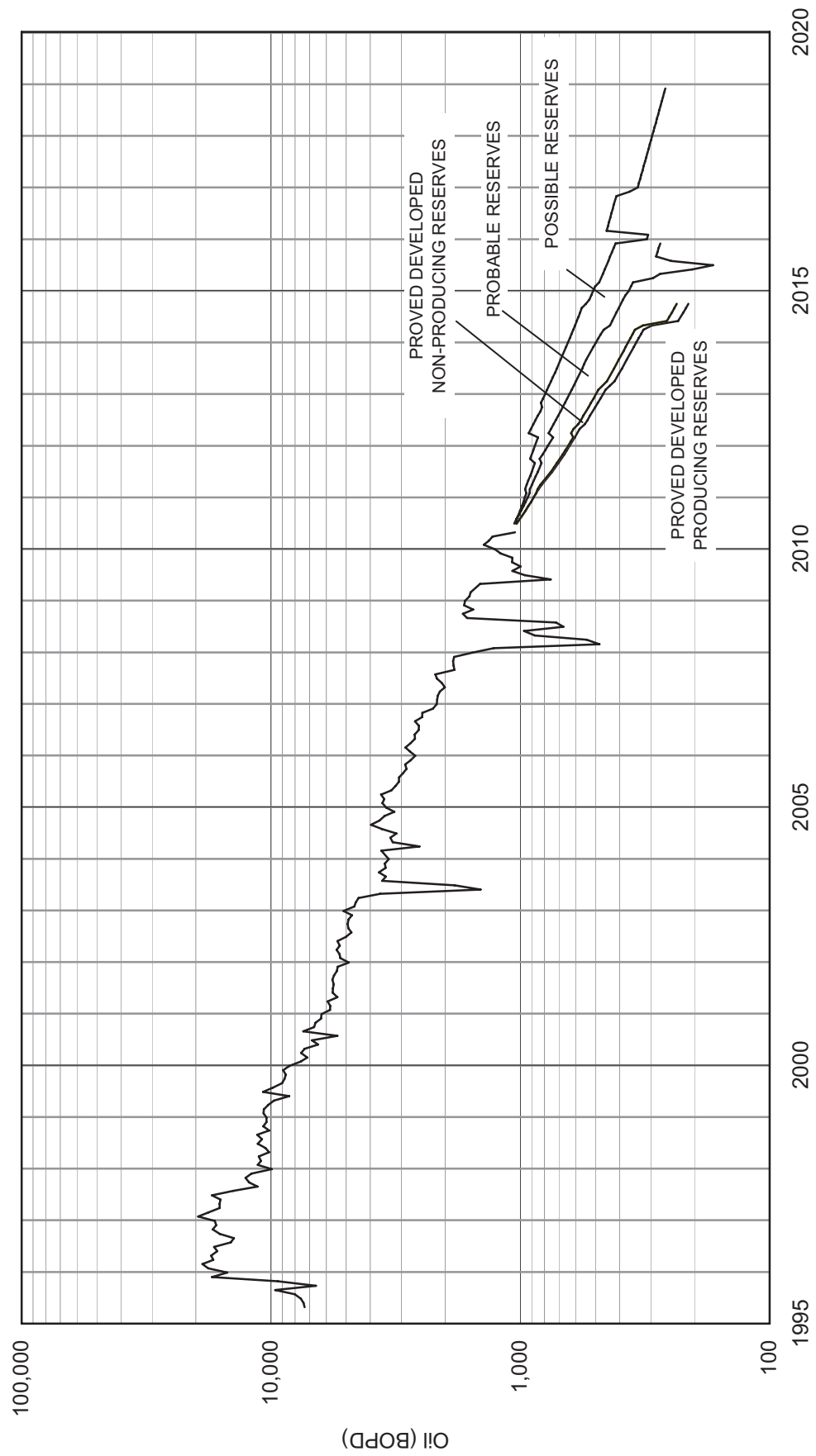


Figure 41
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

GROSS (100 PERCENT) HISTORICAL AND PROJECTED GAS PRODUCTION
LION AND PANTHÈRE FIELDS, BLOCK CI-11, OFFSHORE CÔTE D'IVOIRE
AS OF AS OF JUNE 30, 2010

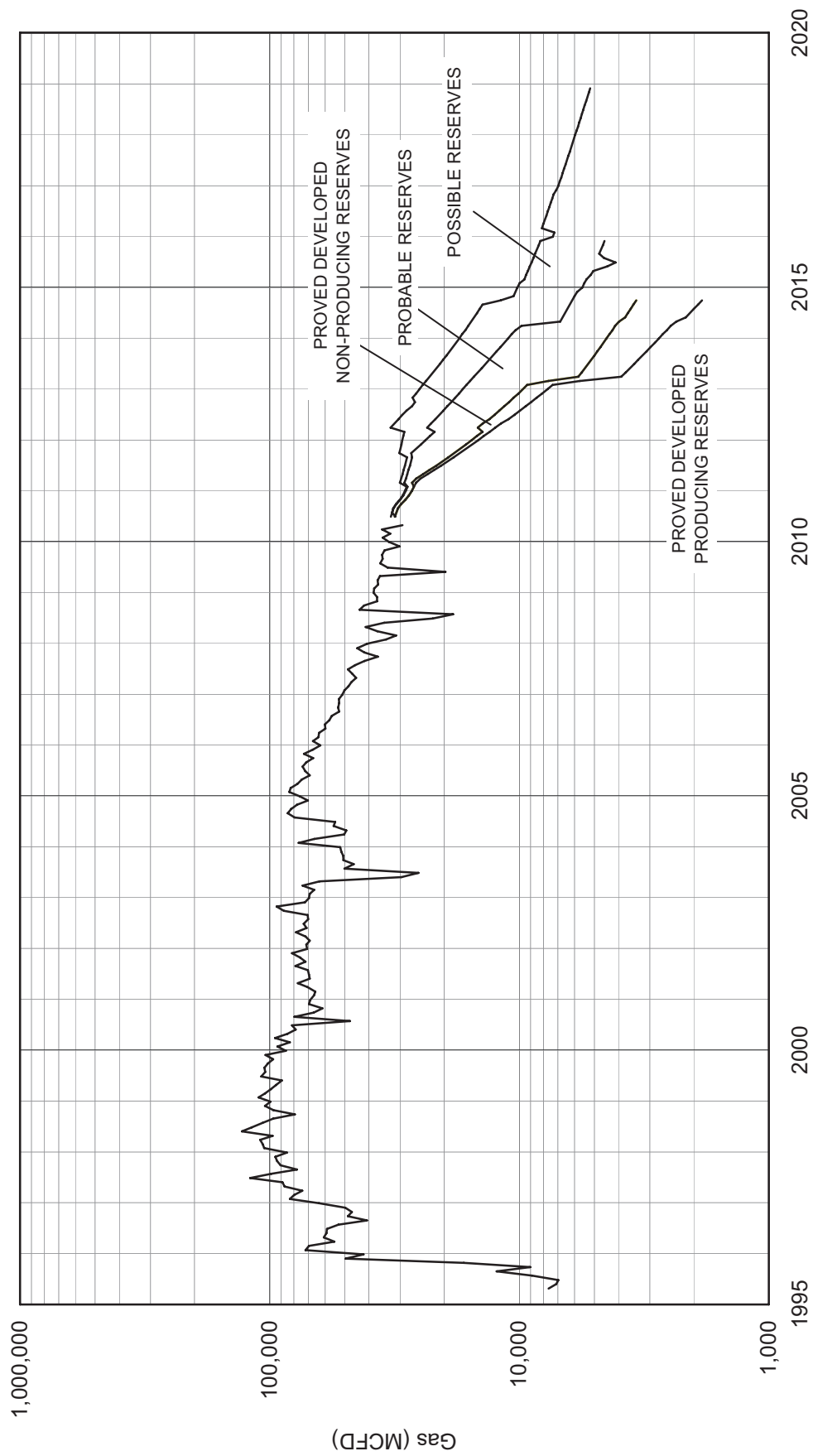


Figure 42
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2010

SUMMARY - CERTAIN PROPERTIES LOCATED IN LION AND PANTHERE FIELDS BLOCK CL-11, CÔTE D'IVOIRE													
PROVED (1P) RESERVES													
AFREN PLC INTEREST													
Period Ending	Gross Reserves			Effective Working Interest Before Royalties ⁽¹⁾			Net Entitlement Reserves ⁽²⁾			Gross Revenue to Net Interest			Cum P.W. at 10% (MM\$)
	Oil (MMBBL)	Gas (BCF)		Oil (MMBBL)	Gas (BCF)		Oil (MMBBL)	Gas (BCF)		Cost Recovery (MM\$)	Oil Profit (MM\$)	Pipeline Revenue (MM\$)	
12-31-2010	0.2	5.4		0.1	2.6		0.0	1.3		3.4	8.2	0.4	8.3
12-31-2011	0.3	8.1		0.1	3.9		0.1	1.9		7.0	13.7	0.8	13.9
12-31-2012	0.2	4.7		0.1	2.2		0.1	1.4		10.2	8.1	0.7	8.3
12-31-2013	0.2	2.2		0.1	1.1		0.0	0.7		6.7	4.2	0.7	4.6
12-31-2014	0.1	1.3		0.0	0.6		0.0	0.5		5.7	1.7	0.6	1.8
12-31-2015	0.0	0.0		0.0	0.0		0.0	0.0		0.0	0.0	0.0	(14.1)
12-31-2016	0.0	0.0		0.0	0.0		0.0	0.0		0.0	0.0	0.0	0.0
12-31-2017	0.0	0.0		0.0	0.0		0.0	0.0		0.0	0.0	0.0	0.0
12-31-2018	0.0	0.0		0.0	0.0		0.0	0.0		0.0	0.0	0.0	0.0
12-31-2019	0.0	0.0		0.0	0.0		0.0	0.0		0.0	0.0	0.0	0.0
12-31-2020	0.0	0.0		0.0	0.0		0.0	0.0		0.0	0.0	0.0	0.0
Total	0.9	21.7		0.4	10.4		0.3	5.7		33.0	35.8	3.2	22.9
Cum Prod	33.0	338.7											23.6
Ultimate	33.9	360.4											23.6

Totals may not add because of rounding.

⁽¹⁾ Effective working interest reserves are 47.96 percent of gross reserves.

⁽²⁾ Net reserves include Afren plc's portion of cost and profit oil and gas.

⁽³⁾ Abandonment costs are included as capital costs.

⁽⁴⁾ Net profits payments include payments made to Frank T. Barr and G. Willard Frank.

BASED ON AFREN PLC PRICE AND COST PARAMETERS

Figure 43

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2010

AFREN PLC INTEREST										SUMMARY - CERTAIN PROPERTIES LOCATED IN LION AND PANTHERE FIELDS BLOCK CL-11, CÔTÉ D'IVOIRE				
PROVED + PROBABLE (2P) RESERVES														
Period Ending	Gross Reserves		Effective Working Interest Before Royalties ⁽¹⁾		Net Entitlement Reserves ⁽²⁾		Gross Revenue to Net Interest		Capital Cost ⁽³⁾ (MM\$)	Operating Expense (MM\$)	Domestic Market Obligation (MM\$)	Net Profits Payments ⁽⁴⁾ (MM\$)	Future Net Revenue (MM\$)	Cum P.W. at 10% (MM\$)
	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Cost Recovery (MM\$)	Profit Oil (MM\$)						
12-31-2010	0.2	5.6	0.1	2.7	0.1	1.7	9.3	6.1	5.8	3.4	0.1	0.4	6.1	6.0
12-31-2011	0.3	10.0	0.2	4.8	0.1	2.5	9.6	14.8	2.5	6.9	0.2	0.6	14.9	19.6
12-31-2012	0.3	7.6	0.1	3.7	0.1	2.1	10.5	11.6	3.4	7.0	0.1	0.6	11.7	29.2
12-31-2013	0.2	5.1	0.1	2.5	0.1	1.3	7.2	9.9	0.0	7.1	0.1	0.4	10.1	36.8
12-31-2014	0.2	2.8	0.1	1.4	0.0	0.8	7.1	5.2	0.0	7.0	0.1	0.3	5.4	40.5
12-31-2015	0.1	1.8	0.0	0.9	0.0	0.6	7.1	2.3	4.0	6.7	0.1	0.2	(1.4)	39.7
12-31-2016	0.1	1.5	0.0	0.7	0.0	0.6	6.9	1.6	0.0	6.7	0.1	0.2	1.7	40.6
12-31-2017	0.1	1.0	0.0	0.5	0.0	0.4	4.9	1.2	0.0	6.0	0.1	0.2	(0.0)	40.6
12-31-2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.1	0.0	0.0	0.0	(14.1)	34.0
12-31-2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0
12-31-2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0
Total	1.4	35.5	0.7	17.0	0.4	10.0	62.5	52.5	29.7	50.6	0.8	3.0	34.5	34.0
Cum Prod	33.0	338.7												
Ultimate	34.4	374.2												

Totals may not add because of rounding.

⁽¹⁾ Effective working interest reserves are 47.96 percent of gross reserves.

⁽²⁾ Net reserves include Afren plc's portion of cost and profit oil and gas.

⁽³⁾ Abandonment costs are included as capital costs.

⁽⁴⁾ Net profits payments include payments made to Frank T. Barr and G. Willard Frank.

BASED ON AFREN PLC PRICE AND COST PARAMETERS

Figure 44

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2010

AFREN PLC INTEREST														SUMMARY - CERTAIN PROPERTIES LOCATED IN LION AND PANTHERE FIELDS BLOCK CI-11, CÔTE D'IVOIRE			
PROVED + PROBABLE + POSSIBLE (3P) RESERVES																	
Period Ending	Gross Reserves			Effective Working Interest Before Royalties ⁽¹⁾			Net Entitlement Reserves ⁽²⁾			Gross Revenue to Net Interest			Operating Expense (MM\$)	Domestic Market Obligation (MM\$)	Net Profits Payments ⁽⁴⁾ (MM\$)	Future Net Revenue (MM\$)	Cum P.W. at 10% (MM\$)
	Oil (MMBBL)	Gas (BCF)		Oil (MMBBL)	Gas (BCF)		Oil (MMBBL)	Gas (BCF)		Cost Recovery (MM\$)	Profit Oil (MM\$)	Pipeline Revenue (MM\$)					
12-31-2010	0.2	5.7		0.1	2.7		0.0	1.3		3.5	8.5	0.4	3.4	0.1	0.3	8.6	8.4
12-31-2011	0.3	10.6		0.2	5.1		0.1	3.0		14.4	13.7	0.8	6.9	0.2	0.7	13.7	20.9
12-31-2012	0.3	10.5		0.2	5.0		0.1	3.1		16.4	12.4	0.7	7.1	0.2	0.7	12.4	31.1
12-31-2013	0.3	7.8		0.1	3.7		0.1	1.9		7.3	13.0	0.7	7.2	0.1	0.5	13.2	41.0
12-31-2014	0.2	5.3		0.1	2.5		0.1	1.4		7.3	10.1	0.6	7.2	0.1	0.4	10.2	48.0
12-31-2015	0.2	3.3		0.1	1.6		0.0	0.9		7.0	6.3	0.2	6.9	0.1	0.3	6.1	51.8
12-31-2016	0.1	2.8		0.1	1.3		0.1	1.0		11.0	3.3	0.1	6.9	0.1	0.4	3.1	53.5
12-31-2017	0.1	2.4		0.1	1.1		0.0	0.7		6.9	3.7	0.1	6.8	0.1	0.3	3.5	55.3
12-31-2018	0.1	2.0		0.0	1.0		0.0	0.7		6.9	2.8	0.1	6.8	0.1	0.3	2.6	56.6
12-31-2019	0.1	1.7		0.0	0.8		0.0	0.6		6.8	2.0	0.1	6.8	0.1	0.2	1.8	57.3
12-31-2020	0.0	0.0		0.0	0.0		0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	(14.1)	51.9
Total	1.9	52.1		0.9	25.0		0.5	14.5		87.6	75.8	3.7	66.0	1.2	4.2	61.2	51.9
Cum Prod	33.0	338.7															
Ultimate	35.0	390.8															

Totals may not add because of rounding.

⁽¹⁾ Effective working interest reserves are 47.96 percent of gross reserves.

⁽²⁾ Net reserves include Afren plc's portion of cost and profit oil and gas.

⁽³⁾ Abandonment costs are included as capital costs.

⁽⁴⁾ Net profits payments include payments made to Frank T. Barr and G. Willard Frank.

BASED ON AFREN PLC PRICE AND COST PARAMETERS

Figure 45

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

PART 12

GCA REPORT ON BLACK MARLIN

GCA

GAFFNEY, CLINE & ASSOCIATES

**COMPETENT PERSON'S REPORT
ON CERTAIN PROPERTIES
IN EAST AFRICA**

Prepared for

BLACK MARLIN ENERGY HOLDINGS LIMITED

24TH AUGUST, 2010

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BCR/E2249.01/jlb/0052

24TH August, 2010

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Dear Sirs,

**COMPETENT PERSON'S REPORT
ON CERTAIN PROPERTIES IN EAST AFRICA**

INTRODUCTION

Gaffney, Cline & Associates Ltd (GCA) understands that Afren plc (Afren) is preparing a prospectus and a class 1 circular in accordance with the requirements of Chapters 10 and 13 of the UK Financial Service Authority's Listing Rules in relation to the issue of certain of its ordinary shares in connection with the acquisition of the Black Marlin Energy Holdings Limited (BMEHL) and the admission of such shares to the official list and to trading on the London Stock Exchange's main market for listed securities.

Black Marlin Energy Holdings Limited (BMEHL) commissioned Gaffney, Cline & Associates (GCA) to to prepare a Competent Person's Report (CPR) on the Blocks operated on its behalf by Africa Oil Corporation (AOC) in East Africa (Figure 1) on behalf of BMEHL. We understand that the CPR will be included in the Prospectus and the Circular in

accordance with the requirements of the Listing Rules and the Committee of European Securities Regulators' recommendations on the implementation of European Commission Regulation on Prospectuses No. 809/2004.

In the completion of this CPR, GCA has undertaken an evaluation of the resource potential on each of these blocks and has relied on data and presentations provided by AOC, supplemented by public domain data. GCA attended presentations on the Kenyan and Ethiopian blocks at the offices of Lundin Petroleum AB in Geneva, Switzerland (previous operator of these blocks). GCA was provided with SMT Kingdom Suite (Kingdom) seismic interpretation projects covering all of the blocks being assessed. The Kingdom projects provide the major database for this work.

For the purposes of the Report, GCA used the Petroleum Resources Management System published by the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) in March, 2007 ("SPE PRMS"). See Appendix I.

Industry Standard abbreviations are contained in the attached Glossary (Appendix II), some or all of which may have been used in this report.

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status. All categories of Reserve volumes quoted herein have been determined within the context of an economic limit test assessment (pre-tax and exclusive of accumulated depreciation amounts).

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no evident viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Prospective Resources are those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

Prospective Resources include Prospects and Leads. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that

they are considered drillable. Leads, on the other hand, are not sufficiently well defined to be drillable, and need further work and/or data. In general, Leads are significantly more risky than prospects and therefore are not suitable for explicit quantification.

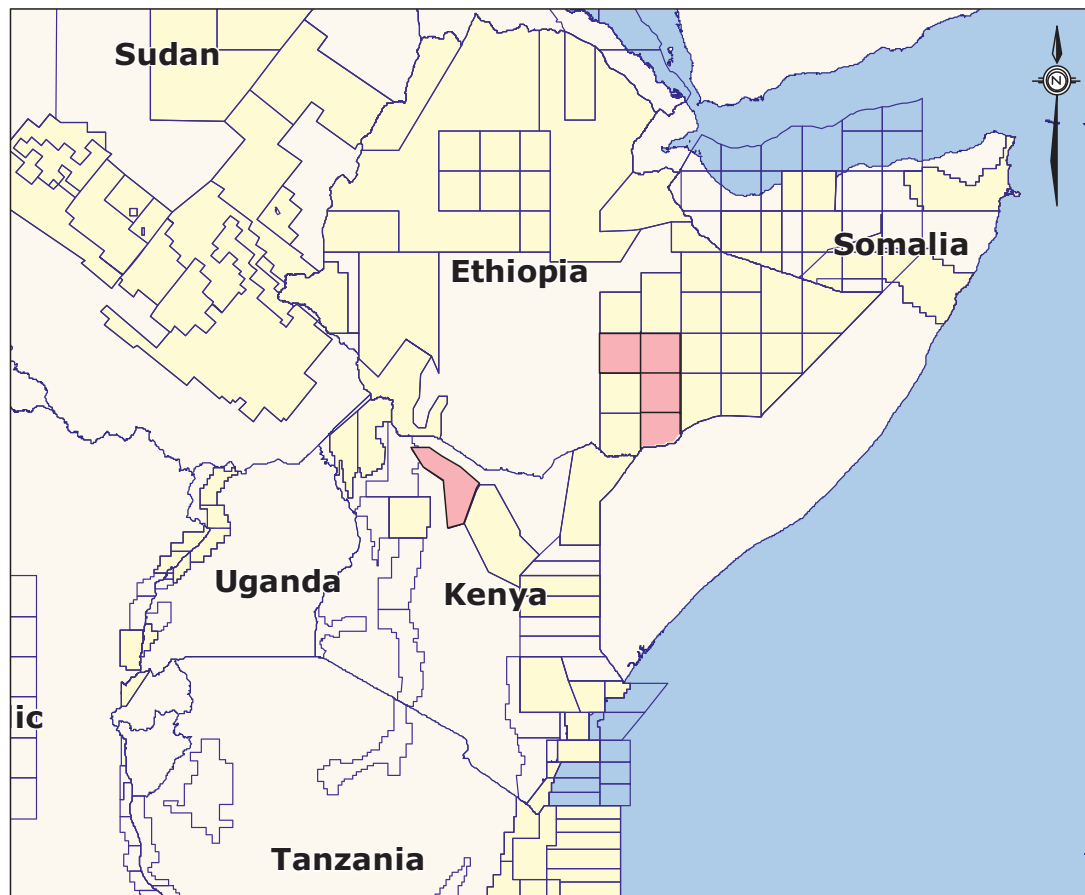
Prospective Resource volumes are presented as unrisks. It must be appreciated that Prospective Resources are risk assessed only in the context of applying the stated 'Geological Chance of Success', a percentage which pertains to the percentage probability of achieving the status of a Contingent Resource (where the Geological Chance of Success is unity). This dimension of risk assessment does not incorporate the considerations of economic uncertainty and commerciality.

It must be clearly understood that any determination of resources volumes, particularly involving continuing field development, will be subject to significant variations over short periods of time as new information becomes available and perceptions change. Not only are such estimates of Reserves and Contingent and Prospective Resources based on that information which is currently available, but such estimates are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. Contingent and Prospective Resources quantities should not be confused with those quantities that are associated with Reserves due to the additional risks involved. Those quantities that might actually be recovered may differ significantly from the estimates presented herein. A possibility exists that the accumulations and prospects will not result in successful discovery and development, in which case there could be no positive potential present worth.

GCA is an energy consultancy specialising in independent petroleum advice on resource evaluation and economic analysis. In the preparation of this report, GCA has maintained, and continues to maintain, a strict consultant-client relationship with BMEHL. The management and employees of GCA have been, and continue to be, independent of BMEHL in the services they provide to the company including the provision of the opinion expressed in this review and audit. Furthermore, the management and employees of GCA have no interest in any assets or share capital of BMEHL or in the promotion of the company. In the ordinary course of business GCA has previously provided services to BMEHL and may do so in the future.

The CPR must only be used for the purpose for which it was intended.

FIGURE I

**BLACK MARLIN ENERGY LIMITED: EAST AFRICAN ACREAGE OPERATED
BY AFRICA OIL CORPORATION****Legend:** BMEL Blocks

Source: Deloitte

BMEHL holds non-operated blocks in East Africa that contain under-explored plays in basins that have proven and productive analogues, or where the petroleum system is calibrated by existing well and seismic data. BMEHL's Gross and Net acreage is summarised in Table I.

TABLE I
BMEHL GROSS AND NET ACREAGE

Country	Blocks	Gross Acreage (Km ²)	Net Acreage (Km ²)
Kenya	Block 10A	14,747	2,949.4
Ethiopia	Blocks 2 and 6	24,570	7,371
	Blocks 7 and 8	21,840	6,552

The current seismic and well database provides sufficient information to identify a large number of leads. Some of these leads have the potential to target multiple stacked plays. Other leads will test only single plays, but with the potential to test stacked-pay.

The basins where these blocks are located have been explored over an extended period (often more than 50 years) and this activity has to date failed to discover commercial or potentially commercial volumes of hydrocarbons.

In Kenya, Block 10A is located in the Anza Graben. This is a Mesozoic basin related to similar Mesozoic basins of southern Sudan (Muglad Basin) where the petroleum system is proven and productive. The Muglad Basin is a potential analogue and provides calibration for the analysis of the prospectivity of these licences.

In Ethiopia, the Ogaden Basin is a proven hydrocarbon basin, however, to date no commercial production has been established. Oil, gas and condensate discoveries indicate that there is a complex petroleum system. The limited available data indicate (Calub and Hilala Gas discoveries in the Ogaden Basin of Ethiopia) that there is a wide range of potential petroleum type and volumes in this basin.

The estimation of Prospective Resource volumes for high-risk and poorly calibrated basins can be subject to large variation from the introduction of new information. The estimates presented in this report are based on all of the information available; however, new data or information is likely to have a material effect on the resource assessment values. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Tables 2, 3, and 4 detail the Prospective Resources of the company.

TABLE 2

**KENYA: SUMMARY OF PROSPECTIVE RESOURCES
AS AT 31st March, 2010**

Licence	Lead	Gross Best Estimate (MMBbl)	BMEHL Working Interest (%)	Net Best Estimate (MMBbl)	GCoS
Block 10A	Lead A	103	20	20.6	0.08
Block 10A	Lead B	82	20	16.4	0.09
Block 10A	Lead C	12	20	2.4	0.10
Block 10A	Lead D	53	20	10.6	0.08

Notes:

1. Net Prospective Resources are stated herein in terms of BMEHL's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSC. In this regard these volumes stated herein will exceed the volumes which will arise to BMEHL under the terms of the PSC.
2. It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
3. The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the re-categorisation of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.

TABLE 3
ETHIOPIA: OIL PROSPECTIVE RESOURCES
AS AT 31st March, 2010

Licence	Lead	Reservoir	Gross Best Estimate (MMBbl)	BMEHL Working Interest (%)	Net Best Estimate (MMBbl)	GCoS
Block 07	Lead A	U. Hamanlei	88	30	26.4	0.14
		Adigrat	83	30	24.9	0.09
		Calub	106	30	31.8	0.12
Block 07	Lead B	U. Hamanlei	50	30	15.0	0.12
		Adigrat	52	30	15.6	0.08
		Calub	98	30	29.4	0.10
Block 07	Lead C	U. Hamanlei	103	30	31.0	0.12
		Adigrat	112	30	33.6	0.08
		Calub	86	30	25.8	0.10
Block 06	Lead D	U. Hamanlei	40	30	12.0	0.13
		Adigrat	112	30	33.6	0.09
		Calub	34	30	10.2	0.11

Notes:

1. Net Prospective Resources are stated herein in terms of BMEHL's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSA. In this regard these volumes stated herein will exceed the volumes which will arise to BMEHL under the terms of the PSA.
2. It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
3. The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the re-categorisation of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.
4. The Prospective Resource volumes are for Oil or Gas, not Oil and Gas (the alternative volumes for gas are presented in Table 4).

TABLE 4

**ETHIOPIA: GAS PROSPECTIVE RESOURCES
AS AT 31st March, 2010**

Licence	Lead	Reservoir	Gross Best Estimate (BCF)	BMEHL Working Interest (%)	Net Best Estimate (BCF)	GCoS
Block 07	Lead A	Adigrat	525	30	157.5	0.09
		Calub	1,129	30	338.7	0.12
Block 07	Lead B	Adigrat	326	30	97.8	0.08
		Calub	1,120	30	336.0	0.10
Block 07	Lead C	Adigrat	724	30	217.2	0.08
		Calub	1,010	30	303.0	0.10
Block 06	Lead D	Adigrat	221	30	66.3	0.09
		Calub	394	30	118.2	0.11

Notes:

1. Net Prospective Resources are stated herein in terms of BMEHL's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSA. In this regard these volumes stated herein will exceed the volumes which will arise to BMEHL under the terms of the PSA.
2. It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
3. The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the re-categorisation of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.
4. The Prospective Resource volumes are for Oil or Gas, not Oil and Gas (the alternative volumes for oil are presented in Table 3).

DISCUSSION

I. REGIONAL GEOLOGICAL SETTING

The blocks are all located onshore in the north of East Africa (Horn of Africa) (Figure 1). All of the blocks are sparsely explored with only limited well and seismic data available to constrain the petroleum system and prospectivity. However, there is sufficient data on the blocks to demonstrate that multiple petroleum systems are developed within (at least) part of these blocks.

The density and quality of available data are variable and reflects the variation in exploration maturity of each block. However, in general the exploration maturity and data density are low.

All of the Licences contain Mesozoic petroleum systems, but the Ogaden Basin also has Permian potential. Figure 2 provides a summary of the stratigraphy in each of these areas. There are many similarities between these petroleum systems; however, there are also several critical differences between the areas.

The northern part of East Africa was part of the much larger Gondwana mega-continent at the start of the Mesozoic (Figure 3). Rifting associated with the northerly drift of this mega-continent and the separation of parts of the continent throughout the Mesozoic (e.g. separation of Australia / India / Africa) led to the development of complex rift geometries across the area. It is within these basins that the petroleum systems developed.

Following the deposition of the sediments in these basins further tectonic activity has led to the generation of the geological structures. This deformation is as a consequence of the further break-up of Gondwana and the development of the Central African Rift Basin in the Cretaceous and the separation of Arabia from Africa and the evolution of the East African Rift Basin in the Tertiary.

I.1 Common Themes to the Analysis

All of the Prospective Resources summarised in this report were derived using Monte Carlo volumetric simulation, however, in this report only the Best Case (P_{50}) values are reported. The inputs for this analysis were obtained from data, reports and independent analysis of the information supplied by AOC.

GCA uses a Geological Chance of Success (GCoS) template (Figure 4) illustrates two elements) to derive an estimate of the risk associated with Prospective Resources. The use of the template ensures that consistency is maintained between prospects. The template takes into account the information available to be used in the evaluation and also the quality / applicability of these data to resolve the issue. This allows a consistent GCoS to be derived.

FIGURE 2

EAST AFRICA STRATIGRAPHIC COLUMN COMPARISON

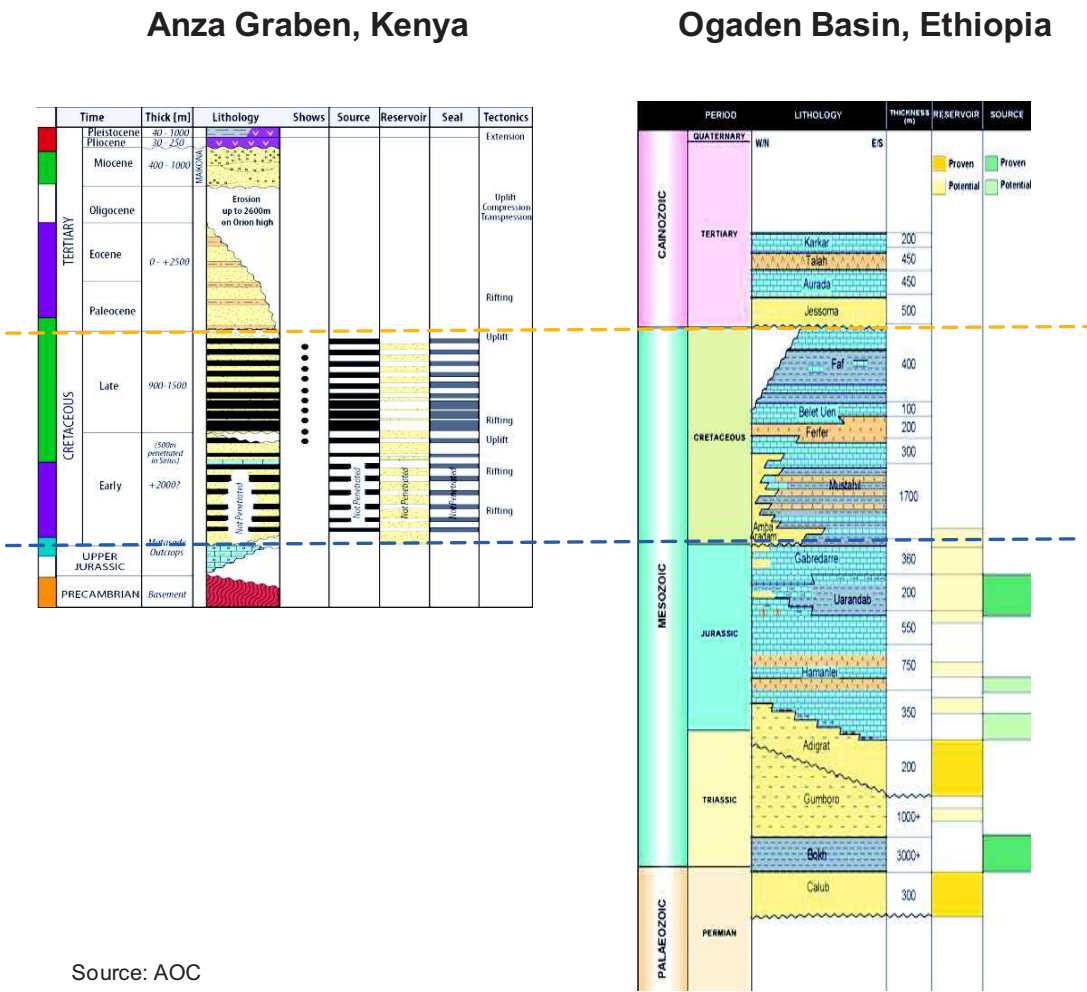
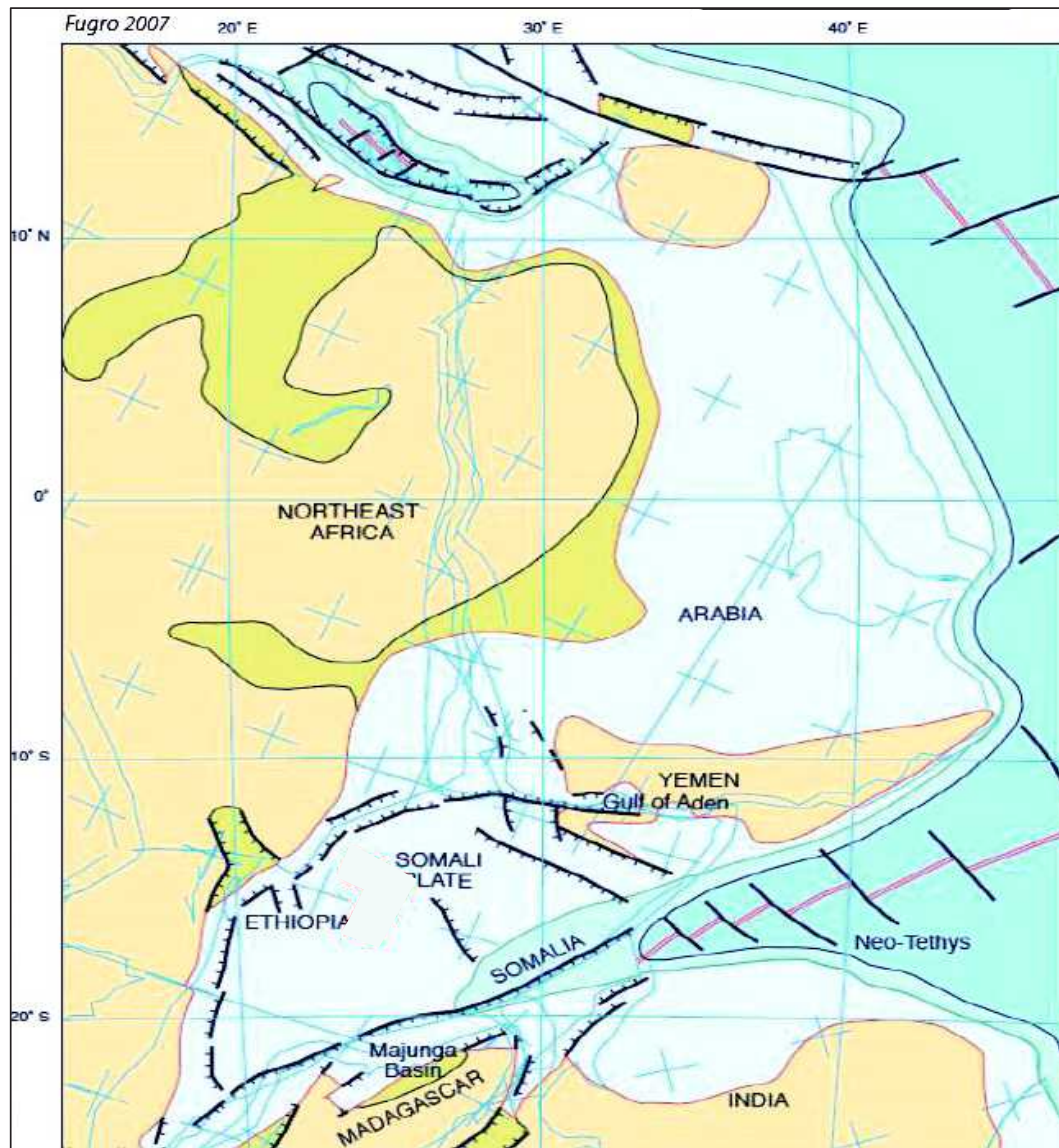


FIGURE 3
GONDWANA LATE JURASSIC RECONSTRUCTION



Source: AOC

FIGURE 4

GCA GEOLOGICAL CHANCE OF SUCCESS (GCOS) TRAP AND SEAL TEMPLATE

**Confidence level based
on quality and quantity
of relevant data**

- High**
- Multiple wells
 - Good quality seismic (mainly 3D)
 - Petroleum system well understood
- Moderate**
- Some wells
 - Variable quality seismic (mainly 2D)
 - Knowledge of petroleum system
- Low**
- Regional knowledge; trendology
 - Evaluation uses analogues

Confidence ↑

Trap and Seal

0.1 – 0.3	NO INPUT ALLOWED	0.8 – 1.0*
0.2 – 0.3	0.5 – 0.7	0.7 – 0.9
0.3 – 0.4	0.3 – 0.5	0.4 – 0.6
Low	Moderate	High
GCOS →		

Low

Moderate

High

Complex, poorly defined trap, mainly stratigraphic/structural

Moderately complex; mainly structural traps; some stratigraphic component.

Simple, well defined trap, mainly structural.

Thin, discontinuous seal

Thin, continuous seal

Thick, continuous seal

Multiple, intersecting faults – fault leakage

Some fault seal concerns

Simple fault pattern – fault seal

2. KENYA

2.1 Location

Block 10A is located in the Anza Graben of NE Kenya (Figure 5) a NW-SE oriented Mesozoic graben along trend from the prolific Mesozoic play of southern Sudan.

AOC and its co-venturers (EAX- Kenya (a wholly owned subsidiary of BMEHL) and Raytec) holdings are shown in Table 5. However, this Block is held a under Production Sharing Contract (PSC) and the percentages shown are working interest (WI) percentages, does not reflect the resource attributable to the co-venturers through their economic entitlement in these licences. Net Prospective Resources are stated herein in terms of BMEHL's net WI in the properties and, due to the very immature nature of these prospective resources, have not been computed as net entitlement volumes under the terms of the PSC. In this regards these volumes stated herein will exceed the volumes which will arise to BMEHL under the terms of the PSC.

2.2 Geological Overview

The Anza Basin is a NW-SE trending rift basin which forms part of a Late Jurassic-Cretaceous rift system, which extends across central Africa. The basin is over 580 km long and 150 km wide with a potential prospective area in excess of 50,000 km². The basin is filled in places with more than 6,000 m of Mesozoic and Cenozoic sediments and locally by Plio-Pleistocene basalts. Bouger and residual gravity anomalies have highlighted several sub-basins separated by intra-basin highs.

A Karoo-aged, NE-SW trend rift occurred in the eastern part of Mozambique, Kenya, Ethiopia and Somalia, and renewed extension along this trend during Mid Triassic-Early Jurassic resulted in the separation of Madagascar from Africa and marine transgression into Eastern Kenya. The subsidence of the NW trending Anza rift began during the Late Jurassic at the time of the deposition of the marine limestone deposition in the central Anza Basin. Rift expansion during the Neocomian, during a continent-wide extension phase in the Anza Graben was contemporaneous with the formation of the along strike NW trending Muglad and Melut rift basins of Sudan. Further extension during the Late Cretaceous reactivated the subsidence in the Anza Basin and the Cretaceous saw the deposition of up to 6 km of predominantly continental and fluvial lacustrine sediments in the deepest parts of the basin. Further rifting in the Palaeocene-Eocene saw thick continental deposition in subsiding troughs.

During the Oligo - Miocene, as a result of tectonic movements related to the formation of the East African Rift System in Ethiopia and Northern Kenya, the Anza Basin was affected by significant compressional and/or transpressional movements. Some of the normal faults formed during Cretaceous-Paleogene rift phases were reactivated and large scale inversion occurred. New faults with different fault orientations were also formed which uplifted large basement blocks. Basin modelling and well data indicate that several thousand feet of sediments were locally eroded. Following basin inversion during the Miocene, thick lacustrine and continental fluvial sediments were deposited above the regional Base Miocene unconformity.

FIGURE 5
KENYA BLOCK 10A

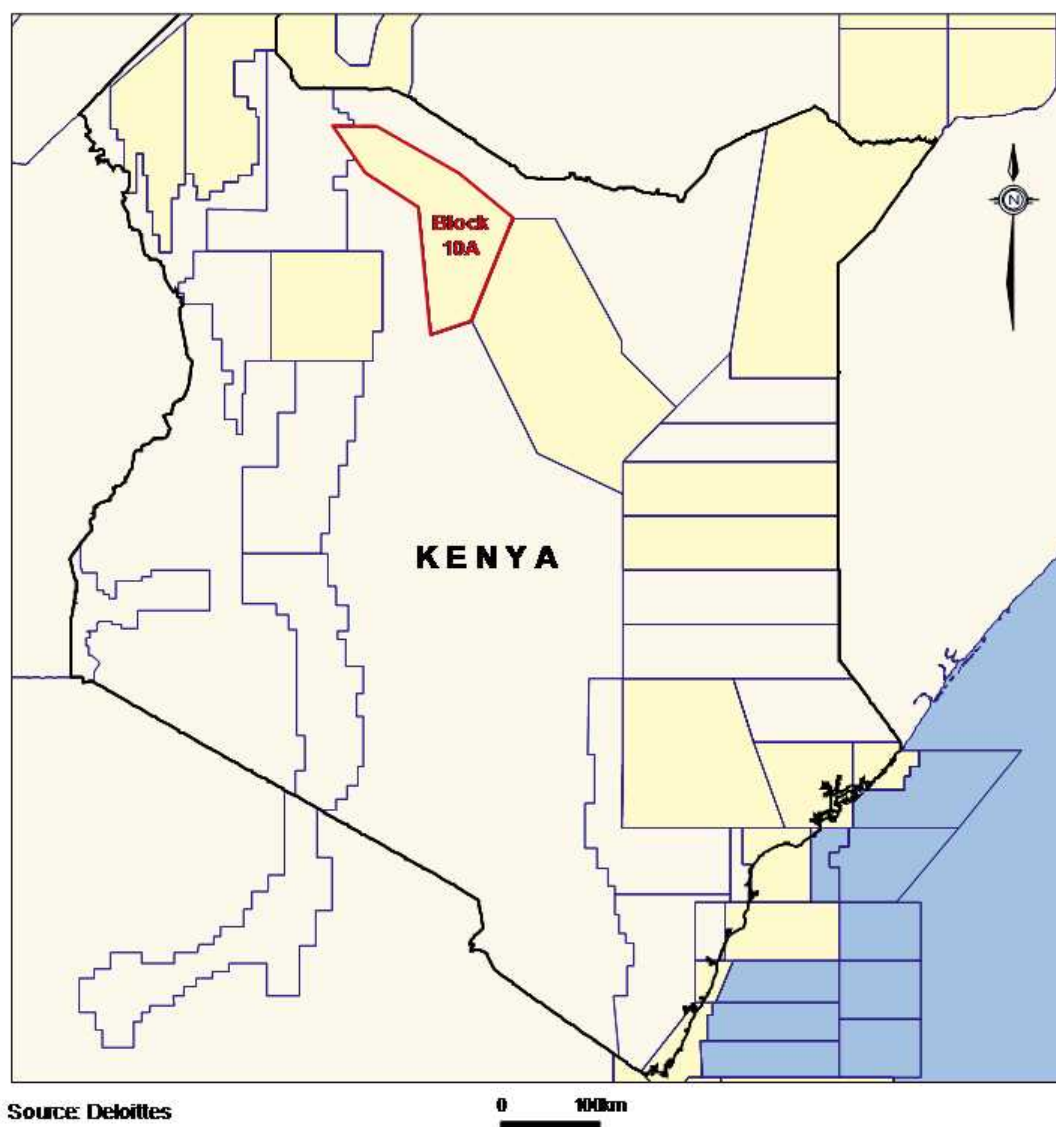


TABLE 5
KENYA: BLOCK 10A WORKING INTEREST

Block	Company	Working Interest
Block 10A	AOC – Kenya	55
	EAX-Kenya ²	20
	Raytec	25

Notes:

1. This is the Working Interest equity, and does not take into account the effects of the PSC.
2. EAX – Kenya is a wholly owned subsidiary of BMEHL.

The basin has undergone two periods of extensive flood basalt extrusion associated with the East African Rift System during the Latest Miocene-Early Pliocene and the Late Pliocene-Pleistocene. These basalts covered the whole area of Block 10A with thicknesses varying from 30-250 m. This volcanic activity is believed to have had only a limited effect on the petroleum system.

The Petroleum System has been tested by several wells and the presence of reservoir, seals and potential source rocks has been demonstrated. The Anza Graben is interpreted to be an extension of the prolific Sudan Basin, a Cretaceous rift basin system of north-Central Africa.

The low level of exploration activity in both blocks means that ages and thicknesses of the formations drilled to date are poorly constrained and no formal stratigraphy is defined. Source rocks, reservoirs and seals are known from exploration wells and there is only partial penetration of most of the units in the basin. In addition, correlation between the wells is difficult because they are drilled in different sub-basins each containing units not present in the other wells.

2.3 Exploration History

Exploration in the Anza Basin began in the 1970's, to the South of Block 10A, by a Chevron/Esso Joint Venture which undertook geological surveying and the acquisition of potential field data (gravity and magnetics). Approximately 2,000 km of 2D seismic was acquired, and in 1976 two exploration wells were drilled. Both wells were plugged and abandoned with minor gas shows being reported in Anza-I well. These disappointing results led to Chevron relinquishing the contract in 1977.

In 1977, gravity data were compiled and these indicated the presence of the NW trending Anza Basin, aligned with the Muglad and Melut rift basins of Sudan. In 1982 an aeromagnetic survey over the North of Kenya defined the overall shape of the Anza rift basin and modelling results indicate a basin fill of up to 6,000 m of sediment as well as identifying the location of several sub-basins separated by basement highs. The gravity data indicated that the basin extended northwards below the Chalbi desert towards Sudan which sparked renewed interest in Kenya and the Anza Rift. In 1985, Amoco signed three Production Sharing Contracts (PSC's) with the Government of Kenya. This included Block 10, which incorporated the area now covered by Block 10A.

2.4 **Block 10A**

2.4.1 **Overview**

Block 10A covers an area of 14,747 km² in the north west of the Anza Basin (Figure 5). The PSC was signed on 4th October, 2007 with an effective date of 2nd January, 2008. The initial exploration period is four years with the option of extending this for two further periods of 18 months each. The work commitments for the first exploration period include the acquisition of 750 km 2D seismic and the drilling of one well to a minimum of 3,000 m vertical depth. The two extension periods each carry a commitment to drill 1 further well.

2.4.2 **Previous Exploration**

Amoco signed the Block 10 PSC on 1st March, 1985 in the northern Anza Basin. It undertook regional landsat image interpretation and geological fieldwork over the block and acquired 6,550 gravity readings to infill the gravity data base.

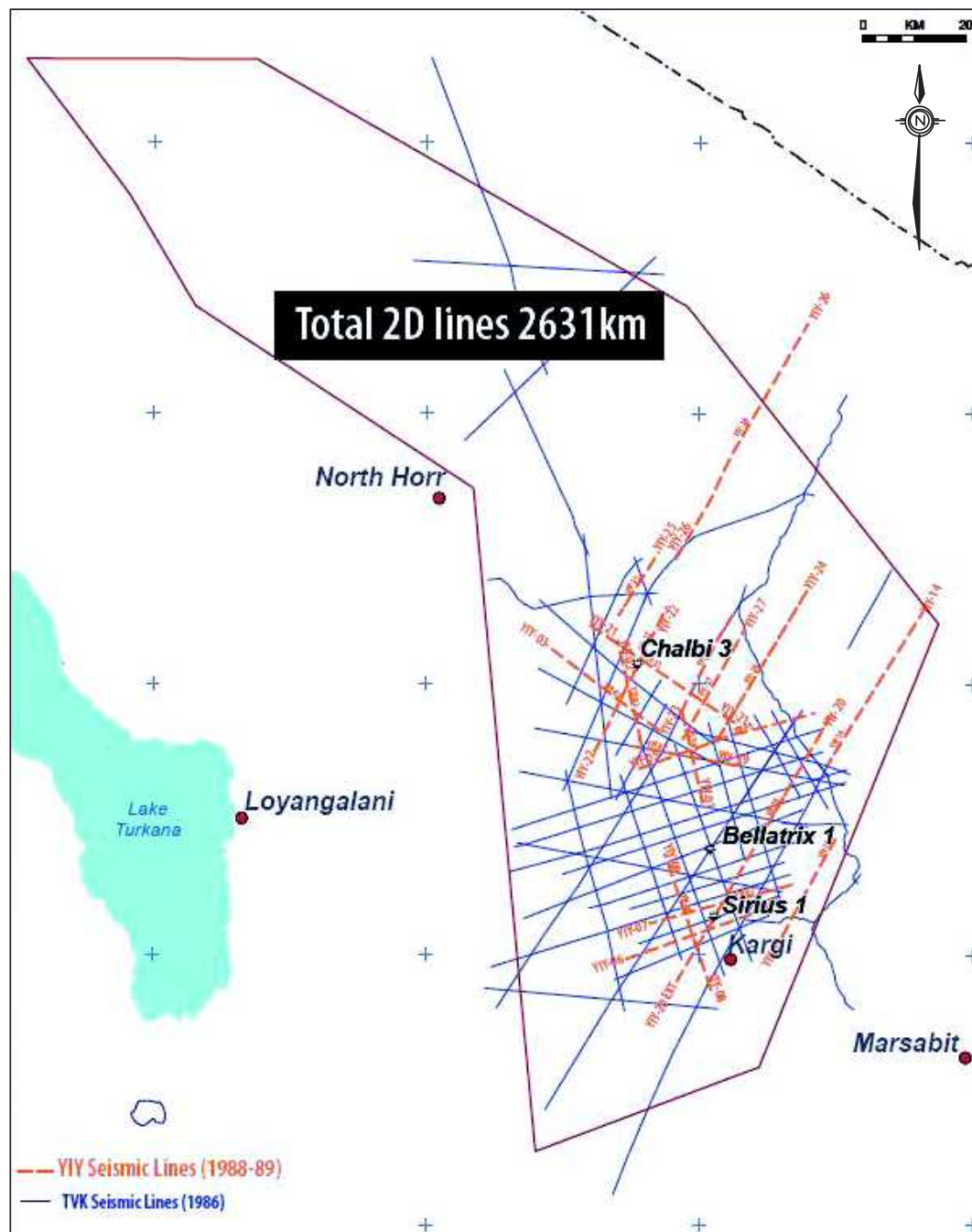
Two cored stratigraphic wells Kargi-1A (TD 770 ft (235 m)), Laga Balal (TD 2,270 ft (692 m)) and two water wells, Kargi-1 (305 ft) and Kobi Fora-1 (540 ft (165 m)) were drilled within Block 10A. These were logged and cored to provide porosity and grain density data and to determine the thickness of the Pliocene flood basalts.

In 1986, 2,070 km 2D seismic (TVK lines) were acquired in a sparse grid focussing on the southern part of Block 10A. The integration of the seismic interpretation with the gravity data allowed several large fault closed structures to be mapped and in 1988 Amoco drilled two exploration wells. Figure 6 summarises the well and seismic database for Block 10A.

Sirius-1

Sirius-1 (TD = 11,000 ft (3,353 m)) tested the Mesozoic and Cenozoic section of a NW trending horst block. The well drilled 40 m of Pliocene basalts, underlain by some 900 m of Miocene, Maikona Formation sandstone and conglomerates. The underlying Upper Cretaceous consisted of more than 1,000 m of alternating shales and arkosic sandstones. The sandstones, which form approximately 50% of this interval, are porous (15-25%) fluvial and lacustrine deposits. The shales are organic rich with Total Organic Carbon (TOC) of up to 5.3% and contained amorphous kerogen with high Hydrogen Index that have good source rock potential. Abundant oil and gas shows were reported in the Cretaceous sandstone between 1,150 and 2,255 m KB. The Lower Cretaceous is represented by 345 m of quartz sandstone (porosity = 10-20%) interbedded with lacustrine shale. This is underlain by a massive, 146 m of thick fine to medium grained well sorted lacustrine littoral or aeolian sandstone with good porosity (8-22%; average 15.4%) and good N/G (84%), which represents a good reservoir target.

FIGURE 6
KENYA BLOCK 10A, WELL AND SEISMIC DATABASE



Source: AOC

At 2,597 m KB the well encountered an doleritic intrusion which was incorrectly interpreted as Basement. Seismic data indicates a further Lower Cretaceous section below the TD which could offer the potential of further source or reservoir rocks. Five DST's recovered low salinity water DST #3 recovered 30 Bbl water with traces of paraffinic oil from an Upper Cretaceous sandstone. Geochemical studies indicate the oil is similar to that from the Muglad Basin in Sudan.

The failure of the well to find economic accumulations of hydrocarbons is attributed to a lack of lateral seal with Cretaceous reservoir sandstone being juxtaposed across faults with Cenozoic sandstone. In addition the well was drilled on the old TVK lines and is thought to have missed the crest of the structure, therefore potentially missing any hydrocarbon column.

Bellatrix-I

The Bellatrix-I well was drilled to test a rotated fault block to the north of Sirius-I. The well penetrated Pliocene basalts underlain by Miocene Maikona sandstones and conglomerates which lie above the Miocene base unconformity. Below this, the well penetrated 1,220 m of sandstone and shale of Upper Cretaceous or possibly Paleogene age. This interval is underlain by Upper Cretaceous, fluvial/lacustrine arkosic sandstones and grey shales deposited in a freshwater (lacustrine) environment. The well TD'd at 11,414 ft MD (3,479 m) prior to reaching the Lower Cretaceous target (Figure 7).

Coal seams were penetrated between 2,237-2,288 m KB and oil and gas shows were reported between 2,752 m and TD. Log analysis indicates sands with 10-20% porosity, but high water saturation. Most cutting samples are poor in organic matter, but a few samples contained up to 5% TOC and the cored coal up to 15%. Amorphous oil prone kerogen was observed in several samples below 2,360 m KB with vitrinite reflectance increasing from 0.78% at 2,217 m KB to 1.07% at TD.

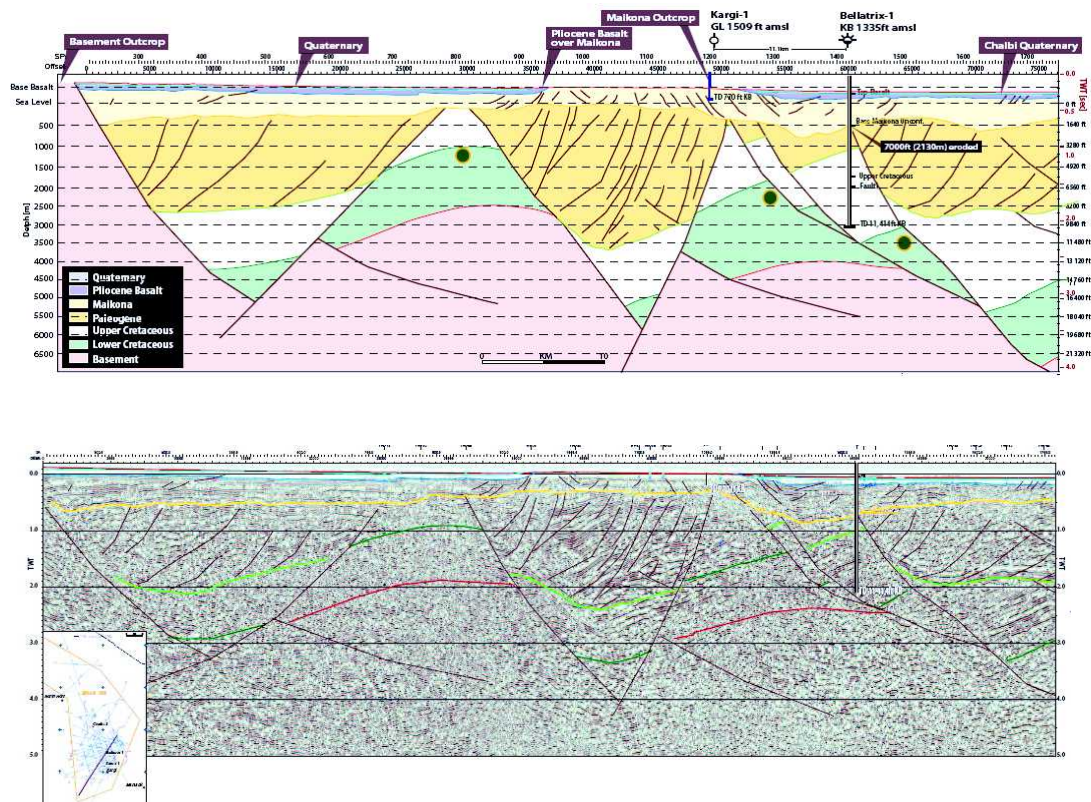
Bellatrix-I did not discover potentially commercial hydrocarbons and failure is attributed to a lack of lateral seal. In addition the well was also drilled on maps from the widely spaced TVK seismic lines and may have been located off of the crest of the structure.

Chalbi-3

Chalbi-3 (1989) was drilled following the acquisition of a further 535 km of 2D seismic, and an airborne gas sensing radar survey. The well was drilled to the NW of Bellatrix-I to evaluate Lower Cretaceous reservoirs in a 4 way dip closed structure. The well penetrated the Pliocene Basalts and Maikona Formation above the Base Miocene unconformity. This was underlain by over 900 m of very sandy Upper Cretaceous sediments followed by an Aptian and Albian section of lacustrine shales and interbedded sandstones which were absent in both Sirius-I and Bellatrix-I. The well found minor shows of oil and gas, and was TD'd in the Lower Cretaceous.

Failure of the well is attributed to the lack of a seal due to the very sandy Upper Cretaceous section. The Lower Cretaceous section is poor reservoir quality due to the presence of Laumonite cement. The structure was not as simple as first anticipated, probably lacking closure and being heavily faulted.

FIGURE 7
KENYA BLOCK 10A, GEOSEISMIC SECTION



Source: AOC

No exploration work was performed in Block 10 after 1990, and Amoco relinquished the Block in 1994.

2.4.3 Petroleum Systems and Plays

The ages and thicknesses of the formations drilled to date in Block 10A are poorly defined and no formal stratigraphic column has been developed. Source rocks, reservoirs and seals have been found in the exploration wells, but there is only partial penetration of many of the units in the basin.

Oil and gas shows are reported in all of the wells, indicating that a petroleum system has at some stage generated, expelled and migrated hydrocarbons. The most likely source rocks are the dark grey lacustrine shales of the Upper Cretaceous. In Sirius-I these demonstrated excellent source rock potential with TOC values of 1-5% and Hydrocarbon Index of 200-700 concentrated in the interval between 1,470 – 1,980 m KB. The section contains a mixture of Type I and Type III Kerogen in thin organic rich layers capable of generating light oil and condensate and/or wet gas. The Upper Cretaceous of Bellatrix-I averaged 1.46% TOC between 2,243 – 3,440 m KB. The section also contained coal layers with high Hydrogen Index and up to 14.95% TOC. The Lower Cretaceous offers lower source rock potential however sampling and penetration has been limited. Oil samples recovered from Sirius-I RFT and DST#3 have geochemical similarities with oil recovered from the Muglad Basin of Sudan.

Basin modelling indicates that peak oil generation was from the Upper Cretaceous to the Palaeocene and on into the Eocene. Generation ceased during the Oligocene when basin inversion occurred. Analysis of the well data indicates that the amount of uplift varied from well to well. There is no clear trend with regard to the opening of the East African Rift Valley at this time (although this may be a major contributor) and the different values may indicate localised inversion and redefinition of the traps.

Log analysis of the exploration wells has identified potential reservoirs in the Palaeogene and Upper and Lower Cretaceous sections. In the Palaeogene and Upper Cretaceous arkosic sandstones offer good reservoir potential. The section includes a 233 m section with high net-to-gross and with average porosity of 21.5% (15-35%). The Lower Cretaceous (Barremian-Neocomian) reservoir is formed of quartz sandstone. The Neocomian section in well Sirius-I, contains a 146 m thick section of clean aeolian or lacustrine littoral sandstone with a high N/G of 84% and average porosity of 15.4% (8-22%). The Barremian section contains over 275 m of quartz sandstone with calcareous cement deposited in a fluvial to lacustrine environment. The reservoir has a N/G of 43% and average porosity of 12.8% (8-18%). Reservoir porosities decrease with depth due to deep burial before Oligocene inversion and uplift.

The interbedded shale and sandstone nature of the Upper and Lower Cretaceous offers the potential for intraformational reservoir - seal pairs. In addition, the thick (170 m) Upper Cretaceous shale is a potential regional seal above the Lower Cretaceous reservoirs.

2.4.4 Prospective Resources Evaluation

The Operator has identified four leads in the southern part of Block 10A (Figure 8). The target reservoir is the Lower Cretaceous quartz sandstone penetrated at Sirius-I well.

All of the leads require, to some extent, cross-fault seal to generate the trap size to support the Prospective Resource estimates shown below. This is the critical risk factor in all of the prospects and leads.

GCA has derived Gross in-place and Gross and Net Prospective Resource estimates for the leads. The results of this analysis are reported in Tables 6 and 7.

Lead A

Lead A represents a 4-way dip closure over a basement high. Mapping is based on limited data (4 seismic lines) and the interpretation is immature. The lead has an area of 18.4 km² based on the Operator's mapping. The target depth is 1,600 to 2,000 m.

Lead B

Lead B is a fault closed south west dipping tilted fault block. Trap integrity relies on cross-fault juxtaposition of Upper Cretaceous shale with the Lower Cretaceous reservoir. The lead is constrained by more than 10 seismic lines and is updip from Sirius-I which demonstrated good source and reservoir potential with significant oil and gas shows. On the Operators' map the lead has an area of 15.3 km². The target drill depth is 2,010 - 2,160 m.

Lead C

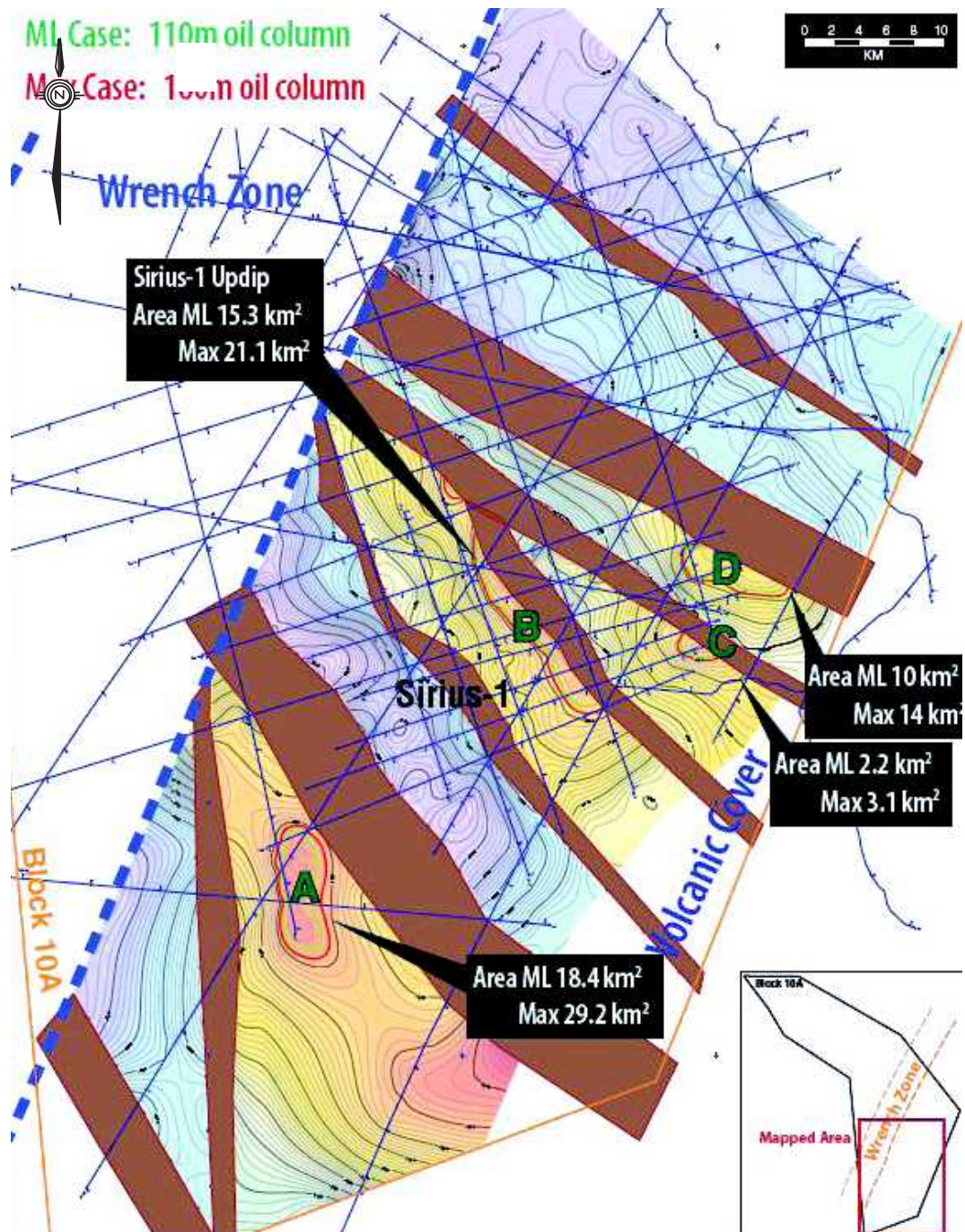
Lead C is a second fault closed south-west dipping tilted fault block defined on 5 to 6 seismic lines. Structural control is poor to the south due to the absence of seismic data. Like Lead B the integrity of the trap relies upon the cross-fault juxtaposition of Upper Cretaceous shale with the Lower Cretaceous reservoir. The Operator maps a most-likely area of 2.2 km². The target drill depth is 2,080 - 2,230 m.

Lead D

Lead D is also a fault closed, south-west dipping tilted fault block defined on 3 seismic lines, plus the tails of 2 additional lines. Trap integrity relies on cross-fault juxtaposition of Upper Cretaceous shale with the Lower Cretaceous reservoir. The lead has an area of 10 km². The target drill depth is 2,530 - 2,680 m.

FIGURE 8

KENYA BLOCK 10A, LEADS



Source: AOC

TABLE 6

**KENYA: SUMMARY OF INPLACE ESTIMATE
AS AT 31st March, 2010**

Licence	Lead	Gross Best Estimate (MMBbl)
Block 10A	Lead A	442
Block 10A	Lead B	335
Block 10A	Lead C	48
Block 10A	Lead D	217

TABLE 7

**KENYA: SUMMARY OF PROSPECTIVE RESOURCES
AS AT 31st March, 2010**

Licence	Lead	Gross Best Estimate (MMBbl)	BMEHL Working Interest (%)	Net Best Estimate (MMBbl)	GCoS
Block 10A	Lead A	103	20	20.6	0.08
Block 10A	Lead B	82	20	16.4	0.09
Block 10A	Lead C	12	20	2.4	0.10
Block 10A	Lead D	53	20	10.6	0.08

Notes:

1. Net Prospective Resources are stated herein in terms of BMEHL's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSC. In this regard these volumes stated herein will exceed the volumes which will arise to BMEHL under the terms of the PSC.
2. It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
3. The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the re-categorisation of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.

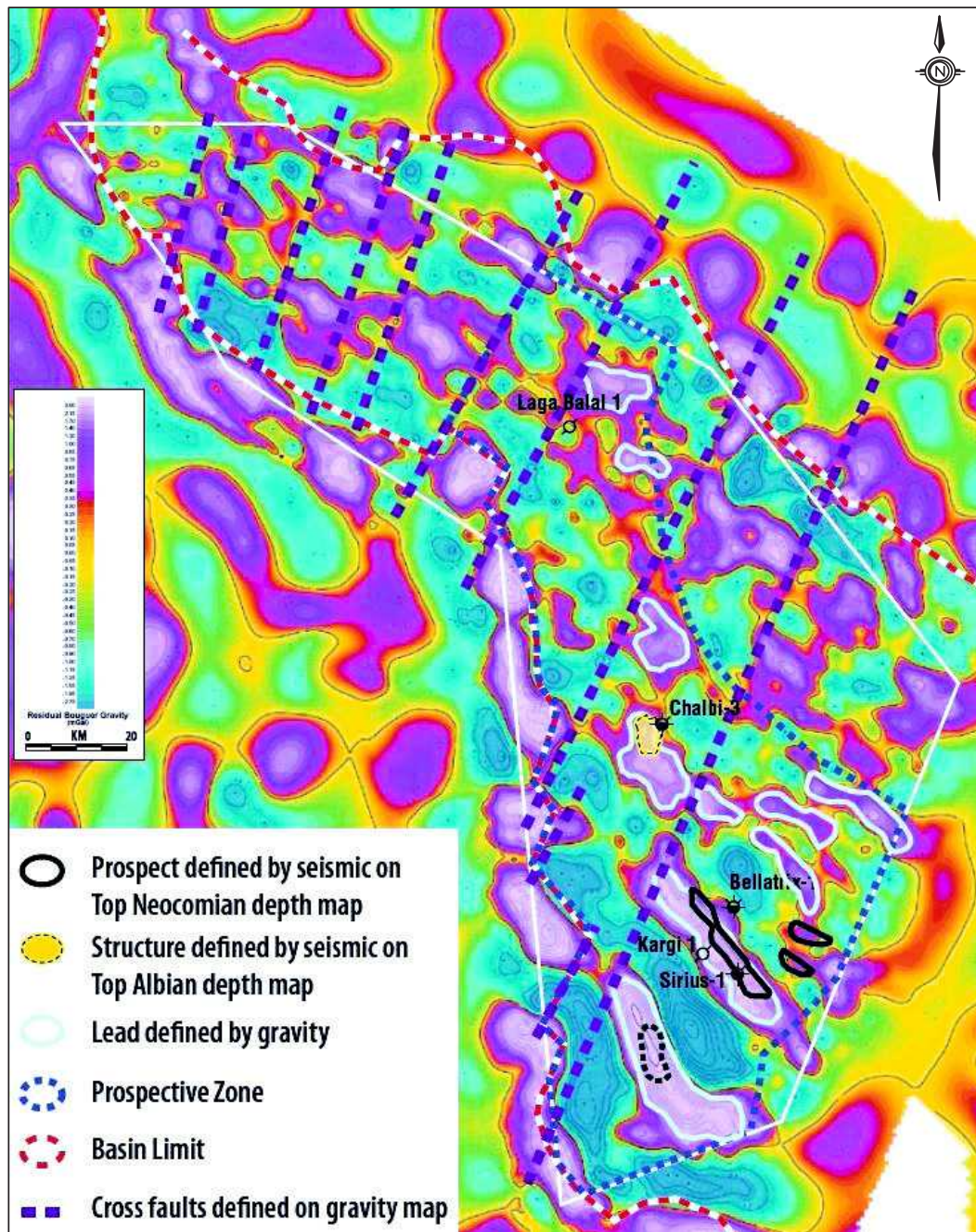
Additional Leads

In addition to the four leads identified on the seismic data grid, The Operator has defined eight additional leads based on the interpretation of the gravity data (Figure 9). These leads fall in areas where there is some seismic coverage to areas outside the survey area. These leads provide additional attraction should one of the seismically defined leads be successful. No volumes are attributed to these leads in this report.

2.4.5 Kenya Block 10A GCoS

Block 10A lies in the north-western part of the Anza Basin. Only the Cretaceous Clastic play has been identified. The Cretaceous clastic play has been proved by drilling on and near to the block, however, to date no commercial hydrocarbons have been found in this play in Kenya. This play is an extension of the proved and productive

FIGURE 9
KENYA BLOCK 10A, BOUGUER GRAVITY MAP



Source: AOC

Muglad Basin of Sudan where age equivalent reservoir and source rocks charge fault bounded traps.

GCA has derived a GCoS for each of the prospects and leads. The results of this analysis are summarised in Table 9.

The principal risk associated with these prospects is trap definition. This is not solely the presence of a structure at the location, and includes trap effectiveness (top and cross-fault seal). Therefore the effectiveness of cross-fault seal has to be taken into account. In all of the leads on the block cross-fault seal into an adjacent “thief” bed is the main risk for the lead.

Given the current seismic database it is possible only to define structural highs. The quality and density of data precludes the quantification of the sealing capacity of the faults that bound these structures. Earlier explorers attempted to use Allen diagrams to map out the sealing capacity. However, GCA believes that there is insufficient data available on the geometry of the faults or the stratigraphy to make this activity a worthwhile risk reducer.

3. ETHIOPIA

3.1 Overview

BMEHL has an interest in two licences consisting of 4 blocks in the Ogaden Basin of eastern Ethiopia (Figure 10). The Ogaden Basin blocks are relatively underexplored with limited well and seismic data to constrain the petroleum system proved by the Calub and Hilala Fields to the east.

BMEHL holds these Blocks in two PSA with a net WI of 30% (Table 8) Net Prospective Resources are stated herein in terms of BMEHL's net Working Interest (WI) in the properties and, due to the very immature nature of these prospective resources, have not been computed as net entitlement volumes under the terms of the PSA. In this regards these volumes stated herein will exceed the volumes which will arise to BMEHL under the terms of the PSA.

3.2 Blocks 2 and 6, and 7 and 8, Ogaden Basin

3.2.1 Overview

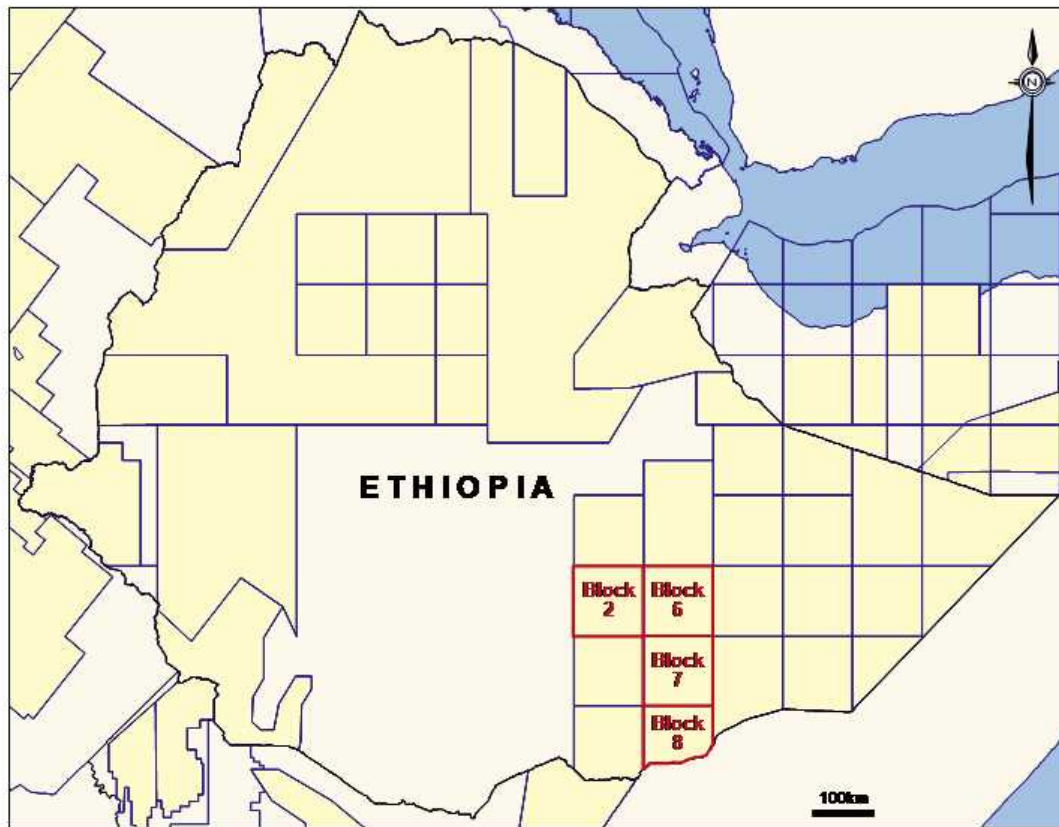
Blocks 2 and 6, and Blocks 7 and 8 are located in the Ogaden Basin of eastern Ethiopia, Lundin signed the PSA for Blocks 2 and 6, which cover a total area of 24,570 km², in November, 2007 and the PSA for Blocks 7 and 8, covering 21,840 km² in July, 2007.

Block 2 and 6 PSA

The PSA's has an initial exploration period of four years, with minimum expenditure of U.S.\$10.8 MM. In the initial period all existing 2D seismic data was reprocessed and 15,000 line km of airborne gravity and magnetic data was acquired over both PSA's. A 1,250 line km 2D seismic is to be acquired on the PSA. There is an option to extend the agreement for a further 2 years, incurring a minimum expenditure of U.S.\$10.5 MM. There is a commitment to acquire and process and additional 1,300 line km 2D seismic lines and drill one exploration

FIGURE 10

ETHIOPIA LOCATION, BLOCKS 2 AND 6 AND 7 AND 8



Source: Deloitte

TABLE 8
ETHIOPIAN BLOCKS AND WORKING INTERESTS

Block	Company	Working Interest
Blocks 2/6	AOC – Ethiopia (Op)	55
	New Age	15
	EAX-Ethiopia ²	30
Blocks 7/8	AOC-Ethiopia (Op)	55
	New Age	15
	EAX-Ethiopia ²	30

Notes:

1. This is the Working Interest percentage, and does not take into account any PSA effect.
2. EAX-Ethiopia is a wholly owned subsidiary of BMEHL.

well to a minimum depth of 3,000 m. A further 2 year extension is available with a minimum expenditure of U.S.\$13.0 MM, with a work programme to include the acquisition and processing of 200 km 2D seismic and a further two exploration wells to a minimum depth of 3,000 m.

Block 7 and 8 PSA

The PSA's has an initial exploration period of four years, with minimum expenditure of U.S.\$17 MM. In the initial period all existing 2D seismic data was reprocessed and 15,000 line km of airborne gravity and magnetic data was acquired over both PSA's. A 1,250 line km 2D seismic is to be acquired on the PSA, and one exploration well is to be drilled to a minimum depth of 3,000 m. There is an option to extend the agreement for a further 2 years, incurring a minimum expenditure of U.S.\$17.0 MM. This includes a commitment to acquire and process 1,300 line km 2D seismic lines and one exploration well to a minimum depth of 3,000 m. A further 2 year extension is available with a minimum expenditures of U.S.\$13.0 MM, with a work programme to include the acquisition and processing of 200 km 2D seismic and a further two exploration wells to a minimum depth of 3,000 m.

Blocks 2 and 6, and 7 and 8 are within in the Ogaden Basin of eastern Ethiopia. The basin developed in the Palaeozoic Karroo and has undergone a complex deformation history. Since the Late Cretaceous there have been periods of compression and deformation due to its broader plate tectonic setting. This tectonic and stratigraphic history has resulted in accumulations of up to 10 km of sediments. The succession can be broadly divided into two megasequences; the Lower comprising mainly continental clastics of Permian to earliest Jurassic and the Upper Late Jurassic to Cretaceous formed dominantly of shallow water carbonates and clastics (Figure 11).

Deposition of the largely non-marine Lower Megasequence commenced in the Carboniferous and continued through the Permian until the Early Jurassic. The lowest formation is the Calub Formation which overlies crystalline basement, and was deposited as basal sandstones and conglomerates in a glacial-fluvial environment. The overlying Bokh Formation consists of lacustrine shale deposited at the onset of rifting

FIGURE 11

ETHIOPIA STRATIGRAPHY AND PETROLEUM SYSTEMS

		TIME SCALE	PHASE	FORMATION	SOURCE	RESERVOIR		
Upper Megasequence	CRETACEOUS		POST RIFT	FERFER	AMBA ARADOM			
				MUSTAHL				
				GORRAHEI				
	JURASSIC	LATE	POST RIFT	GABREDARRE			Upper Mega-sequence - Primarily inner ramp and platform carbonates and evaporites - Jurassic to Cretaceous	
				ANTALO	UARANDAB			
					UPPER HAMANLEI			
		MIDDLE						
			SYN RIFT	MIDDLE HAMANLEI				
		EARLY	EARLY RIFT	LOWER HAMANLEI				
TRIASSIC		INITIAL RIFT	ADIGRAT			Lower Mega-sequence - Primarily terrigenous clastics - Permian to Triassic/Earliest Jurassic - Accumulated in initial Karroo Rift and overlying thermal sag basin		
PERMIAN			GUMBARO	KAROO GROUP				
			BOKH					
CARBONIF.		PRE RIFT?	CALUB					
PALEOZOIC PRECAMB.			BASEMENT					

Source: AOC

of the Karoo. These sediments pass upwards in to the Gumbaro Formation sandstone and shale deposited in a fluvial - deltaic environment. The uppermost Formation of the Lower Megasequence is the fluvial and shallow marine sandstones of the Adigrat Formation.

The Upper Megasequence is marine dominated and was deposited in response to continued rifting and the break-up of Gondwana as Madagascar and India separated from north east Africa. The syn-rift Lower, Middle and Upper Jurassic Hamanlei Formations formed as inner ramp and platform limestones and evaporites deposited in shallow and sometimes isolated marine depositional settings. The overlying Uarandab Formation which is formed of dark laminated marls and limestone represents the maximum flooding surface. This sequence is followed by Cretaceous sediments. Inversion in the basin occurred in the Cretaceous and later in the Tertiary. The magnitude and extent of the inversion varies across the basin.

3.2.2 Previous Exploration (Well Review)

Three exploration wells have been drilled on Blocks 2 and 6, and Blocks 7 and 8.

El Kuran-1 (EK-1) was drilled in 1972 by Tenneco to a TD of 10,462 ft (3,189 m) in the Gumbaro Formation. The well targeted a Cretaceous fold above a minor basement fault. Oil was found in a core and minor flows of oil occurred from the Middle Jurassic Upper Hamanlei. Gas shows were reported from the Triassic Adigrat Formation.

El Kuran-2 (EK-2) was also drilled in 1972 to appraise further the EK-1 structure. The well reached a TD of 6,610 ft (2,015 m) in the Jurassic. The well found oil in core and flowed oil at minor rate on test from the Upper Hamanlei and also reported high fluorescence in the Middle Hamanlei.

Bodle-1 (1974, Tenneco, TD = 12,398 ft (3,779 m)) found only fluorescence in the Hamanlei Formation and gas shows in the Adigrat Formation. The well targeted a structure defined on poor quality, sparse seismic data. Well failure has been attributed to lack of structural closure.

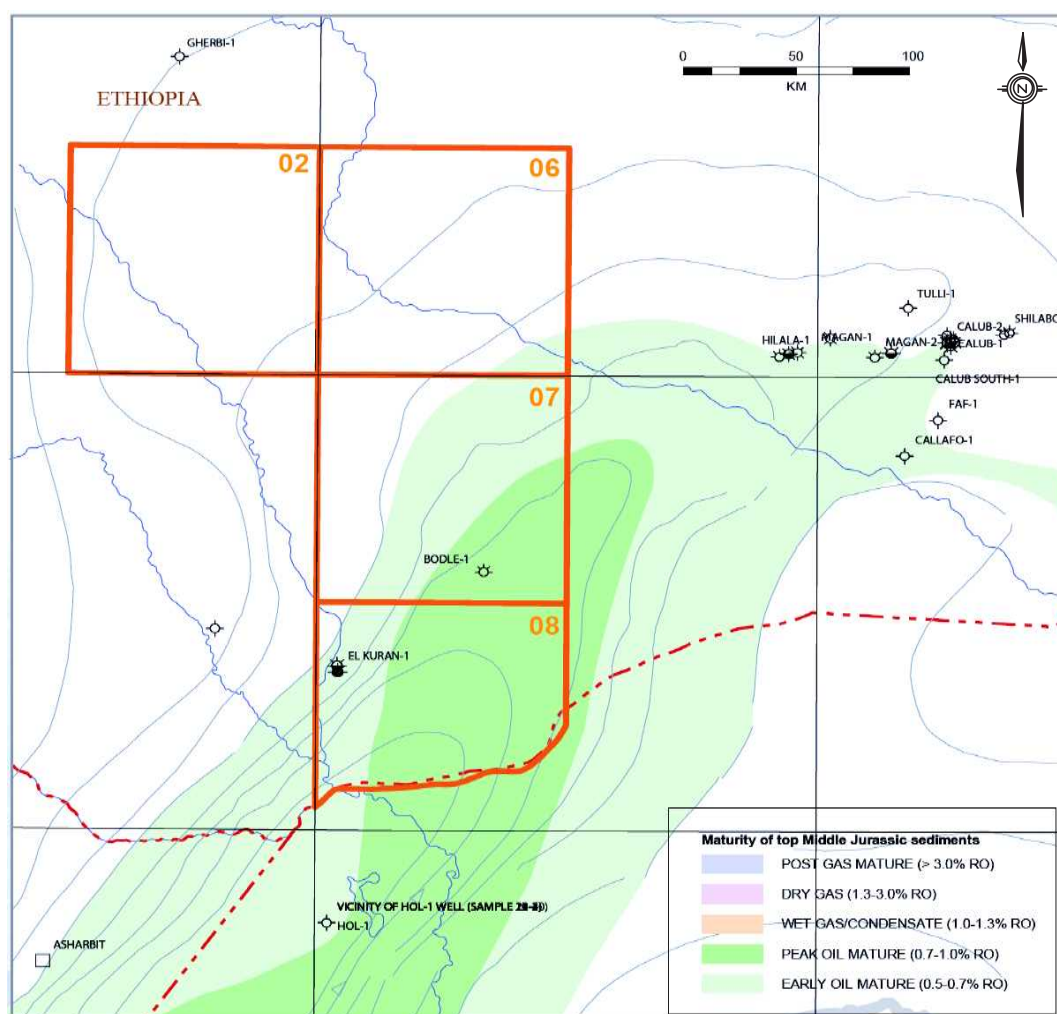
The surrounding wells prove a working petroleum system with several wells discovering oil and gas shows. Genale-1, drilled approximately 45 km to the west of Block 8 had oil and gas shows in the Triassic. Two discoveries lie to the east, Hilala, approximately 100 km away which has recovered 35 Bbl oil from the Upper Hamanlei and flowed 5.7 MMscfd gas from the Adigrat. The Calub Field, approximately 165 km away which flowed 17 MMscfd gas and condensate from the Adigrat reservoir and 24 MMscfd gas and condensate from the Calub reservoir.

3.2.3 Petroleum Systems and Plays

The principal oil-prone source rock is the Late Jurassic Uarandab Formation of the Upper Megasequence, which is a high quality source rock with Type II kerogen, TOC of up to 9.5% (average 2%), high Hydrogen Index and moderate maturity (Figure 12).

FIGURE 12

ETHIOPIA OGADEN BASIN, MATURITY AT TOP MIDDLE JURASSIC



Source: AOC

Additional source rocks include the Middle Jurassic, Middle Hamanlei Formation which is Type II, oil prone shale within a carbonate sequence and with TOC of 3.95% (average 1.2%). The Lower Hamanlei, transition zone shale found at the base of the Upper Megasequence is formed of tidal flat and lagoonal facies. The shales are mixed Type II/III kerogen, between 50 to 1,220 m thick and with TOC of 1.2%.

In the Lower Megasequence, the Bokh Shale, a lacustrine shale, is a gas and oil-prone source rock, up to 450 m thick with TOC of 0.5-1.5%. The Bokh shale may be the source of the gas in the Ogaden Basin fields at Calub and Hilala. This is stratigraphically equivalent to the world class Permian Sakamean source rock of Madagascar.

There are several potential reservoirs within the Ogaden Basin, which have been penetrated by the exploration wells.

The Middle Jurassic, Upper Hamanlei Formation is a thick interval of carbonates ranging in thickness from 275 m to 550 m, consisting of fossiliferous packstones and grainstones deposited in an inner to outer shelf environment. The formation has been penetrated in EK-2 where porosity was typically less than 10% and in EK-1 where the middle section was penetrated and oil shows found but had lower porosities of 5%. Reservoir quality is interpreted to improve to the north. In the Hilala-1 well porosity averaged 10-15% with a maximum of 20%.

The Middle Hamanlei consists of a thick, up to 700 m, interval of dolomites and anhydrites with pelletal, oolitic and fossiliferous packstones and grainstones interbedded with anhydrite and dolomitised carbonates, deposited in an inner shelf to restricted marine and intertidal environment. Porosities in the dolomites are up to 25%. In EK-2 circa 2 Bbl of oil were recovered by a DST and porosity was found to be approximately 10%. Oil shows were also found in Gherbi-1 to the north and Magan-1 to the east.

A third reservoir opportunity is present in the Adigrat Formation which is formed of interbedded sandstone and shale. Reservoir quality varies with burial depth and facies type but good sands have porosities of up to 20%. The Adigrat Formation was deposited in a continental fluvial environment with channels and interchannel sands and floodplain shales. In the Gherbi-1 well to the north, channel bodies are of up to 30 m thick. Porosity is good at 15-20% due to relatively shallow burial. Gas was discovered in the Adigrat Formation at the Calub and Hilala fields to the east. Calub-1 flowed gas at 17 MMscfd from a large upward fining channel structure with porosity in excess of 15%.

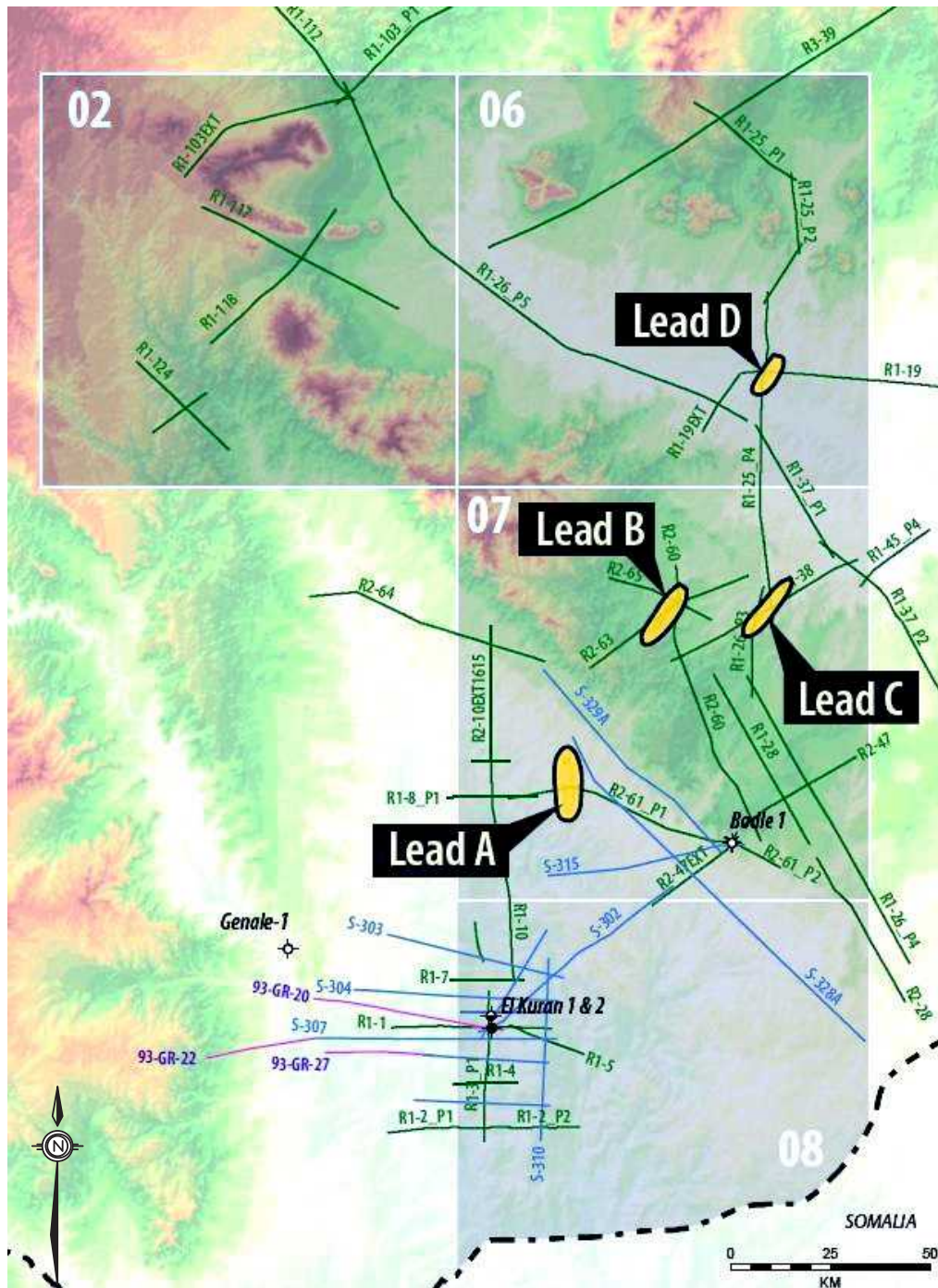
The Carboniferous Calub Formation flowed gas at up to 24 MMscfd with porosities of up to 15% despite deep burial. Wells in Blocks 2, 6, 7 and 8 have not penetrated to this level.

3.2.4 Prospective Resource Estimation

Four leads have been identified in the PSA's (Figure 13). Prospective Resource estimates for each lead have been calculated for the Upper Hamanlei, Adigrat and Calub Formations for oil, and at the Adigrat and Calub Formations for gas.

FIGURE I3

ETHIOPIA OGADEN BASIN, LEADS AND SEISMIC DATABASE



Source: AOC

Results from the basin (e.g. Hilala and Calub Fields) show that stacked plays can be at least in part successful. However, it is GCA's experience that success at one reservoir level does not guarantee success at others. Therefore although Prospective Resource Estimates have been prepared for each reservoir (play) it is unlikely that all three will be equally developed at the same location. The GCoS for each of the reservoir horizons has been calculated to ensure that the most-likely reservoir interval has the highest GCoS estimate. In general this means that the deeper reservoirs have lower GCoS due to increased depth of burial (reservoir effectiveness) and seismic imaging challenges.

Hydrocarbon in-place and Prospective Resource estimates have been made for both oil and gas each of the potential reservoirs in each lead. It is important to understand that the volumes are for oil or gas and not oil and gas. The results are reported in Tables 9, 10, 11 and 12.

Lead A

Lead A, in the south west of Block 7 is a low amplitude north-south trending fold. The Lead is identified by a single east-west seismic line and closure to the north and south cannot be confirmed. In addition, line S-328A which lies to the north east and runs in a north west-south east direction suggests a south east dip to the strata therefore increasing the risk that the lead does not close to the north. In addition, the size of the structure in the north south orientation cannot be accurately defined.

Lead B

Lead B is a four way dip closed structure located towards the centre of Block 7. The Lead is fairly well defined as it is crossed by three lines. The trap appears to be heavily faulted, particularly at the Hamanlei level making the trap seal a risk. Detailed depth conversion and additional seismic data will be required to quantify this lead.

TABLE 9
ETHIOPIA: OIL IN PLACE ESTIMATES
AS AT 31st March, 2010

Licence	Lead	Reservoir	Gross Best Estimate (MMBbl)
Block 07	Lead A	U. Hamanlei	335
		Adigrat	400
		Calub	422
Block 07	Lead B	U. Hamanlei	199
		Adigrat	206
		Calub	389
Block 07	Lead C	U. Hamanlei	415
		Adigrat	447
		Calub	346
Block 06	Lead D	U. Hamanlei	161
		Adigrat	447
		Calub	134

TABLE 10
ETHIOPIA: OIL PROSPECTIVE RESOURCES
AS AT 31st March, 2010

Licence	Lead	Reservoir	Gross Best Estimate (MMBbl)	BMEHL Working Interest (%)	Net Best Estimate (MMBbl)	GCoS
Block 07	Lead A	U. Hamanlei	88	30	26.4	0.14
		Adigrat	83	30	24.9	0.09
		Calub	106	30	32.0	0.12
Block 07	Lead B	U. Hamanlei	50	30	15.0	0.12
		Adigrat	52	30	15.6	0.08
		Calub	98	30	29.4	0.10
Block 07	Lead C	U. Hamanlei	103	30	31.0	0.12
		Adigrat	112	30	33.6	0.08
		Calub	86	30	25.8	0.10
Block 06	Lead D	U. Hamanlei	40	30	12.0	0.13
		Adigrat	112	30	33.6	0.09
		Calub	34	30	10.2	0.11

Notes:

1. Net Prospective Resources are stated herein in terms of BMEHL's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSA. In this regard these volumes stated herein will exceed the volumes which will arise to BMEHL under the terms of the PSA.
2. It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
3. The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the re-categorisation of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.
4. The Prospective Resource volumes are for Oil or Gas, not Oil and Gas (the alternative volumes for gas are presented in Table 12).

TABLE 11
ETHIOPIA: GAS IN PLACE ESTIMATE
AS AT 31st March, 2010

Licence	Lead	Reservoir	Gross Best Estimate (BCF)
Block 07	Lead A	Adigrat	656
		Calub	1,410
Block 07	Lead B	Adigrat	407
		Calub	1,400
Block 07	Lead C	Adigrat	905
		Calub	1,263
Block 06	Lead D	Adigrat	276
		Calub	492

TABLE 12
ETHIOPIA: GAS PROSPECTIVE RESOURCES
AS AT 31st March, 2010

Licence	Lead	Reservoir	Gross Best Estimate (BCF)	BMEHL Working Interest (%)	Net Best Estimate (BCF)	GCoS
Block 07	Lead A	Adigrat	525	30	157.5	0.09
		Calub	1,129	30	338.7	0.12
Block 07	Lead B	Adigrat	326	30	97.8	0.08
		Calub	1,120	30	336.0	0.10
Block 07	Lead C	Adigrat	724	30	217.2	0.08
		Calub	1,010	30	303.0	0.10
Block 06	Lead D	Adigrat	221	30	66.3	0.09
		Calub	394	30	118.2	0.11

Notes:

1. Net Prospective Resources are stated herein in terms of BMEHL's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSA. In this regard these volumes stated herein will exceed the volumes which will arise to BMEHL under the terms of the PSA.
2. It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
3. The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the re-categorisation of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.
4. The Prospective Resource volumes are for Oil or Gas, not Oil and Gas (the alternative volumes for oil are presented in Table 10)).

Lead C (Figure 14)

Lead C is located in Block 7 and is a fold that is fault bound to the south. The lead is covered by 4 lines however two of these are of poor quality and the east-west closure is not very clearly defined. The ultimate size of this lead is poorly constrained given the available data.

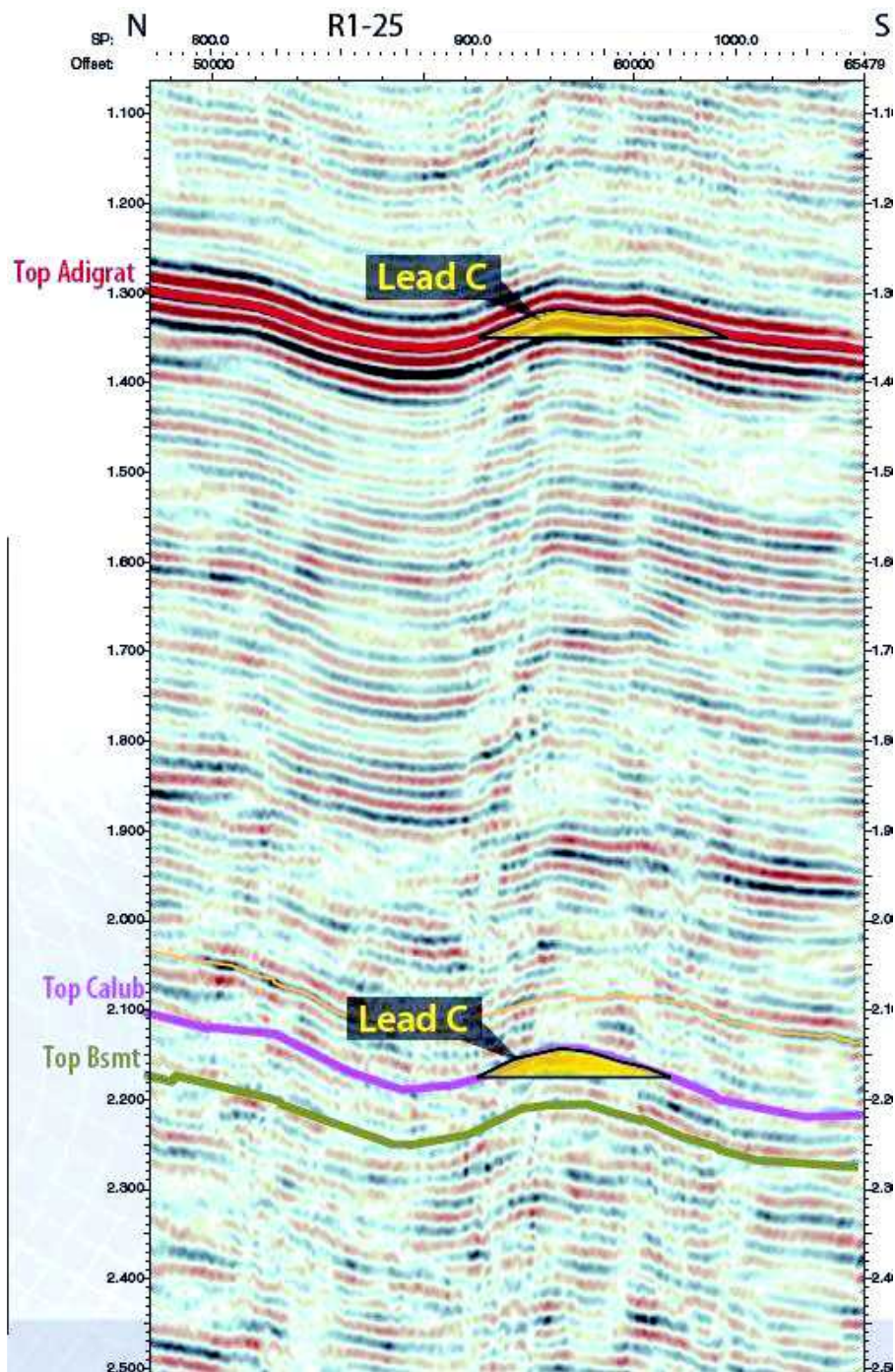
Lead D

Lead D is in the time domain a low amplitude, four way dip closed structure located in Block 6 which is intersected by two lines. The size of the lead is poorly constrained by the available seismic data.

Other Leads

In addition, four further leads are identified by Operator in the SMT project which was provided to GCA. No volumes are attributed to these leads in this report.

FIGURE 14
ETHIOPIA OGADEN BASIN, LEAD C



Source: AOC

Lead I

Lead I is a north south trending low amplitude anticline intersected by three parallel lines which run adjacent to each other in a north-south direction. The seismic confirms closure in these two directions however; closure and size of the structure cannot be determined in an east west orientation. Nearby structures do show some evidence of closure in an east west orientation increasing the likelihood of closure at this location.

Lead L

Lead L is a small, low amplitude fold defined by a single seismic line of poor quality. Both the size of the structure and closure cannot be determined to the north west and south east. With the present data set the lead remains high risk.

Lead SEK

A lead is identified in the SMT project as South of EK-I (SEK). This lead is a four way dip closed structure. The fold is of higher amplitude than the other leads in the blocks and is on the fault trend as the structure the EK-I well targeted. The size of the structure is well defined on seismic data which confirm closure in all directions. The proximity of this lead to the failed SE-I structure suggests that the risks associated with SE-I will also be present in SEK however the shows found in the EK-I well are encouraging evidence of hydrocarbon migrations into the area.

Lead "Untitled I"

"Untitled I" lead is named in the SMT project; this lies in the east of Block 7 and crosses the boundary into the adjacent Block 12. The lead is a four-way dip closed structure. The prospect seems reasonable and could be larger than the area defined in the SMT project, in particular to the northwest and northeast.

In the validation of the leads identified by the Operator, GCA has noted an additional nine antiforms which could increase the prospectivity on the block. The majority of these are features are identified on single seismic lines and will require significant additional data and interpretation for them to be classified as drillable prospects. They do however, help to highlight the additional prospectivity of the blocks and indicate that additional data and a better understanding of the block could derive considerable upside. The leads identified are located in all four of the blocks.

Hydrocarbon Phase

Oil and gas shows have been reported from the Ogaden Basin wells. However, to-date only two have been discovered, the Hilala and Calub are the only commercial discoveries that prove the presence of an active petroleum system.

Several source rocks have been identified (see above) and the Operator provided basin modelling results (maps and generation plots) to show that both oil and gas has been generated and expelled from these potential source rocks.

This work indicates that either oil or gas could be trapped, with the oil chance factor increasing in the more marginal and shallower reservoirs. Both oil and gas In-Place and

Prospective Resource Estimates are presented in (Tables 13 to 18). These numbers are interchangeable, and must not be aggregated.

Establishing the oil versus gas risk at an individual lead's location will require additional basin modelling, which is outside of the scope of this report.

0

3.2.5 Ethiopia (Ogaden) GCoS

The BMEHL blocks in the Ogaden Basin lie in or on the margin of the proved petroleum system. The Hilala and Calub discoveries proving that an active petroleum system occurs within the basin.

Using the Template GCA has derived a GCoS for each of the leads at each reservoir level. The results of this analysis are summarised in Tables 14, 15, 17 and 18.

The principal risk associated with these prospects is trap definition. Reservoir presence and effectiveness is the next most important factor and this is reflected in the differences in GCoS shown above.

QUALIFICATIONS

GCA is an independent international energy advisory group of 48 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

The report is based on information compiled by professional Associates of GCA.

Professional Associates who participated in the compilation of this report includes Mr. Brian Rhodes, and Dr Stephen Wright. All hold at least a bachelor's degree in geoscience, petroleum engineering or related discipline. Mr. Rhodes holds a B.Sc. (Hons) Geology, is a member of the Energy Institute, the Petroleum Exploration Society of Great Britain, the Society of Petroleum Engineers and the European Association of Geoscientists and Engineers, and has more than 36 years industry experience. Dr. Wright has more than 20 years of Industry experience holds a B.Sc. (Hons) Geology from Kings College, University of London and a D.Phil from the University of Oxford, he is a fellow of the Geological Society of London and a member of the Petroleum Exploration Society of Great Britain.

BASIS OF OPINION

This assessment has been conducted within the context of GCA's understanding of the effects of petroleum legislation, taxation, and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties.

Sincerely yours,
Gaffney, Cline & Associates



Brian Rhodes

APPENDIX I

Summary of SPE PRMS Guidelines and Definitions

**Society of Petroleum Engineers, World Petroleum Council, American Association of
Petroleum Geologists and Society of Petroleum Evaluation Engineers**

Petroleum Resources Management System

Definitions and Guidelines ⁽¹⁾

March 2007

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definition of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE PRMS document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that SPE PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE PRMS Definitions and Guidelines can be viewed at:

¹ These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project “chance of commerciality” can be said to be 100%. The project “decision gate” is the decision to initiate commercial production from the project.

Approved for Development

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity’s current or following year’s approved budget. The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Justified for Development

Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity’s assumptions of future prices, costs, etc. (“forecast case”) and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to

demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project “decision gate” is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

- (1) the area delineated by drilling and defined by fluid contacts, if any, and
- (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see “2001 Supplemental Guidelines,” Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a

reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

- (1) completion intervals which are open at the time of the estimate but which have not yet started producing,
- (2) wells which were shut-in for market conditions or pipeline connections, or
- (3) wells not capable of production for mechanical reasons.

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

- (1) from new wells on undrilled acreage in known accumulations,
- (2) from deepening existing wells to a different (but known) reservoir,
- (3) from infill wells that will increase recovery, or
- (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to
 - (a) recompleting an existing well or
 - (b) installing production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Development Pending

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to “On Hold” or “Not Viable” status. The project “decision gate” is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclassified or on Hold

A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to “Not Viable” status. The project “decision gate” is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project “decision gate” is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

PROSPECTIVE RESOURCES

Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

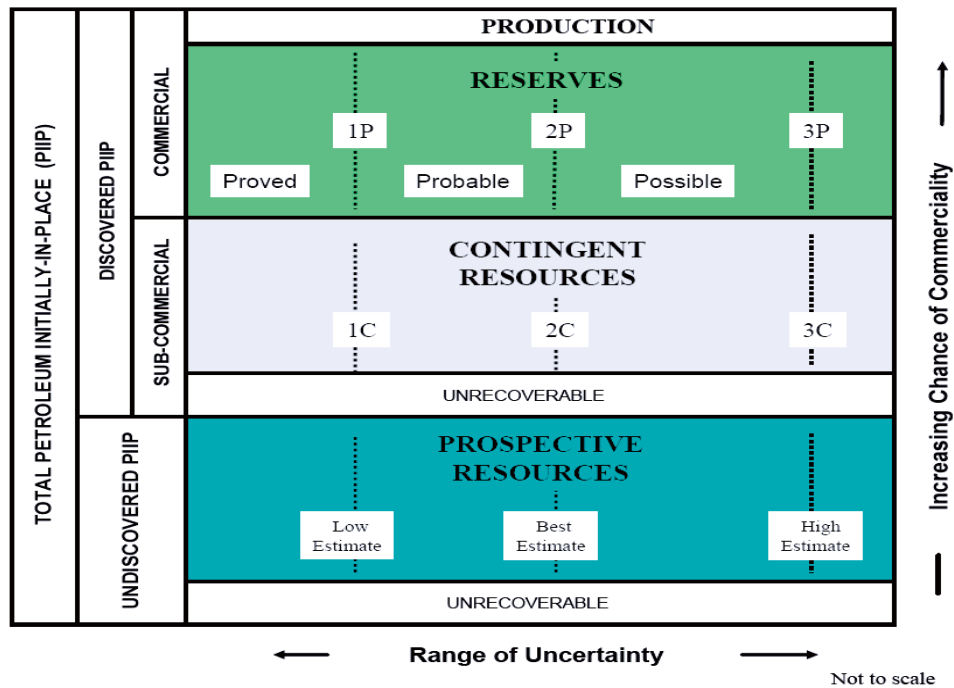
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

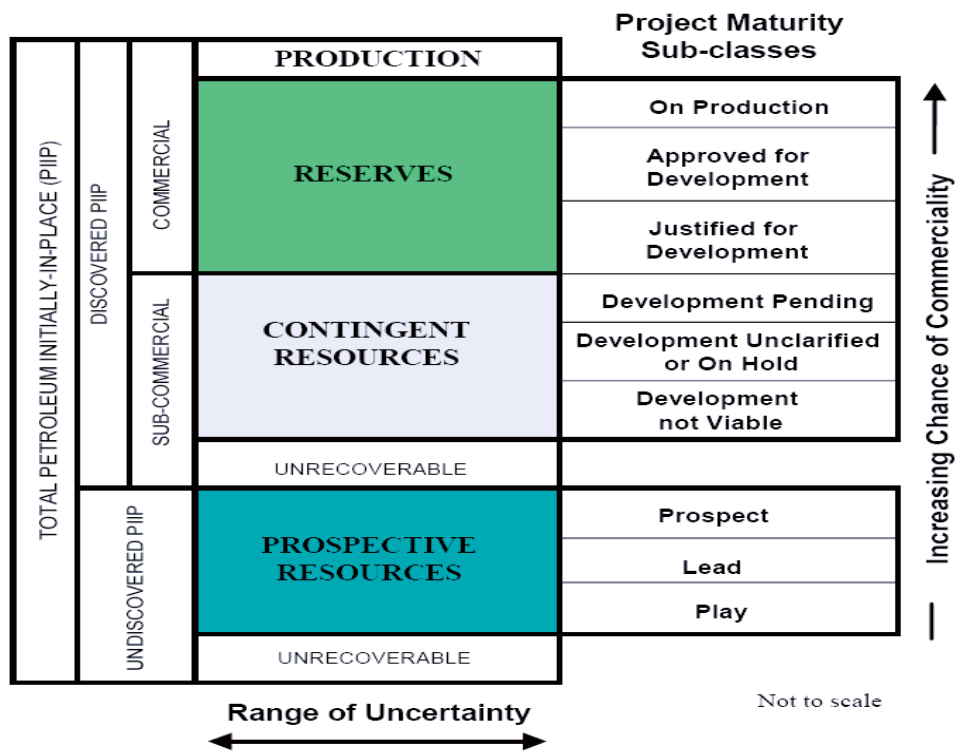
A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

RESOURCES CLASSIFICATION



PROJECT MATURITY



APPENDIX II
Glossary of Terms

GLOSSARY

List of Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
°API	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A\$	Australian Dollars
B	Billion (10 ⁹)
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm ³	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day
bpd	Barrels per day
boe	Barrels of oil equivalent @ xxx mcf/bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/bbl
BOP	Blow Out Preventer
bopd	Barrels of oil per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels of water per day
CBM	Coal Bed Methane
CO ₂	Carbon Dioxide
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal
E&P	Exploration and Production
EBIT	Earnings before Interest and Tax

GLOSSARY (Cont'd.)

EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement Interest
EIA	Environmental Impact Assessment
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design
FPSO	Floating Production, Storage and Offloading
FSO	Floating Storage and Offloading
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre
gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs
GBP	Pounds Sterling
GDT	Gas Down to
GIIP	Gas initially in place
Gj	Gigajoules (one billion Joules)
GOR	Gas Oil Ratio
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H ₂ S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy. 1 kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km ²	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons
LKO	Lowest Known Oil
LNG	Liquefied Natural Gas
LoF	Life of Field

GLOSSARY (Cont'd.)

LPG	Liquefied Petroleum Gas
LTi	Lost Time Injury
LWD	Logging while drilling
m	Metres
M	Thousand
m ³	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m ³ d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrammes per litre
MJ	Megajoules (One Million Joules)
Mm ³	Thousand Cubic metres
Mm ³ d	Thousand Cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
mya	Million years ago
NGL	Natural Gas Liquids
N ₂	Nitrogen
NPV	Net Present Value
OBM	Oil Based Mud
OCM	Operating Committee Meeting
ODT	Oil down to
OPEX	Operating Expenditure
OWC	Oil Water Contact
p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Non-producing
PI	Productivity Index
PJ	Petajoules (10 ¹⁵ Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch
psia	Pounds per square inch absolute

GLOSSARY (Cont'd.)

psig	Pounds per square inch gauge
PUD	Proved Undeveloped
PVT	Pressure volume temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
R _f	Recovery factor
RFT	Repeat Formation Tester
RT	Rotary Table
R _w	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cf/d or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
s _o	Oil Saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
ss	Subsea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
s _w	Water Saturation
T	Tonnes
TD	Total Depth
T _e	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10 ¹² Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVD _{ss}	True Vertical Depth Subsea
USGS	United States Geological Survey
U.S.\$	United States Dollar
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent

GLOSSARY (Cont'd.)

IH05	First half (6 months) of 2005 (example of date)
2Q06	Second quarter (3 months) of 2006 (example of date)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
%	Percentage

PART 13

McDANIEL REPORT ON BLACK MARLIN

BLACK MARLIN ENERGY HOLDINGS LIMITED

Exploration Potential Assessment Report

East Africa Properties

August 2010



BLACK MARLIN ENERGY HOLDINGS LIMITED

**Exploration Potential Assessment Report
East Africa Properties
August 2010**

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August 2010

BLACK MARLIN ENERGY HOLDINGS LIMITED

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Reference: **Exploration Potential Assessment
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Dear Sirs:

Pursuant to your request McDaniel & Associates Consultants Ltd. ("McDaniel") has prepared an assessment of the crude oil and natural gas prospective resources as of June 1, 2010 for the interests of Black Marlin Energy Holdings Limited ("BMEHL") in Block 1 and Block L17/L18 in Kenya; Areas A, B & C in Seychelles; and Block 1101 in Madagascar.

McDaniel originally prepared an assessment of the prospective resources of BMEHL in the subject properties in a report issued on September 28, 2009 with an effective date of August 31, 2009. BMEHL has provided written representation that since the August 2009 Assessment no new information or data has become available that would materially affect or could materially affect our opinions related to the August 2009 Assessment of the Blocks. Consequently, the assessment of the subject properties in this report has not changed from the September 28, 2009 report.

The resource estimates have been prepared in accordance with the resource definitions and standards set out in the Canadian National Instrument NI 51-101 and the Canadian Oil and Gas Evaluation Handbook (COGEH).

This assessment was prepared during the period from August 2009 to September 2009 and was based on technical data to the end of August 2009. All of the basic information employed in the preparation of this report was obtained from BMEHL. A summary of the results of this assessment and the methodology employed to determine the resource estimates is presented below.

Black Marlin Energy Holdings is made up of two wholly owned subsidiaries East Africa Exploration (“EAX”) and Upstream Petroleum Services Limited (“UPSL”). The exploration contracts detailed in this report are all held in the name of EAX.

1. EXECUTIVE SUMMARY

BMEHL has an interest in the following Blocks and Areas in Kenya, Seychelles and Madagascar summarized in Table 1. An overall property location map showing these Blocks and Areas is presented in Figure 1 (Figures referenced in this report are presented in the Appendix).

Table 1 - BMEHL Asset Summary

Contract	Country	Operating Company	Interest (%)	Contract Expiry Date (1)	Area (2) (sq.km)
Block 1	Kenya	EAX (Kenya) Ltd.	50%	Oct 2011	31,781
Block L17/L18	Kenya	EAX (Kenya) Ltd.	65%	Jan 2010	4,905
Area A, B & C	Seychelles	EAX (Seychelles) L td.	75%	Nov 2015	14,964
Block 1101	Madagascar	Candax Energy Inc.	40%	Jul 2010	14,900

(1) Contract expiry date is to the end of the current exploration period and excludes possible extensions and any development period.

(2) The Kenya Block 1 and L17/L18 Areas are not directly specified in the respective Contracts.

A large number of leads have been identified by BMEHL in the Blocks and Areas mentioned above. McDaniel has reviewed these leads and independently estimated the prospective resources for twenty three of the leads where some form of closure could be verified. A summary of the prospective crude oil and natural gas resources is summarized in Table 2.

Table 2 – BMEHL Prospective Resources

Prospective Resources	Property Gross (1) (4) (5)				
	Unrisked Low Est.	Unrisked Best Est.	Unrisked Mean Est.	Unrisked High Est.	Risked Mean Est.
Crude Oil Resources, Mbbl	29,949	193,522	482,595	1,157,905	34,172
Natural Gas Resources, MMcf	171,632	806,912	1,597,444	3,746,311	116,893
Total BOE Resources, Mbbl (3)	58,555	328,008	748,835	1,782,291	53,654

Prospective Resources	Company Gross (1) (2) (4) (5)				
	Unrisked Low Est.	Unrisked Best Est.	Unrisked Mean Est.	Unrisked High Est.	Risked Mean Est.
Crude Oil Resources, Mbbl	18,093	116,850	294,942	709,994	22,382
Natural Gas Resources, MMcf	119,174	568,577	1,141,800	2,686,290	84,630
Total BOE Resources, Mbbl (3)	37,955	211,613	485,242	1,157,709	36,487

- (1) The total resource estimates are based on an arithmetic aggregation of the individual leads.
- (2) Company gross resource estimates reflect BMEHL's interest of the property gross resource estimates.
- (3) Gas was converted to barrels of oil equivalent ("BOE") at a ratio of 6 Mcf to 1 bbl.
- (4) Each lead has its own estimated probability of geological success. Refer to the Table 1 in the Appendix of this report for the estimated probability of geological success for each lead.
- (5) There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be economically viable or technically feasible to produce any portion of the resources.

It is worth stressing that for all the Blocks and Areas the overall seismic coverage is generally very sparse (which is expected considering the early stage of the exploration). There are a number of potential structures which cannot be closed due to the limited data set and it may be possible for them to be advanced to a lead or prospect classification with further seismic. This potential is discussed on a qualitative basis in this report.

The ratio of the total portfolio risked to un-risked mean boe prospective resources is 0.08 implying that the overall portfolio has a relatively high risk. Further analysis and data acquisition is required for all leads to effectively de-risk and "high grade" the leads and thereby translate the best leads into drillable prospects. Apart from better defining potential structures more analysis is required to firm up any potential play fairways where all the elements of a working petroleum system (structure, source, migration, timing, reservoir and seal) come together. At this stage many of these elements have a high risk and as such the overall chance of success of any individual lead is quite low.

2. RESOURCE CLASSIFICATION

The assessment of the prospective resources in this report were based on the resource definitions presented in the Canadian Oil and Gas Evaluation Handbook ("COGEH") Section 5 and are re-stated below:

2.1 Prospective Resources

Prospective resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

2.2 Uncertainty Categories

Estimates of resources always involve uncertainty, and the degree of uncertainty can vary widely between accumulations/projects and over the life of a project. Consequently, estimates of resources should generally be quoted as a range according to the level of confidence associated with the estimates. An understanding of statistical concepts and terminology is essential to understanding the confidence associated with resources definitions and categories.

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or a probability distribution. Resources should be provided as low, best and high estimates, as follows:

- **Low Estimate** – This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- **Best Estimate** – This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- **High Estimate** – This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

3. RESOURCE ASSESSMENT METHODOLOGY

McDaniel & Associates conducted a detailed review of all available seismic, log and general geological data provided by BMEHL for existing wells and for the exploration leads identified by BMEHL within Kenya, Seychelles and Madagascar.

BMEHL has identified a large number of exploration leads in a large exploration portfolio of which twenty three have been assessed by McDaniel in this report as shown in Table 1 of the Appendix. Two leads in Kenya Block 1 and five leads in Kenya Block L17/L18 have been identified by BMEHL but, as they had very limited seismic coverage or did not demonstrate a defined closure, are considered too uncertain to be evaluated as part of this assessment. BMEHL also holds an interest in Block C in Seychelles, however, there was insufficient information available for this review to quantify the exploration potential of these blocks.

BMEHL prepared a data package consisting of seismic data and structure maps supporting each lead. McDaniel & Associates reviewed the data packages and utilized the structure maps for each of the leads to assess the prospective resources.

Prospective resources for each of the leads were estimated probabilistically. Low (P90) and High (P10) estimates for each of the relevant parameters were used to define the distributions. The parameters used (with the distribution type in parenthesis) were pool area (truncated log-normal), maximum gross pay (truncated log-normal), net to gross ratio (triangular), porosity (truncated normal), oil or gas saturation (truncated normal) together with estimated PVT parameters (truncated normal) and recovery factors (triangular). The pool area was estimated from the structure maps interpreted from the seismic data. Structure maps for all of the leads are presented in the Appendix of the report. The petrophysical parameters and reservoir pressure and temperature, used for estimating PVT parameters, were based on the surrounding wells data. For all leads a geometric correction factor (frequently referred to as a shape factor) of 0.75 was used to account for the reduction in net pay at the edges of the field. Each lead was assigned a certain percentage of being oil bearing or gas bearing based on types of fluid observed in the surrounding wells and the likely maturity of any source rocks.

The leads were risked using five parameters including source, migration, reservoir, structure and seal. The overall geological chance of success is the product of these individual parameters and is used to determine the risked mean resources.

A summary of the resulting unrisked resources and risked mean resources is presented in Table 1. A brief summary of each of the blocks is described below. A summary of the unrisked oil in place ("OOIP"), unrisked gas in place ("OGIP"), unrisked resources, geological chance of success and risked recoverable resources is presented on a property gross basis in Table 1 and on a company gross basis in Table 2 of the Appendix.

4. KENYA - BLOCK 1

4.1 Property Overview

Block 1 is located on the western margin of the Mandera-Lugh basin in northeastern Kenya bordering both Somalia and Ethiopia as shown in Figure 2. The block covers an area of over

30,000 square kilometers and is highly under-explored (the area in square kilometers is not defined explicitly in the PSC but is estimated by EAX to be 31,781 km²).

Early exploration occurred during the 1970's when Burmah Oil conducted gravity and seismic surveys over Block 1. This was followed during the 1980's when Amoco and Total acquired a combined 850 kilometers of 2-D seismic data. After this exploration effectively ceased until Lion Petroleum was awarded the block in October 2007. EAX farmed into the block in January 2009 taking a 50 percent interest and becoming operator of the block.

Gravity and magnetic data suggests that there are some structural highs in the basin, however, the seismic coverage across Block 1 is poor and only one shallow well, Tarbaj-1 has been drilled on the block. Two exploratory wells, Elgal-1 and Elgal-2, were drilled by Amoco in 1987 on the western edge of the Mendera basin in Block 2 approximately 35 kilometers south from Block 1, but geochemical data taken during drilling indicated that the Karoo sequences were highly over-mature and non-porous. The closest deep well to Block 1 (well Hol-1), located approximately 50 kilometers east across the border in Somalia in the central part of the basin, encountered no hydrocarbon shows.

The PSC for Block 1 was originally signed November 19, 2007 and became effective in February 2008. The start of the initial term though was then delayed by a force majeure to October 2008. Block 1 is in an initial three year exploration term which can be extended twice, two years each time. During the exploration phase the contractor is required to relinquish 30 percent after the initial term of three years and another 30 percent after the first and second extension period. The work program for the initial exploration period for Block 1 consists of acquiring 1,200 kilometers of 2-D seismic and US \$500,000 of gravity and magnetic data. There is a contingency to drill one exploration well if merited.

4.2 Regional Geology

4.2.1 Ogaden Basin

The Paleozoic - Mesozoic Ogaden Basin is located directly north of the Mendera-Lugh basin to the south in Kenya. The Ogaden basin has a proven hydrocarbon system confirmed by a gas field discovery and a number of oil and gas shows reported in the exploration wells drilled in the area. To the east is the major Calub-Hilala gas field discovered in the 1970s by Tenneco which has recently been awarded to Petronas, who are now making appraisal and development drilling plans to commercialize the field.

The basin as a whole was initiated as several northeast – southwest trending grabens during Carboniferous to Triassic times with continental rift infill of the Karoo Group, followed by a phase of intra-cratonic Post-Rift sag and passive infill through the whole region during the Jurassic and Cretaceous time. During the Cretaceous period the area experienced a compression and fault rejuvenation. The whole region experienced regional uplift during Oligo-Miocene time as a result of the development of the East African Rift System.

Proven hydrocarbon source rocks of the Permo-Triassic Bokh shales are the source of the gas in the Calub-Hilala field. In addition there are several shales within the Middle and Upper Jurassic section acting as potential younger oil source rocks, the best of which are the Oxfordian - Kimmeridgian Uarandab shales which are interpreted to be mature to the south of the block areas.

The main potential reservoirs in the basin are clastic sediments of the Carboniferous age Calub formation and the Triassic age Adigrat formation. In addition some permeable Jurassic carbonate rocks in the Hamanlei formation can be considered potential reservoirs.

The oldest rocks in the basin are represented by Pre-Cambrian granites, which are outcropping to the north and to the west from the blocks. The deepest well in the area is the Bodle-1 well which was drilled to a total depth ("TD") of 3,878 meters and penetrated the Adigrat formation at TD. No wells have penetrated the Calub formation in Blocks 2, 6, 7 and 8.

4.2.2 Mandera-Lugh Basin

The Mandera-Lugh sedimentary basin is located in north-eastern Kenya and continues partly into Somalia and Ethiopia where it is connected to the much larger and extensive Ogaden basin. The Mandera-Lugh is a graben type basin developed in the middle of the continent with Mesozoic to Cenozoic sedimentary fill. The graben trends northeast to southwest with the deepest part of the basin located along the border between Kenya and Somalia where the maximum estimated thickness of the sedimentary rocks is 5 to 8 kilometers. Most of the wells that have been drilled in the basin are located in Somalia.

The Mandera-Lugh basin was initiated as several northeast – southwest trending grabens during Carboniferous to Triassic times with continental rift infill of the Karoo Group. The Karoo rocks are regionally covered by a fluvial succession of the Mansa Guda formation. In early Jurassic time the basin became partly enclosed and some 2,000 meters of evaporites, shales and mudstones of the Meregh formation were deposited in the central part of the basin. Thick carbonates were deposited throughout the region during the next phase of the intra-cratonic Post-Rift sag during Late Jurassic and Cretaceous time. The whole region experienced regional uplift during Oligocene-Miocene times as a result of the development of the East African Rift System.

The stratigraphy of the Mandera-Lugh and Ogaden basins is interpreted to be similar, except for the evaporite deposition in Early Jurassic time. The Permian and Triassic continental sections of the Karoo Group have been penetrated by wells in the Ogaden basin and also by wells, Elgal-1 and Elgal-2, to the south of Block 1. The Mansa Guda sandstones in the Mandera-Lugh basin are dated Upper Triassic to Lower Jurassic and are considered to be equivalent to the Adigrat formation (a main gas bearing reservoir) in the Ogaden basin. The Mansa Guda overlies the older Karoo sequences (Wajir sandstones / Elgal shales) that are deposited on the granitic basement. The Wajir sandstones and Elgal shales are comparable to

the shale and silt deposits of the Bokh formation (a proven source rock) in the Ogaden basin. The gas bearing Calub formation in the Ogaden basin cannot be correlated with a formation in the Mandera-Lugh basin however it may be present in the deeper parts of the basin and pinch-out to towards the basin margins.

The main regional source rocks, Permo-Triassic Bokh shales and Elgal shales, are over-mature to the south of Block 1 and to the north into Ethiopia. In the central part of the Mandera-Lugh basin (located in Somalia) the source rocks are also likely to be over-mature or in the gas generating window. However limited oil accumulations may exist on the margins of the basin, where Block 1 is located, as organic matter could be at lower stages of maturity.

Analogies with the Ogaden basin also suggest there may be other potential source rocks and reservoirs. The Bur Mayo and the Kalicha-Seir formations in the Mandera-Lugh basin appear comparable to the Lower and Upper Hamanlei (Jurassic) formations in the Ogaden basin. If analogous these formations should have high total organic content ("TOC") source rocks and in addition permeable reservoirs.

4.3 Exploration Potential

The main exploration potential in Block 1 is believed to lie in the Jurassic and Upper Triassic section where, based on analogy with the Ogaden basin, a working petroleum system could exist. Currently Block 1 is at an early exploration stage with no deep wells drilled to date and only a limited amount of seismic data available. In general the block is interpreted to be in a major syncline area with faulting on the slopes of the syncline. At present BMEHL has identified three main exploration focus areas within Block 1 as shown in Figure 2. These are the Sengif in the north, the Golberobe in the middle of the block and the Khoroff in the south. Several potential faulted blocks are present in these areas on single seismic lines which can be considered immature leads. More seismic data is required to determine if these leads have full closure and, as such, they have not been evaluated as part of this assessment. The main target horizon is the Mansa Guda sandstone with a secondary target a Jurassic limestone. The Jurassic rocks outcrop on the edges of Block 1 and so the best potential for a Jurassic accumulation is located in the middle of the block in the Golberobe area.

Gas is the most likely hydrocarbon type if present in the Mansa Guda reservoirs as the Elgal shales (the source rock) are likely to be within the gas window or over mature. The Jurassic reservoirs are more likely to be oil bearing as there is a separate potential source rock which may not have been buried so deep. An oil seep close to the well Tarbaj-1 in the southwest corner of the block confirms the presence of hydrocarbons.

In addition there may be stratigraphic trap potential within the Mansa Guda sands which pinch out towards the western margin of the basin.

The main geological risks associated with exploration in the Block 1 area are the presence and level of maturity of the source rocks, and the lateral fault seal integrity of any potential tilted fault blocks.

5. KENYA - BLOCKS L17/L18

5.1 Property Overview

The Block L17/L18 PSC is located in the Lamu coastal basin, in southern offshore Kenya as shown in Figure 3. The individual blocks L17 and L18 cover an area of approximately 1,275 and 3,630 square kilometers respectively and are situated in water depths varying from a few meters along the shoreline up to around 500 meters.

Block L17/L18 was originally part of Block L10 which was awarded to Dana Petroleum and Pancontinental in 2000. Woodside Energy later farmed into Block L10 in 2003 and after an extensive 2-D marine survey relinquished the shallow water part of the block. Following the relinquishment the Ministry of Energy re-designated the shallow water area as Block L17/L18. Between 2005 and 2006 UPSL (a subsidiary of Black Marlin Energy Holdings) acquired and processed 770 kilometers of marine 2-D seismic data through a Technical Evaluation Agreement with the Kenyan government. In October 2007, Block L17/L18 was awarded to Aminex (25 percent interest and operator), EAX (40 percent interest) and Somken (35 percent working interest). In 2009 BMEHL swapped the 10 percent interest it held in the Nyuni License in Tanzania for an additional 25 percent in Block L17/L18 held by Aminex and as a result holds a 65 percent interest and is operator of Block L17/L18.

The PSC for Block L17/L18 was originally signed October 24, 2007 and became effective in January 2008. Block L17/L18 is in the initial two year exploration term which can be extended twice with the first extension for two years and the second extension for three years. In a letter dated August 3, 2009 the Ministry of Energy granted a nine month extension to the initial exploration term which will expire in October 2010. During the exploration phase the contractor is required to relinquish 25 percent after the initial term of two years and another 25 percent after the first extension period. The work program for Block L17/L18 consists of carrying out geological and geophysical studies and acquiring 1,000 kilometers of marine 2-D seismic or 100 kilometers of transition zone (shallow water) 2-D seismic during the initial exploration term. BMEHL has met all work obligations associated with the first year and most of the work obligations in the second year are expected to be met by a 350 kilometer short cable shallow water marine 2-D survey commencing in the fourth quarter of 2009.

BMEHL anticipates that some of the exploration drilling could be conducted from onshore using deviated wells, thereby avoiding the requirement for an offshore rig.

5.2 Regional Geology

Block L17/L18 is located in the Lamu basin which occupies the coastal onshore and offshore areas of southeast Kenya. The initiation and evolution of the basin was controlled by plate tectonic movements. The basin originated during Permian to Triassic time as part of the break-up of the Gondwana paleo-continent. Continental clastic sediments of the Karoo formation filled the formed graben. The start of the major rifting stage in the Early Jurassic when Madagascar began to separate from Gondwana led to the invasion of the Tethys Sea. Afterwards restricted marine conditions were developed in the basin which resulted in the deposition of carbonates and evaporites. The rapid separation of Africa and Madagascar and the drifting of Madagascar to the south along the Davie Fault are associated with the development of a passive margin. The extension of the basin slowed during Albian to Cenomanian times as the relative motion between Madagascar and East Africa stopped, and in the Late Cretaceous spreading was initiated further east between Madagascar and India. During the Late Jurassic to Late Cretaceous subsidence of the newly formed rift basin led to the deposition of shallow and deep water marine clastics and carbonates over a large area. Passive infill of the basin from the African continent continued with an increased load of clastic sediments deposited following significant regional uplift during the Eocene-Oligocene associated with the East African Rift System. Shallow seas covered the Lamu basin in the Miocene with the deposition of inner shelf carbonates and clastics prevailing in most of the Lamu basin.

5.3 Exploration Potential

Block L17/L18 is covered by two different vintages of 2-D seismic: the first survey was conducted in 1976 and the second survey of 770 kilometers was completed during 2005 and 2006. The old seismic is generally poor quality, however, both surveys are poorly imaged below the base of the Cretaceous. Overall the seismic is quite sparse with on average between three and five kilometers between lines.

This area is frontier exploration and no exploration drilling has occurred to date within Blocks L17/L18. BMEHL is currently in the process of re-interpreting the seismic and identifying potential Mesozoic structures prior to acquiring additional seismic to better define the potential structures. BMEHL believes the primary exploration focus is within the Cretaceous, although previous work has also evaluated Tertiary potential. The prospective resources estimated as part of this assessment are all within the Cretaceous.

5.3.1 Cretaceous Interval

Prospective resources were assigned to eleven leads in Block L17/L18 all within the Upper Cretaceous reservoir interval. BMEHL has so far prepared a map of the near base Tertiary SB3 seismic horizon and this structural interpretation was used as a proxy for the Upper Cretaceous since the two horizons are expected to be reasonably conformable within a given

lead area. The reservoir is likely to be comprised of marine sands interbedded with shales. It has been reported that the average porosity in the Upper Cretaceous in several offshore wells in the Lamu basin is approximately 20 percent. The closest well, Simba-1, to Block L17/L18 is reported to have porosity ranging from 10 to 20 percent. A structure map for the SB3 seismic reflector is presented in Figure 4 showing the location of the identified leads.

There are several potential source rocks for the Cretaceous in the southern Lamu basin including the Permo-Triassic Karoo interval and sections within the Lower to Middle Jurassic. The hydrocarbons are expected to have been generated in the deep Pemba trough which corresponds to a gravity low south of Block L18.

The Karoo source rock in the Pemba area is likely over-mature, whereas shales within the Lower to Middle Jurassic may be in the gas generating window. For these reasons all of the exploration leads within the Upper Cretaceous assessed in this report are assumed to be gas bearing. It should though be noted that there are oil seeps on Pemba Island reportedly linked to a Jurassic source. A source of oil in the Jurassic would mean the structures in Block L17/L18 could be oil bearing. However as the depth of any Jurassic source within the Pemba trough is too deep to support the generation of oil, this information has been treated as anomalous. Further work is required to study the maturity level of Jurassic rocks that outcrop in Kenya to try and better understand the source rock potential.

The main risk associated with the exploration leads in Block L17/L18 is related to the reliability of structural closure due to the relatively sparse seismic coverage and quality of seismic. All of the exploration leads are faulted anticline structures. The faults are considered to have been recently active and depending on the cross-fault juxtaposition against other strata could represent a significant risk to the trap seal.

The average mean unrisks resources of the eleven leads in Block L17/L18 is approximately 45 Bcf, but no assessment has been made of the minimum field sizes that would be required for a commercial development. Block L17/L18 is located close to the city of Mombasa so there is likely a market for gas sales.

BMEHL also carries four additional leads (SB3-10, SB3-11, SB3-13, SB3-15) in Block L17/L18 but, due to very limited seismic, they are considered too uncertain to be quantified as part of this assessment. Closure has been mapped by BMEHL for each of the four leads on the SB-3 seismic reflector structure map as presented in Figure 4. The mapped closure for lead SB3-10 is 715 acres, lead SB3-11 is 1,313 acres, lead SB3-13 is 917 acres and lead SB3-15 is 803 acres which compares to an average mapped closure of 2,402 acres for the eleven leads evaluated in this assessment.

5.3.2 Tertiary Interval

There may be additional exploration potential in clastic reservoirs within the Tertiary. The Upper Cretaceous – Tertiary source rocks appear to be immature in the Pemba-5 and Simba-1 wells but could possibly be oil generating in the deep basin Pemba trough. Any structures

located in the southern area of Block L18 are ideally located to receive hydrocarbon charge from the source rocks buried in the Pemba trough.

BMEHL provided three intra-Tertiary seismic horizon maps: SB1, SB2 and SB3. As discussed previously the SB3 map was used as a proxy for the deeper Cretaceous interval. All three maps show a number of potential structures, however the shallow nature of the structures combined with the fact that many of the faults are continuous to surface suggests there is a very high risk that the structures will have been breached and so it was decided not to evaluate these structures as part of this assessment.

6. SEYCHELLES - AREAS A, B & C

6.1 Property Overview

Areas A, B and C are located in the Seychelles micro-continent covering a combined area of approximately 14,964 square kilometers as shown in Figure 5. Area A and B are located in mainly shallow water in the northern half of the Seychelles plateau while Area C is in shallow water to the south.

The majority of exploration activity occurred in 1977 when three separate Petroleum Agreements were signed by a Oxoco, Siebens and Burmah Oil (later acquired by Amoco) led consortium. A total of 6,400 kilometers of seismic was acquired between 1977 and 1979 revealing several structural and stratigraphic leads. Amoco committed to the drilling phase and three wells (Owen Bank A-1, Reith Bank-1 and Seagull Shoals-1) were drilled between 1980 and 1981. All three wells were plugged and abandoned although there were indications of hydrocarbons shows. Between 1982 and 1983 Amoco commissioned 27,900 kilometers of aeromagnetic survey, 7,100 kilometers of seismic as well as other gravity and geochemical surveys. Amoco later relinquished their acreage in 1986 following the collapse of oil prices. In 1985, Enterprise Oil signed an Agreement for the South-Eastern Shelf plus Constant, Coetivy and Fortune Banks with an option to later include Platte Banks. A total of 4,870 kilometers of seismic was conducted and in 1990 Enterprise Oil drilled the Constant Bank-1 well which was plugged and abandoned. Both Texaco and Ultramar (now LASMO) later signed Agreements and along with Enterprise Oil conducted a group-shoot acquisition program in 1991, gathering 3,675 kilometers of seismic, gravity and magnetic data as well as Enterprise's airborne ultra-violet seepfinder survey. All of the areas were later relinquished.

On November 28, 2008 EAX (75 percent interest) and its partner Avana (25 percent interest) were awarded a Petroleum Agreement for Areas A, B and C. The agreement has a 7 year exploration phase and a 25 year development phase. During the exploration phase the contractor is required to relinquish 25 percent after the second contract year and another 25 percent after the fourth contract year. The work program for Areas A, B and C consists of carrying out a high resolution analysis of existing gravity and magnetic data, integration of

all old and new seismic and geochemical data and acquiring 655 kilometers of 2-D infill seismic or 150 square kilometers of 3-D seismic.

6.2 Regional Geology

The complexity of the tectonic evolution of the Seychelles plateau is due to the imposition of three phases of rifting and drifting that isolated the micro-continent from the centre of Gondwana.

The first sedimentary rocks of Seychelles began forming during the Permo-Carboniferous time as part of the early Karoo section on the Gondwana paleo-continent. The western Seychelles margin can be reconstructed to a position adjacent to Somalia and as a northern extension of Madagascar prior to drifting from Africa in the Upper Jurassic.

The Karoo-Gondwana sequence equivalents in the Seychelles consist of sandstones, shales and mudstones deposited on the Precambrian granitic basement.

After transgression during the Middle Jurassic, marine shales dominated deposition in deep basin areas while interbedded shales, mudstones and sandstones are characteristic of the shallower section. An oolitic layer forms a Middle Jurassic marker horizon.

A second phase of rifting occurred during the mid Cretaceous when India and Seychelles separated from Madagascar. The Madagascar landmass acted as a major sediment source for the Seychelles micro-continent during this period. During this time a significant part of Seychelles was covered by basalts and volcanic rocks.

The third and final rift phase occurred in the late Cretaceous with the drift between Seychelles and India initiating during the early Paleocene. The Tertiary succession is characterized by thick shelf carbonates with local reef developments and thick volcanic-clastic sequences.

The main core of the Seychelles micro-continent includes some twenty five islands with basement rocks exposed to the surface and therefore no exploration potential. The basement rocks consist of granites and granitoids dated as Neoproterozoic.

6.3 Exploration Potential

The area is covered by 2-D seismic mostly acquired between 1977 and 1987. In 2007 EAX completed a seismic program consisting of 3,637 kilometers of 2-D seismic over the plateau area. Overall the seismic is quite sparse with on average between three and five kilometres between lines in Area A and up to 10 kilometres in Area B. A map showing the location of the seismic is presented in Figure 5.

Prospective resources were assigned to eight leads in Area A and one lead in Area B. No prospective resources were assigned to Area C as the current data is too limited to properly define any leads. A near top Karoo seismic reflector map showing each of the leads is present in Figures 6, 7 and 8.

The main exploration target is the Permo-Triassic Karoo interval which comprises non-marine sands interbedded with shales. The Karoo formation contains both the source rock and the reservoir. An additional source rock may exist in the Jurassic interval which contains marine or restricted marine algal organic matter. Whilst not straightforward it may be possible that Jurassic oil generated deep in the graben could have migrated into the Karoo reservoir in uplifted blocks on the edges of the graben.

Two wells have penetrated the Karoo reservoir and confirmed the presence of permeable reservoirs with oil-shows. The maturity level of the organic source rock was reported to be high and the source rock is estimated to be partly in the gas window and partly in the oil window. The high maturity level cannot be explained by the present day thermal gradient which is quite low, but is explained by the influence of basalts and volcanic rocks that were deposited in the late Cretaceous, which locally increased the paleo-thermal gradient.

The southern part of Area A should have a higher maturity level of organic rocks where basalts were confirmed by seismic interpretation and drilling. This area is likely to have a greater chance of being gas bearing whereas in the northern part of Area A and Area B there is a greater chance of any reservoirs being oil bearing as basalts were either not deposited or have been eroded. The relative position of the leads to the areas of known basalts was used to guide the relative percentage of oil or gas assigned to each lead.

The potential source rock may only be present in a limited area between the central part of the micro-continent and the deep water area. The potential source rock is likely outcropping to the ocean on the edges and central part of the plateau which may have caused some of the generated hydrocarbons to leak into the ocean.

Most of the structures were formed during the latest re-activation of the area in early Paleocene. All of the leads were defined based on time structure maps and the time to depth conversion may be difficult due to the presence of basalts, volcanic rocks and salt in the above Karoo section.

There are three groups of leads in Area A defined as the deep water, southern and western areas. The deep water area contains one lead located in water depths of 1,700 meters. It is a faulted anticline structure on an isolated downthrown block outside the main micro-continent and fault seal is a critical risk. The southern area consists of three leads, two faulted anticlines and one anticline. The main risk is associated with the integrity of the fault seal. The western area includes four leads related to faulted anticline structures inside small tilted grabens. The critical risk is structural interpretation as these leads might be an artifact of poor seismic processing. Area B contains only one large structure, however, it is defined by sparse, poor quality seismic and additional seismic may show a more complex structure.

All of the interpreted leads have a high risk and require additional geological and geophysical exploration work for better definition of structures and to assess the hydrocarbon potential.

There may be additional exploration potential in Area C, however, no information was provided as part of this assessment to evaluate the exploration potential of this block. Area C is located in southern Seychelles in shallow water approximately 300 to 350 kilometers from Area A and B and covers an area of 168,000 acres. BMEHL is targeting structures in tilted fault blocks.

Potential reservoirs in the volcanic rocks and Jurassic clastic sediments may exist although further exploration work is needed.

7. MADAGASCAR - BLOCK 1101

7.1 Property Overview

The Block 1101 Contract area is located on the eastern flank of the Ambilobe basin in northern Madagascar as shown in Figure 9. The Block encompasses an area of approximately 14,900 square kilometers onshore and lies adjacent to the Exxon-operated, offshore, Ampasindava Block and the Ambilobe Block of Sterling Energy Plc. where Exxon has farmed in.

To date, there has been limited exploration activity in the block with two wells drilled and subsequently abandoned. The first well was drilled as long ago as 1901 near the village of Ankaramy to 193 meters and the second well, Ambilobe-1, was drilled by Societe Des Petroles de Madagascar ("SPM") in 1963 with neither well penetrating the Karoo formation. The block was held by Maxus in the 1990's, however, little work was undertaken on the onshore. Triton Energy Ltd. who was later bought out by Amerada Hess Corporation ("Hess") also held acreage in the region. Hess later relinquished its offshore exploration assets that were later acquired by Sterling Energy Plc. The onshore region remained open until EAX (40 percent interest) and Candax Energy (60 percent interest and operator) signed a PSC for Block 1101 in September 2006, which became effective on July 24, 2007. Since that time an aeromagnetic survey has been commissioned and approximately 220 kilometers of 2-D seismic has been acquired over the southern area of the block.

The Block 1110 exploration period comprises three phases each of two years. The first phase would have ended in July 2009, however the government has granted a one year extension taking it to July 2010. During the exploration phase the contractor is required to relinquish 50 percent of the block area after the completion of the second exploration phase and the remaining 50 percent at the end of the third exploration phase. The initial exploration term carries a one-well commitment to 800 meters by July 2010.

7.2 Regional Geology

The formation of the Ambilobe basin and the corresponding stratigraphic suites are closely related to the break-up of Gondwana and the later separation of eastern Gondwana. Extensional block faulting in the late Carboniferous to late Permian resulted in a series of

horst and graben structures and the deposition of thick fluvial, deltaic and immature terrestrial clastics of the Lower Karoo sequence (Sakoa and Lower Sakamena formations). The Middle Sakamena formation is the only significant marine deposit in the Karoo sequence and coincides with a decrease in tectonic activity during late Permian. The deposition of terrestrial clastics continued until early Jurassic with the deposition of the continental beds and sandstones of the Upper Sakamena and Isalo formations with some locally significant flood plain shales.

Re-activation of the rift in early Jurassic as East Gondwana began to separate from West Gondwana created a restricted basin with local development of salt. As the separation continued a carbonate platform (Dogger) developed over the tilted and eroded Karoo sequence. The carbonate platform was superseded by a major transgression in Late Jurassic and the deposition of marine clastics.

The separation of the Indian plate in Late Cretaceous led to further subsidence and the deposition of thick Mesozoic and Cenozoic sequences in the basin. This led to a westward tilt and uplift of Madagascar, which resulted in substantial sub-aerial erosion and a general elevation of the onshore Karoo sequence.

7.3 Exploration Potential

The area is covered by 220 kilometers of 2-D seismic as shown in Figure 9. The seismic data is quite sparse with an average of 2 kilometers between lines.

Three leads (A, B and C) have been identified on the intra-Karoo time structure map as presented in Figure 10. The structures are tilted fault blocks formed during the re-activation of the area in Early Jurassic.

The Permo-Triassic, continental sands of the Isalo formation are considered to be the main exploration target. Unfortunately the only well in the area, Ambilobe-1, did not penetrate the Isalo formation and so there is limited data available on the reservoir quality. There are proven heavy oil accumulations in the Isalo formation in Central Madagascar such as Bermolanga and Tsimiroro which indicate good reservoir conditions.

The main source rock is assumed to be the Upper Permian Middle Sakamena marine shales. These shales have been proven oil prone in the onshore Manandaza basin Karoo corridor, which also contains the Bemolanga and Tsimiroro oil fields south of the Ambilobe basin.

All of the exploration leads are faulted anticline structures. These faults are considered to have been recently active and depending on the cross-fault juxtaposition against other strata could represent a significant risk to the trap seal.

All of the interpreted leads have a high risk and require additional geological and geophysical exploration work for better definition of structures and hydrocarbon potential

8. USE OF THIS REPORT

In preparing this report, we relied upon certain factual information including ownership data, seismic data, well data and other relevant data supplied by BMEHL. The supplied information was only relied upon where in our opinion it appeared reasonable and consistent with our knowledge of the properties however no independent verification of the information was made. We have also relied upon written representations made by BMEHL as to the completeness and accuracy of the data provided.

We understand that this report will be used by BMEHL, Afren plc and Merrill Lynch International for inclusion in the prospectus and class 1 circular that Afren plc is sending to its shareholders in connection with the acquisition of the Company however it should be noted that prepared in accordance with the resource definitions and standards set out in the Canadian National Instrument NI 51-101 and the Canadian Oil and Gas Evaluation Handbook (COGEH). This report is not to be reproduced, distributed or made available, in whole or in part, to any person, company or organization without the knowledge and consent of McDaniel & Associates Consultants Ltd. As additional information becomes available, we reserve the right to revise our opinions and estimates to incorporate such information.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.



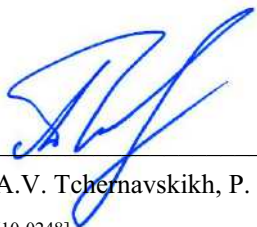
B. H. Emslie, P. Eng.



P.M. Taylor, MEI CEng.



C. T. Boulton, E. I. T.



A.V. Tchernavskikh, P. Geol.

[10-0248]

BHE/CTB/PMT/AVT:lmb

PERMIT TO PRACTICE
McDANIEL & ASSOCIATES CONSULTANTS LTD.

Signature 

Date Tuesday, August 24, 2010

PERMIT NUMBER: P 3145

The Association of Professional Engineers,
Geologists and Geophysicists of Alberta



McDaniel
& Associates Consultants Ltd.

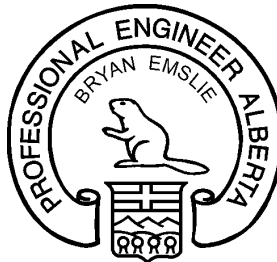
CERTIFICATE OF QUALIFICATION

I, Bryan Howard Emslie, Petroleum Engineer of 2200, 255 - 5th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am a Senior Vice President of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Black Marlin Energy Holdings Limited, the report entitled "Black Marlin Energy Holdings Limited, Exploration Potential Assessment Report, East Africa Properties, as of August 2010", dated August 24, 2010, and that I was involved in the preparation of this report.
2. That I attended the University of Alberta in the years 1973 to 1980 and that I graduated with a Bachelor of Science Degree in Mechanical Engineering, that I am a registered Professional Engineer with the Association of Professional Engineers, Geologists & Geophysicists of Alberta and that I have in excess of twenty-six years experience in oil and gas reservoir studies and evaluations.
3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Black Marlin Energy Holdings Limited, any associate or affiliate thereof.
4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.



B. H. Emslie, P. Eng.
Senior Vice President



Calgary, Alberta
Dated: August 24, 2010

CERTIFICATE OF QUALIFICATION

I, Paul M. Taylor, Petroleum Engineer of 74 North Street, Guildford, Surrey, UK hereby certify:

1. That I am a Senior Evaluation Engineer of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Black Marlin Energy Holdings Limited, the report entitled "Black Marlin Energy Holdings Limited, Exploration Potential Assessment Report, East Africa Properties, as of August 2010", dated August 24, 2010, and that I was involved in the preparation of this report.
2. That I attended the University of Nottingham (UK) in the years 1982 to 1986 and that I graduated with a Master of Engineering in Chemical Engineering, that I am a Member of the Energy Institute and have been awarded the use of the special designatory title Chartered Petroleum Engineer with the Engineering Council (UK), and that I have in excess of twenty-one years experience in oil and gas reservoir studies and evaluations.
3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Black Marlin Energy Holdings Limited, any associate or affiliate thereof.
4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.



P. M. Taylor, MEI CEng

Calgary, Alberta

Dated: August 24, 2010

CERTIFICATE OF QUALIFICATION

I, Cameron Boulton, Engineer In Training of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an Engineer In Training of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Black Marlin Energy Holdings Limited, the report entitled "Black Marlin Energy Holdings Limited, Exploration Potential Assessment Report, East Africa Properties, as of August 2010", dated August 24, 2010, and that I was involved in the preparation of this report.
2. That I attended the Queen's University in the years 2002 to 2006 and that I graduated with a Bachelor of Science degree in Chemical Engineering, that I am a registered Engineer In Training with the Association of Professional Engineers, Geologists & Geophysicists of Alberta and that I have in excess of four years experience in oil and gas reservoir studies and evaluations.
3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Black Marlin Energy Holdings Limited, any associate or affiliate thereof.
4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.



C. T. Boulton, E. I. T.

Calgary, Alberta

Dated: August 24, 2010

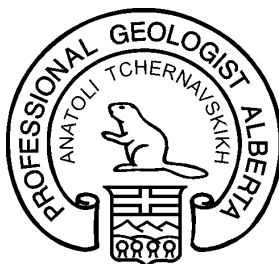
CERTIFICATE OF QUALIFICATION

I, Anatoli V. Tchernavskikh, Petroleum Geologist, of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am the Manager of International Geology of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Black Marlin Energy Holdings Limited, the report entitled "Black Marlin Energy Holdings Limited, Exploration Potential Assessment Report, East Africa Properties, as of August 2010", dated August 24, 2010, and that I was involved in the preparation of this report.
2. That I attended Moscow State University (Russia) in the years 1984 to 1991, graduating with a Honorary Master of Science degree in Geology; that I am a registered Professional Geologist with the Association of Professional Engineers, Geologists & Geophysicists of Alberta and that I have in excess of sixteen years experience in oil and gas reservoir studies and evaluations.
3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Black Marlin Energy Holdings Limited, any associate or affiliate thereof.
4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.



A. V. Tchernavskikh, P. Geol.



Calgary, Alberta

Dated: August 24, 2010

APPENDIX



Black Marlin Energy Holdings Limited Exploration Potential Assessment Summary - Property Gross Effective June 1, 2010																				
#	Lead	Oil & Gas Original in Place						Oil & Gas Resources						BOE Resources						GCOS Frac
		Unrisked OOIP	Unrisked OOIP	Unrisked OOIP	Unrisked OGIP	Unrisked OGIP	Unrisked OGIP	Unrisked Resources	Unrisked Resources	Unrisked Resources	Unrisked Resources	Unrisked Resources	Unrisked Resources	Unrisked Resources	Unrisked Resources	Unrisked Resources	Unrisked Resources	Unrisked Resources	Unrisked Resources	
		P50	P50	P50	P10	P10	P10	P90	P90	P50	P50	P10	P10	P90	P90	P50	P50	P10	P10	
		Mbbl	Mbbl	Mbbl	MMcF	MMcF	MMcF	Mbbl	Mbbl	MMcF	MMcF	MMcF	MMcF	Mbbl	Mbbl	MMcF	MMcF	Mbbl	Mbbl	
Kenya Block L17/18																				
1	SB 3-1	-	-	-	18,591	82,625	140,848	317,639	-	-	-	-	-	12,909	57,986	97,669	220,809	5,274	879	
2	SB 3-2	-	-	-	14,892	60,355	97,339	220,168	-	-	-	-	-	10,306	41,801	67,487	152,200	3,645	607	
3	SB 3-3	-	-	-	17,192	69,407	107,090	235,625	-	-	-	-	-	11,968	48,006	74,313	162,460	4,013	669	
4	SB 3-4	-	-	-	20,125	79,748	127,210	285,726	-	-	-	-	-	14,046	55,566	88,254	196,891	4,766	784	
5	SB 3-5	-	-	-	14,259	54,827	84,454	184,828	-	-	-	-	-	9,912	38,009	58,564	127,253	3,162	527	
6	SB 3-6	-	-	-	14,291	52,305	77,242	168,125	-	-	-	-	-	9,909	36,965	53,635	116,807	2,896	483	
7	SB 3-7	-	-	-	6,241	20,708	27,396	56,532	-	-	-	-	-	4,319	14,322	19,997	39,463	1,026	171	
8	SB 3-8	-	-	-	10,656	35,874	48,487	101,131	-	-	-	-	-	7,398	24,747	33,629	70,573	1,816	303	
9	SB 3-9	-	-	-	6,151	18,417	23,477	47,224	-	-	-	-	-	4,243	12,720	16,286	32,766	879	147	
10	SB 3-12	-	-	-	10,177	36,393	51,336	108,290	-	-	-	-	-	7,036	25,208	35,604	75,595	1,923	320	
11	SB 3-14	-	-	-	4,981	18,003	26,519	57,424	-	-	-	-	-	3,456	12,447	18,380	39,617	993	165	
Subtotal		-	-	-	137,557	528,664	811,398	1,779,711	-	-	-	-	-	95,503	386,067	562,828	1,234,433	30,393	5,065	
Seychelles Areas A & B																				
1	Tazard	30,785	211,903	576,710	1,411,369	5,634	39,012	106,037	260,591	5,329	38,918	114,300	278,288	8,641	3,879	26,891	73,519	181,430	5,558	
2	Bonil	6,185	35,962	83,285	202,924	47,996	277,230	642,137	1,557,694	1,052	6,624	16,813	40,176	1,059	33,065	192,354	445,178	1,081,028	28,046	
3	Espadon Near	12,693	84,962	229,694	559,120	17,924	118,612	317,125	782,031	2,114	15,605	46,082	112,072	5,058	12,375	81,646	219,176	542,673	24,138	
4	Bekin	13,936	89,118	219,290	547,326	13,067	82,741	204,025	485,155	2,371	16,001	43,214	106,882	5,082	9,062	57,118	141,769	343,860	16,672	
5	Libin	9,063	40,495	75,769	175,486	7,672	34,199	63,976	146,718	1,461	7,885	14,899	35,455	2,103	5,337	23,682	44,252	104,027	6,245	
6	Lusher	8,749	37,242	62,540	145,217	5,532	23,217	39,112	89,149	1,410	6,864	12,530	29,591	786	3,817	16,093	27,120	61,981	1,701	
7	Zekker	9,762	45,681	85,416	205,649	5,513	25,828	48,570	115,688	1,607	8,368	17,155	40,993	807	3,809	17,654	33,702	79,144	1,585	
8	Dorad	8,560	49,146	103,920	249,399	4,580	26,988	56,049	136,645	1,444	8,984	20,699	49,217	974	3,177	18,650	38,865	94,277	1,828	
9	Banane	4,220	16,978	27,545	62,757	2,305	9,194	14,922	33,818	678	3,139	5,461	12,561	385	1,607	6,357	10,295	23,448	726	
Subtotal		103,955	611,387	1,464,169	3,559,247	110,221	637,020	1,491,753	3,629,479	17,465	112,688	291,154	705,234	24,895	76,129	440,646	1,034,616	2,511,878	86,500	
Madagascar Block 1101																				
1	A	20,735	75,985	124,238	278,850	-	-	-	-	2,585	13,458	24,980	59,231	1,403	-	-	-	-	-	
2	B	27,309	119,952	217,900	511,523	-	-	-	-	3,526	21,235	43,548	105,399	1,834	-	-	-	-	-	
3	C	48,806	258,861	616,514	1,458,127	-	-	-	-	6,374	46,142	122,913	288,042	6,040	-	-	-	-	-	
Subtotal		96,849	454,796	958,652	2,248,501	-	-	-	-	12,484	80,834	191,441	452,672	9,277	-	-	-	-	-	
Total		200,804	1,066,185	2,422,821	5,807,748	247,779	1,165,684	2,303,152	5,400,191	29,949	193,922	482,595	1,157,905	34,172	171,632	806,912	1,597,444	3,746,311	116,893	
(1) The total resource estimates are based on an arithmetic aggregation of the individual leads.																				
(2) Gas was converted to barrels of oil equivalent ("BOE") at a ratio of 6 Mcf to 1 bbl.																				
(3) There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be economically viable or technically feasible to produce any portion of the resources.																				
McDaniel & Associates																				



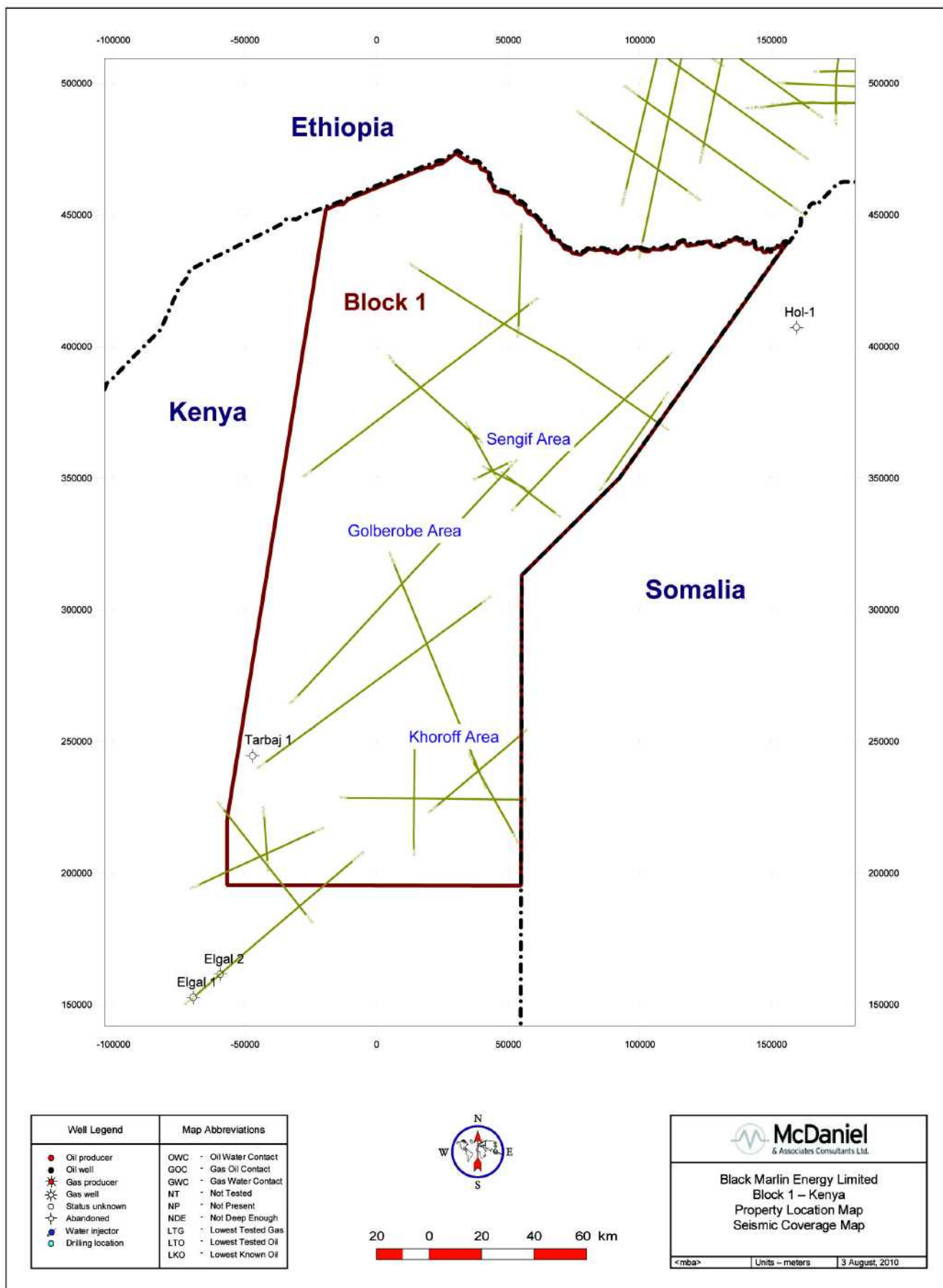
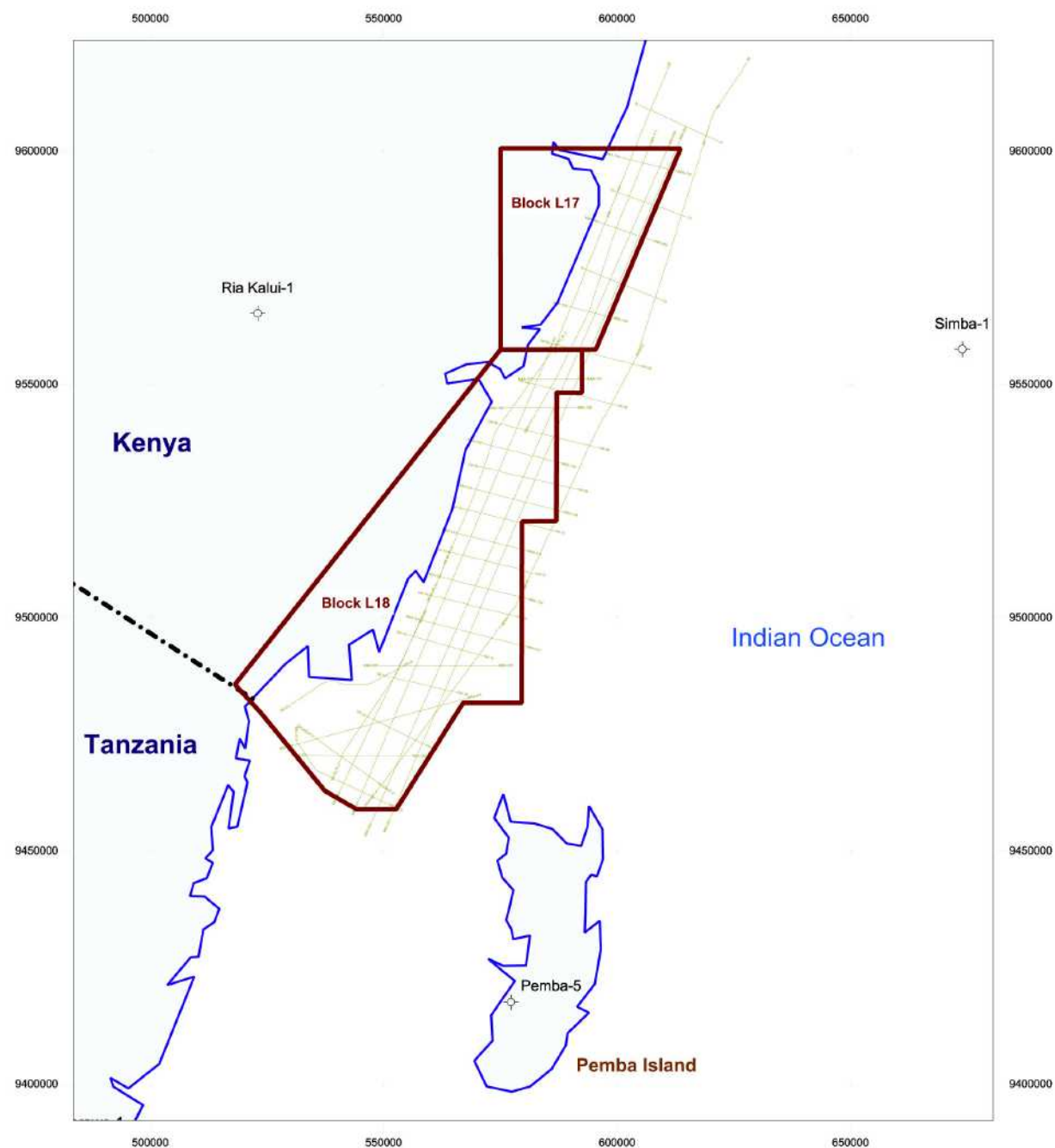
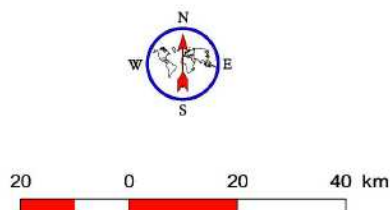


Figure 3



Well Legend	Map Abbreviations
● Oil producer	OWC - Oil Water Contact
● Oil well	GOC - Gas Oil Contact
★ Gas producer	GWC - Gas Water Contact
★ Gas well	NT - Not Tested
○ Status unknown	NP - Not Present
✱ Abandoned	NDE - Not Deep Enough
⬇ Water injector	LTG - Lowest Tested Gas
⬇ Drilling location	LTO - Lowest Tested Oil
	LKO - Lowest Known Oil



Black Marlin Energy Limited Blocks L17, L18 - Kenya Property Location Map Seismic Coverage Map		
<mba>	Units – meters	28 September, 2009

Figure 4

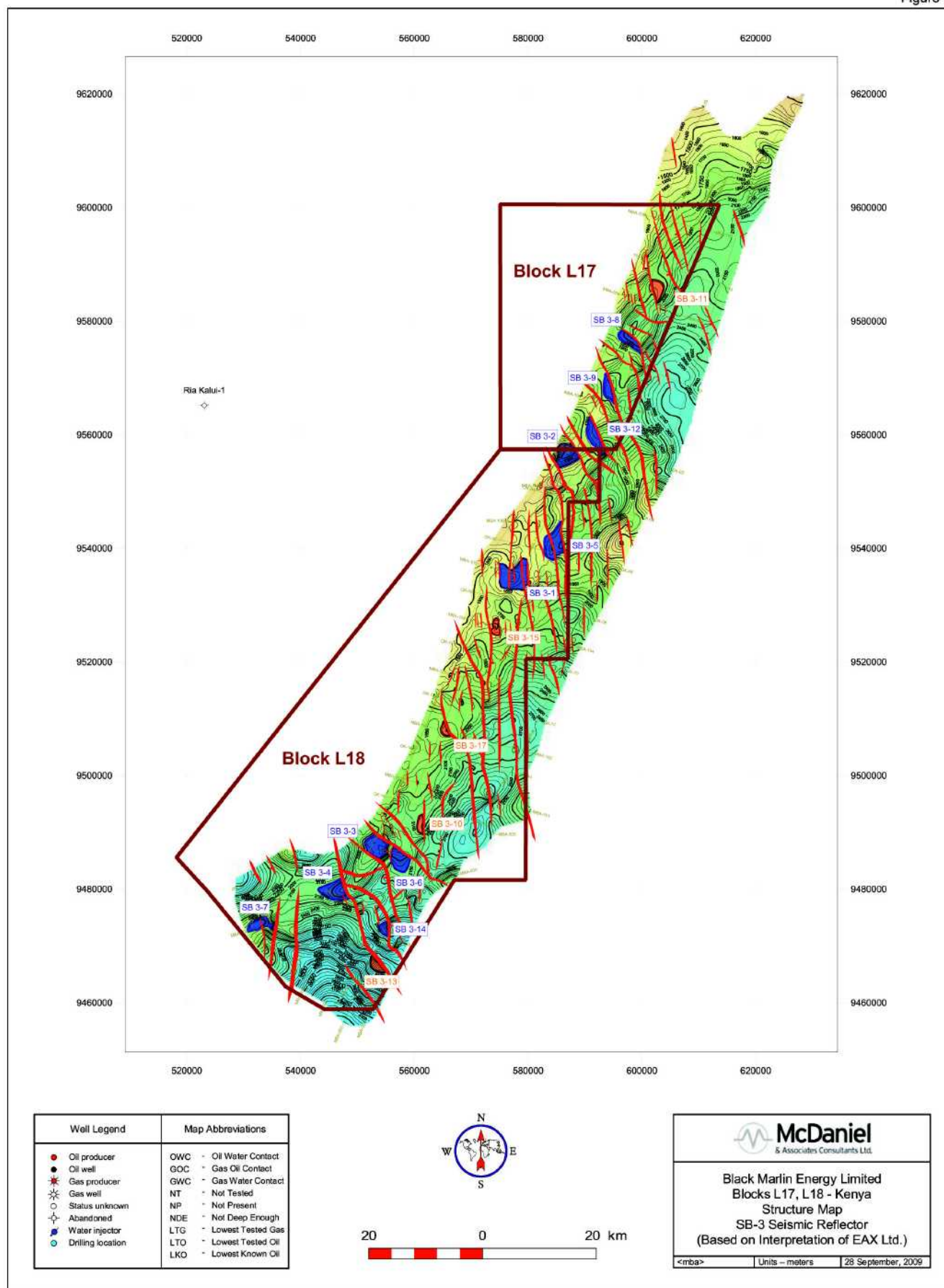


Figure 5

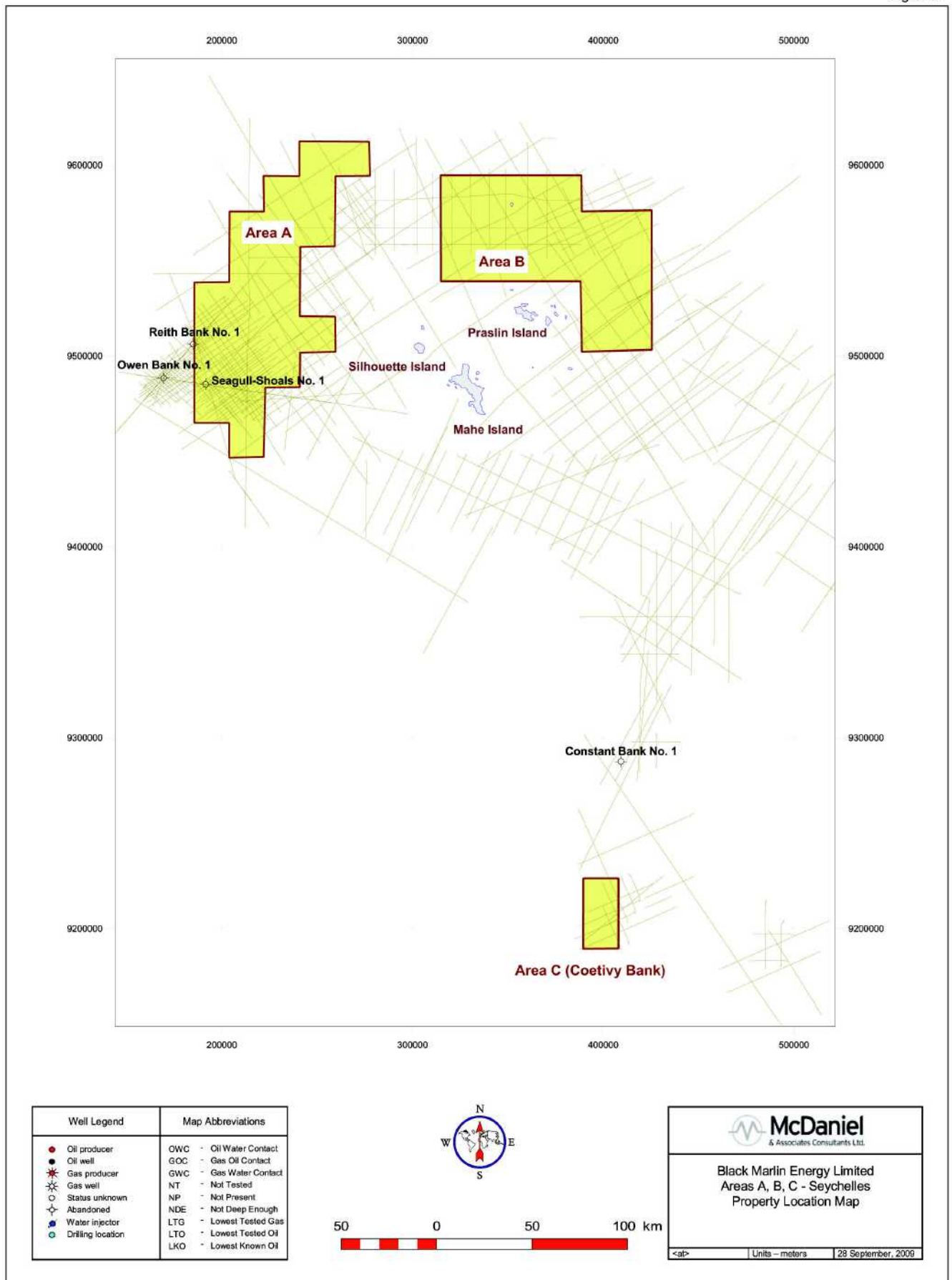


Figure 6

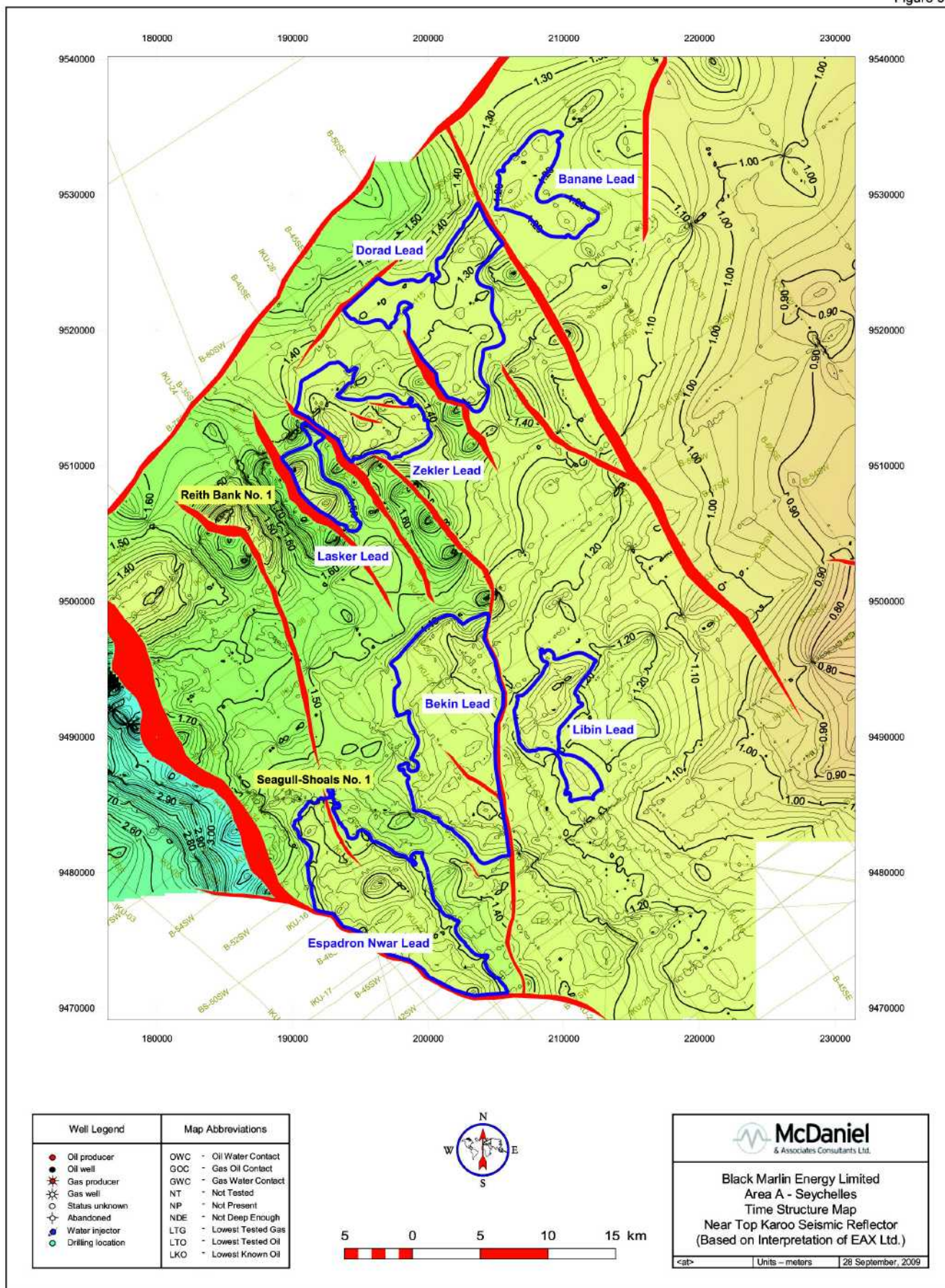


Figure 7

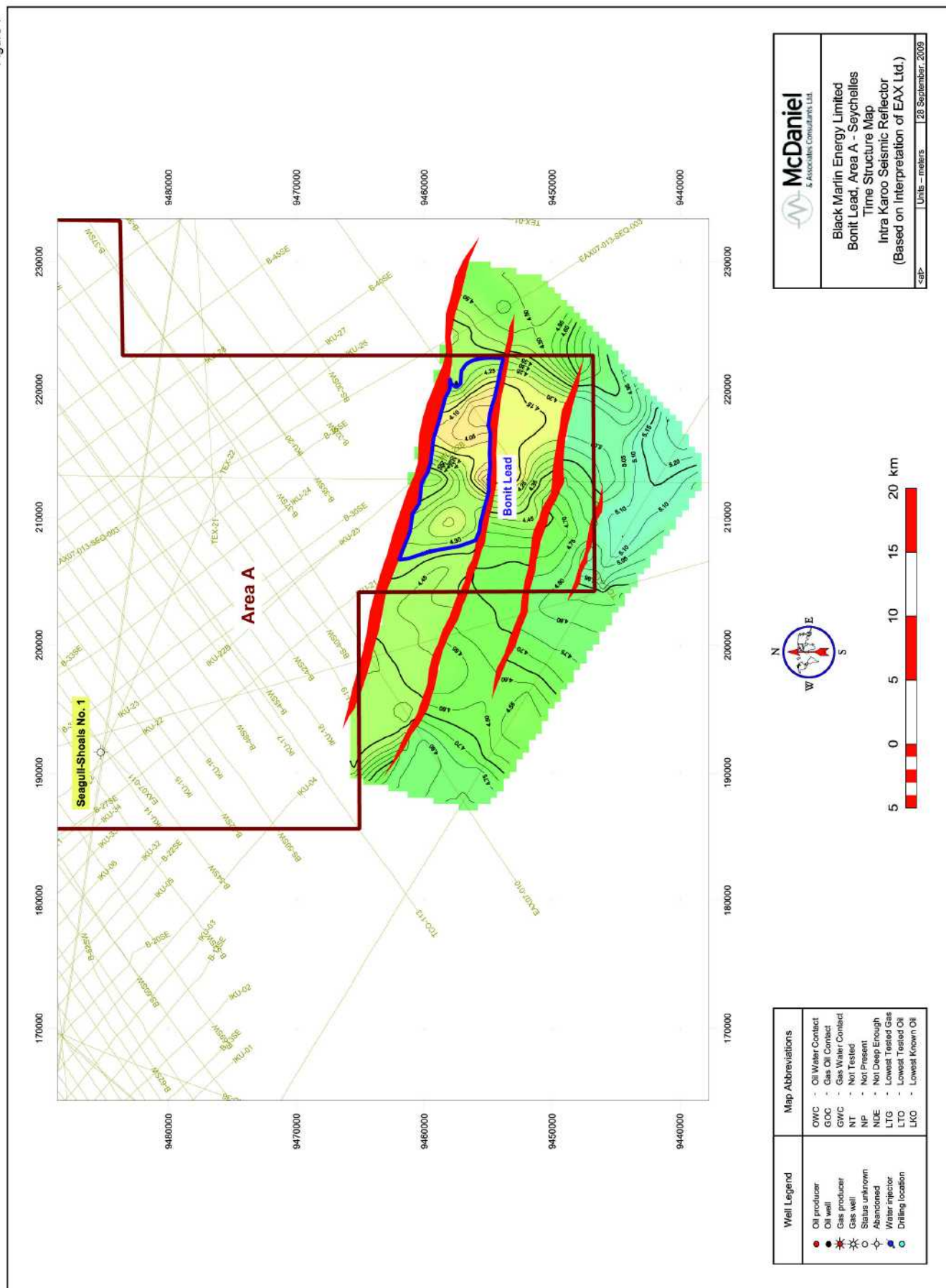
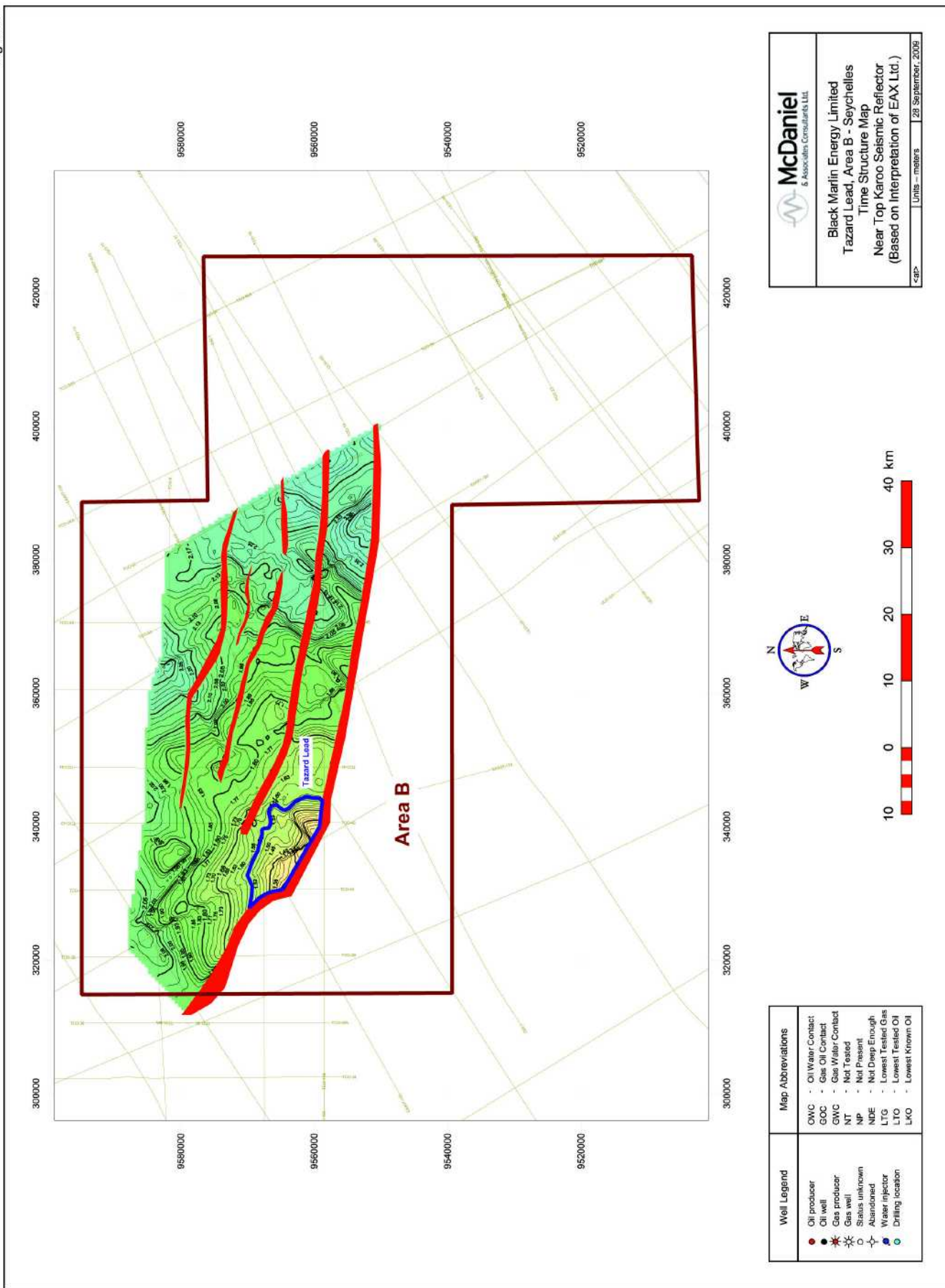


Figure 8



McDaniel
& Associates Consultants Ltd.

Black Marlin Energy Limited
Tazard Lead, Area B - Seychelles
Time Structure Map
Near Top Karoo Seismic Reflector
(Based on Interpretation of EAX Ltd.)

Units – meters

28 September, 2009

Figure 9

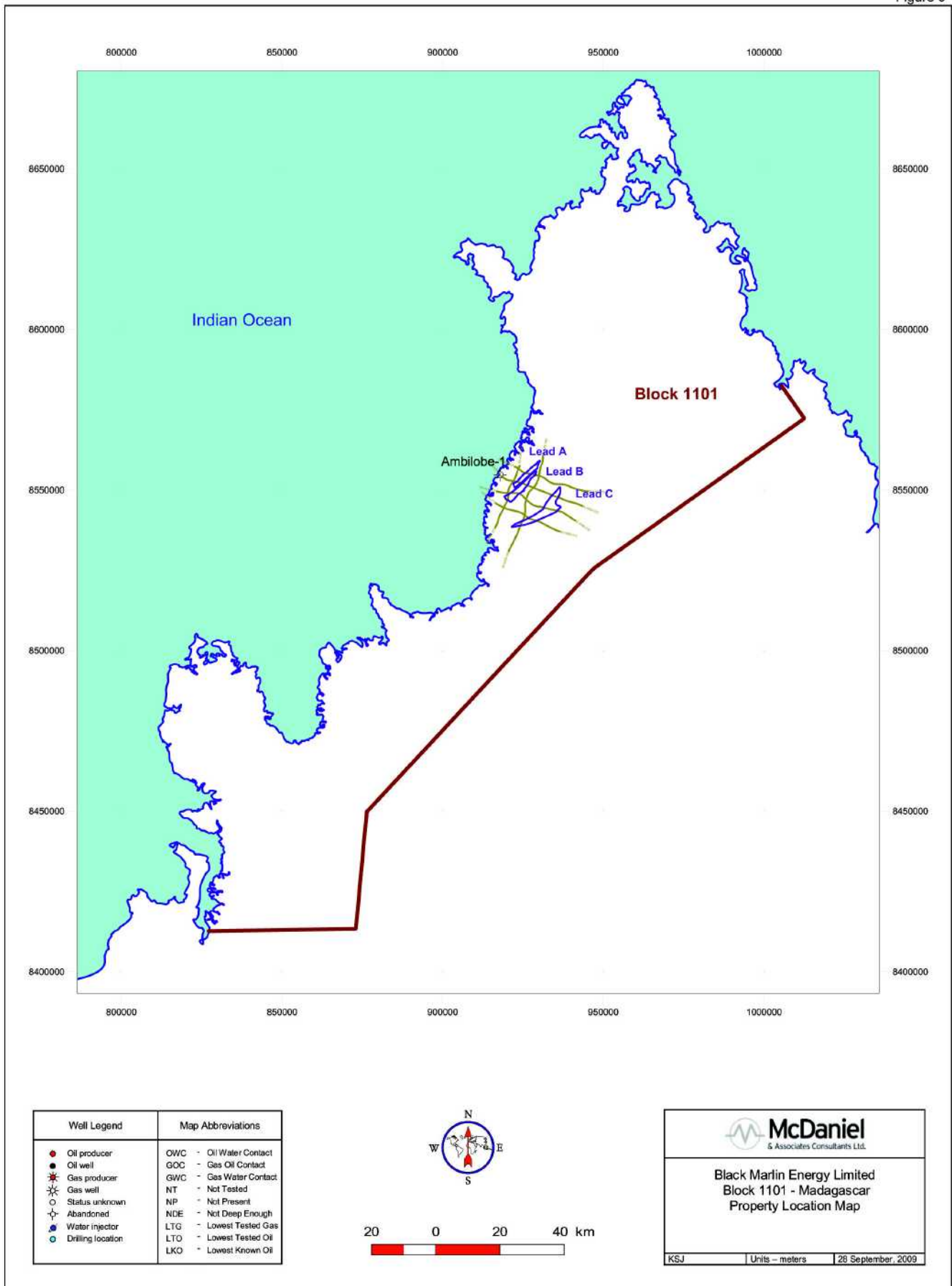
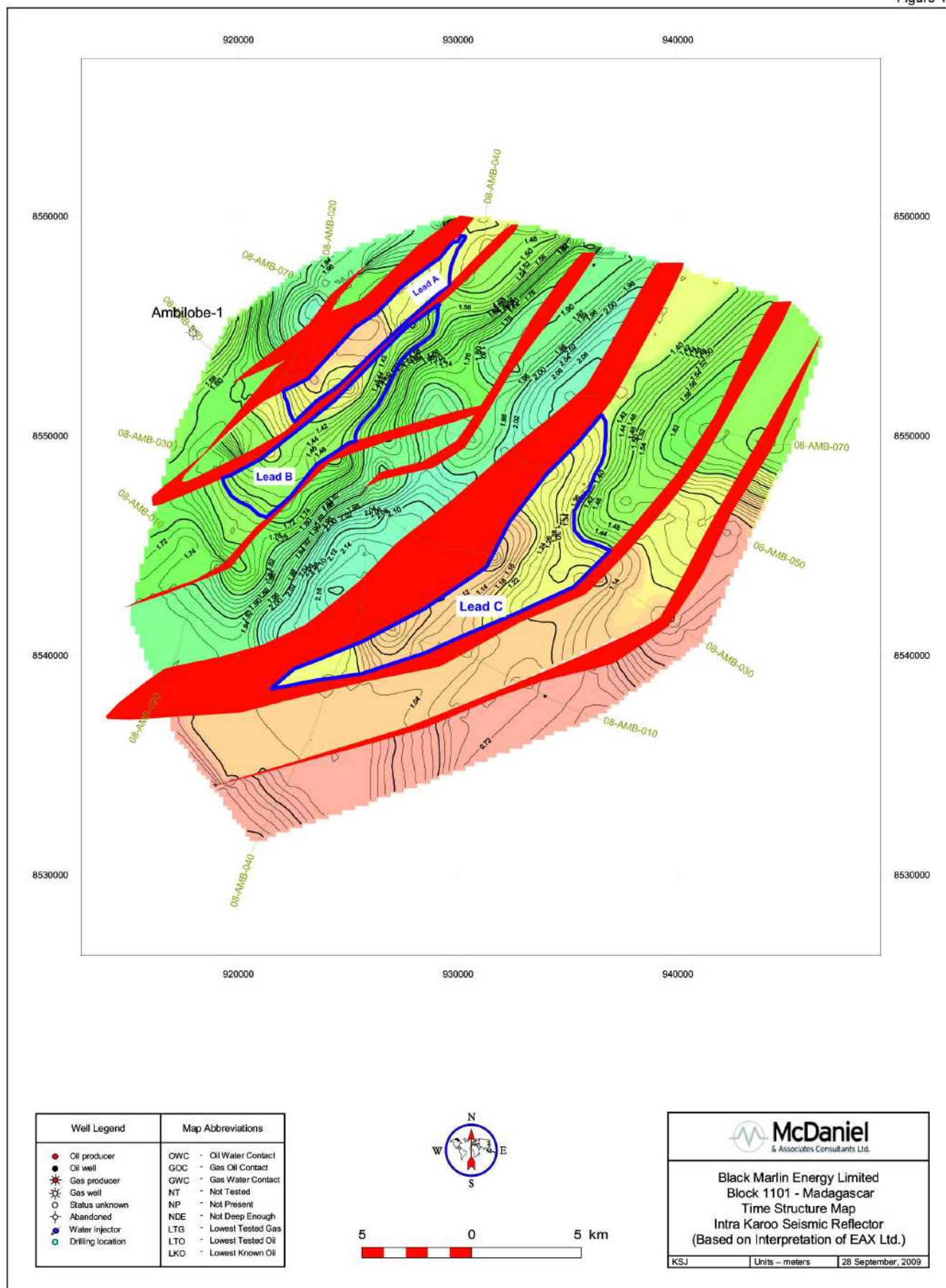


Figure 10



PART 14

DEFINITIONS AND GLOSSARY

“2006 Act”	the Companies Act 2006, as amended
“2009 Prospectus”	the prospectus dated 30 November 2009 prepared by Afren in connection to the admission of 889,050,354 Ordinary Shares to the Official List and to trading on the London Stock Exchange’s main market for listed securities on 3 December 2009
“2009 Admission”	the admission of 889,050,354 Ordinary Shares of Afren to listing and to trading on the London Stock Exchange’s main market for listed securities on the Official List on 3 December 2009
“AAPG”	American Association of Petroleum Geologists
“Acquisition”	the acquisition of Black Marlin by Afren to be implemented by way of the Scheme, pursuant to the terms of and subject to the conditions in the Arrangement Agreement
“Addax”	Addax Petroleum (Nigeria Offshore) Limited
“AERL”	Afren Energy Resources Limited
“Afren Cote d’Ivoire”	Afren Cote d’Ivoire, Ltd
“Afren Exploration”	Afren Exploration and Production Nigeria Alpha Limited
“Afren Investments”	Afren Investments Oil & Gas (Nigeria) Limited
“Afren Nigeria”	Afren Nigeria Holdings Limited
“Afren Okoro”	Afren Okoro Limited
“Afren Resources”	Afren Resources Limited
“Afren Shareholders”	holders of Ordinary Shares
“Afren Shareholder Circular”	the class 1 circular to Afren Shareholders pursuant to Chapters 10 and 13 of the UK Listing Rules
“AGER”	Afren Global Energy Resources Limited
“Agip”	Azienda Generale Italiana Petroli
“AIM”	the Alternative Investment Market, regulated by the London Stock Exchange
“Amni”	Amni International Petroleum Development Company Limited
“Annual Report”	Afren’s Annual Report for the financial year ended 31 December 2009
“April Placing”	defined in Part 10
“Arrangement Agreement”	the agreement dated 2 June 2010 between Afren and Black Marlin setting out the terms and conditions of, and the arrangements for the implementation of the Acquisition as amended by an amended and restated arrangement agreement between the same two parties dated 11 August 2010, summarised in Part 10 of this Prospectus
“Articles”	the articles of association of Afren

“Audit and Risk Committee”	the audit and risk committee of the Board
“BDO”	BDO Chartered Accountants & Advisors, which is a civil company operating under a professional license issued by the Government of Dubai and the United Arab Emirates Ministry of Economy.
“Black Marlin”	Black Marlin Energy Holdings Limited and its subsidiary undertakings from time to time
“Black Marlin Directors”	the directors of Black Marlin
“Black Marlin Energy”	defined in Part 2
“Black Marlin Options”	options to purchase Black Marlin Shares granted or governed under KCC’s stock option plan
“Black Marlin Shareholders”	holders of Black Marlin Shares
“Black Marlin Shares”	the ordinary shares without par value in the capital of Black Marlin
“Black Marlin Warrants”	defined in Part 3
“Block CI-01”	Block CI-01, offshore Côte d’Ivoire which contains Kudu, Eland and Ibex
“Block CI-11”	Block CI-11, offshore Côte d’Ivoire which contains Lion and Panthère
“Board”	the board of directors of Afren from time to time including a duly constituted committee thereof
“Break Fee”	defined in Part 3
“BofA Merrill Lynch”	Bank of America Merrill Lynch
“BNP”	BNP Paribas
“BVI”	British Virgin Islands
“BVI BCA”	British Virgin Islands Business Companies Act, 2004 (as amended)
“CFA”	CFA franc
“Chevron”	ChevronTexaco JDZ Limited
“City Code”	the City Code on Takeovers and Mergers
“CNR”	Canadian Natural Resources Limited
“COGEH”	Canadian Oil and Gas Evaluation Handbook
“Combined Code”	the Combined Code on Corporate Governance published by the Financial Reporting Council
“Company” or “Afren”	Afren plc
“Court”	the Commercial Division of the High Court of Justice of the Eastern Caribbean Supreme Court of the BVI
“Court Hearing”	defined in Part 3
“Court Order”	defined in Part 3
“CREST”	the relevant system (as defined in the Uncertified Securities Regulations 2001 (SI 2001 No. 3755) operated by CRESTCo Limited

“Directors”	the directors of Afren, whose names are set out in paragraph 1 of Part 5 of this Prospectus
“DEER”	Dangote Energy Equity Resources Ltd
“Deloitte”	Deloitte LLP
“Devon Energy”	Devon Energy Corporation
“DMCC”	defined in Part 2
“EAX”	defined in Part 2
“Ebok” or “Ebok (OML67)”	the Ebok field located in OML 67
“Effective”	the Scheme having become effective pursuant to its terms
“Effective Date”	the date of which the Scheme becomes effective, which is expected to be 8 October 2010
“Effective Time”	the first moment in time on the Effective Date, or such other time as may be agreed in writing between Black Marlin and Afren
“Eland”	the Eland field located in Block CI-01
“Enlarged Group”	the Group following completion of the Acquisition with Black Marlin
“Esso”	Esso Australia Pty. Ltd
“EUR”	euro
“European Economic Area” or “EEA”	the trading area established by the European Economic Area Agreement of 1 January 1994, currently comprising the member states of the European Union (currently, Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain, Sweden and the UK) and Norway, Iceland and Liechtenstein
“Evolution”	Evolution Securities Limited
“ExxonMobil/NNPC Joint Venture”	ExxonMobil Corporation and Nigerian National Petroleum Corporation joint venture
“FCMB”	First City Monument Bank
“FHN”	First Hydrocarbon Nigeria Limited
“Founder Shares”	defined in Part 10
“FPU”	defined in Part 10
“FSA”	the UK Financial Services Authority
“FSMA”	the Financial Services and Markets Act 2000, as amended
“Gasol”	Gasol plc
“GBP” or “£”	pound sterling
“GCA”	Gaffney, Cline & Associates
“GCA Report”	defined in Part 2

“GEC”	Global Energy Company Limited
“GNPC”	Ghana National Petroleum Corporation
“Governmental Entity”	(i) any supranational, international, multinational, national, federal, provincial, state, regional, municipal, local or other government, governmental or public department, ministry, central bank, court, tribunal, arbitral body, office, commission, commissioner, board, bureau or agency, whether domestic or foreign; (ii) any subdivision, agent or authority of any of the foregoing; or (iii) any quasi-governmental or private body, including any tribunal, commission, stock exchange, regulatory agency or self-regulatory organization, exercising any regulatory, expropriation or taxing authority (including the TSXV, the SEC, the FSA and the LSE)
“Group”	Afren and its subsidiary undertakings from time to time
“Gulf”	Gulf Atlantic Energy Ltd
“Ibekelia” or “Ibekelia Licence”	Ibekelia Licence located in the Southern Gabon Subbasin, offshore Gabon
“Ibex”	the Ibex field located in Block CI-01
“IEL”	Independent Energy Limited
“IFC”	International Finance Corporation
“IFRS”	International Financial Reporting Standards as adopted by the European Union
“Interim Order”	defined in Part 3
“Iris Marin” or “Iris Marin Licence”	Iris Marin Licence located in the Southern Gabon Subbasin, offshore Gabon
“ISIN”	International Security Identification Number
“JDZ Block 1”	Block 1 located in the JDZ, offshore Nigeria and São Tomé and Príncipe
“Jefferies”	Jefferies International Limited
“KCC”	defined in Part 2
“KCC Acquisition”	defined in Part 2
“KCC Acquisition Circular”	defined in Part 2
“KCC Acquisition News Release”	defined in Part 2
“Keta” or “Keta Block”	Keta Block located offshore Ghana
“Kosmos”	Kosmos Energy LLC
“Kudu”	the Kudu field located in Block CI-01
“La Noumbi” or “La Noumbi Permit”	La Noumbi Permit located in the Congo Basin, onshore Congo-Brazzaville
“Legal Impediment”	defined in Part 3

“LIBOR”	London Interbank Offered Rate
“Lion”	the Lion field located in Block CI-11
“Listing Rules”	the rules and regulations made by the UK Listing Authority pursuant to Part VI FSMA, as amended from time to time
“Lock-up Agreement”	defined in Part 10
“London Stock Exchange” or “LSE”	London Stock Exchange plc
“JDZ”	Joint Development Zone
“Joint Development Authority”	Nigeria-São Tomé & Príncipe Joint Development Authority
“McDaniel”	McDaniel & Associates Consultants Ltd.
“McDaniel Report”	defined in Part 2
“Merrill Lynch International”	Merrill Lynch International, which is authorised and regulated in the United Kingdom by the FSA and is a member of the London Stock Exchange
“Mitsui Ghana”	Mitsui E&P Ghana Keta Limited
“Mobil”	Mobil Producing Nigeria Unlimited
“Morgan Stanley”	Morgan Stanley Securities Limited
“New Ordinary Shares”	the new ordinary shares of one penny each in the capital of Afren proposed to be issued and credited as fully paid to Black Marlin Shareholders pursuant to the Acquisition
“New Ordinary Share Admission”	the admission of the New Ordinary Shares to listing on the Official List becoming effective in accordance with the Listing Rules and admission to trading having been granted and becoming effective on the London Stock Exchange’s market for listed securities
“NNPC”	Nigerian National Petroleum Corporation
“Nomination Committee”	the committee of the Board which reviews senior appointments within the Group
“Nomura”	Nomura International plc
“NSAI”	Netherland, Sewell & Associates, Inc.
“NSAI Report” or “Competent Person’s Report”	the competent person’s report by NSAI set out in Part 11 of this Prospectus
“Ofa” or “Ofa (OML 30)”	the Ofa field located in OML 30
“Official List”	the Official List of the UK Listing Authority
“Okoro” or “Okoro (OML 112)”	the Okoro field located in OML 112
“Okwok” or “Okwok (OML 67)”	the Okwok field located in OML 67
“OML 30”	Oil Mining Lease 30, onshore Nigeria which contains Ofa
“OML 67”	Oil Mining Lease 67, Gulf of Guinea, offshore Nigeria which contains Ebok and Okwok

“OML 112”	Oil Mining Lease 112, Gulf of Guinea, offshore Nigeria which contains Okoro and Setu
“OPEC”	Organisation for Petroleum Exporting Countries
“OPL 310”	Oil Prospecting Licence 310 located in the Niger Delta, offshore Nigeria
“OPL 907”	Oil Prospecting Licence 907 located in the Anambra Basin, onshore Nigeria
“OPL 917”	Oil Prospecting Licence 917 located in the Anambra Basin, onshore Nigeria
“Optimum”	Optimum Petroleum Development Limited
“Ordinary Shares”	the ordinary shares of one penny each in the capital of Afren , including the New Ordinary Shares
“Oriental”	Oriental Energy Resources Limited
“Overseas Shareholders”	Shareholders who are resident in , ordinarily resident in or citizens of jurisdictions outside of the United Kingdom
“p”	pence
“Panthère”	the Panthère field located in Block C1-11
“Petroci”	Société Nationale d’Operations Pétrolières de la Côte d’Ivoire
“Phillips”	Phillips Petroleum Company Abidjan
“Placing”	the placing of 129.5 million new shares in Afren to institutional investors announced on 10 November 2009
“Placing Price”	81 pence per Ordinary Share
“Placing Shares”	defined in Part 10
“PDMR”	person discharging management responsibilities as defined in the Listing Rules
“PRMS”	the Petroleum Resource Management System
“Prospectus”	this document
“Prospectus Directive”	EU Prospectus Directive (2003/71/EC)
“Prospectus Rules”	the prospectus rules made by the FSA pursuant to Part VI of FSMA
“Rakgas”	RAKGAS International FZ
“Restricted Subsidiaries”	any body or bodies corporate which would be prohibited under section 136 of the 2006 Act from being a member of Afren upon the Scheme becoming Effective
“Registrars”	Computershare Investor Services PLC, PO Box 82, The Pavilions, Bridgwater Road, Bristol BS99 7NH
“Regulations”	the Uncertificated Securities Regulations 2001 (including any modification, re enactment or substitute regulations for the time being in force)

“Remuneration Committee”	the committee of the Board which determines the remuneration and employment terms of the executive directors
“Requisite Approval”	defined in Part 3
“Scheme”	defined in Part 3
“Scheme Document”	the document sent to Scheme Shareholders proposing the Scheme
“Scheme Shareholders”	the holders of Scheme Shares on the register of Black Marlin
“Scheme Shares”	the Black Marlin Shares in issue immediately prior to the Effective Time
“SEC”	US Securities and Exchange Commission
“SEDAR”	the System for Electronic Document Analysis and Retrieval, described in National Instrument 13-1010-System for Electronic Document Analysis and Retrieval – of the Canadian Securities Administrations and available for public view at www.sedar.com
“Setu” or “Setu (OML 112)”	the Setu field located in OML 112
“Shareholder”	a holder of Ordinary Shares
“Shareholder Meeting”	the meeting of the Scheme Shareholders to be held to consider and, if thought fit, approve the Scheme
“Significant Shareholder”	defined in Part 10
“SIR”	Société Ivoirienne de Raffinage
“SOGEPÉ”	Société de Gestion du Patrimoine du Secteur de l’Electricite
“SPDC”	Shell Petroleum Development Corporation of Nigeria Limited
“SPE”	Society of Petroleum Engineers
“SPEE”	Society of Petroleum Evaluation Engineers
“Sterling Energy”	Sterling Energy plc
“TSXV”	TSX Venture Exchange
“UK”	the United Kingdom of Great Britain and Northern Ireland
“UK Listing Authority”	the Financial Services Authority acting in its capacity as the competent authority for the purposes of Part VI of FSMA
“UMC”	United Meridian Corporation
“UMIC”	United Meridian International Corporation
“Underwriters”	Merrill Lynch International, Morgan Stanley, Evolution, Nomura and Jefferies
“United States” or “US” or “USA”	United States of America
“UPSL”	defined in Part 2
“US Securities Act”	the US Securities Act of 1933, as amended, and the rules and regulations promulgated thereunder
“US\$” or “\$” or “USD”	US dollars
“WPC”	World Petroleum Council

Glossary

“1P”	Proved
“2P”	proved plus probable
“3P”	proved plus probable plus possible
“1C”	low estimate scenario of contingent resources
“2C”	best estimate scenario of contingent resources
“3C”	high estimate scenario of contingent resources
“Low Estimate”	A probability of at least 90% that the quantities recovered will equal or exceed a stated amount
“Best Estimate”	A probability of at least 50% that the quantities recovered will equal or exceed a stated amount
“High Estimate”	A probability of at least 10% that the quantities recovered will equal or exceed a stated amount
“2D seismic”	geophysical data that depicts the subsurface strata in two dimensions
“3D seismic”	geophysical data that depicts the subsurface strata in three dimensions. 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic
“accumulation”	an individual body of moveable petroleum. A known accumulation (one determined to contain Reserves or Contingent Resources) must have been penetrated by a well
“API”	American Petroleum Institute
“appraisal well”	well drilled in order to assess characteristics (such as flow rate, volume) of a proven hydrocarbon accumulation
“barrel” or “b” or “bbl”	a stock tank barrel, a standard measure of volume for oil, condensate and natural gas liquids, which equals 42 US gallons
“bcf”	billions of cubic feet
“bcpd”	barrels of condensate per day
“Block”	an area of licenced territory comprising one or more licences
“boe”	barrels of oil equivalent
“boepd”	barrels of oil equivalent per day
“bopd”	barrels of oil per day
“Brent”	a particular type of crude oil that is a light, sweet oil produced in the North Sea with most of it being refined in Northwest Europe. Brent is a benchmark oil
“clastic”	a sedimentary rock formed from mechanically transported mineral particles
“crude oil”	unrefined oil

“contingent resources”	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies
“cost oil”	Oil that is available to a company to reimburse previous qualifying expenditures
“deltaic”	related to, or like a river delta and often shaped like the Greek letter ‘Δ’. A delta is a deposit formed where a river flows into an ocean, sea, desert, lake or estuary. Deltaic sediments have high potential as hydrocarbon reservoirs
“DST”	drillstem test
“EPSC”	exploration and production sharing contract
“exploration well”	a well drilled to find hydrocarbons in an unproved area or to extend significantly a known oil or natural gas reservoir
“farm in”	to acquire an interest in a licence from another party
“farm out”	to assign an interest in a licence to another party
“field”	an area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition
“formation”	a body of rock that is sufficiently distinctive and continuous that it can be mapped
“FPSO”	floating production, storage and offloading vessel
“FSO”	floating storage and offloading vessel
“GOR”	gas to oil ratio
“gross reserves”	the total estimated petroleum to be produced from a field
“gross resources”	the total estimated petroleum that is potentially recoverable
“hydrocarbons”	compounds formed primarily from the elements hydrogen and carbon and existing in solid, liquid or gaseous forms
“km”	Kilometre
“km²”	square kilometre
“LPG”	liquefied petroleum gas
“m”	Metres
“mmbbl”	million barrels of oil
“mmboe”	million barrels of oil equivalent
“mmcfd”	millions of cubic feet of gas per day
“MOPU”	mobile offshore production unit
“NGL”	natural gas liquids

“Total Petroleum Initially-In-Place” (PIIP)	is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”)
“Undiscovered Petroleum Initially-In-Place” (equivalent to undiscovered resources)	is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as “prospective resources,” the remainder as “unrecoverable.”
“Discovered Petroleum Initially-In-Place” (equivalent to discovered resources)	is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable
“OML”	oil mining lease
“OGIP”	original gas in place
“OOIP”	original oil in place
“OPL”	oil prospecting licence
“petroleum system”	geologic components and processes necessary to generate and store hydrocarbons, including a mature source rock, migration pathway, reservoir rock, trap and seal. Exploration plays and prospects are typically developed in basins or regions in which a complete petroleum system has some likelihood of existing
“play”	a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects
“reserves”	those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions
“proved reserves”	are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations
“probable reserves”	those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves
“possible reserves”	those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than probable reserves
“Unrecoverable”	is that portion of Discovered or Undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks

“production”	the cumulative quantity of petroleum that has been recovered at a given date
“production sharing (contract) (agreement)” or “PSC”	contract by which production of a field is shared between the host government and the oil company operating the field
“production well”	a well drilled to obtain production from a proven oil or gas field. Production wells may be used either to extract hydrocarbons from a field or to inject water or gas into a reservoir in order to improve production
“profit oil”	total volume of oil less the cost oil
“prospect”	a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target
“prospective resources”	those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations (equivalent to undiscovered resources)
“reservoir”	a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. A reservoir is a critical component of a complete petroleum system
“RFT”	repeat formation tester
“seal”	a relatively impermeable rock, commonly shale, anhydrite or salt, that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system
“SEC”	Securities and Exchange Commission
“seismic survey”	a method by which an image of the earth’s subsurface is created through the generation of shockwaves and analysis of their reflection from rock strata. Such surveys can be done in two or three dimensional form
“SPE”	reserves definitions consistent with those approved in March 1997 by the Society of Petroleum Engineers and the World Petroleum Council
“spud”	to start the well drilling process by removing rock and sediment with the drill bit
“STOHP”	stock tank oil initially in place
“tcf”	trillion cubic feet
“TEA”	technical evaluation agreement
“upstream”	activities related to the exploration, appraisal, development and extraction of crude oil, condensate and gas
“wellhead”	all connections, valves, nozzles, pressure gauges, thermometers, installed at the exist from a production well
“WTI”	West Texas Intermediate