Oando Energy Resources

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2013

March 31, 2014

TABLE OF CONTENTS

Page

GLOSSARY **1**

ABBREVIATIONS AND TECHNICAL TERMS **9**

INTERPRETATION **9**

FORWARD-LOOKING STATEMENTS **10**

INCORPORATION AND ORGANIZATION **12**
Intercorporate Relationships 12

BUSINESS OF THE CORPORATION **14**
General 14
Relevant Three Year History 15
Description of OER's Assets 21
Other Corporate Matters 39

THE NIGERIAN OIL AND GAS INDUSTRY AND REGULATORY FRAMEWORK **41**
Overview 41
Government 42
Petroleum Industry 42

STATEMENT OF RESERVES AND RESOURCES DATA AND OTHER OIL AND GAS INFORMATION **50**

RISK FACTORS **51**
Risks Relating to OER 51
Risks Related to the COP Acquisition 55
Risks Related to Carrying on Business in Nigeria 56
Risks Relating to OER's Operations 60
Risks Relating to the Oil Industry 64
Other Risks 68

DIVIDENDS AND DISTRIBUTIONS **70**

DESCRIPTION OF SHARE CAPITAL **70**
Common Shares 70
Warrants 71
Restricted Share Units 71

MARKET FOR SECURITIES **72**
Trading Price and Volume 72
Prior Sales 73
Escrowed Securities 73

DIRECTORS AND OFFICERS **74**
Biographies for Executive Officers and Directors 74
Voting Securities 75
Cease Trade Orders, Bankruptcies, Penalties and Sanctions 75
Conflicts of Interest 76

LEGAL PROCEEDINGS AND REGULATORY ACTIONS **76**
OML 125 76
OML 122 77
OPLs 321 and 323 77
Regulatory Actions 78

AUDIT COMMITTEE **78**
The Audit Committee Charter 78
Composition of the Audit Committee 78
Pre-Approval Policies and Procedures 78
Auditors' Fees 78

PROMOTER **79**

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS **79**
Referral and Non-Competition Agreement 79
ROFO Agreement 80
Cooperation and Services Agreement 80
Transitional Services Agreement 80
Operating Associate Shareholder Agreements 80
2014 Oando Loan Documentation 80

TRANSFER AGENT AND REGISTRAR **80**

MATERIAL CONTRACTS **81**

INTEREST OF EXPERTS **81**

ADDITIONAL INFORMATION **81**

SCHEDULE "A" – Form 51-101F1 Statement of Reserves Data and Other Oil and Gas Information **A-1**

SCHEDULE "B" – Form 51-101F2 Report on Reserves Data by Independent Qualified Resources Evaluator **B-1**

SCHEDULE "C" – Form 51-101F3 Report of Management and Directors on Oil and Gas Disclosure **C-1**

SCHEDULE "D" – Audit Committee Charter **D-1**

GLOSSARY

In this AIF, unless otherwise defined, the following words and terms shall have the following meanings:

2012 Oando Loan	means a $345 million loan advanced to OER from Oando on December 20, 2012.
2013 Oando Loan	means the loan facility established under the 2013 Oando Loan Documentation under which OER may borrow up to $401 million from Oando, repayable by the issuance of securities of OER in certain circumstances.
2013 Oando Loan Documentation	means the facility agreement and repayment deed, each dated May 30, 2013, as amended, pursuant to which Oando agreed to loan up to $401 million (including amounts borrowed under the 2012 Oando Loan) to OER.
2014 Oando Loan	means the loan facility established under the 2014 Oando Loan Documentation under which OER may borrow up to $1.2 billion from Oando, repayable by the issuance of securities of OER in certain circumstances.
2014 Oando Loan Documentation	means the facility agreement dated February 10, 2014 and repayment deed dated February 26, 2014 pursuant to which Oando agreed to loan up to $1.2 billion to OER.
Abo FPSO	means a leased FPSO designed to process oil, gas and water, as well as reinject water and gas, from and into OML 125.
Acquisition Agreements	means, collectively, the CEPNL Acquisition Agreement, PDENL Acquisition Agreement and POCNL Acquisition Agreement.
AGRA	means the *Associated Gas Re-Injection Act* (Nigeria), as amended.
AIF	means this annual information form of OER for the year ended December 31, 2013.
Akepo	means the Akepo Marginal Field as carved out of OML 90.
Amending Agreements	means, collectively, the First COP Amendment, Second COP Amendment, Third COP Amendment, and Fourth COP Amendment.
Arrangement	means the plan of arrangement under Section 192 of the CBCA between OER and Oando dated July 24, 2012 more particularly described under the heading "*Business of OER – Relevant Three Year History – Reverse Takeover Involving Oando and OER*".
Bilabri Settlement Agreement	means the settlement agreement dated September 13, 2007 entered into between EEL 122 and Peak, as more particularly described under the heading "*Legal Proceedings and Regulatory Actions – OML 122*".
Board of Directors	means the board of directors of OER.
Bonny LNG plant	means the Bonny LNG gas plant, owned by NLNG.
Brass River Terminal	means the oil production export terminal located on the Nigerian coast where oil from certain of OER's assets is loaded onto tankers for international export.
Brent	means a type of sweet crude oil that is used as a benchmark for the prices of other crude oils in the world energy market.
CBCA	means the *Canada Business Corporations Act* and the regulations thereunder, as amended from time to time.

CEO	means Chief Executive Officer.
CEPNL	means Conoco Exploration & Production Nigeria Limited (previously known as DuPont E and P Nigeria Limited), a corporation incorporated under the laws of Nigeria, and holding OML 131.
CEPNL Acquisition Agreement	means the share purchase agreement dated December 20, 2012, as amended, among Conoco Holdings Limited and Phillips Investment Company LLC (together as the seller), as well as Oando OML 131 Holding BV and Oando (together as the buyer), in respect of the shares of CEPNL.
CFO	means Chief Financial Officer.
Chevron	means Chevron Corp., a corporation incorporated under the laws of Delaware, and its affiliates.
Chief Compliance Officer	means the chief compliance officer of OER.
Circular	means the management information circular of OER dated April 22, 2013 with respect to the shareholders' meeting of OER held on May 21, 2013.
CITA	means the *Companies Income Tax Act*, 2004 (Nigeria), as amended.
Class A Share	means, in respect of an Operating Associate, a share of such Operating Associate designated as a Class A Share with voting rights, but no right to receive distributions or dividends from such Operating Associate or any of the assets (save nominal capital upon a liquidation or winding-up of the Operating Associate).
Class B Share	means, in respect of an Operating Associate, a share of such Operating Associate designated as a Class B Share with voting rights and rights to receive distributions and dividends from such Operating Associate, as well as the right to all of the assets (save nominal capital in respect of the Class A Shares of such Operating Associate upon a liquidation or winding-up of the Operating Associate).
COGE Handbook	means the Canadian Oil and Gas Evaluators Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy and Petroleum (Petroleum Society), as amended from time to time.
Common Shares	means the common shares of OER.
Cooperation and Services Agreement	means the cooperation and services agreement between Oando and OER dated July 24, 2012.
COP	means ConocoPhillips Company, a corporation incorporated under the laws of the state of Delaware, and its affiliates.
COP Acquisition	means the proposed indirect acquisition by OER of the COP Nigerian Business.
COP Companies	means, collectively, CEPNL, PDENL and POCNL.
COP Nigerian Business	means the offshore business carried out by COP in Nigeria through its indirectly wholly-owned subsidiaries CEPNL and PDENL and the onshore (or shallow water) business in Nigeria currently conducted by COP through its subsidiary, POCNL.

Corporate Facility	means the $350 million loan established by the corporate facility agreement between OER and a syndicate of Nigerian lenders, as well as FBN Capital Limited, FCMB Capital Markets Limited and First Trustees Nigeria Limited, dated January 17, 2014, as amended.
Corporate Governance Committee	means the corporate governance committee of the Board of Directors of OER.
Domestic Supply Obligation or DSO	means a prescribed volume of gas supply dedicated for domestic (Nigerian) power consumption based on reserves, production and volumes flared, which is not being enforced at present due to the lack of an established regulatory authority and insufficient demand in the domestic power sector.
DSRA	means a debt service reserve account established with a lender as required by a facility under which OER borrows money from such lender.
DPR	means the Department of Petroleum Resources.
Ebendo	means the Ebendo/Obodeti Marginal Field.
Ecobank Loan	means the loan of $20 million from Ecobank to OER for the purpose of financing a portion of the deposit payable in connection with the COP Acquisition, as amended.
Education Tax	means the tax payable pursuant to the *Education Tax Act No.7 of 1993* (Nigeria), as amended.
EEL	means Equator Exploration Limited, a corporation incorporated in the British Virgin Islands.
EEL 122	means Equator Exploration (OML 122) Limited, a corporation incorporated in Nigeria.
EEL Loan	means an unsecured advance provided to EEL by Oando for working capital purposes.
EEZ	means exclusive economic zone.
EHS Policy	means environmental health and safety policy.
Eleme Petrochemical plant	means the petrochemical plant located at Eleme, Nigeria owned by Indorama.
Energia	means Energia Limited, a corporation incorporated under the laws of Nigeria.
Eni	means Eni International N.A N.V. S.a.r.l., a corporation incorporated under the laws of Luxembourg, and its affiliates, including NAOC and NAE.
Ethics Code	means the Corporate Code of Business Conduct and Ethics of OER.
ExxonMobil	means Exxon Mobil Corporation, a corporation incorporated under the laws of New Jersey, and its affiliates.
FIRS	means the Federal Inland Revenue Service (Nigeria).
FBN	means First Bank of Nigeria Plc.
Fifth COP Amendment	means the agreement to amend the Acquisition Agreements, as amended, dated March 27, 2014.
First COP Amendment	means the agreement to amend the Acquisition Agreements dated September 13, 2013.

Flowstation	means a production station that separates gas from liquids.
Forcados Terminal	means the terminal located at the port of Forcados owned by Shell.
Forward-Looking Information	has the meaning given pursuant to applicable securities legislation and includes future-oriented financial information, financial outlook disclosure and forward-looking statements.
Fourth COP Amendment	means the agreement to amend the Acquisition Agreements, as amended, dated February 28, 2014.
FPSO	means a floating vessel that processes and stores hydrocarbons for subsequent offloading export.
Gross or gross	means, when used in relation to production, reserves and resources, OER's working interest share of production, reserves and resources before deduction of royalties.
HoldCo Subsidiary	means any one of Oando Netherlands Holding 1 Coöperatief U.A., Oando Netherlands Holding 2 BV, Oando Netherlands Holding 3 BV, Oando OML 125&134 (BVI) Limited, Oando Netherlands Holding 4 BV, Oando Netherlands Holding 5 BV, Oando OPL 214 Holding BV, Oando OML 131 Holding BV, all incorporated in the Netherlands, except for Oando OML 125&134 (BVI) Limited which is incorporated in the British Virgin Islands. Oando Netherlands Holding 1 Coöperatief U.A. is a direct, wholly-owned subsidiary of OER and all others are indirect, wholly-owned subsidiaries of OER, which hold interests in the Operating Associates, and collectively "**HoldCo Subsidiaries**".
IFRS	means International Financial Reporting Standards.
Indorama	means Indorama Corporation Pte. Ltd., a corporation incorporated under the laws of Singapore, and its affiliates.
IOC	means an international oil company that is not owned or controlled by a government.
ITA	means an investment tax allowance deductible in the calculation of PPT in Nigeria.
ITC	means an investment tax credit deductible in the calculation of PPT in Nigeria.
JOA	means joint operating agreement.
KNOC	means Korea National Oil Corporation, a corporation incorporated under the laws of Korea, and its affiliates.
Kwale gas plant	means the Kwale gas plant located on OML 60.
Kwale-Okpai IPP	the Kwale-Okpai independent power plant located in OML 60.
LIBOR	the London interbank offered rate.
License	means OMLs and OPLs, or interests therein or interests in areas therein, whether held through a JOA or PSC, acquired under the Marginal Field Development Program, or otherwise.
LNG	means liquified natural gas.
Local Content Act	means the *Nigeria Oil and Gas Industry Content Development Act*, 2010 (Nigeria).
Marginal Field	means a field defined as a "marginal field" in the Petroleum Act and that the President of Nigeria may, from time to time, identity as a marginal field under the

	Petroleum Act.
Marginal Field Development Program	means an initiative of the Nigerian Government to increase and facilitate the participation of Nigerian companies in Marginal Fields, which is based, in part, on paragraph 16A of the Petroleum Amendment Act 1996 and the Guidelines for Farmout and Operation of Marginal Fields issued by the DPR.
MEND	means the Movement for the Emancipation of the Niger Delta.
NAE	means Nigerian Agip Exploration Limited, a subsidiary of Eni, the operator of OMLs 125 and 134.
NAOC	means Nigerian Agip Oil Company, the operator of the NAOC JV and a Nigerian subsidiary of Eni.
NAOC JV	means the NAOC joint venture, comprised of Eni, the NNPC and POCNL, in respect of which POCNL has a 20% interest.
NDDC	means Niger Delta Development Commission.
NDDC Levy	means a levy payable pursuant to the *Niger-Delta Development Commission Act*, 2004 (Nigeria).
NEPN	means Network Exploration & Production Nigeria Limited, a corporation incorporated under the laws of Nigeria.
Net or net	means, when used in relation to production, reserves and resources, either OER's working interest share of production, reserves and resources after deduction of royalties or OER's entitlement to production reserves and resources after deduction of royalties and PPT for production sharing contracts. In relation to OER's interest in wells, "Net" or "net" means the number of wells obtained by aggregating OER's working interest in each of its gross wells. In relation to OER's interest in property, "Net" or "net" means the total area in which OER has an interest multiplied by the working interest owned by OER.
Netherlands/Nigeria BIT	means an agreement on encouragement and reciprocal protection of investments between the Kingdom of the Netherlands and Nigeria signed on November 2, 1992 and entered into force on February 1, 1994.
NGL	means natural gas liquids.
NHT	means a proposed Nigerian hydrocarbon tax under the PIB.
NI 51-101	means National Instrument 51-101 of the Canadian Securities Administrators - Standards of Disclosure for Oil and Gas Activities, as amended.
NI 52-110	means National Instrument 52-110 of the Canadian Securities Administrators – Audit Committees, as amended.
Nigeria	means the Federal Republic of Nigeria.
Nigerian Government	means the government of Nigeria and, in some cases, political subdivisions thereof.
NLNG	means Nigeria LNG Limited, a corporation incorporated under the laws of Nigeria.
NNPC	means Nigerian National Petroleum Corporation, the Nigerian state-owned oil company.
Oando	means Oando Plc, a corporation existing under the laws of Nigeria, whose shares trade on the Nigerian Stock Exchange and the Johannesburg Stock Exchange

	Limited.
Oando OML 125 & 134	means Oando OML 125& 134 Limited, a corporation incorporated under the laws of Nigeria.
OEPL	means Oando Exploration & Production Limited, a corporation incorporated under the laws of Nigeria.
OER	means OER and the business of OER, as now carried on by it through its subsidiaries and as previously carried on by Oando prior to the Arrangement.
OER 2012 Warrant	one share purchase warrant exercisable to acquire one Common Share of OER at an exercise price of C$2.00 per share for a period of 24 months from the date of issue.
OER 2014 Warrant	one share purchase warrant exercisable to acquire one Common Share of OER at an exercise price of C$2.00 per share for a period of 24 months from the date of completion of the COP Acquisition (subject to an acceleration provision).
OML	means oil mining lease.
OPDC	means Oando Production and Development Company Limited, a corporation incorporated under the laws of Nigeria.
OPEC	means the organization of the petroleum exporting countries.
Operating Associate	means a corporation with Class A Shares, which are held (directly or indirectly) by Oando, and Class B Shares, which are indirectly held by OER, including Oando OML 125&134 Limited, Oando Akepo Limited, Oando Petroleum Development Company Limited, OQI, ORPS, and, immediately following the COP Acquisition, CEPNL and PDENL.
OPL	means oil prospecting license.
OQI	means Oando Qua Ibo Limited, a corporation incorporated under the laws of Nigeria and an Operating Associate.
ORL	means Oando Resources Limited, a wholly-owned subsidiary of Oando, and which is incorporated under the laws of Nigeria.
ORPS	means Oando Reservoir and Production Services Limited, a corporation incorporated under the laws of Nigeria and an Operating Associate.
PA	means a proposed petroleum allowance under the PIB.
PDENL	means Phillips Deepwater Exploration (Nigeria) Limited, a corporation incorporated in under the laws of Nigeria, and holding OPL 214.
PDENL Acquisition Agreement	means the share purchase agreement dated December 20, 2012, as amended, among COP and Abimbola Ogunbanjo (together as the seller), as well as Oando OPL 214 Holding BV and Oando (together as the buyer), in respect of the shares of PDENL.
Peak	means Peak Petroleum Industries Nigeria Limited, a corporation incorporated under the laws of Nigeria.
Petrenel	means the Petroleum and Renewable Energy Company Limited, an independent and qualified reserves evaluator based in Ascot, United Kingdom.
Petroleum Act	means the *Petroleum Act,* 2004 (Nigeria).
Phillips Brass	means Phillips (Brass) Limited.

PIB	means *The Petroleum Industry Bill* (Nigeria).
POCNL	means Phillips Oil Company Nigeria Limited, a corporation incorporated under the laws of Nigeria.
POCNL Acquisition Agreement	means the share purchase agreement dated December 20, 2012 among COP and Phillips Investment Company LLC (together as the seller), as well as Oando OML 60, 61, 62 & 63 Holding BV and Oando (together as the buyer), in respect of the shares of POCNL.
PPT	means tax payable pursuant to the *Petroleum Profits Tax Act 1994* (Nigeria), as amended.
PSC	means production sharing contract.
Qua Ibo	means the Qua Ibo Marginal Field situated in OML 13.
RBL	means the $450 million senior secured facility agreement between certain of OER's affiliates and a group of Nigerian and international banks including Standard Chartered Bank, BNP Paribas and The Standard Bank of South Africa Limited dated January 31, 2014, to be amended.
Referral and Non-Competition Agreement	means the referral and non-competition agreement between OER and Oando dated July 24, 2012.
Restructuring	means the restructuring completed pursuant to the Arrangement between OER and Oando, as more particularly described under the heading "*Business of OER – Relevant Three Year History – Reverse Takeover Involving Oando and OER*".
Rivers State IPP	means the Rivers State independent power plant.
ROFO Agreement	means the right of first offer agreement between OER and Oando, dated September 27, 2011, as amended on December 16, 2011.
Second 2013 Oando Facility	means a $200 million loan advanced to OER by Oando dated December 24, 2013.
Second COP Amendment	means the agreement to amend the Acquisition Agreements, as amended, dated November 28, 2013.
SEDAR	means the System for Electronic Document Analysis and Retrieval at www.sedar.com.
Shareholders Agreements	has the meaning ascribed to such term under "*Incorporation and Organization – Intercorporate Relationships*".
Shell	means Shell Petroleum Development Company of Nigeria Limited, a corporation incorporated under the laws of Nigeria, and its affiliates.
Shell JV	means a joint venture among Shell, Total, Eni and the NNPC.
single-well discovery	means known accumulations of hydrocarbons that have been found within a single well, but have not yet been appraised or developed.
Sogenal	means Sogenal Limited, a corporation incorporated under the laws of Nigeria.
STP	means the Democratic Republic of Sao Tome & Principe.
subsidiary	means any corporation, joint venture or other legal entity that is controlled, in fact, by the associated entity, including, in the case of OER, the HoldCo Subsidiaries and Operating Associates.
swamp	means an area of low-lying, water saturated land within the coastal region of the

	Niger Delta that is typically covered in palms and mangroves and is uncultivated.
Tax Act	means the *Income Tax Act* (Canada), as amended.
Third COP Amendment	means the agreement to amend the Acquisition Agreements, as amended, dated January 31, 2014.
Total	means Total E&P Nigeria Limited, a corporation incorporated in under the laws of Nigeria, and its affiliates.
Transitional Services Agreement	means the transitional services agreement dated July 24, 2012 between OER and Oando Servco Nigeria and OEPL.
TSX	means the Toronto Stock Exchange.
VAT	means value added tax.
working interest or WI	means with respect to interests governed by a JOA, PSC, farm-in agreement or farm-out agreement, the undivided interest of such party (expressed as a percentage of the total interests of all parties in the contract) in the rights and obligations derived from such contract, which may be an operating or non-operating interest.
Xenergi	means Xenergi Oilfield Services Limited, a corporation incorporated under the laws of Nigeria.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

ABBREVIATIONS AND TECHNICAL TERMS

In this AIF, the following abbreviations and technical terms set forth below have the meanings indicated:

Crude Oil and Natural Gas Liquids

$/bbl	dollars per barrel
bbl	barrel
bbls	barrels
bbls/d	barrels per day
Mbbls	thousand barrels
Mbbls/d	thousand barrels per day
MMbbls	million barrels
MMbbls/d	million barrels per day

Natural Gas

$/Mcf	dollars per thousand standard cubic feet
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million standard cubic feet
MMcf/d	million standard cubic feet per day
scf/stb	standard cubic feet per stock tank barrel
Tcf	trillion standard cubic feet

Other

3D	three dimensional
API	American Petroleum Institute and, in the context of a gravity measurement of crude oil, refers to an inverted scale for denoting the 'lightness' or 'heaviness' of crude oils and other liquid hydrocarbons
boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
"Gross" or "gross"	in relation to production, reserves and resources, OER's working interest share of production, reserves and resources, before deduction of royalties.
km	Kilometres
km^2	square kilometres
Kv	Kilovolt
m	Metres
mD	milliDarcy
MD	measured depth
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
MMboe/d	million barrels of oil equivalent per day
mss	metres subsea
net to gross	the ratio of the thickness of those sections of a reservoir that are able to produce oil and/or gas to the total thickness of a reservoir
NPV	net present value

For purposes of calculating boe or barrel of oil equivalent, natural gas and NGL have been converted to crude oil on the basis of 6 Mcf of natural gas and 1.429 bbls of NGL, respectively, for 1 bbl of crude oil. Disclosure provided herein in respect of boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf of natural gas (or 1.429 bbls of NGL): 1 bbl of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value based on the current price of oil as compared to natural gas (and NGL) is significantly different from the energy equivalency conversion ratio of six (or 1.429) to one, utilizing a boe conversion ratio of 6 Mcf of natural gas (or 1.429 bbls of NGL): 1 bbl of crude oil would be misleading as an indication of value.

INTERPRETATION

References to "management" mean the management of OER. Any statements in this AIF made by or on behalf of management are made in such persons' capacities as managers within OER and not in their personal capacities.

References to "C$" and "Canadian dollars" are to Canadian dollars, references to "$", "US$", "dollars" and "U.S. dollars" are to United States dollars and references to "Naira" and "₦" are to Nigerian Naira, the official currency of Nigeria. Amounts are stated in U.S. dollars unless otherwise indicated.

The interest of OER in a License sometimes refers to an interest in a field or an area of land within the legal boundaries of a License, such as interests held by OER in fields acquired pursuant to the Marginal Field Development Program. See "*The Nigerian Oil and Gas Industry and Regulatory Framework - Petroleum Industry - Marginal Field Development Program*".

Unless otherwise noted, the average daily production volumes and production disclosed in this AIF are based on OER's working interest (operating or non-operating) share of production before deduction of royalties paid to others, including the Nigerian Government.

OER holds an indirect 95% equity interest in Oando Petroleum Development Company Limited, which holds a 45% working interest in Ebendo. OER's working interest is reflected herein as 42.5%. Financial and production information about Ebendo is reflected herein as 45%, being the percentage that OER consolidates for the purposes of its financial statements.

OER holds an indirect 81.5% equity interest in EEL. EEL holds indirect 30% working interests in OPL 321 and OPL 323. OER's working interest in these OPLs, as well as financial and production information about these OPLs, is reflected herein as 24.45%. EEL holds an indirect 5% working interest in oil and an indirect 12.5% equity interest in gas produced from OML 122. OER's working interest in such oil and gas produced from OML 122 is reflected herein as 4.08% and 10.2%, respectively.

The information contained in this AIF is dated as of December 31, 2013 unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

This AIF contains certain information that may constitute Forward-Looking Information. Forward-Looking Information is necessarily based on a number of estimates and assumptions that are inherently subject to significant uncertainties and contingencies. All information, other than statements concerning reporting results or statements of historical fact set forth or incorporated herein by reference, is Forward-Looking Information that may involve a number of known and unknown risks, uncertainties and other factors that, typically, are beyond OER's ability to control or accurately predict. The use of words such as "expect", "anticipate", "continue", "estimate", "may", "will", "should", "could", "believe", "budget", "outlook", "intend", "forecast", "plans", "guidance", "projection" and similar expressions is intended to identify Forward-Looking Information. More particularly, and without limitation, this AIF contains Forward-Looking Information relating to the following:

- Completion of the COP Acquisition on the terms publicly disclosed, or at all;
- expectations regarding future acquisitions or dispositions, including the COP Acquisition, and effects of the terms, timing and completion of those acquisitions and dispositions on OER;
- OER's future oil and natural gas production levels and levels of illegal bunkering;
- OER's expected future revenues, cash flows and expected dividends;
- Statements as to future capital, operating and other expenses and their timing and allocation to exploration and development activities;
- OER's expectations of future royalties and taxes;
- OER's ability to prevent theft or sabotage of oil or infrastructure and the Nigerian Government's response to such activities;
- the expected timing for and production rate of wells being drilled and completed currently or in the future;
- OER's reserve and resource potential and ultimate reserve recoverability;
- the timing, depth, placement, nature and chances of success of any well drilling;

- OER's exploration work plans, conceptual development plans, marketing plans and business or strategic plans;
- OER's access to the Licenses to complete work, including the building of any facilities;
- OER's expectations concerning unitization or the resulting interest of OER in a unitized block;
- the ability of each of OER and its partners to fund ongoing exploration and development activities to meet existing and future License and contractual obligations;
- OER's expectations regarding any PSC, JOA or other contractual negotiations;
- future relinquishment of land or reduction of License areas;
- renewals or extensions of Licenses;
- upon completion of the COP Acquisition, OER's ability to process gas and any other increased LNG capacity in Nigeria;
- expected future liabilities with respect to historic and future gas flaring activities;
- expectations as to future environmental liabilities or events that may give rise to future environmental liabilities;
- expectations regarding the outcome of litigation and other disputes;
- projections of supply and demand for oil and gas;
- projections or estimates of market prices, exchange rates, interest rates;
- treatment under governmental regulatory regimes and royalty laws, including any preferential treatment available to OER as an indigenous company and its characterization as such;
- the political, economic, regulatory and business stability of the jurisdictions in which OER operates;
- the amount, nature, timing and effects of OER's capital expenditures;
- expectations regarding the ability to raise capital or future sources of capital;
- the availability of committed credit facilities, future debt levels and OER's ability to service its debt obligations;
- expectations as to the ability of OER to continually add to reserves through acquisitions and development;
- expectations with respect to future assistance and benefits from OER's relationship with Oando; and
- receipt of required regulatory approvals, including Nigerian Government approval of the COP Acquisition;

An expectation, anticipation, estimate, belief, intention, forecast, plan, guidance, projection or similar forecast made in respect of OER is a forecast made by OER.

The Forward-Looking Information contained in this AIF is based on certain key expectations and assumptions made by OER, including expectations and assumptions relating to: the completion of the COP Acquisition and the other transactions ancillary thereto, the continued generation and access to expected cash flow from operations of OER, the ability of OER to explore and develop its assets, the ongoing stability of the countries in which OER holds Licenses, the ability to renew Licenses on reasonable terms, the ability of OER to be characterized as an indigenous company, future forecast commodity prices and exchange rates, royalty rates, tax laws and well production rates, the success of drilling new wells, the availability of capital to undertake planned activities, the ultimate recoverability of reserves and resources, and the availability and cost of labour, services and other costs of operations. Although OER believes that the expectations reflected in the Forward-Looking Information in this AIF are reasonable it can give no assurance that such expectations will prove to be correct.

Statements relating to "reserves" or "resources" are forward-looking statements as they involve the implied assessment, based on estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and can profitably be extracted in the future. See "*Statement of Reserves and Resources Data and Other Oil And Gas Information*."

Since Forward-Looking Information addresses future events and conditions, by its nature it involves inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a

number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation. Those risks and others are described or referred to below, under the heading "*Risk Factors*".

The Forward-Looking Information contained in this AIF is as the date of this AIF and, unless so required by applicable law, OER undertakes no obligation to update publicly or revise any Forward-Looking Information, whether as a result of new information, future events or otherwise. The Forward-Looking Information contained in this AIF is expressly qualified by this cautionary statement.

INCORPORATION AND ORGANIZATION

Oando Energy Resources Inc. was incorporated under the CBCA on August 9, 2005 as "Exile Resources Inc.". Effective September 20, 2011, Articles of Amendment were filed to change OER's registered office from the Municipality of Metropolitan Toronto, Ontario to the Province of Alberta.

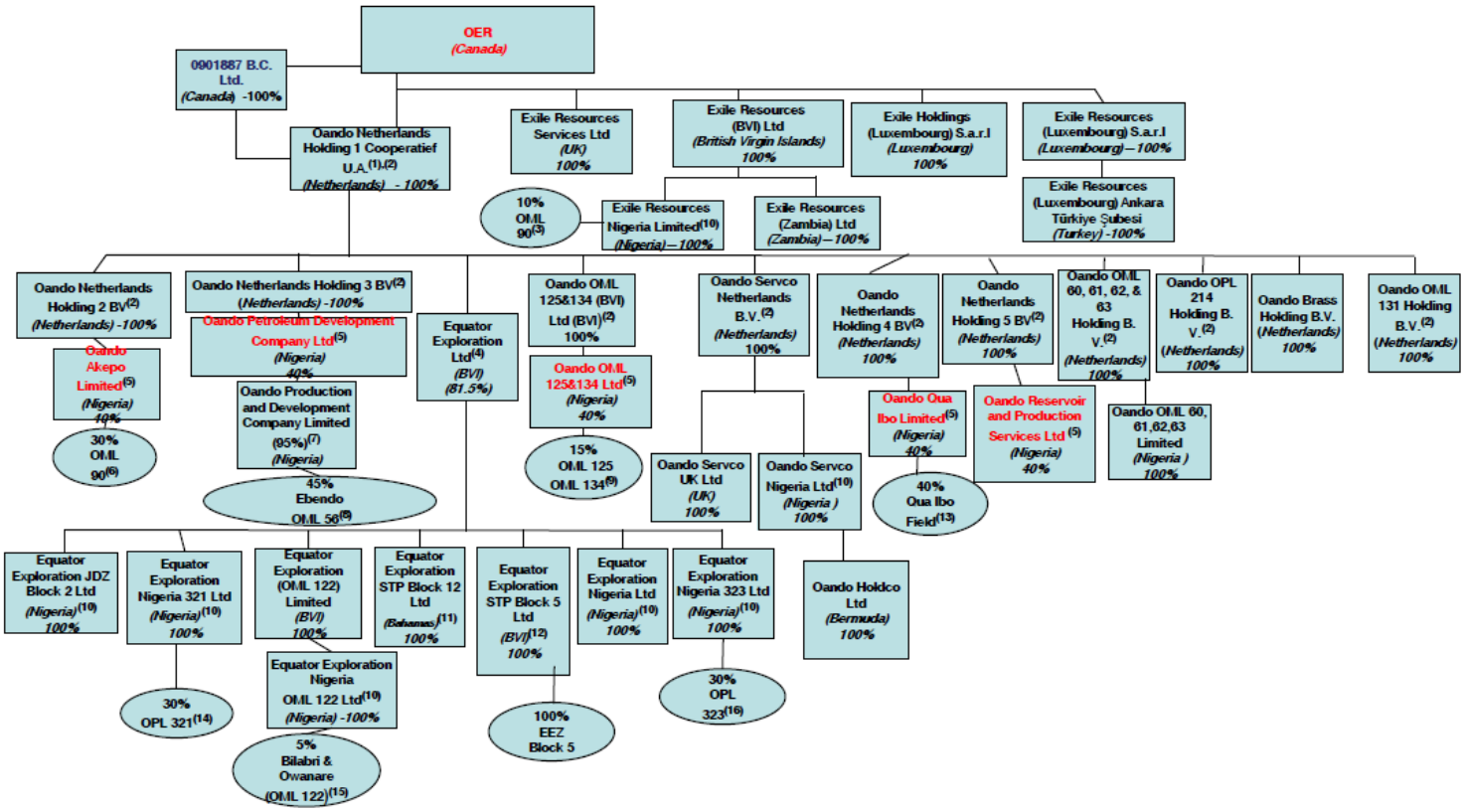
On July 24, 2012, Articles of Arrangement were filed to, among other things; change OER's name from "Exile Resources Inc." to "Oando Energy Resources Inc." pursuant to the terms of the Arrangement. In connection with the Arrangement, Oando transferred the majority of the oil and gas assets that it held at the time to OER. See "*Business of OER - Relevant Three Year History*".

The Common Shares were listed, and commenced trading, on the TSX Venture Exchange (the "**TSXV**") on November 7, 2005 under the symbol "ERI". Following the completion of the Arrangement, the Common Shares were listed, and commenced trading, on the TSX on July 30, 2012 under the symbol "OER". In addition, the OER 2012 Warrants are listed and trade on the TSX under the symbol OER.WT.A.

OER's head office is located at Suite 1230, Sunlife Plaza, 112 4th Avenue SW, Calgary, Alberta, Canada, T2P 0H3. OER's registered office is located at 3400, 350 – 7th Avenue S.W., Calgary, Alberta, Canada, T2P 3N9. OER also has a branch office in Toronto, located at Suite 1210, 333 Bay Street, Bay-Adelaide Centre, Toronto, Ontario, Canada, M5H 2R2. OER's operations are conducted from of its Lagos office located at 8th Floor, 2, Ajose-Adeogun Street, Victoria Island, Lagos Nigeria.

Intercorporate Relationships

Set forth below is a corporate chart indicating the names, jurisdictions of existence and inter-corporate relationships between OER and its subsidiaries as at December 31, 2013. Unless otherwise indicated, each subsidiary on the chart below is wholly-owned by its direct parent. Ovals represent interests in an OML, OPL or block, as applicable.



Notes:

1. Less than 0.1% is held indirectly through 0901887 B.C. Ltd., a wholly-owned subsidiary of OER.
2. Each of these entities is referred to as a "HoldCo Subsidiary".
3. A 10% working interest is held by Exile Resources Nigeria Limited. A balance 30% working interest is held directly by Oando Akepo Limited. (Please see footnote 6).
4. The remaining 18.5% interest is held by a number of minority shareholders.
5. Each of these entities is referred to as an "Operating Associate". 100% of the economic rights and 40% of the voting rights are conferred by Class B Shares held by a HoldCo subsidiary, each of which is a wholly-owned subsidiary of OER. The remaining 60% voting interest in each Operating Associate is held by Oando through a holding of all Class A Shares. In respect of each Operating Associate, the Operating Associate, as well as the holders of the Class A Shares and Class B Shares, have entered into a Shareholders Agreement. See below.
6. A 30% working interest is held directly by Oando Akepo Limited. An additional 10% working interest is held by Exile Resources Nigeria Limited, an indirect wholly-owned subsidiary of OER. (Please see footnote 3).
7. The remaining 5% shareholding interest is held by the Delta State Government.
8. Oando Production and Development Company Limited holds a 45% working and economic interest in Ebendo.
9. Oando OML 124&134 Ltd (Nigeria) holds a 15% working interest in OML 125&134.
10. In compliance with Nigerian law, which requires at least two shareholders for the formation of a company in Nigeria, 0.01% of the shares are held by a nominee shareholder who holds such shares on behalf of the 99.99% shareholder.
11. This Company was formerly known as Aqua Exploration Ltd (Bahamas).
12. This Company was formerly known as Equator Exploration (Congo) Limited BVI.
13. Oando Qua Ibo Limited (Nigeria) holds a 40% working interest in the Qua Ibo Field which is also known as OML13.
14. Equator Exploration Nigeria 321 Ltd holds a 30% working interest in OPL 321.
15. Equator Exploration Nigeria OML 122 Ltd holds a 5% economic interest for crude in Bilabri & Owanare which is also known as OML 122.
16. Equator Exploration Nigeria 323 Ltd holds a 30% working interest in OPL 323.

In relation to the Operating Associates:

- shareholder agreements dated July 24, 2012 (and replaced in December 2013) were entered into between Oando and:
  - Oando Netherlands Holding 2 BV ("**HoldCo 2**") and Oando Akepo Limited ("**Oando Akepo**") in respect of Oando Akepo;
  - Oando Netherlands Holding 3 BV ("**HoldCo 3**") and Oando Petroleum Development Company Ltd. ("**OPDC2**") in respect of OPDC2,
  - Oando, Oando OML 125 & 134 (BVI) Limited and Oando OML 125 & 134 Limited ("**Oando OML 125 & 134**") in respect of Oando OML 125 & 134, and
- and shareholder agreements dated April 30, 2013 were entered into between Oando and:
  - Oando Netherlands Holding 4 BV ("**HoldCo 4**") and OQI in respect of OQI;
  - Oando Netherlands Holding 5 BV ("**HoldCo 5**") ORPS in respect of ORPS.

Under the terms of the shareholders agreements described above (the "**Shareholders Agreements**"), Oando owns Class A Shares of each Operating Associate and the respective HoldCo Subsidiaries own Class B Shares, respectively. Ownership of the Class A Shares by Oando provides it with 60% voting rights but no rights to receive dividends or distributions from the applicable Operating Associate, except on liquidation or winding up. Ownership of the Class B Shares entitles the HoldCo Subsidiaries (each an indirectly wholly-owned subsidiary of OER) to 40% voting rights and 100% dividends and distributions, except on liquidation or winding up. Pursuant to each of these agreements, Oando on the one hand, and the respective HoldCo Subsidiaries, on the other hand, agreed to exercise their respective ownership rights in accordance with the manner set forth in the Shareholder Agreements. Pursuant to the Shareholders Agreements, each of Oando and the respective HoldCo Subsidiary is entitled to appoint two directors to the board of Oando Akepo, OPDC2, Oando OML 125&134, OQI and ORPS respectively, with the HoldCo Subsidiary being entitled to appoint the Chairman, who has a casting vote in the event of deadlock. Where a director is conflicted by virtue of his also being a director, officer or otherwise connected with Oando, an independent director of the OER shall be appointed as his alternate. In addition, the applicable HoldCo Subsidiary has the power to compel Oando to sell its Class A Shares for nominal consideration. No amounts have been paid or are due to be paid by either party to the other under the Shareholders Agreements. The business purpose of the Shareholders Agreements is to ensure that OER retains a capital structure which allows it to remain an indigenous company and thereby enjoy preferential status under Nigerian laws. See "*Risk Factors*".

Transfer of the Class A Shares by Oando is subject to: (i) pledges of the Class A Shares which Oando has granted in favour of certain of its lenders; pledges of the Class A Shares of Oando OML 125&134 and OQI in favour of certain of their respective lenders; (iii) the approval of the Nigerian Securities Exchange Commission which may be required for changes of control of companies (subject to certain exemptions); and (iv) the consent of the Nigerian Minister of Petroleum which may be required for changes of control of companies which have interests in OMLs or OPLs. Where such approvals are required for the transfer of Class A Shares, Oando is required to exercise its power and authority over the Class A Shares only in accordance with the instructions of the applicable HoldCo Subsidiary.

BUSINESS OF THE CORPORATION

General

OER is an indigenous Nigerian energy company with a portfolio of oil and gas Licenses (which, as used herein, includes interests in fields within Licenses) and related facilities and infrastructure concentrated in Nigeria and the Gulf of Guinea. OER is involved in the acquisition of petroleum and natural gas rights, the exploration for, and development and production of, oil and natural gas primarily focused in Nigeria and São Tomé and Príncipe. OER holds interests in 11 licenses for the exploration, development and production of oil and gas fields or blocks located

onshore on land or swamp, and offshore in shallow or deep waters. OER, indirectly through EEL, is a party to two deep water PSCs which are presently the subject of a dispute between the operator, KNOC, and the Nigerian Government, and is currently negotiating a PSC for a further License in the region. It has also been awarded a further deep water License in the region for which it is negotiating the PSC. See "*Description of OER's Assets*."

For the year ended December 31, 2013, a total production of 1.46 MMbbl of light to medium oil (or an average of 3,991 bbls/d) was attributable to OER's working interests in OML 125 and Ebendo. In addition, OER's working interest of total gas production was 917 MMscf (or an average of 2.5 MMscf/d) for the year ended December 31, 2013. Production from Akepo and Qua Ibo Marginal fields are scheduled to commence in the second and fourth quarters of 2014 respectively. See "*Description of OER's Assets*."

On December 20, 2012, OER agreed to acquire the COP Nigerian Business, with effect from January 1, 2012. OER anticipates that the COP Acquisition will significantly increase the scale of OER's operations, adding four producing onshore licenses (OML 60 to OML 63), two non-producing offshore licenses (OML 131 and OPL 214) and approximately 36,515 boe/d of working interest production (comprising 10,803 bbls/d of oil and condensate, 138.9 MMscf/d of sales gas and 2,551 boe/d of natural gas liquids) based on average rates in 2013. The COP Acquisition consists of an interest in 23 producing oil and gas fields, four undeveloped fields (all with significant recoverable resources), four discoveries, seven oil and gas fields that have been produced in the past but are currently shut-in, seven single well discoveries, and 48 prospects and leads with potentially significant additional resources. The discovered fields within the licensed area contain light oil and condensate, associated and non-associated natural gas and natural liquids. See "*Business of OER – Three Year History – COP Acquisition*."

Relevant Three Year History

Reverse Takeover Involving Oando and OER

Oando, through its predecessor companies, has been operating in Nigeria since 1956. Oando listed on the Nigerian Stock Exchange in 1992 and merged with Agip Nigeria Plc in 2003. Also in 2003, Oando formed an upstream exploration and production division with the acquisition of Ebendo. In 2008, Oando acquired an interest in a producing deepwater asset through its 15% working interest in OML 125. As of July 24, 2012, Oando's upstream exploration and production division had grown to include several Licenses that were contributed to the business of OER in connection with the Restructuring. Oando retained three Licenses with no reserves or production due to, among other matters, ongoing negotiations with governmental authorities. See **"***Interests of Management and Oando in Material Transactions – ROFO Agreement" and "Interests of Management and Oando in Material Transactions – Referral and Non-Competition Agreement*."

On September 27, 2011, OER entered into a definitive master agreement with Oando providing for the Restructuring and including, among other matters, the acquisition by OER of interests in certain Oando subsidiaries holding, directly or indirectly, various OMLs and OPLs for consideration of 100,339,052 Common Shares. In 2012, Oando transferred (in connection with the Restructuring) the majority of the oil and gas assets held by its upstream exploration and production division to Exile Resources Inc., a company holding a minority interest in one of Oando's Licenses and listed on the TSX Venture Exchange.

The Restructuring and Arrangement were approved by shareholders at a special meeting held on December 29, 2011 and closed on July 24, 2012. The Restructuring and Arrangement were effected simultaneously to complete the following transactions, among other matters:

- a share consolidation of the existing shares of Exile Resources Inc. on the basis of one newly issued Common Share for every approximate 16.28 previously existing shares;
- the issuance to shareholders immediately prior to the Arrangement of two warrants for every approximate 16.28 shares of held immediately prior to the Arrangement: one share purchase warrant exercisable to acquire one Common Share at an exercise price of C$1.50 per share for a period of 12 months, and the second share purchase warrant exercisable to acquire one Common Share at an exercise price of C$2.00 per share for a period of 24 months; and

- the change of name of "Exile Resources Inc." to "Oando Energy Resources Inc." and the graduation of the company from the TSX Venture Exchange to the TSX.

In connection with the Arrangement, Oando received 100,339,052 Common Shares, resulting in Oando owning approximately 94.6% of the outstanding Common Shares, on a non-diluted basis, immediately following closing. See "*Promoter*".

EEZ Block 5 and EEZ Block 12 Acquisition

EEL 5 signed a PSC for EEZ Block 5 in STP on April 18, 2012, which was ratified by the Prime Minister of STP five days later. EEL 5 paid a $2 million signature bonus. A PSC for EEZ Block 12 is currently being negotiated and EEL understands that a signature bonus will be payable once the PSC is concluded. See "*Description of OER's Assets*".

COP Acquisition

On December 20, 2012, OER, through certain affiliates, entered into the Acquisition Agreements to acquire the COP Nigerian Business and Phillips Brass (with effect from January 1, 2012) for total cash consideration that was estimated at the time to be approximately $1.79 billion (including a $435,000,000 deposit), subject to customary adjustments related to working capital and interest on the balance purchase commitment for the COP Acquisition. The Acquisition Agreements were subsequently amended upon execution of the Amending Agreements. Closing of the COP Acquisition is subject to customary conditions, including the receipt approvals or consents from Nigerian governmental authorities (including the Honourable Minister of Petroleum Resources in Nigeria). Pursuant to the Fifth COP Amendment the outside closing date for completion is April 30, 2014.

On signing of the Acquisition Agreements, OER paid a non-refundable deposit of $435 million to COP. The payment of the deposit was financed by a $345 million loan from Oando and $90 million borrowed under secured bridge loans (see "*—Financing Activities -- FBN Loan #2*" and the "*—Financing Activities -- Ecobank Loan*"). As part of the terms of Amending Agreements entered into during 2013, OER was required to pay an additional $15 million deposit such that the total deposit paid to COP at December 31, 2013 was $450 million. Pursuant to the Fourth COP Amendment OER paid an additional deposit of $50 million in February 2014 thereby bringing the total deposit to $500 million. Under the terms of the Fifth COP Amendment OER will be required to pay an additional deposit if the consent of the the Nigerian Minister of Petroleum Resources is not obtained by April 11, 2014.

Under the First COP Amendment OER terminated its obligation to acquire Phillips Brass and the purchase price was reduced to $1.65 billion as a result. OER had initially paid a $35 million deposit in relation to the Phillips acquisition. COP retained these funds and applied them against the purchase price for the COP Nigerian Business.

Assuming that the transaction closes prior to the current outside date of April 30, 2014, the estimated net purchase price under the COP Acquisition, net of $500 million deposited to date and estimated adjustments of $270 million, is expected to be approximately $1.14 billion.

POCNL, CEPNL and PDENL, after completion of the COP Acquisition, will have a share structure identical to the Operating Associates, except that the Class A Shares of CEPNL and PDENL will be held by a wholly-owned subsidiary of Oando, ORL, rather than directly by Oando, and the Class A Shares of POCNL will be held by a Nigerian incorporated and wholly-owned subsidiary of OER. See "*Incorporation and Organization – Intercorporate Relationships*".

Qua Ibo Acquisition and Related Medium Term Facility

On April 30, 2013, OER acquired the Class B Shares of OQI and ORPS, from Oando for a purchase price of $9.2 million. As a result of these acquisitions, upon the receipt of all consents and approvals described below, OER will own a 40% participating interest in Qua Ibo, which has been carved out of OML 13, located onshore in Nigeria. The field is operated by NEPN. OER purchased its interests in Qua Ibo under the terms of the Referral and Non-Competition Agreement (as defined under "*Interests of Management and Others in Material Transactions - Referral and Non-Competition Agreement*"). The purchase price represented reimbursement of all properly documented and

commercially reasonable expenses incurred by Oando relating to its acquisition up to the date on which OER acquired the Class B Shares of OQI and ORPS plus an administrative fee of 1.75%. See "*Description of OER's Assets*" and "*Interests of Management and Others in Material Transactions - Referral and Non-Competition Agreement*".

The transfer of the interest remains subject to third party and Nigerian governmental consent. Approval of the Nigerian Department of Petroleum Resources was obtained in October 2012 and OER is waiting for approval from the Nigerian Minister of Petroleum Resources. In the event that the consent of the Nigerian Minister of Petroleum Resources is not obtained, OER shall be entitled to certain economic interests in Qua Ibo. If the economic interests are for any reason unenforceable, then OER is entitled to be reimbursed by NEPN in respect of all the disbursements, costs and contributions made by OER in respect of the development and operation of Qua Ibo. Separately, pursuant to the terms of a farm-in agreement, OER has the option and right to acquire up to a 40% interest in the share capital of NEPN at an aggregate subscription price of $1 which, so long as the economic interests are valid and effective, bear no economic rights or obligations and shall, if the economic interests become invalid and ineffective, entitle OER to 40% of the economic rights and benefits in all distributions of NEPN.

Following the acquisition of the Class B Shares of OQI and ORPS, OER entered into a two tranche medium term facility with Diamond Bank (the "**Diamond Bank Loan**"). The purpose of the Diamond Bank Loan is to finance working capital requirements and capital expenditures with respect to the development of Qua Ibo. The Diamond Bank Loan consists of two facilities:

- Facility A is a medium term facility of $25 million. The facility was entered into on April 12, 2012. Facility A's first utilization date was October 18, 2012. Repayments on the Facility A loan amount commenced six months after the first utilization date and the final repayment date is 5 years after the first utilization date. The interest rate is 10% per annum.
- Facility B is a medium term facility of $40 million. The facility was entered into on January 22, 2013. Facility B's first utilization date was January 25, 2013. Repayments will commence six months after Facility B's first utilization date and the maturity date will be five years after the first drawdown date. The interest rate is 10% per annum.

Diamond Bank holds a charge over the shares of OQI in connection with the Diamond Bank Loan. OER is required to maintain a DSRA with Diamond Bank. At December 31, 2013, $1.5 million was maintained in the DSRA.

As at December 31, 2013, OER had $59.1 million outstanding under the Diamond Bank Loan. On January 17, 2014, OER drew down an additional $6 million.

Financing Activities

2012 Oando Loan and 2013 Oando Loan

On December 20, 2012, OER borrowed $345 million from Oando to finance a portion of the deposit required in connection with the COP Acquisition. The 2012 Oando Loan was subsequently rolled into the 2013 Oando Loan pursuant to the 2013 Oando Loan Documentation. The purpose of the 2013 Oando Loan was to provide for an aggregate increase in the maximum amount that may be borrowed by OER to $401 million and set up three borrowing facilities. The details of each facility are as follows:

- Facility A was a $362 million loan. The purpose of Facility A was to refinance the $345 million loan (together with accrued interest of approximately $17 million) extended by Oando as part of the $435 million required to be paid as the deposit for the COP Acquisition. The annual interest rate was 5% and interest was payable on maturity. Facility A was originally required to be repaid in full (plus interest) by September 30, 2013. However, this was extended first to December 31, 2013 and then subsequently to January 31, 2014.
- Facility B1 was a $24 million loan and its purpose was to finance working capital requirements of OER. The annual interest rate was 5% and interest was payable on maturity. Facility B1 was due to be repaid by December 31, 2013, but this was subsequently extended to January 31, 2014.

- Facility B2 was a $15 million loan and its purpose was to fund a portion of the deposit for the COP Acquisition. The annual interest rate was 5% and interest was payable on maturity.

The 2013 Oando Loan Documentation provided that, if the election by OER to repay the 2013 Oando Loan by the issuance of Common Shares would result in Oando having an ownership interest in OER in excess of 94.6% (on a non-diluted basis), the number of Common Shares to be issued would be reduced so as to ensure that Oando's interest in OER did not exceed such percentage and the balance, of amounts owing under the 2013 Oando Loan would be payable in cash.

On February 10, 2014, the 2013 Oando Loan was rolled into the 2014 Oando Loan. See "*Relevant Three Year History – Financing Activities – Oando $200 Million Loan Facility and Rollover of Oando 2013 Loan and Oando $200 Million Facility into 2014 Oando Loan*".

Oando $200 Million Loan; Rollover of 2013 Oando Loan and Oando $200 Million Facility into 2014 Oando Loan; Conversion of Tranche A of 2014 Oando Loan

On December 24, 2013, OER entered into a loan agreement to borrow $200 million from Oando in order to fund payments in relation to the COP Acquisition. Interest on the facility was charged at 5% per annum and the amount was to be available for draw down from December 24, 2013 to February 27, 2014. The loan was drawn down on February 12, 2014 and was required to be repaid on February 28, 2014.

On February 10, 2014, the $200 million loan and the 2013 Oando Loan were rolled into the 2014 Oando Loan under which OER may borrow up to an aggregate $1.2 billion. The 2014 Oando Loan became effective on February 25, 2014. The 2014 Oando Loan comprised $401 million borrowed under the 2013 Oando Loan and the $200 million loan which was drawn down on February 12, 2014 (together, Tranche A), as well as an additional $599 million (Tranche B) which has yet to be drawn.

The purpose of the 2014 Oando Loan is to fund the COP Acquisition and other general corporate requirements. The 2014 Oando Loan will mature on December 31, 2015 and bears interest at the rate of 4% per annum. Pursuant to the 2014 Oando Loan Documentation OER agreed to pay a $48 million facility fee to Oando.

On February 26, 2014, principal and interest (in the aggregate amount of $614.4 million) outstanding under Tranche A was converted into 432,565,768 Units (as defined below under "*— Private Placement*") at a deemed price of C$1.57 per Unit. Immediately following such conversion, $1 million in interest relating to Tranche A and the facility fee of $48 million remained outstanding.

FBN (Loan #1)

On June 24, 2011 OER borrowed $60 million from FBN ("**FBN Loan #1**"). FBN Loan #1 will mature on June 30, 2016 and bears interest at a rate of 10.5% per annum. FBN Loan #1 was entered into to support the further development of OML 125 &134. FBN Loan #1 is secured by OER's interest in OML 125 & 134. On December 12, 2013, OER and FBN entered into an agreement to increase the principal of the loan amount to $48 million. The balance of this loan as at December 31, 2013 was $32.9 million.

OER is required to maintain a minimum deposit of $15 million in a DSRA until the outstanding balance of the loan is $15 million or less. The amount in the DSRA is available for paying cash calls in the event that OER has no other means of financing its obligations to the operator. During 2013 $11.7 million was utilized in financing cash calls to the operator of OML 125 & 134 so the balance in the DSRA as at December 31, 2013 was $3.3 million.

FBN (Loan #2)

On December 17, 2012, OER borrowed $70 million from FBN ("**FBN Loan #2**") to fund part of the initial $435 million required as deposit for the COP Acquisition. FBN Loan #2 bears interest at the annual rate of 10.5% and the principal amount is repayable after 180 days from December 17, 2013, up to the closing of the COP Acquisition.

On October 7, 2013, OER obtained a letter of commitment from FBN for $109 million of the $815 million Corporate Facility. As part of the agreements establishing the Corporate Facility, FBN Loan #2 was converted into a 60 month loan, due January 30, 2018, with a 6 month moratorium on principal repayments.

The FBN Loan #2 is expected to be repaid from the Corporate Facility.

FBN (Short Term Loan)

On October 7, 2013, OER obtained a temporary loan from FBN in the amount of $7.8 million to supplement its working capital requirements. Interest on the facility accrued at 10.5% per annum. The loan was re-paid on January 24, 2014.

Ecobank Loan

On December 17, 2012, OER obtained a $20 million loan from Ecobank Nigeria to fund part of the $435 million required as deposit for the COP Acquisition. The interest rate is 90 day LIBOR plus 11% per annum and was originally repayable 180 days from the signing date of December 17, 2012. On December 10, 2013, Ecobank extended the maturity date to March 12, 2014. On March 10, 2014 the maturity date was further extended to June 12, 2014.

Enterprise Bank Loan

On August 1, 2013 OER borrowed $30 million loan from Enterprise Bank to fund part of its working capital and capital expenditure requirements. The loan is secured by a charge on crude oil proceeds from Akepo, irrevocable domiciliation of the proceeds of sales of crude oil from the Akepo and the corporate guarantee of Oando Energy Resources Inc. The interest rate is 10% per annum and the loan is repayable at the earlier of 180 days from August 27, 2013 or the drawdown date; however the lender reserves the right to demand repayment at any time it may deem. The maturity date of the loan has since been extended for 90 days.

Corporate Facility

The Corporate Facility was established on January 17, 2014 and amended on January 31, 2014. The total amount of the loan will be $350 million, which will be applied to fund the repayment of approximately $218 million due under the existing loans and $132 million to finance a portion of the COP Acquisition. Interest will be charged from draw down at LIBOR plus 9.5% per annum for the first fifty-seven months of the facility, with an increase of 1% for the remaining life of the facility. The loan will be available for draw down until January 31, 2015. The Corporate Facility will be repaid quarterly using the proceeds of sales of OER's share of crude oil from its various operations.

RBL

OER entered into agreements dated January 31, 2014, to be amended, establishing the RBL. Funds borrowed under the RBL will be used to finance a portion of the COP Acquisition. The RBL consists of two facilities – Facility A and Facility B.

- Facility A provides for a loan amount of $181.7 million. Facility A is required to be repaid one business day subsequent to the completion of the COP Acquisition upon receipt of the funds from, or on behalf of, a COP shareholder loan.
- Facility B provides for a loan amount of $268.3 million. The facility can be draw down until the earlier of (i) two days before the COP Acquisition closes or, upon execution of amending documentation, (ii) May 31, 2014. Once drawn down, the loan is repayable in quarterly installments in accordance with a repayment schedule.

Amounts borrowed accrue interest at LIBOR plus 8.5% per annum and interest payments are due at the end of each quarterly period. Loan B will be repaid each calendar quarter using the proceeds from sales of OER's share of crude oil from its various operations. In addition to regular repayments, 25% of any excess cash observable from proceeds

of sales of crude oil would also be applied against outstanding principal. The RBL will mature on June 30, 2019. The RBL contains financial covenants as follows:

- Interest coverage ratio equal or greater than 4.0:1;
- Leverage ratio equal to or less than 3.0:1; and
- Current ratio as at each reporting date equal to or greater than 1.1:1.

The RBL had an expiry date of March 31, 2014. OER has obtained confirmation from the mandating lead arrangers under the RBL that all banks in the syndicate have received confirmation that all the banks to extend the availability period of the RBL from March 31, 2014 to May 31, 2014. OER has paid the agreed commitment fee for the extension to the mandating lead arrangers and OER has been advised by the mandating lead arrangers that formal documentation reflecting the amendments has been circulated to all syndicate banks and that it is expected that formal documentation reflecting the amendment will be executed promptly following confirmation by the syndicate banks of their agreement with the formal documentation. As of the date hereof, OER has been advised that all syndicate banks (except one) have approved the terms of the formal documents evidencing the extension.

Private Placement

On February 26, 2014 OER completed a private placement of 35,070,063 Common Shares and 17,535,031 OER 2014 Warrants (each Common Share and one-half of one OER 2014 Warrant being a "**Unit**") at a price of C$1.57 per Unit. Each OER 2014 Warrant entitles the holder to acquire one Common Share at a price of C$2.00 per Common Share for a period of 24 months from the date of the closing of the COP Acquisition. The private placement generated gross proceeds of $50 million to be used to finance a portion of the unpaid balance of the purchase price in relation to the COP Acquisition.

Conversion of Certain Amounts Outstanding under 2014 Oando Loan

On February 26, 2014, OER issued Units consisting of an aggregate 432,565,768 Common Shares and 216,282,884 OER 2014 Warrants as repayment of approximately $614.4 million of outstanding principal and interest outstanding under the 2014 Oando Loan. Pursuant to the terms of the 2014 Oando Loan Documentation, the nature and deemed price of securities issued in connection with the conversion were determined with reference to the nature and price of the securities issued pursuant to the concurrent private placement. Accordingly, Oando received its Units at a deemed price of C$1.57 per Unit. Immediately following such conversion approximately $1 million in interest and $48 million representing facility fees remained outstanding. Up to $599.4 million remains available to be borrowed under the 2014 Oando Loan. See "*Material Contracts – Oando Loan Agreements*".

EEL Loan

OER owns 81.5% of the outstanding common shares of EEL. In addition, three of OER's directors comprise the entire board of directors of EEL. Between 2010 and July 2012, Oando advanced funds to EEL on an unsecured basis in order to enable EEL to finance its ongoing operating and capital expenditures. The advances bear interest at an annual rate of 16%, which is payable upon repayment of the loan. As at the date hereof, the principal and interest outstanding under these advances was approximately $9.9 million.

Description of OER's Assets

Onshore Assets

Licenses with Production

Ebendo

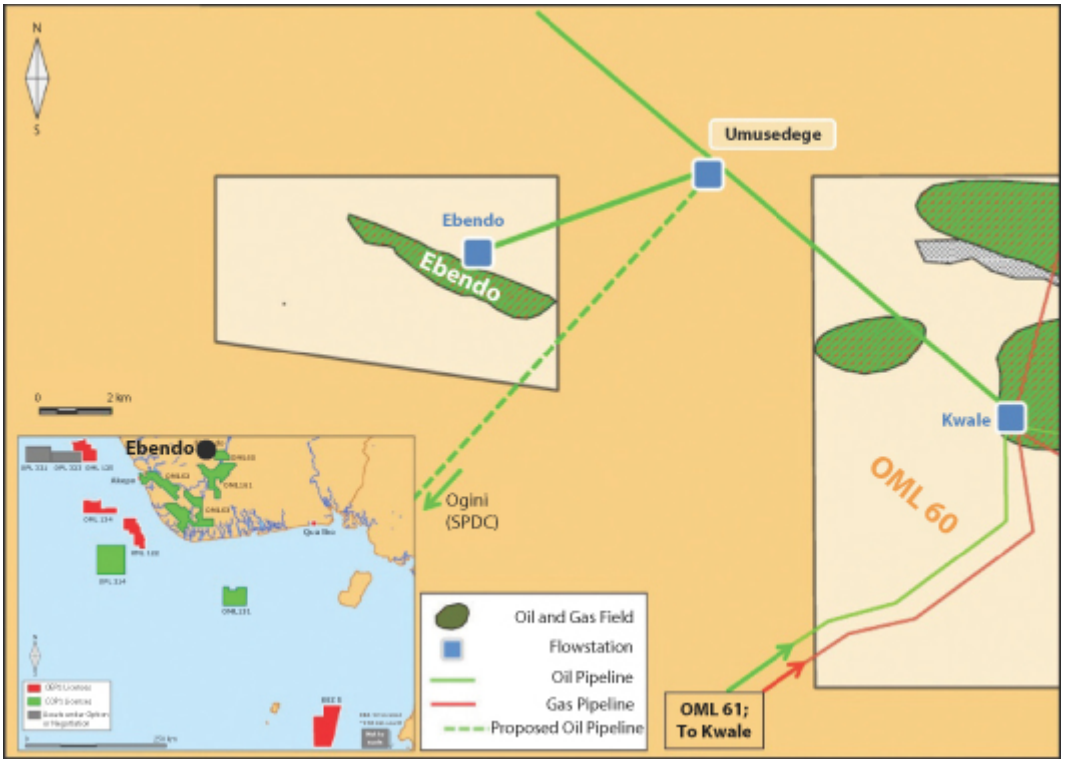
Overview

Ebendo (42.75% WI; Energia, an indigenous company and operator, 55% WI) is located onshore, in the central Niger Delta approximately 100 km north-west of Port Harcourt and covers an area of 65 km^2 (16,062 acres). The License includes two fields, Ebendo (producing) and the Obodeti field (undeveloped).

After losses, oil and gas production (gross, WI) in 2013 averaged at 1,089 boe/d (671 bbls/d of light oil plus 2,5 MMscf/d of sales gas), representing a 14% increase in production due to additional well capacity and the optimisation of crude storage and injection.

As at December 31, 2013, there were four production wells on Ebendo. Three wells were active producers in 2013. OER's total production attributable to its working interest for 2013 (net of crude oil losses) was approximately 398,000 boe (245,000bbl of light oil plus 917 MMscf of natural gas).

Ebendo



History

The Ebendo Marginal Field License, which has been carved out of OML 56, was originally operated as a joint venture partnership between the NNPC and Elf, a predecessor of Total. Ebendo was awarded to OER and its partner, Energia, in 2003 during the Marginal Field round. A number of 2D and 3D seismic campaigns have been carried out

on the block. Production from Ebendo started in 2009 through an early production facility, which was later upgraded to a permanent Flowstation.

Geological Description

Ebendo is located in the north central section of the Niger Delta sedimentary basin, with the majority of fields in the north central depocentre produced from the Agbada formation. The formation consists of a number of individual stack reservoir sands that are of good quality, often with high permeabilities and capped by shales with a high sealing capacity. The fields contain primarily sweet, mostly light to medium oil, with varying gas to oil ratios. Gas caps are common. Some reservoirs are over-pressured and primary production is mainly from gas cap expansion with natural water drive. The most common traps in this region are structural (mainly associated with rollover anticlines, structures bounded with multiple growth faults, and collapsed crest structures), although stratigraphic traps are not uncommon.

Producing Fields

Ebendo is situated in the eastern part of the License. The field was discovered in 1980. Production commenced in 2009 and has not yet achieved a peak production rate, as it is still under development. Four wells have been drilled in Ebendo, of which three are currently producing (Ebendo-1, Ebendo-4 and Ebendo-5) and one is shut-in (Ebendo-6). An additional well is currently being drilled.

Ebendo-4 and Ebendo-5 are completed as dual strings, allowing for production from two separate reservoirs. Ebendo-4 long–string, which was completed on level XXa, began producing in January 2013. The last production test on the well indicated light oil production rates of 260 bbls/d (gross WI) and natural gas rates of 1.0 MMscf/d. Ebendo-6 was drilled and completed in 2013 but is currently shut-in due to pipelines and facilities constraints. There are plans to drill additional wells in 2014 and beyond to target discovered shallower reservoirs.

Structurally, the field is an anticlinal rollover structure at shallow levels, gradually becoming a steeply dipping hanging wall at depth against a WNW-ESE fault. Light, sweet oil (45° to 47° API) and associated gas has been found within 13 hydrocarbon bearing levels, of which two sands are the key reservoirs. The reservoirs are characterized by moderate porosity of around 15%, water saturation of 30% to 50%, net to gross of 53% to 91% and permeability of up to several hundred mD.

Undeveloped Fields and Exploration Potential

There is currently one discovered field in Ebendo, which is the Obodeti field. The Obodeti field is located in the western part of the License and is a sub-commercial oil and solution gas discovery. Containing only one well, there are no plans to develop the field at this time.

Capital Projects

Ebendo oil production is currently evacuated to a third party gathering facility at Umusadege and then, via the Kwale-Akri pipeline, to the NAOC JV crude oil transportation infrastructure for export at the Brass River Terminal. Ebendo experienced notable downtime in 2013 and 2012 due to incidents of sabotage and crude oil theft on the export pipeline. In 2013, NAOC allocated crude oil losses of 25% to the production from Ebendo (2012 – 17%).

In addition to losses experienced due to crude oil theft and sabotage, the current evacuation route through the 7,000 bbls/d Kwale-Akri pipeline is subject to capacity restrictions on the volumes of oil that can be transported. In an effort to increase pipeline capacity, evacuation options and to reduce losses from theft and sabotage, OER is involved in the construction of an alternative 45,000 bbls/d, 51km pipeline. The Umugini pipeline will provide an alternative evacuation route through the Trans Forcados export pipeline. The Trans Forcados export pipeline will deliver crude oil from to the Forcados Terminal. To date OER has contributed $3.72 million for its share of costs. Construction was suspended at the start of the third quarter of 2013 due to rising water levels in the seasonally flooded areas of the terrain over which the pipeline is being constructed. The pipeline is now expected to be completed by the end of 2014. It is expected that further expenditures of $4.3 million will be required from OER to

complete the pipeline. Negotiations regarding the crude handling agreement with the pipeline and export terminal operators are ongoing.

In addition to the pipeline construction, OER spent $19.1 million on completing Ebendo 5 and Ebendo 6wells . Drilling of Ebendo-5 well commenced in October 2012 with a budget of $8.5million (gross WI). It was completed as a dual string on sands XV and XVIIId early in Q2 2013. Defective equipment had a negative impact on completion and testing and these contributed to final well cost amounting to approximately $15.2 million (gross WI), of which $9.1 million (gross WI) was spent in 2013. During its last test, Ebendo-5 produced approximately 452 bbls/d (gross WI) of light oil plus 1.9 MMscf/d of natural gas (gross WI) from the short string. From the long string, the test rates were 253 bbls/d (gross WI) of light oil plus 1.4 MMscf/d of natural gas (gross WI). Ebendo-5 produced intermittently during 2013 and is currently shut-in due to limited export capacity.

The partners also drilled and completed the Ebendo-6 well in 2013 with a budget of $7.7 million (gross WI). The well discovered two shallow reservoirs (XIIa and XIII sands) and encountered five hydrocarbon bearing reservoirs (XV, XVI, XVII, XVIIIa and XVIIIb). Ebendo 6 was completed as a dual string, with levels XV on the short string and XVI on the long string, for an final cost of $10.0 million (gross WI). The maximum rates recorded during the Drill Stem Test (DST) for Ebendo-6 short string were 169 bbls/d (gross WI) of light oil and 0.6 MMscf/d of natural gas. For the long string, the rates were 368 bbls/d (gross WI) of light oil and 2.1 MMscf/d of natural gas. Ebendo 6 is currently shut-in due to limited export capacity.

There are plans for three further production wells, Ebendo-7, Ebendo-8 and Ebendo-9. Ebendo-7, which is expected to spud and complete in Q1 2014, will be drilled at the crest of the structure and is proposed to target the XVI and XVII reservoir sands, in addition to exploring the shallower sands (IVa to X). The budget for this well is $8.7 million (gross WI). Budgets for Ebendo-8 and Ebendo-9 have not been determined.

Budgeted Capital Expenditure

The capital expenditure budget of $22.7 million represents the estimated level of required funding to support the planned growth, development and maintenance of the oil and gas field. The following expenditures are budgeted for 2014 and beyond:

- $4.3 million to complete the 12 inch, 51 km Umugini pipeline (in addition to the approximately $3.7 million spent to date).
- $8.7 million for drilling of Ebendo-7, which is expected to occur during the second quarter of 2014. In addition, $9.7 million is to be spent throughout the course of 2014 on other capital construction commitments on various completion works and maintenance.

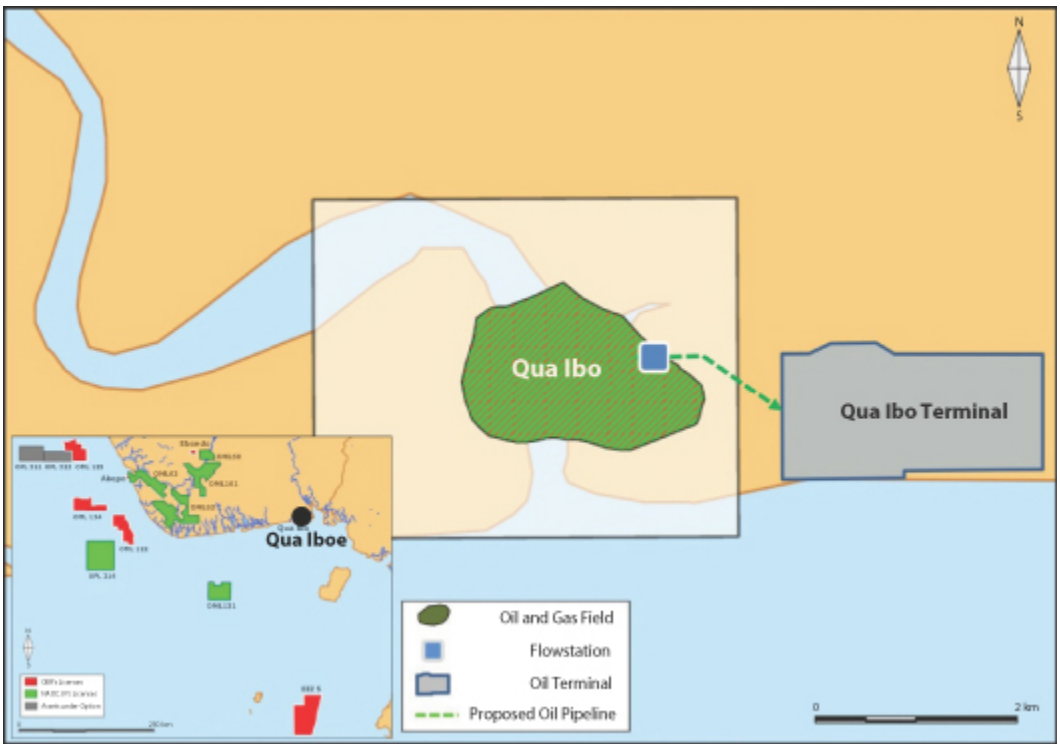
Licenses without Production

Qua Ibo

Overview

Qua Ibo (40% WI and technical partner; NEPN, an indigenous company, 60% WI and operator) is located at the mouth of the Qua Iboe River in the eastern Niger Delta and covers an area of 14 km^2 (3,459 acres). The License is immediately adjacent to the ExxonMobil Qua Iboe Terminal. The field is expected to be in production by the fourth quarter of 2014.

In its capacity as technical services provider, ORPS oversees, together with NEPN, the operations on Qua Ibo. ORPS has agreed to fund certain of NEPN's costs on Qua Ibo until first oil, following which ORPS will be entitled to be reimbursement plus a 10% fee.



History

Qua Ibo was discovered in the 1960s by the Shell JV. The Qua Ibo-1 exploratory well was drilled on the flank of the structure and found hydrocarbons in four reservoirs, including shallow gas in two reservoirs, a possible hydrocarbon-water contact in a deeper reservoir and oil in a deeper reservoir. The Qua Ibo-2 appraisal well was drilled in a crestal location, approximately 1.7 km west of the Qua Ibo-1 well, and found hydrocarbons in four additional reservoirs. Qua Ibo was awarded to NEPN in 2003 under the Nigerian Government's Marginal Field allocation program. Mart Resources Inc. signed an agreement with NEPN to participate in the development of the field in March 2005, which was terminated in February 2012. The Qua Ibo-3 well was drilled in 2008 to appraise the deeper discovery, although this was found to be wet at the well location. OEPL farmed-in to the License in 2012. The Qua Ibo-4 well was drilled in the fourth quarter of 2012 and found oil in one reservoir, although this did not flow freely upon testing. Qua Ibo-3 was sidetracked and completed in 2013. It was successfully tested before it was suspended.

Geological Description

Qua Ibo is located in the coastal swamp section of the Niger Delta sedimentary basin. Most fields in this area produce from the Agbada formation. The formation consists of a number of individual stacked reservoir sands that are of good quality, often with high permeabilities and capped by shales with a high sealing capacity. The fields contain primarily sweet, mostly light to medium oil, with varying gas to oil ratios. Gas caps are common. Some reservoirs are over-pressured and primary production is mainly from gas cap expansion with natural water drive. The most common traps in this region are structural (mainly associated with rollover anticlines, structures bounded with multiple growth faults, and collapsed crest structures), although stratigraphic traps are not uncommon.

Production Facilities and Infrastructure

There are currently no production facilities at Qua Ibo. Front end engineering has been completed for an Early Production Facility (EPF) that is expected to be installed before Q3-2013. From the EPF, oil will be evacuated via a group gathering facility (shared between three local operators), which is also under construction andand expected to

be completed in the fourth quarter of 2014. Production will be routed from here to the ExxonMobil Qua Iboe Terminal, which is located directly east of the field.

Undeveloped Field

Presently, Qua Ibo is under development within the License area. Qua Ibo is situated in the central part of the License. The field was discovered in 1960 by Shell. To date, a total of four wells (of which, two are suspended and two have been abandoned) and one sidetrack have been drilled**.**

Qua Ibo is a simple low relief, rollover structure and contains 12 hydrocarbon bearing reservoirs. These reservoirs show distinct facies differences, with a sandy section underlain by a marine paralic section. This results in different hydrocarbon trapping mechanisms in the shallow and deep water areas of the field (a pure dip-closure in the shallow sandy section and a hanging wall closure in the deeper paralic section). Due to the low relief of the structure, the hydrocarbon columns in the shallow section are small. Top seals are formed by thin overlying shales. This implies that the structure is a gentle rollover structure without crestal faults. Hydrocarbon columns are larger in the deeper section, with intraformational seals in excess of tens of feet. One reservoir is a barrier bar type with sand over- and underlain by marine shales. The reservoirs are characterized by good porosity of around 25% to 30%, water saturation of 20% to 35%, net to gross of 50% to 90% and permeability of up to several hundred mD.

Capital Projects

Phase 1 development at Qua Ibo started with a drilling campaign in 2012. Two wells, Qua Ibo-4 and Qua Ibo-3 ST1, were successfully drilled and completed in 2013. Qua Ibo-4 drilling operations commenced in September 2012 with an initial budget of $7.9 million (gross WI). The well was suspended in November 2012 after a failed attempt at a drill stem test (DST) on C4 reservoir. The string was later retrieved and the screens were found to be plugged with sand, explaining the failed DST. After completing Qua Ibo-3ST1, the rig returned to recomplete Qua Ibo-4 with a gravel pack and an electrical submersible pump for artificial lift. The revised budget for Qua Ibo-4 was $10.6 million (gross WI) and it was eventually completed in July 2013 at an actual cost of $12.2 million (gross WI). Production from the C4 reservoir is expected to commence in Q1 2015.

Qua Ibo-3 was re-entered in November 2012 to be sidetracked for an initial budget of $4.6 million (gross WI). It encountered light oil in two hydrocarbon bearing sands within the D5 reservoir. Due to encouraging DST results from the lower D5 sands, a decision was made to recomplete Qua Ibo-3ST as a dual string with a revised budget of $7.3 million (gross WI). The first dual string completion was found to have integrity issues and was therefore replaced for safety reasons. Qua Ibo-3ST1 was finally completed in June 2013 at an actual well cost of $12.9 million (gross WI). Oil production from D5 reservoir is expected to commence in the fourth quarter of 2014 after the commissioning of the OER/NEPN crude processing facility (total estimated capital expenditures at the facility are expected to be $8.5 million (gross WI)) which is currently ongoing and should be finalized in the second quarter of 2014.

Cost expended in 2013 for both wells amounted to $21.8 million (gross WI). A possible third well, Qua-Ibo 5 is budgeted in 2015 for additional off-take from C4 reservoir. The estimated expenditure for this well is USD 7.7 million (gross WI).

Budgeted Capital Expenditure

OER's working interest share of capital expenditure is up to $16.2 million, representing the estimated level of funding required to support the planned growth, development and maintenance of the oil and gas field. The following are the working interest share of expenditures as budgeted for 2014 and beyond:

- $8.5 million to be spent over 2014 on a crude processing facility; and
- $7.7 million could be spent in the second quarter of 2014 for drilling and completion works on Qua Ibo 5.

Offshore Oil & Gas Business

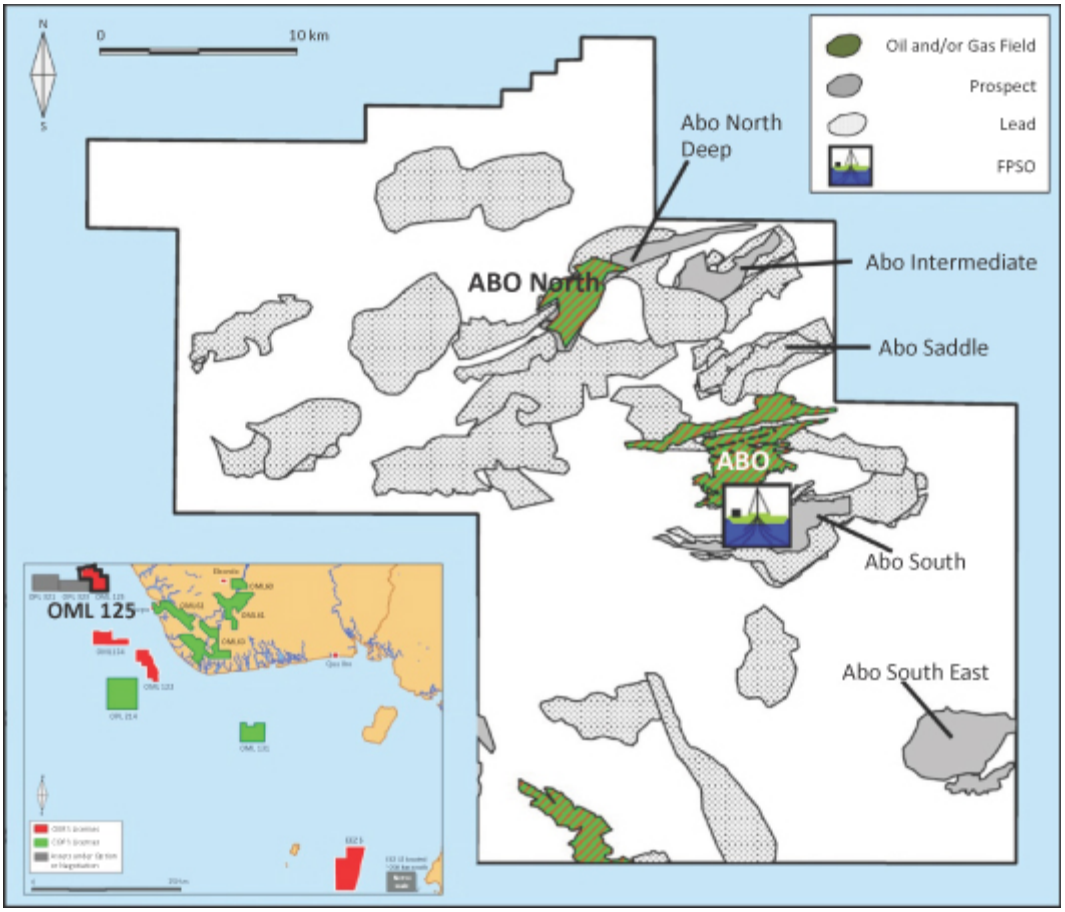
Licenses with Production

OML 125

Overview

OML 125 (15% WI; Eni, operator, 85% WI) is located approximately 40 km offshore from the Nigerian coast on the western edge of the Niger Delta, at a water depth of 550 m to 1,000 m. The License covers an area of 1,983 km^2 (490,010 acres). For the year ended December 31, 2013, OML 125 produced an average (gross, WI) of 3,319 bbls/d and total production of 1.21 MMbbls oil (gross WI). Production began from the Abo field in 2003 and the field currently has four producing wells, two water injection wells and two gas injection wells. Two additional production wells are shut-in, with one of them waiting for flowline repairs and another one awaiting flowline installation. A third production well is currently being completed.

OML 125



History

Exploration in OML 125 began with the discovery of Abo in 1996. Initial development of Abo began in 2003. In addition to Abo, OML 125 has two other discovered fields, the Abo North and Okodo fields, and five prospects, Abo Saddle, Abo Intermediate, Abo South, Abo South East and Abo North Deep. There are a number of leads, but

these have not been included in the estimates of prospective resources. Abo contains medium oil (20° to 37° API) and solution gas.

OML 125 is covered by three 3D seismic data sets. The third and most recent state-of-the-art survey seismic survey was undertaken in 2011/2012 to identify fluid current contacts and the location of the remaining oil in the field using 4D time lapse techniques. The small quantities of discovered and recoverable oil and gas in the Abo North field have been classified as contingent resources. These resources are sub-commercial at expected oil and gas prices and the future classification of these resources as petroleum reserves is contingent upon further technical studies leading to either the identification of additional recoverable volumes or a reduction in development costs or a significant rise in oil price or a reduction in development costs.

Geological Description

OML 125 lies mainly in the extensional but also partly in the translational zone of the Niger Delta. The extensional zone is characterized by a listric fault and a counter-regional fault development near the present day continental shelf. The translational zone is dominated by intense shale diapirism, creating intra-diapiric basins for sediment deposition and forming radial faults at the crest of shale ridges.

Two plays are recognized in OML 125. The first is a shallow to intermediate amplitude supported play containing all the discovered hydrocarbons to date in the block as well as the majority of the exploration potential. Reservoirs in the amplitude supported play are Pliocene to Upper Miocene in age and comprise either channel/levee or amalgamated channel sands. The second play is non-amplitude supported. This play is more speculative and modelled to be Middle Miocene, occurring at depths where over-pressures are expected and thought to be composed of lower slope fans.

The northern part of OML 125 is dominated by a series of east-west trending strike-slip/wrench faults related to a fracture zone. The central and southern parts are characterised by normal faults, shale diapirs and the associated radial faults. The shale diapirs are also concentrated in the central and south-eastern portion of the block, around Abo and the Abo South East and Abo Intermediate prospects.

Production Facilities and Infrastructure

There are a total of 14 wells on OML 125 (five producing, two water injection, two gas injection, four plugged and abandoned and one suspended). Abo is produced through the Abo FPSO, which includes production and test manifolds, separators, fuel gas processing and water treatment facilities and has an oil production capacity of 40,000 bbls/d, a gas production capacity of 114 MMcf/d and a water production capacity of 9 Mbbls/d. The Abo FPSO also has the capacity to reinject up to 30 Mbbls/d of water and 12 MMcf/d of gas.

Producing Fields

Abo is situated in the eastern part of OML 125. Abo was discovered in 1995 and appraised in 1996 and 2001. Development commenced in 2001 with the first oil produced in 2003 through the Abo FPSO. A total of 11 wells have been drilled to date (two exploration wells, five producers, two water injectors and two gas injectors).

Abo is an amalgamated channel and turbidite system with five defined pools that are stratigraphically trapped. Oil accumulations are present in 11 different sand horizons between depths of 1,600 mss and 2,600 mss. The main reservoir consists of turbidite sandstone bodies crossed by a clay filled channel. In total, there are over 130 m of gross sands, with an average porosity of 17%, average hydrocarbon saturation of 73%, and an average net to gross ratios of 14%.

Undeveloped Fields

There are two discovered fields in OML 125, the Abo North and Okodo discoveries. The hydrocarbon pools in both of the discoveries were smaller than expected and have been classified as a marginal oil/gas rim discoveries and are considered sub-commercial at this time. The discovery wells were subsequently plugged and abandoned.

Exploration Potential

OER has identified a large portfolio of oil and gas prospects and leads in OML 125. The current portfolio consists of six prospects, including Abo Saddle, Abo Intermediate, Abo South, Abo South East, Abo North West, and Abo North Deep. In addition to these six prospects, there are a number of deep leads, including Abo Deep, A151, B254, Obra Deep and Ovoro Deep.

Capital Projects

In the first quarter of 2013, NAE and OER completed (at a cost of approximately $9.0 million (gross WI) compared to a budget of $10.5 million (gross WI)) the work-over of the Abo-9 well that was started in 2012. Abo-9 is a gas injection well that should provide pressure support for the Anom01 and Anom02 producing reservoirs. Gas injection was successfully restored in the first quarter of 2014, after solving issues with one of the gas compressors on the FPSO.

The Abo phase 3 development commenced in January 2013 with the side track of Abo-4 well. Abo-4 was drilled and completed in the second quarter of 2013 on the B207 reservoir at a cost of approximately $14 million (gross WI). Abo-4ST was producing light oil at a rate of 1,380 bbls/d (gross, WI) on December 31, 2013.

In June 2013, an up-dip side track of Abo-3 on B200 reservoir was completed, which only flowed for 72 hours (approximately) during testing before production ceased. The actual cost of this program was approximately $24.7 million compared with the budgeted amount of approximately $18 million. Production ceased due to a sand blockage in the flow line to the Abo FPSO. OER expects production to re-commence from Abo3-ST in the second quarter of 2014 on clearance of the sand blockage in the flow line. The budget to clean out the flow line is approximately GBP 0.4 million. Production is expected to recommence in Q2 2014.

Finally, the Abo-8 well was re-entered in December 2013 and completed as an oil producer on the Anom01 and Anom02 reservoirs in the first quarter of 2014. Budgeted costs were approximately $12.3 million. Production has not commenced from Abo-8 as the required flow line is a long lead item, delivery of which is expected to be in the third quarter of 2014.

Budgeted Capital Expenditure

The capital expenditure budget represents the estimated level of required funding to support the planned growth, development and maintenance of the oil and gas field. The following expenditures are budgeted for 2014 and beyond:

- additional capital expenditure is required prior to commencing production from Abo-8. As such, budgeted expenditure of $5.1 million has been agreed to fund the purchase of the flow line. This expenditure was initially expected to be incurred in 2013. However, due to long lead times, this expenditure has been delayed and is now expected to be completed in the third quarter of 2014.
- the capital expenditure budget includes $7.5 million to be spent on the initial drilling of Abo-12. Abo-12 is a development well with an exploration tail. The well is expected to be drilled during the second quarter of 2014. The well is planned to further drain the Anom02 reservoir and explore the shallow A197 reservoir and the deeper Anom3 reservoir.
- the capital expenditure budget also includes an additional $19 million to fund the completion of both the Abo-8 and Abo-12 wells and $5.9 million to extend the life of the existing FPSO. Both capital projects are expected to be completed by the end of 2014.

Until the re-processed seismic data for OML 125 has been reviewed by NAE, and prospectively re-assessed, there are no further plans to drill exploration wells on any of the other prospects in OML 125.

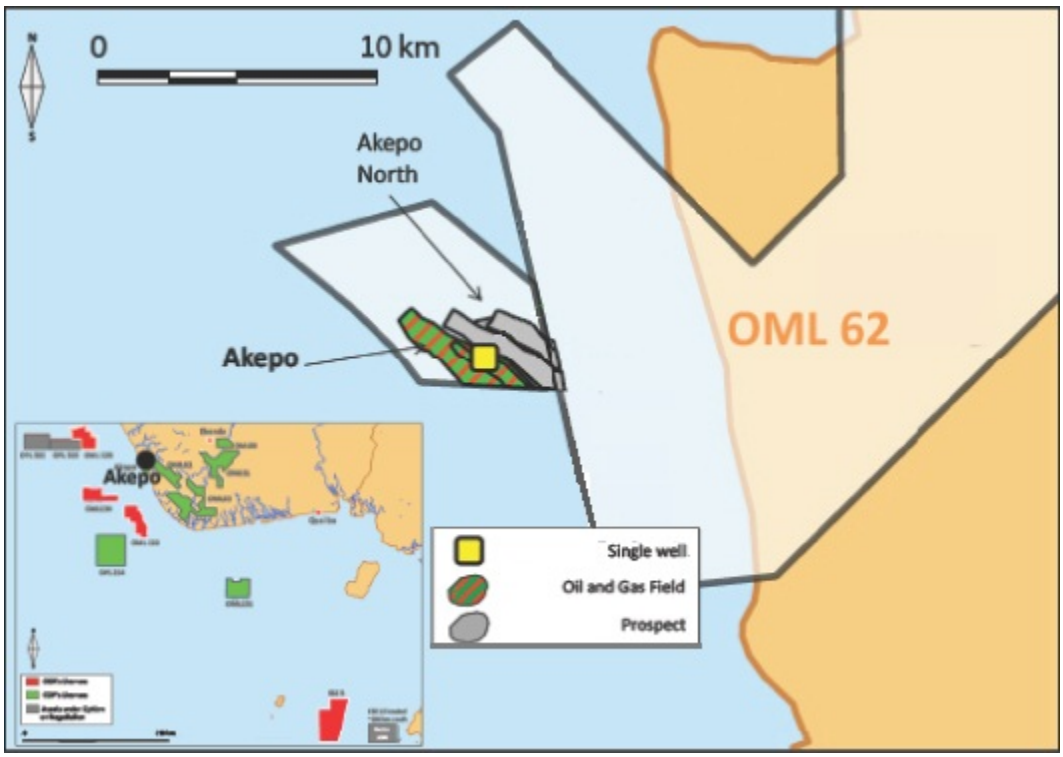
Licenses without Production

Akepo

Overview

Akepo (40% WI and technical partner; Sogenal, operator, 60% WI) is located offshore, around 15 km off the Nigerian coastline at a water depth of 8 m to 10 m. The License covers an area of 26 km^2 (6,425 acres). The License includes one undeveloped field, the Akepo field, and two prospects (A and B, collectively referred to as Akepo North). The Akepo oil field was discovered in 1993 and is currently being developed. Production from the Akepo field is expected to commence in the third quarter of 2014 at an initial rate of approximately 135 bbls/d of oil (gross, WI).

Akepo



History

The original License (OML 90) was relinquished by Chevron. The Akepo Marginal Field License was awarded to Sogenal during the Marginal Field round. Exile Resources Inc. farmed-in to the Sogenal interest in 2006. OER farmed-in for 75% of Exile Resources Inc.'s interest in 2008 and, following the Arrangement in 2012, OER now holds a 40% working interest in the License. The operator, Sogenal, holds the remaining 60% working interest.

Geological Description

Akepo is located in the shallow offshore section of the Niger Delta sedimentary basin. Most fields in this area produce from the Agbada formation. The formation consists of a number of stacked reservoir sands that are of good quality, often with high permeabilities and capped by shales with a high sealing capacity. The fields contain primarily sweet, mostly light to medium oil, with varying gas to oil ratios. Gas caps are common. Some reservoirs are over pressured and primary production is mainly from gas cap expansion with natural water drive. The most

common traps in this region are structural (mainly associated with rollover anticlines, structures bounded with multiple growth faults, and collapsed crest structures), although stratigraphic traps are not uncommon.

Production Facilities and Infrastructure

There are no production facilities installed at Akepo. OER is currently developing the Akepo field. A production well (Akepo-1) was drilled and tested in 2009. This well is currently shut-in until production facilities become available. OER plans to produce via a leased mobile production unit. Oil will be transported by barges to the Chevron Escravos Terminal. First oil from the Akepo field is planned for Q3 2014.

Undeveloped Field

The Akepo field is located offshore, around 15 km from the Nigerian coastline at the centre of the License area. Akepo was discovered in 1993 by Chevron with the Akepo-1 well, which encountered 33 m of net oil pay and was drilled to a total vertical depth of 3,048 m. The discovery well was sidetracked with the Akepo-1ST sidetrack to a total vertical depth of 2,832 mss and confirmed oil and gas to be present in a number of levels, some of which were tested. Akepo-1ST was re-entered, tested and completed in December 2009 as a dual string completion on two of the reservoirs. The field is currently undergoing development and production is expected to commence in 2014.

The Akepo structure lies in the central belt of the Meji Megastructure on the southern end of the Ajapa anticline. There are a series of crestal sub-listric normal faults dipping south-west. The Akepo field comprises a number of 3-way and 4-way closures within a single fault block. Oil from the Akepo field is trapped in a series of eight sands. The total net pay of the reservoirs is 33.2 m, with an average porosity of 27.5%, net to gross of 77% and hydrocarbon saturation of 55%.

Akpeo-1ST was tested and completed during December 2009. One sand produced clean light sweet oil (42°API) with a gas oil ratio of 569 scf/stb at a rate of over 1,800 bbls/d (total, 100%). Another sand produced clean medium oil (23°API) during a short test at a rate of 993 bbls/d, and another sand produced a maximum of 540 bbls/d of clean medium sweet oil (20°API) during the drill stem test. These reservoirs are characterized by moderate to good porosity of 27% to 29%, hydrocarbon saturation of 42% to 77%, and net to gross of 39% to 93%.

There has been no production from the field to date (other than well testing).

Capital Projects

OER, with its partner, successfully re-entered and tested the suspended Akepo-1 ST well. Drill stem tests proved flowing hydrocarbons in all the three targeted reservoirs. The Akepo-1 ST was completed as a two-string multiple on two of the three zones, with the third zone selective on the long string. Following the completion, the Akepo-1 ST was successfully flow tested on D6 sand. The well is now suspended, awaiting completion of field development.

OER, with the operator, had originally commenced negotiations with NAE to evacuate the oil to NAE's Beniboye facility through a planned 5km onshore and 10km offshore pipeline. As a result of unforeseen issues with the contractor selected to construct the pipeline (insolvency of contractor), OER revised its field development plan to include the use of barges to transport crude oil production to the Chevron Escravos Terminal rather than through the pipeline to the Beniboye facility.

Budgeted Capital Expenditure

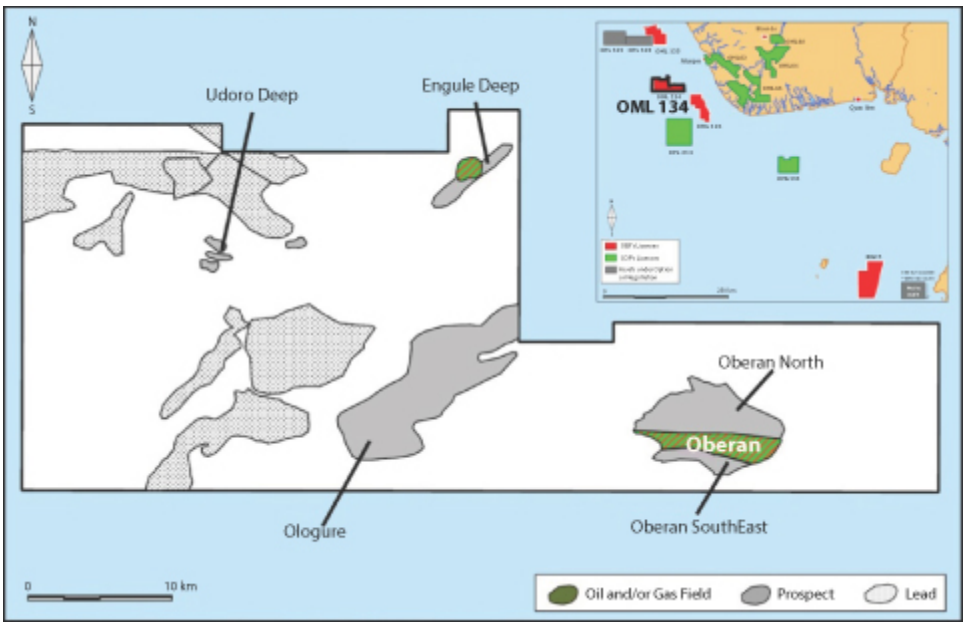
The capital expenditure budget of $3.2 million represents the estimated level of required funding to support the planned growth, development and maintenance of the oil and gas field. The field development plan was revised in 2013 and now involves leasing a mobile production unit and transporting the oil by barge to the Escravos Terminal instead of building a pipeline to the Beniboye facilities. The new development strategy provides flexibility for future development. It involves higher operating costs but is less capital intensive, with capital costs estimated at $3.2 million (gross WI). Production from the field is now expected to commence in Q2, 2014.

OML 134

Overview

OML 134 (15% WI; Eni, operator, 85% WI) is located offshore in the western Niger Delta, approximately 80 km from the Nigerian coast in a water depth of 500 m to 1,000 m. The License covers an area of 1,132 km^2 (279,723 acres). The License includes one undeveloped field, the Oberan field, three single-well discoveries (Engule,Udoro and Mindiogboro) and a number sizeable leads and prospects. The block is in the exploration phase and there has been no production from OML 134 to date.

OML 134



History

OML 134 was awarded in 1993, with two five-year exploration periods. During the first exploration phase, 2D and 3D seismic was acquired, leading to the drilling of the Engule structure in 1998, but, due to its small hydrocarbon column, the single-well discovery was considered uncommercial at the time and consequently plugged and abandoned. Two further wells, on Udoro and Oberan, were drilled during the second exploration phase, which led to conversion of the former OPL to OML 134. The OML conversion was awarded in 2006 for a 20-year development period (expires July 2023). The most recent exploration and development activities on OML 134 include the 2009 Oberan appraisal well, a block wide 3D seismic survey that was acquired in 2010 (processing was completed in 2012) and an exploration well spudded in Q4 2013, in a fault block lying to the east of the earlier Oberon wells.

Geological Description

OML 134 is located in the deep offshore section of the Niger Delta sedimentary basin where sediments are mostly Oligocene and Miocene in age and consist of turbidites, sheet sands and debris flows. Two key play concepts can be recognized in OML 134, including shallow plays supported by strong amplitude anomalies and deep weaker amplitude plays. The shallow plays are Upper Miocene and Pliocene channel reservoirs, which are gas prone and contain geologically complex amalgamated reservoirs. The Engule-1X, Udoro-1X and Mindiogboro-1 wells tested this type of play. The deep plays are Lower and Middle Miocene channel reservoirs that are difficult to image based on existing 3D seismic, but were successfully tested by the Oberan-1 and 2 wells.

The sedimentary sequence in OML 134 can be characterized by two main areas with clearly different clastic influx: a north-west area, with an overall thinner section on the main target section, rarely intersected by turbidite channels and a larger southern area, with a thicker section and where the turbidite pathways are more developed.

Production Facilities and Infrastructure

There are currently no oil and gas production facilities within OML 134. The nearest production facilities to OML 134 are those of the Bonga FPSO, approximately 45 km to the south-west.

Undeveloped Fields

Presently, there are no producing fields within the License area. There is one discovered and partially appraised field (Oberan) and three shallow single-well discoveries (Engule,Udoro and Mindiogboro).

Oberan Field

The Oberan field is located around 80 km from the coast of Nigeria at a water depth of approximately 650 m. The field is formed by a faulted anticline cut by several east-west trending crestal faults. The field closure could be as large as 275 km^2. The Oberan oil field was discovered in 2002 and appraised with the 2009 Oberan-2 well. The main target of the wells was the same turbidite sequence encountered in the nearby Bonga field. The Oberan-1 exploratory well penetrated 81 m gross sand, with 31 m net hydrocarbon bearing sand, with a porosity ranging from 18% to 23% and net to gross of 24% to 54%. Due to operational difficulties the drilling of the well was stopped prematurely and subsequently the well was suspended. An appraisal well, Oberan-2 was spudded on the structure in the fourth quarter of 2008 and completed in 2009. The well found a number of gas and light oil bearing sands.

Exploration Potential

There are currently three single-well discoveries in OML 134, the Engule,Udoro and Mindiogboro fields. The Engule accumulation was discovered by the 1998 Engule-1X well, which found gas underlain by an oil rim. The Udoro-1X well was drilled in 2000 in the central part of OML 134 and encountered hydrocarbons in and east-west trending amalgamated channel system. The hydrocarbon pools found in these discoveries were considered uncommercial at the time and both wells were subsequently plugged and abandoned. An amplitude supported exploration well was drilled into the Minidiogboro prospect in the fourth quarter of 2013 which encountered gas in the shallow reservoir.

Capital Projects

Based on results of the seismic interpretation an exploration well was drilled into the Minidiogboro prospect in the fourth quarter of 2013. A number of shallow (H245, H310, H350, H355) and intermediate (H520, H522, H524) sands were targeted by the drilling, with an average probability of success of 26%. Four of the target sands in the shallow zone were found to be gas-bearing while two were found to be water-bearing. In the intermediate zone, only one water-bearing sand was penetrated before the well had to be suspended due to increasing pressures. The well has been suspended as a gas discovery, whilst the field undergoes further appraisal. The capital expenditure incurred in drilling the well was $7.3 million.

Budgeted Capital Expenditure

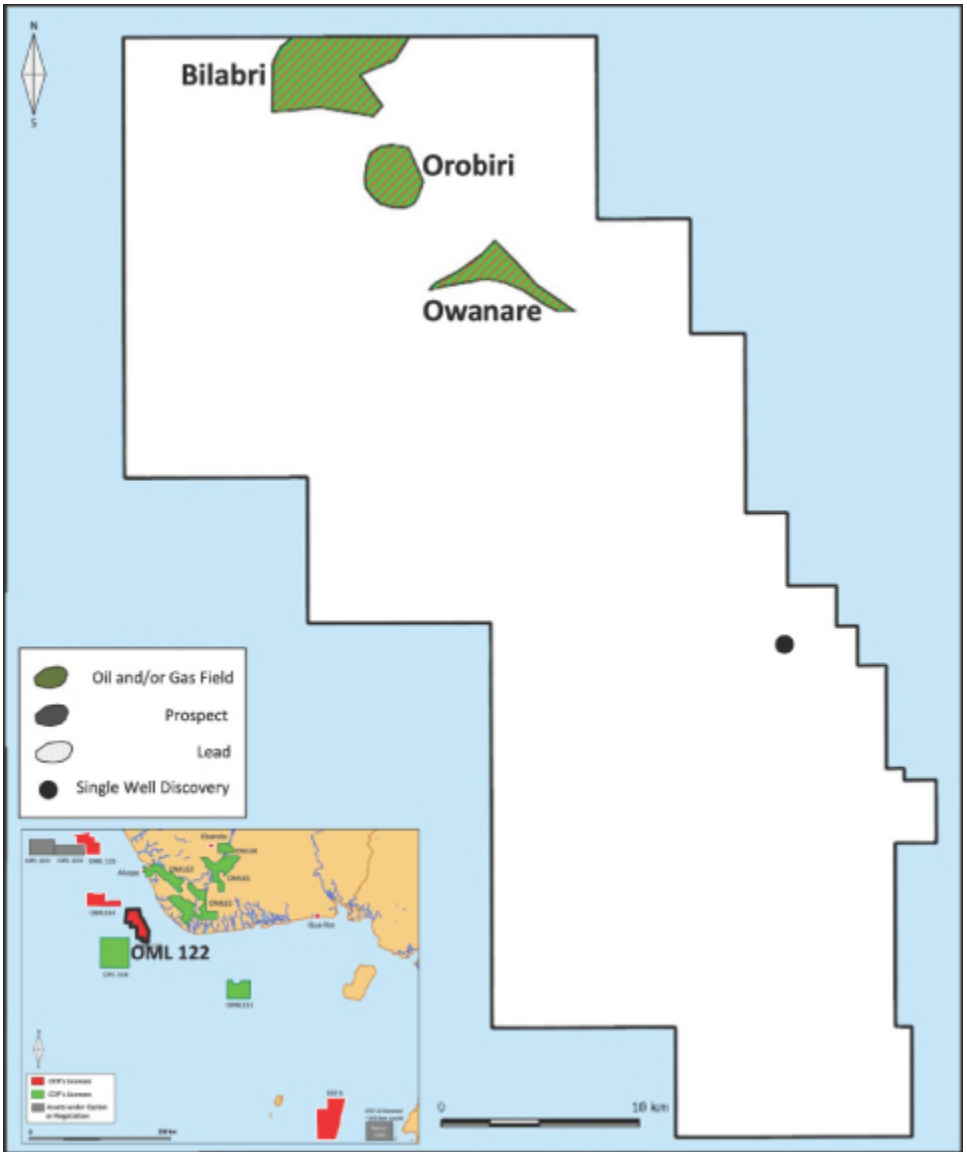
The capital expenditure budget represents the estimated level of required funding to support the planned growth, development and maintenance of the oil and gas field. The work plan includes interpretation of the 3D seismic data, updating existing interpretations and revisions to the field volumetrics. It is expected that new drilling targets will be prognosed and more exploratory/appraisal wells will be drilled in 2015 and 2016. Based on results from the drilling of the exploration well into the Minidiogboro prospect, OER plans to continue exploration and evaluation activities throughout the course of 2014. Budgeted expenditures associated with the project for 2014 and beyond are estimated to be $7.4 million.

OML 122

Overview

OML 122 (10.2% gas WI and 4.1% oil WI; Peak, an indigenous company, 89.8% gas WI and 95.9% oil WI) is located in the offshore Niger Delta, 40 km from the coastline of southern Nigeria, at a water depth of between 40 m and 300 m and covers an area of 1,599 km^2 (395,122 acres). The License is currently subject to a dispute between Peak and OER. See "*Legal Proceedings and Regulatory Actions*". The License contains two discoveries (Bilabri and Orobiri) and one prospect (Owanare). There has been no production from OML 122 to date.

OML 122



Blocks 5 and 12, EEZ of São Tomé & Príncipe

OER holds its interest in Blocks 5 and 12 through its 81.5% interest in EEL. In February 2010, in accordance with agreements signed in 2001 and 2003, the government of São Tomé & Príncipe awarded OER Blocks 5 and 12, located within the country's Exclusive Economic Zone (the "**EEZ**). EEZ Block 5 (81.5% WI) is the subject of PSCs which were signed on April 18, 2012 and a $2 million signature bonus was paid.

Negotiations with the government for Block 12 are still continuing.

During 2011, existing 2D seismic surveys were used to complete the evaluation of the blocks and identify a number of prospects. In order to manage the exposure to the risks of high cost exploration in a frontier province in ultra-deep water, EEL is considering farm-outs. A number of international oil companies have visited the data room in order to assess the opportunity, though there have been no firm commitments from any of them.

As at December 31, 2013 EEL had a total commitment of $5.2 million related to the provision of a performance guarantee and commitment to a four year work programme of 2D and 3D seismic acquisition and studies. If justified by the results of the seismic surveys, EEL can elect (for an additional cost to be determined) to drill the first exploration well in the following period of two years. OER funded the full $5.2 million commitment during the first quarter of 2014 by delivering a performance bond.

Assets Under Option/Negotiation

OPL 321 and OPL 323

OPL 321 and OPL 323 (24.5% WI) are located adjacent to OML 125, offshore from the Nigerian coast, at a water depth of 950 m to 2,000 m. The Licenses cover a combined area of 2,147 km^2 (530,535 acres). The Licenses are presently the subject of a dispute between the operator, KNOC, and the Nigerian Government. Due to the ongoing dispute, since 2008 exploration on these License areas has not been possible. As a result, Equator requested and received a refund from the Nigerian Government in the amount of $162 million, which will be paid to the Nigerian Government when the dispute has been resolved to Equator's satisfaction. OER anticipates that a settlement of the dispute may be reached as early as mid-2014. (see *"Legal Proceedings and Regulatory Matters – OPLs 321 and 323."*

A high quality 3D seismic survey was used to evaluate and identify a number of large prospects and to select potential well locations. No wells have been drilled on the Licenses pending resolution of the dispute. There is one prospect in OPL 321, Elephant, and four prospects within OPL 323, Gorilla, Lobster, Octopus and Whale. If successful, these prospects would be expected to contain medium oil, solution gas and free gas in a series of deltaic and fluvial sands, found at depths of 2,500 m to 3,000 m. The probability of success given to these prospects ranges from 20% to 25%.

Fiscal Terms

OER holds its material Licenses pursuant to PSCs and Marginal Fields. In addition to the terms specified below, OER expects to continue to benefit from the deductibility of interest on inter-company loans to its Nigerian subsidiaries in the calculation of taxation payable for PPT purposes. In practice, inter-company interest is generally tax deductible to the extent that the interest rate is benchmarked against LIBOR plus a reasonable margin to account for risk. In addition, OER expects to continue to benefit from the deductibility of technical and management services provided by OER to its Nigerian subsidiaries in the calculation of taxation payable for PPT purposes. See "*Nigeria – Petroleum Industry Contractual Framework and Fiscal Regime*" for a detailed description of the general fiscal terms of each License type.

PSCs

The following is a summary of the key terms of OER's material PSCs:

- **Term and relinquishment:** The PSCs specify a ten year exploration period followed by a twenty year OML period, which is subject to further renewal. 50% of the License area is required to be relinquished upon conversion to an OML.
- **Work obligations:** The contractor must perform minimum work obligations specified in each of the PSCs within an applicable exploration period. These minimum work obligations may include a minimum expenditure obligation, a specified activity or a combination of such obligations.
- **Bonus payments:** The contractor is obligated to pay bonus payments upon achieving certain production milestones.

- **Special fiscal considerations:** For PSCs entered into prior to 1998, the contractor may claim an investment tax credit, rather than an investment tax allowance, which can substantially reduce PPT otherwise payable. OMLs 125 and 134 were executed prior to 1998.

The table below summarizes the key fiscal terms of the PSCs, and related key financial terms with its partners, for OER's material PSCs.

	OML 125	OML 134
Contract:	PSC	PSC
OER Working Interest:	15%	15%
License Expiry Date:	2023	2023
Royalty (based on water depth):		
200 m	16.67%	16.67%
201 m - 500 m	12%	12%
501 m- 800 m	8%	8%
801 m - 1,000 m	4%	4%
1,000 m	0%	0%
Currently	8%	—
Investment Tax Allowance(1):	50% ITC	50% ITC
Annual Capital Allowances:		
Years 1-4	20%	20%
Years 5+	19%	19%
Available Cost Pool (OER)(2) ($million):	$8.1(6)	See OML 125(6)
PPT:	50%	50%
Other Taxes/Fees:		
VAT(3)	5%	5%
NDDC Levy(4)	3%	3%
Education Tax(6)	2%	2%
Contractor Share of Profit Oil - Cumulative Production in MMbbls:		
0 - 350	80%	80%
351 - 750	65%	65%
751 - 1000	55%	55%
1001 - 1500	50%	50%
1501 - 2000	40%	40%
Above 2000	Negotiable	Negotiable
Annual Lease Payments per km^2:		
OPL Period	—	—
OML Period for First Ten Years	—	$20
OML Period until Expiration and Renewal	$15	$15
Unpaid Bonus Payments:		
Conversion to OML	—	—
Commencement of Production	—	—
Production Bonus Payments:		
50 MMbbls cumulative	$ equivalent of 0.2% of cumulative production	$ equivalent of 0.2% of cumulative production
100 MMbbls cumulative	$ equivalent of 0.1% of cumulative production	$ equivalent of 0.1% of cumulative production
Partner Carry:	—	—

Notes:

(1) The petroleum investment tax allowance or credit is a tax allowance or credit granted to an exploration and production company in the first year in which qualifying capital expenditures are incurred. The ITA is deducted from assessable profits and the ITC is deducted from assessable tax. Each may only be claimed once in respect of qualifying capital expenditures in the year in which such expenditures have been first claimed (i.e., in the first year in which annual capital allowance is claimed in respect of such qualifying capital expenditures). See further "*Nigeria – Petroleum Industry – Contractual Framework and Fiscal Regime*".

(2) As at December 31, 2012.
(3) VAT is levied at 5% on all capital and operating costs.
(4) The NDDC Levy is 3% of the total annual budget (i.e. all costs) of oil producing companies operating onshore and offshore in the Niger Delta area must be paid to a fund maintained by the NDDC.
(5) Education Tax is levied at 2/102% of assessable profits: revenue less royalty and operating costs (but not capital allowances), as defined for PPT purposes. Education Tax payments are deductible for PPT purposes.
(6) The cost pools for OML 125 and OML 134 are combined owing to the right of OER (through Oando OML 125 & 134) to deduct costs pertaining to either License against assessable taxes earned in respect of the other License. This position is the subject of a dispute with the NNPC. See "*Legal Proceedings – OML 125*".

Marginal Fields

The following is a summary of the key terms relating to OER's Marginal Field Licenses:

- **Term and relinquishment:** All of OER's Marginal Fields have a term of 60 months, but in all cases a right of extension is contemplated where approval has been obtained from the DPR. The DPR has published guidance pursuant to "Guidelines for Farmout and Operation of Marginal Fields" which indicates that the renewal of a Marginal Field will be given for the life span of the field where verifiable evidence has been provided of efforts to progress development of the field. No relinquishment of land area is contemplated in the case of a Marginal Field.
- **Work obligations:** No minimum work obligations exist with respect to the Marginal Fields held by OER, however, the failure to diligently advance operations may be a cause for loss of License. Each of the Marginal Fields has a different contractual framework with only Ebendo being a direct working interest obtained through contract with the NNPC; the other two Licenses, Akepo and Qua Ibo, reflect farm-in arrangements with the original Marginal Field operators where technical partner status has been negotiated by OER. With respect to the latter two arrangements:
  - **Akepo:** OER is a party to a JOA with Sogenal. Sogenal obtained its interest in the License pursuant to a farm-out agreement with the NNPC and Chevron Nigeria Limited in 2004 and agreed to pay an overriding royalty to the farmors. The JOA has a term matching the underlying Sogenal farm-out agreement and confers a working interest of 40% and the role of technical partner on OER. Pursuant to the JOA, both of OER and Sogenal are permitted to charge $600,000 for general and administrative costs (indexed with inflation). Decisions of the joint operating committee require an affirmative vote of 71%; consequently, OER must consent to decisions as to operational and budgetary matters. Decisions of a technical nature that are in dispute are resolved by expert resolution. By way of a supplemental agreement, OER is entitled to recoup certain of the costs advanced on behalf of Sogenal in respect of work programs (including some historic costs incurred by Exile Resources Nigeria Inc. prior to the Arrangement). Prior to such cost recovery, OER shares in 80% of all profit oil; thereafter, OER is entitled to the percentages shown in the chart below.
  - **Qua Ibo:** Two affiliates of OER, OQI and ORPS, are parties to a JOA with NEPN. NEPN obtained its interest in the License pursuant to a farm-in agreement with the NNPC, Shell, Eni and a predecessor of Total in 2004 and agreed to pay an overriding royalty to the farmors. The JOA has a term matching the underlying NEPN farm-in agreement and confers a working interest of 40% upon OQI and the role of technical partner upon ORPS. Pursuant to the JOA, NEPN is permitted to charge $1,500,000 per annum for general and administrative costs prior to first oil and, thereafter, such amount as may be agreed (or, on default of an agreement, the sum of $1,500,000 indexed with inflation). Prior to cost recovery, OER has the final authority on all decisions of the joint operating committee; thereafter decisions are resolved by expert resolution.
- **Bonus payments:** Whilst relatively small bonus payments are due on signing, no further bonus payments are due once the License has been granted.
- **Special fiscal considerations:** With respect to all Marginal Fields, OER has applied for pioneer status for such operations, which confers a five year tax holiday. Such status has been conferred on Ebendo (with approximately three years remaining of the tax holiday) and OER expects such status to be recognized in all relevant tax filings. With respect to Qua Ibo, ORPS has agreed under a 'Financing Agreement' to lend monies to NEPN at a rate of 5% plus its cost of borrowing in order to permit NEPN to satisfy its cash calls under the JOA. In addition to an interest rate charge, ORPS is entitled to a financing fee of 10% of all monies borrowed by NEPN.

	Ebendo	Akepo	Qua Ibo
Contract:	Marginal Field	Marginal Field	Marginal Field
	Marginal Fields Farm-Out agreement between the NNPC and Elf, as Farmor, and Energia and OPDC, as Farmee, dated September 30, 2004.	Marginal Fields Farm-Out agreement between the NNPC and Chevron, as Farmor, and Sogenal, as Farmee, dated March 18, 2004.	Marginal Fields Farm-Out agreement between the NNPC and Shell, Eni and Elf, as Farmor, and NEPN, as Farmee, dated April 27, 2004.
	JOA between OPDC and Energia, dated June 16, 2006.	Farm-In agreement between Sogenal, as Farmor, and Exile Resources Nigeria Limited, as Farmee, dated September 22, 2006.	Farm-In agreement between NEPN, as Farmor, and OQI, as Farmee, dated February 2, 2012.
		Farm-In agreement between Exile Resources Nigeria Limited, as Farmor, and OEPL, as Farmee, dated December 26, 2008.	
OER Working Interest:	42.75%	40%	40%
License Expiry Date:	Life of Field (Expected)[7]	Life of Field (Expected)[7]	Life of Field (Expected)[7]
Royalty (based on bbls/d):			
0-5000	2.5%	2.5%	2.5%
5,001-10,000	7.5%	7.5%	7.5%
10,001-15,000	12.5%	12.5%	12.5%
15,000	18.5%	18.5%	18.5%
Currently	2.5%	-	-
Overriding Royalty (based on bbls/d):			
0-2000	2.5%	2.5%	2.5%
2,001-5,000	3.0%	3.0%	3.0%
5,001-10,000	5.5%	5.5%	5.5%
10,001-15,000	7.5%	7.5%	7.5%
>15,000	negotiated	negotiated	negotiated
Currently	3.0%	-	-
Investment Tax Allowance[1]:	5%	10%	5%
Annual Capital Allowances:			
Years 1-4	20%	20%	20%
Years 5+	19%	19%	19%
Available Cost Pool (OER)[2] ($million):	$37	$53	$34
PPT[3]:	55%	55%	55%
Other Taxes/Fees:			
VAT[4]	5%	5%	5%
NDDC Levy[5]	3%	3%	3%
Education Tax[6]	2%	2%	2%
Annual Lease Payments per km^2:			
OML Period until Expiration and Renewal	$15	$15	$15

Notes:

(1) The petroleum investment tax allowance / credit is a tax allowance / credit granted to an exploration and production company in the first year in which qualifying capital expenditures are incurred and is equal to a percentage of the qualifying capital expenditures in such year.
(2) As at December 31, 2012.
(3) Legally, PPT is 85%, however, the Ministry of Petroleum Resources has indicated that Marginal Fields will only be taxed at a rate of 55% and industry expects the law to be conformed to Nigerian Government policy.
(4) VAT is levied at 5% on all capital and operating costs.
(5) The NDDC Levy is 3% of the total annual budget (i.e. all costs) of oil producing companies operating onshore and offshore in the Niger Delta area must be paid to a fund maintained by the NDDC.
(6) Education Tax is levied at 2/102% of assessable profits: revenue less royalty and operating costs (but not capital allowances), as defined for PPT purposes. Education tax payments are deductible for PPT purposes.

(7) The DPR has published guidance pursuant to "Guidelines for Farmout and Operation of Marginal Fields" which indicates that the renewal of a Marginal Field will be given for the life span of the field where verifiable evidence has been provided of efforts to progress development of the field.

Other Corporate Matters

Competition

OER's competitors include major oil and gas companies and independent oil and gas companies. The major IOCs in the region include Amni International Petroleum Development Company Limited, ExxonMobil, Oriental Energy Resources Limited, Shell, Total, Chevron, Eni, and Addax Petroleum Corporation. The oil and gas business is highly competitive in the search for and acquisition of reserves, in the procurement of rigs and other production equipment, in the production and marketing of oil and gas, and in the recruitment and employment of qualified personnel. The primary areas in which OER encounters substantial competition are in locating and acquiring desirable acreage for drilling and development operations, locating and acquiring attractive producing oil properties, and obtaining equipment for drilling operations.

In addition, OER competes with oil and gas companies in the bidding for exploration and production assets that are made available by the Nigerian government or are for sale by third parties. Competition for such assets is likely to come from companies present in Nigeria as well as new entrants.

Seasonality

Seasonal weather conditions and lease stipulations can limit OER's drilling and producing activities and other oil and natural gas operations in certain areas. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay OER's operations.

Employees

OER, together with its subsidiaries, has approximately 64 full-time employees and four consultants. 59 of OER's employees are located in Nigeria with one located in England and four in Canada. Additionally, OER expects to hire approximately 65 additional employees on completion of the COP Acquisition.

Environmental, Health, Safety and Security

EHS Policy

OER has implemented an environmental, health and safety policy that applies to the management, employees and contractors of OER. The EHS Policy outlines OER's principles of environmental stewardship, maintaining safe and healthy workplaces for its employees and contractors and ensuring compliance with environment, health and safety legislation, regulations and recognized industry standards.

OER has direct responsibility for environmental, health, safety and security matters for controlled areas, including Akepo and Qua Ibo, where OER is the technical partner. During the year ended December 2013 there were no lost time injuries in respect of Akepo or Qua Ibo. OER has implemented policies and operates and auditable management system. The EHS Policy and other corporate policies are an important part of the responsibilities of the managers of OER and significantly influence the operations of OER. In respect of those Licenses where OER is not the operator or technical partner, budgets are approved on an annual basis and meetings are held regularly among the partners (including OER) to agree on appropriate measures to address environmental, health, safety and security matters. If OER's partners are not complying with such programs, OER can refuse to fund cash calls from the operator or, in a worst case scenario, remove the operator from its role

OER's quality management system was certified as "ISO 9001:2008" compliant in March of 2011. OER believes that the certification process assisted in enhancing productivity and efficiency and in reducing accidents and errors. Certification under ISO 9002:2008 involves the audit of a company's quality management system, standards for management responsibility, standards for resource management, process for product realization, and standards for measuring and improving systems.

Environmental Protection

OER's operations are subject to various environmental, health and safety regulations. These regulations govern the handling, generation, storage and management of hazardous substances, including how these substances are released or discharged into the air, water, surface and subsurface. These laws and regulations often require permits and approvals from various agencies before OER can commence or modify its operations or facilities, and on occasion require the preparation of an environmental impact assessment or study (which can result in the imposition of various conditions and mitigation measures) prior to or in connection with obtaining such permits. In connection with the release of hydrocarbons or hazardous substances into the environment, OER may be responsible for the cost of remediation under applicable laws. Failure to comply with applicable laws, permits or regulations can result in project or operational delays, civil or in certain cases criminal fines and penalties and remedial obligations. See "*Risk Factors – OER may be subject to substantial fines for gas flaring*".

Ethics and Integrity

Ethics Policy

OER has adopted the Ethics Code that applies to all directors, officers, managers, employees and persons rendering and providing services, copies of which have been provided to each. A person may also obtain a copy of the Ethics Code by request from the Chief Compliance Officer. The board monitors compliance with the Ethics Code primarily through the Chief Compliance Officer appointed by OER. The Chief Compliance Officer is responsible for the implementation and enforcement of the Ethics Code and conducts periodic audits to measure and evaluate the effectiveness of all aspects of the Ethics Code. The Chief Compliance Officer reports directly to the Corporate Governance Committee of the Board of Directors.

In accordance with the CBCA, directors who are a party to or are a director or an officer of a party to a material contract or material transaction with OER are required to disclose the nature and extent of their interest and are not permitted to vote on any resolution to approve the contract or transaction. The Committee also reviews and make recommendations to the Board of Directors on all matters involving a board member's potential or actual conflict of interest as may be referred to the Committee by the Board of Directors. In addition, OER recognizes that transactions with related parties can present potential or actual conflicts of interest. As a result, OER has adopted a Related Party Transaction Policy in order to identify, notify, review, evaluate and disclose related party transactions.

Anti-Corruption and Anti-Bribery Policy

OER recognizes the principles of respect, integrity and professionalism in all its business dealings as entrenched in the Ethics Code. Corruption has been identified as one of the single greatest obstacles to these principles. OER has adopted the Anti-Corruption and Anti-Bribery Policy that applies to all transactions, operations, projects, bid processes, procurement, negotiations, arrangements, documentation processes, applications, activities, agreements, contracts, awards, decisions, practices and other business dealings of OER. The Anti-Corruption and Anti-Bribery Policy must be complied with by all directors, officers, managers and employees (including consulting or contract staff and any third party personnel providing services to or seconded to OER), as well as OER's business partners.

OER's employees are strictly prohibited from the following corrupt practices, among others: asking for, accepting, offering or receiving any bribe, benefit or gratification of any kind for himself or any other person on account of anything done or omitted to be done by him in the discharge of the employee's duties; putting himself in a position where his personal interests conflict with his duties, responsibilities and OER's commitment to eradicate corruption; and receiving, accepting or giving in to demands to receive or pay a bribe, kickback, facilitation payment or any portion of a contract payment from any business partner or person or entity having any business relationship with

OER. OER and its employees shall exercise due care and take reasonable steps and precautions geared towards evaluating corruption tendency of prospective business partners and in selecting business partners.

Gifts and Benefits Policy

OER has adopted the Gifts and Benefits Policy that applies to the giving and acceptance of gifts and/or benefit, from persons or entities that deal directly or indirectly with OER, by all of OER's employees, their spouses and immediate family members.

OER prohibits gifts and benefits in an amount or on a scale that unduly influences business decision-making or may be perceived by others as an undue influence. In order to comply with the Gifts and Benefits Policy, the value of a gift or benefit must be (i) reasonable; (ii) directly connected to a legitimate business promotional activity or the performance of an existing contract; (iii) permitted under local law and in accordance with local business practice; and (iv) otherwise consistent with OER's business practices. Any Gift or Benefit offered with the intent of some form of obligation to the donor should be rejected. Pursuant to the policy, employees, their spouses, and immediate family members shall declare any gifts and benefits to OER and the Chief Compliance Officer shall maintain a gifts and benefits register. A recipient of a gift or benefit may retain the gift or benefit if is valued below C$150 or the equivalent of ₦25,000 (whichever is less).

Community Relations

OER believes that community relations are critical to its success and has adopted a comprehensive set of policies and protocols in order to guide its employees and contractors in handling grievances and interacting with communities at all stages of development, including protocols in relation to homage and courtesy calls. OER has executed three community agreements pertaining to Ebendo, Akepo and Qua Ibo, which are aimed at assisting with basic necessities of local communities and the provision of needed facilities and equipment. During the year ended December 31, 2012 and the first quarter of 2013, OER convened a number of stakeholder meetings with its host communities, hosted vocational training programs and executed a number of community development projects including the building of access roads and clinics and implementing potable water projects. Going forward, OER will seek to tie its community support programs to revenues or operational activities, such as in the case of the Ebendo community agreement.

OER has three full time employees and utilizes several community consultants dedicated to corporate social responsibility. OER will often temporarily locate staff within such communities in order to facilitate open dialogue, build trust and better understand the challenges facing such communities. In this way, OER can maintain good day-to-day relations with local communities and offer transparent funding and other benefits that OER knows will be of value to the broader community. OER also encourages its contractors to recruit their employees from its host communities in order to improve the economic conditions of those communities.

THE NIGERIAN OIL AND GAS INDUSTRY AND REGULATORY FRAMEWORK

Overview

Nigeria is the largest economy in West Africa. The following table highlights some important statistics regarding Nigeria, its people and its economy for 2012.

Total Area	923,768 km^2
Population	174,507,539
Major Cities	Abuja, Lagos, Kano, Ibadan, Kaduna, Onitsha, Warri, and Aba
Language	English (Official), Yoruba, Hausa, Igbo and over 500 other indigenous languages
Literacy	61%
Government	Federal system of government

Legal System	Primarily English common law
GDP	$272.6 billion
GDP per capita	$1,562
Oil Production	2.4 million barrels of liquids per day
Gas Production	4.2 billion cubic feet of gas per day
Reserves	37.2 billion barrels of oil and 182 trillion cubic feet of gas
Inflation	12.1%

Government

Nigeria is a federation made up of three tiers of government—the federal government, 36 state governments (including Abuja, the federal capital territory) and 774 local government administrations. Nigeria's constitution came into force in May 1999 (following many years of military rule) and is modelled on the constitution of the United States. Under the Nigerian constitution, the President can serve a maximum of two terms of four years each. The Nigerian legislature comprises two houses: the House of Representatives, with 360 elected members, and the Senate, with 109 elected members. The laws of the Nigeria as contained in the Laws of the Federation are based primarily on English common law. President Jonathan was re-elected as President in the general elections conducted in April 2011. The next general election is expected in 2015.

Petroleum Industry

Overview

A key factor in the shaping of modern Nigeria has been the development of the oil industry, which commenced in the 1950s with the discovery of the Oloibiri field by a Shell predecessor. Subsequently, exploration and production

increased rapidly in the 1960s and reached in excess of two MMbbls/d in the mid-1970s. The 1980s saw a decline in oil production, which was partly attributable to an unfavourable investment environment. Revised fiscal terms for oil production reversed the decline and development activity and production increased thereafter. The country's oil industry now accounts for approximately 20% of gross domestic product, 95% of foreign exchange earnings and 65% of budgetary revenues. As such, the economy of Nigeria is strongly dependent upon international oil prices.

Nigeria is the largest producer of oil and gas and the largest reserves holder in Africa. Its proved reserves are reported by BP Statistical Review of World Energy 2013 to be 37.2 billion barrels of liquids and 182 Tcf of gas, making Nigeria the tenth most petroleum-rich nation in the world. In 2012, Nigeria produced 2.4 MMbbls/d of liquids and 4.2 Bcf/d of gas. For several years, the Nigerian Government has been promoting the production of natural gas, which is expected to encourage the further development of infrastructure and markets. Nigeria's oil and gas reserves and resources are well established with decades of commercial discoveries, substantial production and extensive remaining potential. For several years, the Nigerian Government has been promoting the production of oil and gas, which is expected to encourage the further development of infrastructure and markets.

The presence of large IOCs has been prominent in the oil and gas industry in Nigeria. IOCs have faced a number of challenges in recent years, including illegal bunkering, sabotage and security issues, particularly in relation to onshore assets. Some IOCs have announced intentions to spend capital on larger projects, which tend to be predominantly offshore Nigeria. OER believes that such challenges and larger opportunities will lead IOCs to continue to withdraw from onshore interests over time. In recent years, the Nigerian Government has taken steps to increase the involvement of indigenous Nigerian companies, including OER's subsidiaries, particularly with respect to onshore opportunities.

Geological Description

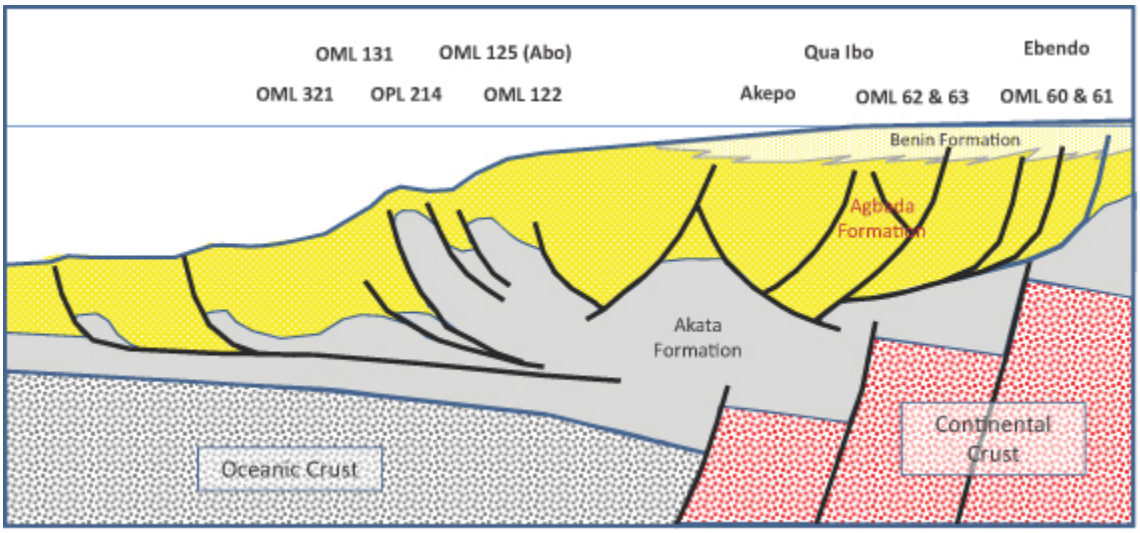
The Niger Delta Basin is Africa's largest and most prolific oil producing basin. It is also one of the world's largest delta systems of the Tertiary age and covers an area greater than 75,000 km^2. Since it began to form in the Late Pliocene, the Niger Delta has been growing towards the southwest, forming a series of depositional belts. Throughout the geologic history of the delta, its structure and deposits have been influenced by both the rate of subsidence and the sediment supply.

The Niger Delta can be divided into a number of distinct provinces – hydrocarbons are contained in all provinces, but the methods of trapping and structures vary throughout. At the landward end of the delta, there is an area of extension with normal faulting. Further seaward, there are areas of shale intrusion and more complex thrust faulting. Common methods of trapping include within fault compartments and beneath folded structures.

The Tertiary section of the Niger Delta is divided into three formations: the Akata Formation, the Agbada Formation and the Benin Formation. The Akata Formation is stratigraphically the deepest, and comprises a thick shale sequence that provides a prolific source rock within the petroleum system. The Agbada Formation contains almost all producing reservoirs in the Niger Delta, with hydrocarbons trapped in a thick mass of interlayered sands and shales. The Benin Formation comprises thick continental and alluvial sands.

Reservoirs in the Niger Delta are found in a number of depositional settings, including turbidites, sheet sands, lobes and a variety of channel forms. Each of these settings shows different reservoir properties.

Stratigraphy of the Niger Delta



OPEC and Oil Production Quotas in Nigeria

In 1971, Nigeria became a member of OPEC. OPEC has 12 members who collectively supply approximately 40% of the world's oil consumption and account for over two-thirds of the world's proved oil reserves. OPEC's member countries are Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela. OPEC's stated objective is "to coordinate and unify the petroleum policies of its member countries and ensure the stabilization of oil markets in order to secure an efficient, economic and regular supply of petroleum to consumers, a steady income to producers and a fair return on capital for those investing in the petroleum industry". Nigeria is the seventh largest oil and gas producer in OPEC.

OPEC establishes production ceilings and quotas for individual members. Nigeria's current quota is set at approximately 2.4 MMbbls/d. The NNPC has historically allocated production quotas among oil producers in Nigeria. These allocations have been based on the aggregate of the technical production limits per well for a producer as negotiated between the producer and the Nigerian Government to reflect good oil field production practices. In practice, OER has experienced no restrictions on its production limits and expects no such restrictions in the future.

Contractual Framework and Fiscal Regime

Overview

The Petroleum Act gives the Minister of Petroleum Resources and the DPR authority to issue Licenses and to attend to the administration of hydrocarbon matters, respectively. The NNPC, which was created soon after Nigeria became a member of OPEC in 1971, is a state-owned petroleum company through which the Nigerian Government participates in joint ventures and enters into PSCs with foreign and indigenous oil companies. Today, the NNPC is typically the holder of the relevant License and one or more oil companies enter into contractual relations with the NNPC in order to conduct exploration, development and production activities on its behalf in return for a share of oil production.

An OPL gives the licensee the exclusive right to explore for petroleum in a specified area, while an OML gives the lessee the exclusive right to produce petroleum from a specified area. Under the Petroleum Act, an OPL may be converted into an OML when the conditions under the License have been fulfilled and the Nigerian Government is satisfied that the License is capable of producing at least 10 Mbbls/d of oil. The Petroleum Act requires the relinquishment of 50 percent of the acreage on the 10th anniversary of the grant of the OML, although OMLs that

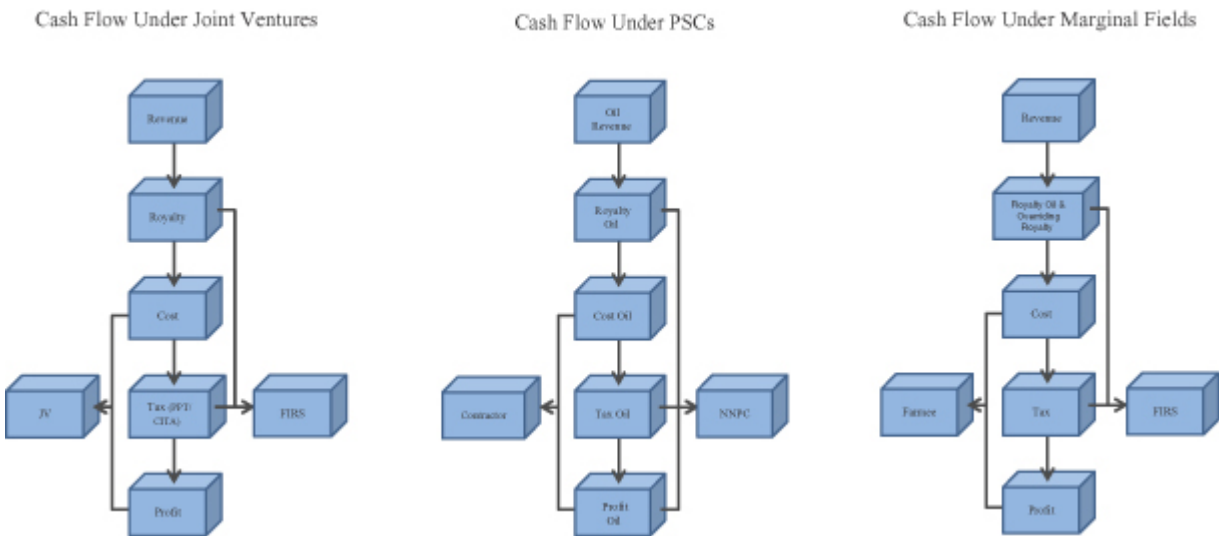
have been renewed are not subject to the relinquishment obligation and negotiations with the DPR may result in the waiver or reduction of a relinquishment obligation. As well, most PSCs contemplate the relinquishment of areas subject to an OPL on conversion to an OML.

Where one or more fields straddle License boundaries, operators may seek to unitize the conjoined fields. In Nigeria, operators will normally enter into a pre-unitization agreement at the exploration or development phase, depending upon their level of understanding of field communications or connectivity. Often pre-unitization agreements will contemplate agreement on unitized interests after further data has been collected from exploration and development activities. All unitization agreements require the approval of the DPR, which may take many years to secure in the normal course. As a practical matter, many operators begin production in reliance upon pre-unitization agreements.

There are three main types of Nigerian Government contracts:

- joint ventures, which date from the 1960s, where the relevant License is held collectively by the joint venture parties (including the NNPC);
- PSCs, which date from 1993, where the relevant License is held by the NNPC which then enters into commercial relations with a contractor/participant in order to conduct exploration, development and production activities on its behalf in return for a share of oil production; and
- Marginal Fields, which date from 2003, where special terms are agreed with a License holder (whether the NNPC or otherwise) in order to permit the exploitation of a field under a farm-out arrangement.

Each of these contract types has different fiscal implications, a summary of which is depicted below.



Joint Ventures

Joint ventures take the form of a partnership agreement (or JOA), where the participatory interest of each of the partners is outlined in the JOA and one of the joint venture partners is appointed operator. The NNPC represents the Nigerian Government in the venture with a majority, accessible, non-operating stake. Joint ventures currently account for the majority of Nigeria's total oil production. Under a joint venture, one or more oil companies enter into a joint venture with the NNPC whereby the oil companies and the NNPC agree to jointly explore for, develop and produce petroleum pursuant to the terms of a License jointly held by them. Each partner in the joint venture contributes to the costs of exploration, development and production and shares the benefits or losses of the operations in accordance with its proportionate equity interest (WI) in the joint venture.

Most joint ventures apply in the onshore or shallow offshore area of Nigeria. For such participants, PPT (petroleum profits tax) is payable at a rate of 85%, except for sales of gas and NGL which are subject to income tax at a rate of 30% under the CITA (Companies Income Tax Act). Royalty is payable at a rate of 20% for onshore and 18.5% for shallow waters (up to 100 m). Capital expenditures may be deducted against PPT, including those pertaining to the recovery, processing and transport of associated gas; capital expenditures are deducted over a straight-line five year period (known as a capital allowance), save that the fifth year permits a deduction of only 19% (vs. 20%). A further incentive (income tax allowance or ITA) permits 5% (onshore) to 10% (shallow waters) of qualifying capital expenditures to be deducted in the year in which the assets are first used. The ITA does not reduce the qualifying capital expenditure balance.

PSCs

PSC arrangements have been used more recently with respect to Nigeria's offshore areas. The NNPC holds the underlying License and then contracts with industry participants to bear the entire cost and risk of exploration activities; upon success, the participant recovers its costs through oil (known as 'Cost Oil'), pays royalty and then splits the resulting 'Profit Oil' in an agreed proportion with the NNPC. The rate of PPT is reduced to 50% for deepwater operations, and 65.75% for onshore and shallow offshore operations where pre-production costs have not yet been fully amortized (usually the first five years of production for a new company). Sales of gas and NGL are subject to CITA at a tax rate of 30%. Royalty is payable based on water depth at a rate of 16.67% for 101 to 200 m, 12% for 201 to 500 m, 8% for 501 to 800 m, 4% for 801 to 1,000 m and 0% thereafter, although a minimum rate of 8% applies to PSCs entered into since 2005 (not applicable to OER's Licenses).

Under a PSC, a capital allowance for qualifying capital expenditures may be deducted against PPT over a straight-line five year period, save that the fifth year permits a deduction of only 19% (vs. 20%). A further incentive in the form of an ITA or ITC permits 50% of qualifying capital expenditures to be deducted in the year in which the assets are first used. ITCs apply only to deepwater PSCs signed in 1993 (e.g., OML 125). The ITC is available as a credit against chargeable tax, while an ITA permits a deduction against adjusted profits in the form of capital allowance. Neither reduces a company's qualifying capital expenditure balance and any amount of ITA or ITC that has not been recouped in a given year may be carried forward to the next year. The rate of ITC and ITA depends upon water depth and is 50% for all Licenses at a water depth beyond 200 m. No cost ceilings were applied before 2005, but newly Licensing rounds applied a cost ceiling of 80% (2005 and thereafter).

Marginal Fields

Marginal Field fiscal terms provide favourable terms to operators with no government share, reduced royalty payments and reduced PPT. PPT is 55%, royalty is based on bbls/d rather than water depth (at rates ranging from 2.5% for 5,000 bbls/d to 18.5% for 15,000 bbls/d) and the NNPC has no share in oil production. Where a Marginal Field is located within an existing OML, an overriding royalty is payable to the License holder at a standardized rate ranging from 2.5% for 2,000 bbls/d to 7.5% for 15,000 bbls/d. It should be noted that the law has not been formally amended to provide for a reduced PPT rate on Marginal Fields so operators are generally compelled to accrue PPT at higher rates in their financial accounts pending the passage of applicable legislation.

Special Tax Considerations

Under both PPT and CITA, losses may not be carried backwards, but can be carried forward indefinitely. As a result, all assessed losses for tax purposes resulting from capital cost allowances, ITA and other permissible expenditures can be effectively carried forward indefinitely until offset against assessable profits. In the case of Licenses granted pioneer status, all prior permissible expenditures can therefore be cumulated and offset against assessable income when payable.

Generally, technical and management service charges incurred within or outside of Nigeria in respect of a Nigerian oil and gas producing business are deductible expenses for PPT purposes. No pre-approval of the technical/management services agreement(s) is required for the charges to be considered as tax deductible under the PPT Act, however, the services must be charged on an arms' length basis for related party transactions as evidenced by a transfer pricing study which confirms such arms' length pricing. As well, to the extent that shareholder loans have been used to fund the petroleum operations of Nigerian subsidiaries, interest paid to the parent or related

parties outside of Nigeria should be deductible for PPT purposes. The Petroleum Profit Tax Act expressly allows as tax deductible "all sums incurred by way of interest on any intercompany loans obtained under terms prevailing in the open market …." In practice, inter-company interest is tax-deductible to the extent that the interest rate is benchmarked against LIBOR plus a commercially reasonable margin, though this may be contested by tax authorities.

Dividends may be remitted within or outside of Nigeria without restriction, provided the company has sufficient distributable profits and provided the share capital of the relevant Nigerian entity has been brought into Nigeria through authorized dealers under a Certificate of Capital Importation. Dividends received by a Nigerian company from another Nigerian company are exempt from corporate income tax. Furthermore, there is no withholding tax on dividends distributed from profits which have been assessed for tax under the PPT. In other cases, dividends are subject to a 10% withholding tax whether paid to a resident or non-resident, unless the rate is reduced under a tax treaty. In the case of dividends paid to the Netherlands (where the HoldCo Subsidiaries are located), the withholding tax on distributions of profits other than profits on which PPT has been paid is reduced to 7.5%. Capital gains tax is generally levied at a rate of 10%; gains from the disposal of shares are not subject to capital gains tax. Losses may not be carried back, but may be carried forward indefinitely.

Illustrative Examples

The following table illustrates the profit and tax allocations under each fiscal regime in year 1 assuming $100 in revenues for a barrel of oil sale (and $2.50 in incremental revenue from an Mcf gas sale in the joint venture example), qualifying capital expenditures of $20 (resulting in a capital cost allowance of $4 in year 1) and operating costs of $10 (with no incremental operating costs for gas in the joint venture example). These examples are not necessarily representative of OER's operations and, in this regard, specific netbacks and other financial information should be referred to in other sections of this AIF.

Joint Ventures[1]					Deepwater PSCs[2]		Marginal Fields[3]	
	$/bbl		**$/Mcf**	**$/boe**		**$/bbl**		**$/bbl**
Oil Revenue	100.00	Gas Revenue	2.50	15.00	Oil Revenue	100.00	Oil Revenue	100.00
Less royalties	(20.00)	Less royalties	(0.18)	(1.05)	Less royalties	(8.00)	Less royalties and overriding royalties	(2.50)
								(2.50)
Less non-capitalized costs	(10.00)	Less non-capitalized costs	–	–	Less non-capitalized costs	(10.00)	Less non-capitalized costs	(10.00)
= Assessable profit	70.00	= Assessable profit	2.32	13.95	= Assessable profit	82.00	= Assessable profit	85.00
Less Education Tax[4]	(1.37)	Less Education Tax[4]	(0.05)	(0.27)	Less Education Tax[4]	(1.61)	Less Education tax[4]	(1.67)
Less NDDC Levy[5]	(0.90)	Less NDDC Levy[5]	–	–	Less NDDC Levy[5]	(0.90)	Less NDDC Levy[5]	(0.90)
Less Capital Allowance	(4.00) (1.00)	Less Capital Allowance	–	–	Less Capital Allowance	(4.00)	Less Capital Allowance	(4.00) (1.00)
Less ITA		Less ITA					Less ITA	
= Chargeable Profit	62.73	= Chargeable Profit	2.28	13.68	= Chargeable Profit	75.49	= Chargeable Profit	77.43
Assessable Tax @ 85%	(53.32)	Assessable Tax @ 30%	(0.68)	(4.10)	Assessable Tax @ 50%	(37.75)	Assessable Tax @ 55%[7]	(42.59)
					Less ITC[6]	10.00		
					PPT payable	(27.75)		
Profit	9.41	Profit	1.60		Profit Oil	47.74	Profit	34.84
					NNPC	9.55		
					Contractor	38.19		
Government Take	75.59	Government Take	0.90	5.42	Government Take	47.81[8]	Government Take[9]	50.16
Net Contractor Take[10]	24.41	Net Contractor Take[10]	1.60	9.58	Net Contractor Take[10]	52.19	Net Contractor Take[10]	49.84

Notes:
(1) Assumes onshore joint venture, which results in an ITA rate of 5%.
(2) Assumes water depth of 600 m and a 1993 PSC, which results in a permitted ITC, rather than an ITA.
(3) Assumes a rate of oil production of 2,000 bbls/d, which results in an overriding royalty of 2.5%.
(4) Calculated as 2/102 x assessable profits.
(5) Calculated as 3% of the total annual budget (i.e. operating and capital expenditures). It is customary to exclude taxes and non-cash expenses in the bases for calculating the NDDC levy.
(6) Legally, PPT is 85%, however, the Ministry of Petroleum Resources has indicated that Marginal Fields will only be taxed at a rate of 55% and industry expects the law to be conformed to Nigerian Government policy.
(7) In the case of deepwater PSCs entered into in 1993, ITC permits 50% of qualifying capital expenditures in the year in which they are first incurred to be applied as a credit against chargeable tax. All other PSCs, including those pertaining to many of OER's Licenses, permit only an allowance against assessable tax.
(8) Including the profit share of the NNPC.
(9) Including overriding royalty payable to License holder, which may include parties other than the NNPC.
(10) Contractor take before operating expenses.

See further "*Description of OER's Assets – Fiscal Terms*".

Petroleum Industry Bill (PIB)

Currently, the petroleum industry in Nigeria is primarily governed by the Petroleum Act. Under the Petroleum Act, the ownership and control of oil and gas in Nigeria is vested in the Nigerian Government. The Ministry of Petroleum Resources, through the DPR and in collaboration with other government agencies, such as the NNPC and the

Ministry of the Environment, has the responsibility for enforcing the Petroleum Act and the related legislation and regulations governing the petroleum industry in Nigeria. The PIB would constitute a major overhaul of the legal framework for the oil and gas industry in Nigeria. The PIB would, among other things, introduce a new tax and royalty regime, increase the participation of local producers, stimulate the gas sector and affect the operation of the NNPC.

The PIB was first proposed to the Nigerian National Assembly in 2009. A revised PIB was presented in the Nigerian National Assembly in 2012. The current draft of the PIB has several objectives, including:

- the consolidation of existing laws regulating the Nigerian petroleum industry;
- reforming and restructuring the Nigerian oil and gas sector and its regulatory bodies;
- introducing new fiscal measures applicable to operators in the Nigerian oil and gas industry, including a general revision of taxes;
- providing for the enhancement of Nigerian content in the petroleum industry; and
- deregulating the downstream sector of the petroleum industry.

The PIB remains under consideration by the Nigerian Government and may be subject to significant changes prior to its enactment. See "*Risk Factors – Risks Related to Carrying on Business in Nigeria*". Nigeria has proposed sweeping changes to its fiscal terms pursuant to the PIB and is subject to significant ongoing change. See further "*Nigeria Oil and Gas Industry and Regulatory Framework – Advantages to Indigenous Oil Companies*" for further information on the PIB.

The PIB proposes to replace the PPT with a new tax, the NHT (Nigerian hydrocarbon tax), with a rate of 50% for onshore and shallow water fields and 25% for deepwater fields. Income tax under the CITA would be applied to petroleum operations at the rate of 30% (thereby giving rise to an effective rate of 80% and 55% for onshore (and shallow water) and deepwater operations, respectively). NHT would be calculated in a manner similar to PPT, and would not be deductible for CITA, nor *vice versa*. A PA (petroleum allowance) would replace the ITA and ITC through a permitted deduction from assessable profits, which would be calculated based on water depth, production volumes and market price of product. A PA would not be permitted for crude oil under joint ventures with the NNPC. Marginal Field operators will be entitled to claim PA from the effective date of the PIB notwithstanding the lack of a PSC.

The PIB would also establish a fund to be utilized for the development of the economic and social infrastructure of communities within petroleum producing areas. All companies engaged in upstream petroleum producing operations would be required to remit to the fund, on a monthly basis, 10% of their net profit. The contributions made by each company would be credited against its royalty, NHT and income tax obligations arising from upstream petroleum operations and contributions to the fund therefore would not increase the financial burden on companies. Industry is concerned about the government take resulting from the proposed PIB and has been actively engaged with the Nigerian Government with a view to ensuring a balanced fiscal regime that continues to attract necessary investment.

Under the PIB, OMLs (or their equivalent) would have a maximum term of 20 years plus the length of any remaining OPL (or their equivalent). OMLs would be renewable for a further term of 10 years, but areas not subject to ongoing commercial production or a firm commitment of expenditures could be expected to be relinquished. With respect to existing OMLs, conversion to a new OML would not be required, however, at the expiry of such Licenses any areas that are proposed to be retained for exploration purposes would necessitate a firm commitment to drill a well of at least 3,000 m. In addition, the PIB would confer upon the Minister of Petroleum Resources the power to revoke a License if production has ceased for a period in excess of 180 days other than for reasons of force majeure, repairs, maintenance, upgrading of facilities, new construction of facilities or other causes as presented to and endorsed by the inspectorate charged with authority to determine such matters.

Advantages to Indigenous Oil Companies

Marginal Fields

In 2003, the Nigerian Government implemented certain initiatives to increase the participation of Nigerian companies in exploration and production through, among other things, its Marginal Field Development Program. Marginal Fields are defined by government guidelines (2001) as being fields that have booked reserves and that have not been producing for ten years or more. Additional characteristics of a Marginal Field may include limited reserves, geologic, economic, technological and/or infrastructure constraints, unfavourable market and fiscal situations, poor or unfavourable crude characteristics and that the field is unlikely to produce 10,000 bbls/d. Pursuant to the Petroleum Act, Marginal Fields are subject to compulsory farm-outs to Nigerian companies (that is, companies incorporated in Nigeria and that are at least 51% Nigerian owned) under a competitive bid process. Non-Nigerian companies are not permitted to hold more than a 40% equity interest in such fields.

In 2003, the Nigerian Government awarded 24 of its Marginal Fields to 31 Nigerian exploration and production companies with some other fields being farmed-out under private arrangement. Approximately seven of the 24 awarded fields are in production. 116 Marginal Fields with 1.3 billion barrels of reserves have been identified as Marginal Fields. OER has successfully obtained three Licenses (Ebendo, Akepo and Qua Ibo), directly or indirectly through farm-in arrangements, under the program. Further advantages for indigenous companies exist (or are proposed) in other legislation, including as set out below.

The Local Content Act

The Local Content Act introduced a regulatory framework for the development of indigenous content in the Nigerian oil and gas industry. The Local Content Act provides for preferential treatment to Nigerian companies by prescribing minimum thresholds of Nigerian participation for various activities in the oil and gas sector, including the award of Licenses. In addition, Nigerian independent operators are given first consideration with respect to the award of Licenses and in all projects for which contracts may be awarded in the Nigerian oil and gas industry. As such, Nigerian participation in the upstream oil and gas industry has increased. For the purposes of the Local Content Act, companies are classified as Nigerian if they have Nigerians holding equity of at least 51%. All oil and gas arrangements, contracts and operations are now required to comply with the minimum Nigerian content standards and thresholds specified in the Local Content Act.

PIB

Though the PIB remains in draft form, indigenous companies are expected to benefit from various provisions, including that the Nigerian Government (through the NNPC or otherwise) will not participate in petroleum operations carried out by indigenous companies whose aggregate production from petroleum operations is not more than 25 Mbbls/d of oil or its natural gas equivalent. Regulations or guidelines are expected to be issued prescribing programs for continuously increasing the level of indigenous participation in the Nigerian petroleum industry and for such participation to be monitored and reviewed on a biennial basis. In respect of existing Marginal Fields, operators would be entitled to apply for and obtain an OML (or its equivalent under the PIB).

Export Infrastructure, Sales and Marketing

Nigeria has extensive export infrastructure, particularly for crude oil. With respect to gas, Nigeria has the Bonny LNG plant and two further LNG plants are proposed for development, including the Brass LNG Project. Of Nigeria's exported crude production approximately 33% is destined for the United States. Approximately 20% of Nigeria's crude exports go to Europe, 17% to Asia and the remainder to other countries.

STATEMENT OF RESERVES AND RESOURCES DATA AND OTHER OIL AND GAS INFORMATION

In accordance with the requirements of NI 51-101, Petrenel prepared a report on Form 51-1-1F1 entitled "*Statement Of Reserves Data and Other Oil and Gas Information*" dated February 28, 2014 (the "**51-101 Statement**"). Attached as Appendix "A" hereto is the Form 51-101F1 Statement. Form 51-101F2 "Report of Independent

Qualified Reserves Evaluator" of Petrenel and Form 51-101F3 "Report of Management on Oil and Gas Disclosure", prepared in accordance with the requirements of National Instrument 51-101, are attached hereto respectively as Appendix "B" and Appendix "C".

RISK FACTORS

An investment in the securities of OER should be considered highly speculative due to the nature of OER's business and the present stage of its development. The following is a summary of certain risk factors relating to the activities of OER and the ownership of OER's securities, which should be carefully considered before making an investment decision relating to OER's securities.

Risks Relating to OER

Oando will continue to exercise significant control over the affairs of OER

Oando currently owns a majority of the Common Shares (approximately 92.9% on a non-diluted basis) and, as such, has the power to elect the majority of the members of OER's Board of Directors and determine the result of any shareholder resolution. Although shareholders of OER (other than Oando) have certain protections in relation to transactions between Oando and OER by virtue of, among other things, Canadian corporate and securities laws, there can be no assurance that Oando's interests will not conflict with the interests of shareholders of OER (other than Oando). So long as Oando holds 20% or more of the Common Shares, the ROFO Agreement provides that OER is restricted from consolidating, merging or entering into any similar business combination with another entity and Oando is permitted to nominate the CEO and Chairman of the Board of Directors.

As well, Oando holds substantial influence within OER by virtue of its holding of all Class A Shares in the Operating Associates. These holdings entitle Oando to appoint an equal number of directors to each of the Operating Associates and thereby restrict OER from independently directing the affairs of the Operating Associates. While OER does have the right to appoint the chairman of the Operating Associates, who can cast a deciding vote in the event of deadlock, and the further right to compel the sale of Oando's Class A Shares for nominal consideration, there can be no assurance that these legal arrangements will operate as anticipated in the event of a dispute between Oando and OER.

OER has relied on financial support from Oando and there can be no assurance that such support will continue in the future

Oando is a promoter of OER and has invested substantially in the business of OER prior to the Arrangement. OER remains substantially dependent on Oando for financing and the provision of guarantees and Oando intends to invest further in the business through the Oando Loan Conversion. There is no assurance that Oando will continue to support OER in the future, including through the provision of guarantees in support of OER's obligations. Investors should not rely on the historical support of Oando or its present or future equity holdings in OER as an indication or guarantee of Oando's future support of, or equity holdings in, OER.

OER is a leveraged business

Upon completion of the COP Acquisition, OER will have substantial debt through a variety of different loans. OER will be subject to certain financial and other restrictive covenants under the terms of its indebtedness that may limit its ability to borrow or otherwise restrict the manner in which it operates. OER's ability to meet these financial covenants and certain financial tests under the terms of its indebtedness may be affected by events beyond OER's control. OER's management cannot give any assurance that OER will be able to satisfy these covenants or meet these tests. A failure to meet such covenants or tests could lead to default under the applicable loans and severely impair the financial condition or prospects of OER. Further, OER's substantial indebtedness could increase its vulnerability to general adverse economic and industry conditions, limit its flexibility in planning for, or reacting to, changes in its business and place it at a competitive disadvantage compared to its competitors that have less debt.

OER relies on key personnel and Oando

OER has experienced rapid expansion and expects this to continue. OER's success is dependent on the ability of its management to operate the growing business and to manage the ongoing changes resulting from accelerated expansion and potential future acquisitions. OER is particularly dependent upon certain of its executive officers, directors and key employees, including OER's Chairman, Mr. Jubril Tinubu, its CEO, Mr. Olapade Durotoye and Mr. Omamofe Boyo, a director. The unexpected loss of their services could have a material adverse effect on the operating results, financial condition or prospects of OER. In addition, OER has entered into a Cooperation and Services Agreement with Oando whereby Oando has agreed to provide certain key services to OER. The non-performance by Oando of any of these services could adversely affect the operating results, financial condition or prospects of OER.

OER's management reporting systems may be insufficient

The Board of Directors is dependent upon management for reporting purposes. Reporting may be hampered by distance and communication, as OER's assets, operations and executive management are located in Nigeria, while certain of the non-executive directors of OER are located in Canada and others are located in Europe. A failure of management to report to the Board of Directors, a delay in reporting, or inaccurate reporting could lead the Board of Directors to omit to take decisions or to take decisions without being informed or fully-informed, any of which could result in a material adverse effect on the operating results, financial condition or prospects of OER.

OER's internal controls and procedures may be insufficient to provide reliable financial reports, prevent fraud and ensure compliance with its anti-bribery and anti-corruption requirements

Effective internal controls are necessary for OER to provide reliable financial reports, make timely disclosure of material information and help prevent fraud. Although OER has undertaken a number of procedures in order to provide assurances as to the reliability of its financial reports and ability to comply with timely disclosure requirements, including those required under Canadian securities laws, OER cannot be certain that such measures will ensure that OER will maintain adequate control over financial processes and reporting or enable it to prevent fraud and ensure compliance with anti-bribery and anti-corruption requirements. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm OER's results of operations or cause it to fail to meet its reporting obligations. If OER or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in OER's consolidated financial statements and adversely affect the trading price of the Common Shares.

Applicable anti-bribery and anti-corruption laws prohibit companies and their intermediaries from making improper payments to government officials or other persons for the purpose of obtaining or retaining business. Recent years have seen a substantial increase in anti-bribery and anti-corruption law enforcement activity, with more frequent and aggressive investigations and enforcement proceedings by regulators, and increases in criminal and civil proceedings brought against companies and individuals. While OER's policies mandate compliance with these anti-bribery and anti-corruption laws, OER operates in jurisdictions that are recognized as having elevated governmental and commercial corruption levels and, in certain circumstances, strict compliance with anti-bribery and anti-corruption laws may conflict with local customs and practices.

OER's ability to comply with anti-bribery and anti-corruption laws is dependent on the success of its ongoing compliance program, including its ability to continue to manage its agents and business partners, and supervise, train and retain competent employees. OER cannot guarantee that its internal controls will always protect it from reckless or criminal acts committed by its employees or third party intermediaries. In the event that OER believes or has reason to believe that its employees or agents have or may have violated applicable anti-bribery and anti-corruption laws, OER may be required to investigate or have outside counsel investigate the relevant facts and circumstances, which can be expensive and require significant time and attention from senior management. Violations of these laws may result in significant criminal or civil sanctions, which could disrupt OER's business and result in material adverse effect on the operating results, financial condition or prospects of OER.

OER may not be able to finance future activities

OER may require additional financing for the development of its existing and to-be-acquired assets, including those assets acquired as part of the COP Acquisition. Investments in facilities, infrastructure, technology and other capital expenditures to generate, improve, maintain or preserve revenues will require significant capital, which OER may be unable to finance on acceptable terms, or at all. OER's ability to arrange such financing will depend in part upon prevailing financing market conditions, as well as OER's business performance. If OER's revenues or reserves decline, for example, it may not be able to raise additional funds or have the capital necessary to undertake or complete future drilling programs or acquisitions. If OER is unable to finance such expenditures then OER may be required to downsize, curtail or abandon certain projects, which could adversely affect the operating results, financial condition or prospects of OER.

OER may have unplanned or forced cash expenditures

OER is required, in certain circumstances, to make cash payments to third parties upon the occurrence of certain contingent events. OER could have unplanned capital expenditures related to natural disasters, capital expenditure overruns or other causes. Other known or unknown expenditures may arise, the timing of which may be uncertain and the budgeting for which may be difficult. As well, OER is a party to various agreements that may compel expenditures pending a permitted withdrawal. Withdrawals may not be permitted at all, until certain trigger events, such as a final investment decision. OER may or may not have the requisite funds to make such payments, when due, the failure of which could adversely affect the operating results, financial condition or prospects of OER.

OER's strategy of expansion through organic growth and acquisition may not be successful

OER's growth strategy contemplates the continued acquisition of additional oil and gas assets, including those assets anticipated to be acquired as part of the COP Acquisition. OER will require substantially greater financial, managerial, and other resources to manage its business following the COP Acquisition and may require additional resources following any other acquisition of assets. There can be no assurance that such resources will be available on terms satisfactory to OER, if at all. In addition, there can be no assurance that OER will effectively integrate the any acquired assets or business into its own business, successfully manage its business following the COP Acquisition or operate any such assets as successfully or profitably as the prior owner. The failure to achieve success with any of the foregoing could adversely affect the operating results, financial condition or prospects of OER.

There can be no certainty that additional assets will be available at attractive or financeable purchase prices to enable OER to continue its expansion strategy. In addition, there can be no assurance that any such asset acquired by OER will prove accretive or become productive in the manner and to the extent contemplated, if at all, or that anticipated benefits to be achieved through operational integration will be realized. The integration of acquired businesses may prove more difficult and/or expensive than anticipated, thereby rendering the value of any company or assets acquired less than the amount paid. Integration of new businesses can be difficult because OER's operational and business culture may differ from the cultures of the businesses it acquires and unpopular cost-cutting measures may be required. To the extent that OER identifies assets to acquire outside of Nigeria, further risk may accrue to OER, since OER's activities have principally been based in Nigeria. The failure to secure additional assets, or properly integrate such assets, or obtain expected benefits from such assets, could adversely affect the operating results, financial condition or prospects of OER.

Although OER has performed due diligence on the assets acquired pursuant to the COP Acquisition and would anticipate performing due diligence investigations of any future assets that are proposed to be acquired, such investigations are inherently incomplete. In particular, it is generally not feasible to review in-depth every individual asset involved in complex acquisitions and the investigation of minority interests in the oil and gas industry can be frustrated or impeded by a lack of direct access to information, including site inspections. Even an in-depth investigation 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. The failure to perform adequate due diligence on assets to be acquired, or the inability to do so, could adversely affect the operating results, financial condition or prospects of OER.

OER's ability to manage growth, whether organic or through acquisition, will depend on OER's ability to (i) develop efficient and integrated managerial and support systems, (ii) standardize technology and operational development, (iii) control costs, (iv) maintain effective quality controls while expanding OER's internal information, accounting and management systems, (v) attract, assimilate and retain additional qualified personnel and (vi) monitor operations effectively. If OER is unable to achieve these necessary measures, OER may not be able to successfully manage any assets or businesses acquired. OER can provide no assurance that it will be able to successfully implement these measures at a pace consistent with OER's requirements, which could have a material adverse effect on the operating results, financial condition and prospects of OER.

OER may not continue to benefit from certain international treaty protections

OER has been structured with the goal of providing OER with certain protections under the Netherlands/Nigeria BIT. The Netherlands/Nigeria BIT applies to Dutch nationals (both natural and legal persons) and to those companies controlled by them (including direct and indirect shareholdings). As such, OER believes that each of the Netherlands entities through which OER holds its Nigerian assets should be afforded the protections of the Netherlands/Nigeria BIT. One of the main protections under the treaty is compensation in the event of expropriation. Nevertheless, there is no guarantee that the Netherlands/Nigeria BIT will not be revoked or that the protections under the treaty will be afforded to OER, which could adversely affect the operating results, financial condition or prospects of OER.

OER may be adversely impacted by "risk off" investment behaviour

Nigeria, as an emerging market, is susceptible to "risk off" investment behaviour, when, during certain periods of economic uncertainty, including times marked by reduced levels of investor confidence, investors are unwilling to invest at all or only willing to invest on terms unfavourable to issuers. As an emerging market, Nigeria is also susceptible to rapid country-specific risk adjustments owing to events that have taken place, such as uncertain election contests, violence, or other circumstances. During periods of dampened foreign investment, Nigeria's economy could be affected and the withdrawal of foreign funding sources could cause a liquidity crisis. In such circumstances, OER may be subject to constraints on accessing foreign currency, the withdrawal of capital, a reduction in available credit or an increase in the cost of debt (through, for example, a decrease in credit rating), any of which could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER may become involved in litigation which could materially impact its business

From time to time, OER may be subject to litigation arising out of its operations and, at present, has ongoing litigation with several parties, including the NNPC. See "*Legal Proceedings and Regulatory Action* ". While OER intends to continue to assess the merits of each lawsuit and expects OER to defend itself or assert its rights accordingly, OER may be required to incur significant expenses or devote significant resources to defending itself against or advancing certain litigation. Adverse publicity surrounding any litigation, such as environmental or community litigation, may give rise to adverse perceptions as to the manner in which OER operates. In certain circumstances, OER may also determine that it is imprudent to pursue litigation against certain parties, such as communities, militants, non-governmental organizations or government agencies, owing to the potential adverse publicity or political repercussions of any such action. The failure to pursue any such litigation, or adverse finding resulting from any litigation, may materially affect the operating results, financial condition or prospects of OER.

The development of alternative sources of energy could adversely affect OER

OER's interests are currently restricted to oil and gas assets. The successful research into, development and commercialization of alternative sources of energy may lead to a decrease in the demand for oil and gas which could have a material adverse effect on the operating results, financial condition or prospects of OER.

Risks Related to the COP Acquisition

The COP Acquisition may not be completed

The completion of the COP Acquisition is conditional upon satisfaction of various conditions, including the conditions regarding the receipt of all approvals and or consents required from any governmental authority under applicable petroleum laws of Nigeria. There can be no assurance that the parties will be able to obtain the necessary consents and approvals on a timely basis, or at all. The outside date for completion of the COP Acquisition is April 30, 2014. If the conditions precedent to closing of the COP Acquisition are not satisfied or waived prior to such date a further amendment to the Acquisition will be required to extend the outside closing date. If completion of the COP Acquisition does not take place as contemplated, or the parties do not mutually agree to extend the outside closing date, the Acquisition Agreements may be terminated and the COP Acquisition may not be completed. Failure to complete the COP Acquisition will result in OER forfeiting its deposit and not receiving any benefits from the expenditure of management time, money, other internal resources devoted to the COP Acquisition. In addition, the loss of opportunities and benefits expected to be derived from the COP Acquisition could have a material adverse effect on the operating results, financial condition and prospects of OER.

OER will assume obligations and liabilities as a result of the COP Acquisition

Under the COP Acquisition, OER generally has accepted responsibility for all risks and liabilities relating to the COP Nigerian Business, including environmental liabilities (whether incurred before or after completion of the COP Acquisition), and has agreed to indemnify and hold COP harmless in relation to such liabilities. The extent of the liabilities to which OER may be exposed from past operations is inherently uncertain. OER will inherit all of COP's decommissioning liabilities, including costs associated with, for example, abandoning and plugging wells, facilities and pipelines and decommissioning infrastructure used in the COP Nigerian Business. Any reserve established in respect of such costs may prove inadequate for its purpose, or any cost that arises in respect of unforeseen liabilities, could adversely affect the operating results, financial condition or prospects of OER.

OER may be required to assume pre-closing liabilities with respect to future acquisitions, including environmental liabilities, and may acquire interests in properties on an "as is" basis.

The COP Nigerian Business is highly dependent on the Brass River Terminal for the export of its oil

The COP Nigerian Business is highly dependent upon the Brass River Terminal. Historically, the Brass River Terminal has been the subject of numerous acts of sabotage and, in the past decade, has declared force majeure several times. In one such incident, the Brass River Terminal lost the use of one of its two moorings. The loss of use of its remaining mooring, whether as a result of sabotage or otherwise, or any other interruption to the normal operation of Brass River Terminal, could have a material adverse effect on the operating results, financial condition or prospects of the COP Nigerian Business.

The COP Nigerian Business is highly dependent on the Bonny LNG plant for the sale of its gas

The COP Nigerian Business is highly dependent upon the Bonny LNG plant as a market for its gas sales. Recently, the Bonny LNG plant was the subject of a blockade by the Nigerian Maritime Administration and Safety Agency, which prevented LNG tankers from accessing the company's loading terminal on Bonny Island in the Niger Delta region. The blockade was the result of a long-running dispute over the payment of duties on freight and exports and led NLNG to declare force majeure to its gas suppliers. Without the ability to transport gas to the Bonny LNG plant, The COP Nigerian Business was forced to reduce production from OMLs 60 and 61. OER can give no assurance that NLNG will operate at capacity or avoid events of force majeure in the future, which could have a material adverse effect on the operating results, financial condition or prospects of the COP Nigerian Business.

Risks Related to Carrying on Business in Nigeria

Nigeria has proposed sweeping changes to its fiscal terms pursuant to the PIB and is subject to significant ongoing change

The Nigerian Government regulates fiscal and tax laws and social policies pertaining to the oil and gas industry through various means, including royalty payments, export taxes, surcharges, value added taxes, production bonuses and other charges. While many aspects of these laws and policies may be modified (or stabilized) in PSCs, there can be no assurance that they will not be changed in the future (or that PSCs will continue to be negotiated so as to mitigate their impact) and any such change or inability or failure to mitigate such change could adversely affect the operating results, financial condition or prospects of OER.

More specifically, Nigeria has proposed sweeping changes to its oil industry fiscal terms pursuant to the draft PIB. The PIB would increase the Nigerian Government take of oil revenue under new PSCs and effect many other changes that industry would consider less advantageous than those under present circumstances. In addition, the PIB, as presently drafted, would not confer advantageous fiscal terms to holders of Marginal Fields under the Marginal Field Development Program. While there is no certainty as to the final form that the PIB will take, nor when it will be passed, any such legislation could have a material adverse effect on the operating results, financial condition or prospects of OER. See "*The Nigerian Oil and Gas Industry and Regulatory Framework – Petroleum Industry – Petroleum Industry Bill*".

Nigeria has experienced significant political instability, ethnic issues, and regionalism since its independence

Nigeria obtained political independence from the United Kingdom on October 1, 1960 and became a federal republic in 1963. From its first military coup d'état on January 15, 1966, Nigeria experienced a long period of military rule and political instability. Since the adoption of a new presidential constitution in May 1999, however, Nigeria has experienced relative stability. In April 2007, the late Umaru Musa Yar'Adua was elected President, marking the first time that one democratically elected government had handed over power to another in Nigeria. President Yar'Adua died on May 5, 2010 and was succeeded by his Vice President, Goodluck Jonathan, who was thereafter elected as President in general elections conducted in April 2011.

Although the 2011 elections were reported to have been conducted peacefully and credibly, prior to the final announcement of the result, post-election violence and riots occurred in certain cities of some of the northern states (Kaduna, Gombe, Bauchi, Kano, Adamawa, Zaria and some parts of the Federal Capital Territory). The violence was reportedly as a result of dissatisfaction with the results by supporters of an opposition party, who believed that the results declared in those states did not reflect the perceived widespread support for their candidate. Nevertheless, the Nigerian Independent National Electoral Commission and international observers upheld the elections as being well-conducted and the commission formally announced the incumbent President Goodluck Jonathan as the winner with a majority of total votes cast.

The ownership and control of minerals at the federal level has provoked regional conflict, as the oil producing areas claim, among other things, compensation for environmental degradation. In addition, recently Nigeria witnessed substantial civil unrest in connection with its attempt to remove fuel subsidies. Often, conflicts have been triggered by religious and ethnic differences. There are over 250 different languages spoken in Nigeria and a similar number of distinct ethnic groups. Nigeria's political parties continue to be based largely upon ethnic allegiance. At the same time, these divisions are reinforced by religious differences, particularly between the mainly Muslim north and broadly Christian south. Certain northern states have adopted Shari'a law since the return to civilian rule in 1999, which resulted in alienation of Christian minorities. Recently, there have been attacks across the northern parts of Nigeria, some of which have been attributable to an Islamist group called Boko Haram, which seeks the imposition of Shari'a law throughout Nigeria. To date, none of these attacks have occurred in areas where OER's assets are located, however, the level of violence can be substantial, such as in July 2012 when the group claimed responsibility for attacks that killed more than 65 people in central Nigeria. In February and March 2014, attacks in the north-eastern part of Nigeria resulted in increasing death tolls and loss of property.

In an effort to ameliorate regional tensions, the Nigerian Government increased the amount of government oil revenue returned to the oil producing states from 3% to 13% in 2000. Opposition from the northern states to this

revenue-sharing formula resulted in the restriction of the application of the formula to the littoral boundaries of the coastal states that comprise the prolific Niger Delta region, down from 200 to 24 nautical miles. The Nigerian Government then enacted the Allocation of Revenue (Abolition of Dichotomy in the Application of the Principle of Derivation) Act 2004 that set the limit of the 13% revenue allocation to waters up to 200 m in depth. However, Niger Delta states still frequently question the existing formula. Unless resolved by the Nigerian Government, these conflicts, whether provoked by disagreements regarding the spread of oil revenue, or ethnic or religious differences, may adversely affect the stability of the country.

OER, and its controlling parent, Oando, are organisations that are owned, managed and staffed predominantly with Nigerian citizens, including community and social responsibility professionals. Many have connections to families and other residents within the Niger Delta and OER makes use of such connections in facilitating information flow as to current and changing community attitudes towards OER and the oil industry more generally. OER has adopted programs aimed at resolving particular issues within a local community in order to enhance goodwill and mitigate its risks of operating within the Niger Delta. OER has entered into agreements, through OER's joint venture partners, with local communities at Ebendo, Qua Ibo and Akepo. There can be no assurances, however, that OER's status or efforts at community outreach will prevent criminal activity or violence from having a material adverse effect on the operating results, financial condition or prospects of OER.

Nigeria experiences high incidence of oil theft and piracy

Illegal bunkering refers to the theft and trade of stolen oil. Theft may occur on a small scale at a local level or as part of wider organized crime. Illegal bunkering in Nigeria occurs through a variety of different means, including by using small cargo canoes that navigate the shallow waters of the Niger Delta where pipelines are punctured to siphon oil into small tanks, stealing crude directly from the wellhead or filling tankers at export terminals. Incidents of sabotage often involve environmental damage associated with leakage and spills.

OER experiences oil production losses due to illegal bunkering (theft) and sabotage activities, which are particularly problematic in respect of Ebendo. Most of the illegal bunkering has occurred from the oil pipelines located in the swamp area which is subject to security challenges. Sabotage occurs to a greater or lesser extent across the entire onshore network. There is a wide range of uncertainty in the estimated losses because of inaccuracies arising from metering systems and production allocations.

Current and future losses due to theft and sabotage have been accounted for by Petrenel in estimating OER's reserves and contingent resources. Estimates of illegal bunkering and sabotage losses are based on information pertaining to the difference between the reported well potential and actual sales. There is considerable uncertainty in estimated losses since oil production leaving the gathering stations is not accurately metered and calculations of loss based on the difference between well potential and sales are capable of being overestimated as they do not take into account some downtime, capacity restrictions, shrinkage, own consumption, leakage and uncertainties in well potential. Given the uncertainties as to the quantities of oil illegally bunkered, estimated future losses have been based on actual losses charged for prior periods. OER will be required to make ongoing adjustments to its reserves, resources or NPV estimates as a result of illegal bunkering or a better understanding of the extent of such bunkering on OER's Licenses, any of which could have a material adverse effect on the operating results, financial condition or prospects of OER. As well, if losses due to theft have been over-estimated, the ability to increase sales through efforts to mitigate such losses may not prove as effective as contemplated, which could have a material adverse effect on the operating results, financial condition or prospects of OER.

There is no certainty that illegal bunkering will not continue or even increase in the future, nor that illegal bunkering has been (historically) or will be (in the future) properly measured.

In addition to illegal bunkering, there have been increased incidents of piracy in the Gulf of Guinea, which pose a risk to deep-water offshore oil operations. Piracy attacks typically target high value cargo and has become more frequent and at greater distances from the coast. Certain of OER's deep water assets have been subjected to piracy and there can be no assurance that they will not be attacked in the future.

OER has interests in the Niger Delta, which is an area of Nigeria with significant security risks

Since late 2005, Nigeria has experienced increased pipeline vandalism, kidnappings of oil workers, and militant takeovers of oil facilities in the Niger Delta. MEND is a particularly active group attacking oil infrastructure for political objectives, as it claims to seek a redistribution of oil wealth and greater local control of the sector. Additionally, kidnappings of oil workers for ransom are common and security concerns have led some oil services firms to pull out of the country and oil workers' unions to threaten strikes over security issues. There have been persistent attacks by MEND since August 2011, despite the Nigerian Government's amnesty to fighters granted in late 2009 and the prior MEND ceasefire. In February 2012, MEND threatened to renew attacks on major oil and gas assets in the Niger Delta and subsequently followed through with oil pipeline attacks. The instability in the Niger Delta has also caused significant amounts of shut-in production at onshore and shallow offshore fields, and forced several companies to declare force majeure on oil shipments. In many cases, OER has little or no control over these infrastructure assets. Any damage or disruption to their use could have a material adverse effect on the operating results, financial condition or prospects of OER.

The Nigerian Government has significant influence over, and dependency upon, Nigeria's oil and gas industry

The federal government's ownership of Nigeria's mineral wealth is reinforced by an array of laws and regulations, including the Petroleum Act, which gives the Ministry of Petroleum Resources the authority to issue Licenses and approve to a great extent the ownership, operatorship and holding of interests of Licenses. In addition, the NNPC is a government-controlled corporation that directly participates in joint ventures in the exploration and production of hydrocarbon reserves and, itself, facilitates participation in the industry. As a consequence, the Nigerian Government plays a key role in determining the extent to which a given competitor, including OER, participates in the Nigerian crude oil and natural gas industry. There can be no assurance that OER will benefit from the support of the Nigerian Government, which could adversely affect the operating results, financial condition or prospects of OER.

According to the International Monetary Fund, oil accounted for over 90% of Nigeria's exports in 2011, while earnings and oil revenue was ₦7,823 billion, which was 76.5% of the total (₦10,226 billion) consolidated government revenue. (Source: IMF Country Report, July 2012.) Higher oil prices helped shrink the overall Nigerian fiscal deficit from 7.7% of GDP in 2010 to approximately 0.2% of GDP in 2011. Historically, some of this revenue has been used to subsidise gasoline prices. On January 1, 2012, an effort to eliminate the subsidy led to a greater than 100% increase in the pump price from approximately ₦65 to ₦141 per litre, as well as national strikes and public protests. Two weeks later, a partial subsidy was reintroduced so as to balance prices around the ₦97 level. These facts demonstrate the interdependency between the oil industry and the Nigerian Government and the potential for civil unrest if governmental revenues from oil production were to fall dramatically. There can be no assurance that, in such event, the Nigerian Government would not seek to expropriate or nationalize assets or alter the payments, taxes and other charges imposed upon OER, which could adversely affect the operating results, financial condition or prospects of OER.

Nigeria's infrastructure is in a poor state of development and/or deterioration and there are numerous interruptions to power and communication systems

The state of Nigerian infrastructure falls considerably below the standard of more developed countries. For example, Nigerian roads are in a poor state of repair. Furthermore, the Nigerian power sector has numerous problems, such as limited access to infrastructure, low connection rates, inadequate power generation capacity, lack of capital for investment, insufficient transmission and distribution facilities, high technical losses and vandalism. This lack of infrastructure could have a material adverse effect on the operating results, financial condition or prospects of OER.

The interpretation and application of laws and contracts is uncertain in Nigeria

Due to insufficient manpower and the significant volume of cases before the law courts, there could be significant delays in the administration of the judicial system. In addition, the Nigerian judicial system faces other challenges such as the promulgation of inconsistent laws, regulations and policies (including delays in judicial interpretations thereof), the inability to effectively enforce judgments, a higher level of discretion on the part of governmental authorities and therefore less certainty, and other such problems. There can also be inconsistency in the

administration and interpretation of contracts, joint ventures, licenses, license applications and other legal arrangements.

Therefore, there can be no assurance that contracts, joint ventures, licenses, license 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. Errors may be due to incompetence, differences of opinion on interpretive matters or wilful actions aimed at bolstering government revenues from oil production. OER can provide no assurance that it will not be the subject of such actions or measures, which could negatively impact the operating results, financial condition or prospects of OER.

Nigeria is a jurisdiction with inherent risks of administrative errors, fraud, bribery and corruption

Nigeria is a developing economy with a vast hydrocarbon resource that is managed by a range of parastatal and governmental agencies. The potential for error in the administration of laws, regulations and policies is substantial and errors often do occur. As well, Nigeria is also not immune from government and business corruption and other criminal activity, which is very high on a comparative global basis. The Nigerian Government has indicated that it takes such activity seriously and has been conducting an ongoing corruption investigation into the oil industry in Nigeria.

In 2012, the federal Nigerian Government set up the Petroleum Revenue Special Task Force headed by a well-known anti-corruption crusader, Mallam Nuhu Ribadu to thoroughly examine the systematic issues giving rise to corruption in the Nigerian oil and gas sector. The committee completed its investigations and submitted a report to the Nigerian Government. The Nigerian Government recently ordered a forensic audit of the NNPC's accounts and has sought to make the oil industry more transparent. The Nigerian Government also inaugurated the Petroleum Revenue Special Task Force, a body set up primarily to investigate, verify and recover all upstream and downstream petroleum revenues accruing and payable to the Nigerian Government. This task force is also charged with the responsibility of developing a system to determine and monitor all oil production and exports in and from Nigeria.

In addition to other applicable anti-corruption legislation, OER is subject to the *Corruption of Foreign Public Officials Act* (Canada), which has recently been amended so as to pass legislation aimed at phasing out "facilitation payments" (i.e., a payment made to a government official to perform an existing duty) and confer clear authority over Canadian companies that have engaged in bribery and other corrupt activities outside of Canada.

OER is not aware of any current investigations specific to its assets or any adverse findings against it, its directors, officers, employees or joint venture partners. Nevertheless, OER and its officers, directors and employees have been, and may in the future be, the subject of press speculation, government investigations and other accusations of corrupt practices or illegal activities, including improper payments to individuals of influence. Findings against OER, its directors, officers, employees, or its joint venture partners, suppliers or customers in corruption or other illegal activity could result in criminal or civil penalties, including substantial monetary fines and penalties, against OER and its directors, officers or employees. In addition any investigation or press speculation with respect to illegal activity could significantly damage OER's reputation, ability to do business or raise financing or jeaopardize its existing assets, including its PSCs, and its personnel, thereby materially adversely affecting its operating results, financial condition or prospects.

OER's Code of Business Conduct and Ethics, its Anti-Corruption and Anti-Bribery Policy, and its Gifts and Benefit Policies mandate strict compliance with applicable laws and prohibit corrupt payments to government officials, businesses and business persons. There can be no assurance, however, that such internal policies and procedures have been or will be adhered to by its directors, officers or employees, nor that its joint venture partners, suppliers or customers will not be in breach of such policies.

The Niger Delta can experience severe flooding that may affect OER's operations

Flooding is a particular problem in the Niger Delta, which experienced one of the worst floods on record in 2012. As a result, substantial damage was inflicted upon roads, bridges, pipelines and communities areas. Such occurrences not only result in the loss of production, but also in the displacement of local populations, the loss of employment

and the inability to reach communities to lend meaningful support. Oil theft and other losses may increase during these periods, as local populations resort to alternative means to support their families. In turn, sabotage during periods of flooding may bring increased environmental damage, along with pollution settlements. Any of the foregoing could have a material adverse effect on the operating results, financial condition or prospects of OER.

Risks Relating to OER's Operations

OER may continue to be impacted by overlifting on the part of the NNPC

OER is involved in arbitration proceedings concerning OML 125, which relates to the overlifting of oil by the NNPC. The dispute concerns the manner in which cost oil and profit oil has been computed, allocated and administered under the relevant PSC since 2006. As at January 2010, the value of the NNPC overlift was estimated to be $385 million (or $57.75 million net to OER) and OER believes that the value of the overlifting is now in excess of $497 million. While any funds recovered from the NNPC and pertaining to the period up to the date of the Arrangement will be paid over by OER to Oando, there can be no assurance that the NNPC will not continue to overlift its share of oil from OML 125.

In this regard, the NNPC's practice has been to issue 'nomination letters' wherein it indicates its intention to lift available crude oil (without regard to the lifting program prepared by Eni, as operator). Prior to, or soon after sending such 'nomination letters', the NNPC agrees in the market to sell the cargo to a particular buyer. For this reason, and due to the need for liftings to be cleared and approved in advance by various governmental agencies, including the Nigerian Navy, the DPR and the Nigerian Ports Authority (which consult with and/or seek the approval of the NNPC), Eni, as operator, is unable to prevent the NNPC from overlifting. There can be no assurance that the NNPC will not continue to overlift from OML 125, or overlift from other producing Licenses, which could have an adverse impact on the operating results, financial condition or prospects of OER. See "*Legal Proceedings and Regulatory Action*".

OER is highly dependent upon its partners and, in particular, Eni and the NNPC

OER is dependent upon cash flow from assets in which it is not the operator. It is likely that OER's future cash flow will also be highly dependent upon non-operated assets. This lack of control may impede OER's ability to affect decisions taken by operators that impair, reduce, terminate or otherwise adversely affect cash flow to OER, as well as decisions concerning the exploration, development or production of or from such assets. OER is also dependent upon the performance of other participants or joint venturers in many instances, such as obligations to obtain insurance protecting the joint venturers from losses arising from operations. OER may incur additional costs or suffer losses if a participant or joint venture partner does not meet its obligations, including but not limited to funding obligations.

Further, OER cannot guarantee the active participation by its joint venture partners in decision making processes required pursuant to the relevant joint venture agreements, leading to potential project delays where a joint venture partner's approval is outstanding. It is also possible that the interests of OER and those of its partners may not be aligned, which may result in project delays, additional costs or disagreements. In the event that any of OER's 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 which may then reallocate the License. The occurrence of any of the above could have a material adverse effect on the operating results, financial condition or prospects of OER.

A substantial portion of OER's production, revenue and cash flow is dependent upon the NAOC JV, which is governed by a JOA with Eni and the NNPC. The JOA for the NAOC JV requires unanimity from all joint venture participants in order to approve work programs and budgets. The failure of either Eni or the NNPC to approve work programs and budgets, or to approve certain types of activities or expenditures under a work program and budget, whether due to a lack of funding or otherwise, or the inability or refusal of Eni or the NNPC to compromise in the interests of the NAOC JV, could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER cannot guarantee that its joint venture partners will comply with applicable law. Any violations of law, and the resulting fines, penalties and other sanctions, could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER may be unable to deduct certain expenses in the calculation of PPT or other tax computations

OER may be unable to deduct certain anticipated expenses in the calculation of PPT or other tax computations. For example, OER expects OER to benefit from the deductibility of interest on inter-company loans and the deductibility of technical and management services provided to such companies in the calculation of PPT. Nevertheless, FIRS has, in some instances, argued against the deductibility of interest on loans from related parties. In addition, the PIB would preclude the deduction of such interest payments in the calculation of PPT. There can be no assurance that OER will benefit from such deductions, which could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER may not benefit from the fiscal terms under the Marginal Field Development Program

The special terms outlined by the Ministry of Petroleum Resources in relation to Marginal Fields has been documented in a letter to the Marginal Field Operators' Corporations (of which OEPL and Akepo are members). The letter purports to indicate that the production of oil from Marginal Fields would be taxed at 55%, even though the law provides for a higher rate. While OER expects the law to be changed in order to support the position of the Ministry of Petroleum Resources, there can be no assurance that the law will be changed and any failure to make such change, or any alternative legal position that may arise in the future, could have a material adverse effect on the operating results, financial condition or prospects of OER.

A substantial portion of OER's reserves and production are concentrated in one geographic location

Virtually all of OER's assets are located in Nigeria. In addition, for the 12 months ended December 31, 2013, 100% of OER's production was derived from OML 125 and Ebendo, which are located in the central Niger Delta in close proximity to one another. The central Niger Delta is a location of instability, militancy, illegal bunkering, sabotage and community unrest. Any event that might reduce, shut-in or otherwise negatively affect production from these Licenses could have a material adverse effect on the operating results, financial condition or prospects of OER.

The Nigerian Government and third parties may cease treating OER as an indigenous company

OER has been structured with the aim of benefitting from Oando's indigenous status. Management believes that this status will aid OER in being treated as a preferred bidder for new Licenses and/or IOC farm-in opportunities and obtaining certain advantages contemplated under the PIB for Nigerian companies. In aid of conferring such status upon OER, Oando holds the Class A Shares in the Operating Associates. Although the structure has been considered with appropriate legal, tax and other advice, there can be no assurance that these legal arrangements will be interpreted in the manner anticipated, or that OER will have the power or ability to maintain the structure.

In particular, there can be no assurance that relevant authorities or IOCs will treat OER as an indigenous company, or that applicable laws, regulations or policies concerning indigenous preferences will not be changed in the future. As well, OER's structure is dependent upon Oando continuing to hold the Class A Shares in the Operating Associates and, itself, being considered "indigenous". It might prove difficult for OER to invoke its power to re-transfer the Class A Shares to an indigenous company, or to find such a company willing to take ownership of the Class A Shares, at all, or on terms considered commercially reasonable by OER. Any such failing or change could result in the loss of Licenses and otherwise have a material adverse effect on the operating results, financial condition or prospects of OER.

Obligation to supply gas to local domestic market may impede profitability

OER is under an obligation to supply a certain quantity of gas to the local Nigerian market at a specified price (under its DSO obligation). Whilst the enforcement of DSO obligations are presently suspended pending the creation of a regulatory authority, the future price and "free" quantities of gas may be reduced, curtailed or

otherwise regulated through DSO regulations. Any such regulations may have a material adverse effect on the operating results, financial condition or prospects of OER.

OER may not be granted the government approvals it requires to operate

OER depends upon governmental Licenses, permits and other approvals in order to acquire, develop and operate its business and assets. These approvals are, as a practical matter, subject to substantial discretion on the part of the Nigerian Government. It is not uncommon to experience lengthy delays in obtaining approvals, which can lead to considerable uncertainty as to the ownership of assets, operatorship, the ability to recover expenditures and other uncertainties. The approval process can be opaque and open to interpretation. OER is awaiting Nigerian Government approval in respect of the transfer of the Akepo and Qua Ibo Licenses, which are held under either a trust arrangement or an economic participation agreement pending approval. Two additional Licenses, OPLs 321 and 323, require certain Nigerian Governmental approvals or resolutions with third parties in order to permit continued exploration activities. In addition, Nigerian Governmental approvals or consents are required in connection with the completion of the COP Acquisition. There is no certainty that approval will be given when needed, which could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER may not be granted consents to disclose information required by it to operate effectively

OER will have obligations imposed upon it to treat certain types of information, such as technical and commercial information in respect of its Licenses, confidential under existing and future agreements. Such agreements are common within the petroleum industry and not all of them permit disclosure to third parties when required for operational or corporate purposes. As a result, OER might be deprived of the ability to seek expert analysis of technical information or be restricted from making public disclosure of material commercial matters. The failure to secure consents from relevant third parties in such circumstances may expose OER to, among other matters, the risk of legal proceedings, a breach of securities laws or a delisting application for failing to comply with stock exchange rules. There can be no assurance that OER will secure all such consents, when needed, or avoid any such consequences, which could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER's title to its Licenses may be challenged or defective

The acquisition of title to hydrocarbon properties in Nigeria is a very detailed and time-consuming process. Failure to make certain payments and take certain actions required to keep Licenses in good standing may result in the loss of such Licenses. Title to, and the area of, hydrocarbon rights may be disputed and subject to challenge and revocation, including because of defects or irregularities in the chain of title. In addition, OER's Licenses may be subject to prior unregistered applications, agreements of transfer or land claims of which OER is currently unaware, and title may be affected by latent defects. There is no guarantee that a latent defect in title, changes in laws or in their interpretation or political events will not arise to defeat or impair the claim of OER to its Licenses, which could result in a material adverse effect on the operating results, financial condition or prospects of OER.

OER's reserves and resources data may not be accurate

Crude oil, natural gas and NGL reserves and resources data are estimates only. Such data represents estimates of underground accumulations of oil, gas and NGL that cannot be measured in an exact manner. They are calculated, along with estimates of cash flows derived therefrom, based upon many variables and assumptions, including, among others, the future price of oil, gas and NGL, the interpretation of geological and geophysical data, assumptions concerning the future performance of wells and surface facilities, assumptions concerning capital expenditures and development plans, assumed effects of regulations, and assumptions concerning future prices and costs. These variables and assumptions are subject to change. The assumptions upon which the estimates of OER's oil, gas and NGL reserves and resources have been based may prove to be incorrect and OER may be unable to recover and produce the estimated levels or quality of oil, gas and other hydrocarbons. Additional risks relating to the estimate of reserves and resources are set out in the Petrenel Report and the Schedules to this AIF.

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 result in substantial upward or downward revisions to OER's reserves or resources data. Moreover, different reservoir engineers may make different estimates of reserves 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. Changes in the price of oil, gas and NGL may also materially and adversely affect the estimates of OER's proved and probable reserves because the reserves are evaluated based on prices and costs as at the appraisal date.

Substantial uncertainties exist with respect to the estimation of contingent resources in addition to those set forth above that apply to reserves. Contingent resources are defined as those quantities of petroleum that are estimated, as at a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but that are not currently considered commercially recoverable due to one or more contingencies. The contingent resource estimates presented in this AIF are estimates only and should not be construed as being exact quantities. Such contingencies or other factors may prevent the recovery of all or some of such resources and there is no certainty that it will be commercially viable to produce any portion of such resources.

OER is dependent upon the continued replacement and growth of proved, probable and possible reserves. The proved, probable and possible reserves in existing fields in which OER has an interest will decline as it extracts and depletes oil, gas and NGL. As well, the volume of production of oil, gas and NGL generally will decline as reserves are depleted. OER's future production depends significantly upon its success in finding or acquiring and developing additional reserves. If OER is unsuccessful, this could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER relies on third party contractors

OER is dependent on third party contractors in many aspects of its operations, including drill rig services. In the case of Nigeria, there can be a limited number of contractors willing to work within the country and even fewer contractors with the competence and willingness to work in the swamp areas of the Niger Delta. Moreover, the imposition of Nigerian content requirements in the procurement of services may further restrict the number of contractors with the expertise and willingness to provide rig and other services to OER. OER can give no assurance that contractors will be available or competent or will complete their work or activities in accordance with internationally acceptable standards, or at all, and any failure to do so may result in the delay of projects, increased costs, risks of damage to persons or property and other consequences that may adversely affect the operating results, financial condition or prospects of OER.

OER may be unable to flare natural gas that is a by-product of oil production, which could restrict future oil production

OER produces a significant amount of gas associated with its oil production, including at OML 125 where there is no existing market for the gas. In 1984, the Nigerian Government enacted the AGRA to proscribe the flaring of associated gas. Various dates by which flaring would be prohibited altogether have been set by successive governments. The Gas Flaring (Prohibition and Punishment) Bill, which is presently before the Nigerian National Assembly, seeks to prohibit the flaring or venting of gas in any operation, except where permission has been granted by the Minister. The adoption of stricter controls over the flaring of gas could lead to additional administrative burdens which could have an adverse impact on the operating results, financial condition or prospects of OER.

OER may be subject to substantial fines for gas flaring

OER produces a significant amount of gas associated with its oil production, including at OML 125 where there is no existing market for the gas. In 1984, the Nigerian Government enacted the AGRA to proscribe the flaring of associated gas, which established a gas flaring penalty. The DPR has sought to impose a gas flaring penalty rate of $3.50/Mcf. To OER's knowledge no industry participant has paid the penalty at the rate of $3.50/Mcf owing to the fact that the DPR directive purporting to impose the penalty rate is considered unconstitutional by industry participants. Presently, the gas penalties be assumed by OER pursuant to the Acquisition Agreements are expected

to be material. The legal enforcement or adoption of such increased penalties could have an adverse impact on the operating results, financial condition or prospects of OER.

OER may be unable to obtain necessary equipment or other resources

Oil and gas exploration and development activities are dependent upon the availability of drilling and related equipment. In the areas in which OER operates, there is significant demand for drilling rigs and other related equipment and services. In addition, costs of third party services and equipment have increased significantly over recent years and may continue to rise. The unavailability and high costs of such services and equipment could result in a delay or restriction in OER's projects, and therefore have a material adverse effect on the operating results, financial condition or prospects of OER.

OER may not be able to attract and retain qualified personnel in the regions where it conducts business

OER may have difficulty attracting and retaining qualified local personnel to work on its projects due to shortages of qualified workers and intense competition for their services. It may also be difficult to attract, employ and retain qualified expatriate workers as a result of legal and political restrictions applying to the use of foreign workers or the socio-economic and security situations in the jurisdictions in which OER operates. In the event of a labour shortage, OER could be forced to increase wages in order to attract and retain employees, which would result in higher operating costs and reduced profitability. A failure by OER to attract and retain a sufficient number of qualified workers could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER's operations may be subject to labour disputes

Some of OER's joint venture partners, suppliers and customers have a significant number of staff belonging to Nigerian trade unions. If there is a material disagreement between union members and their employer, OER's operations could suffer an interruption or shutdown. As well, obligations concerning consultation may impede the efficient shutdown of an unprofitable operation. OER's joint venture partners, suppliers and customers may in the future need to negotiate work agreements with trade unions. OER cannot guarantee that OER's joint venture partners, supplier and customers will be able to agree to such agreements on acceptable terms or at all. Any work agreement may result in material cost increases or additional work rules being imposed. Any of the foregoing could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER is subject to relinquishment obligations

The Petroleum Act requires the relinquishment of 50% of a license area on the 10th anniversary of the grant of an OML, although OMLs that have been renewed are not subject to the relinquishment obligation and negotiations with the DPR may result in the waiver or reduction of a relinquishment obligation. As well, most PSCs contemplate the relinquishment of areas subject to an OPL on conversion to an OML. OPL 214 is currently being converted to an OML and it is expected that 50% of its area will be relinquished. The contract area to be relinquished is to be agreed by OER (and its partners in the particular PSC) and the NNPC. While the Petroleum Act allows licensees to take actions to preserve parts of the contract area in which petroleum has been discovered, there can be no assurance that the areas proposed to be relinquished will be accepted by the NNPC or that relinquished areas will not contain reserves or resources already booked by OER.

Risks Relating to the Oil Industry

The price of oil and gas may affect the profitability of OER

OER's profitability is determined in large part by the difference between the income received from the sale of oil and gas and its operating costs, as well as costs incurred in transporting and selling of oil and gas. As a result, the prices of oil and NGL internationally have a significant impact on the operating results, financial condition or prospects of OER. Historically, the markets for oil and NGL have been highly volatile and will likely continue to be volatile in the future. The prices that OER will receive and the levels of such production depend on numerous factors beyond OER's control, including:

- global and regional supply and demand, and expectations regarding future supply and demand, of oil and petroleum products;
- the impact of recessionary economic conditions on consumers of oil, gas and other petroleum products including reductions in demand;
- global and regional socioeconomic and political conditions and military developments, particularly in the Middle East and other oil producing regions;
- weather conditions and natural disasters;
- levels of oil theft and other sabotage;
- access to pipelines, railways, trucks and other means of transporting oil, gas and other petroleum products;
- the ability of the members of OPEC, and other oil producing nations, to set and maintain specified levels of production and prices;
- governmental regulations and actions, fiscal or otherwise, including export restrictions and taxes;
- prices and availability of alternative fuels and/or new technologies; and
- market uncertainty and speculative activities.

Lower oil, gas and NGL prices may reduce the amount of oil, gas and NGL that OER is able to produce economically or may reduce the economic viability of specific wells or of projects planned or in development because production costs would exceed anticipated income from such production. Any decline in oil and gas prices and/or any curtailment in OER's overall oil, gas or NGL volumes may result in a reduction in net income, impair its ability to make planned capital expenditures necessary for the development of its fields and materially adversely affect the operating results, financial condition or prospects of OER.

OER operates in a highly competitive industry

The oil and gas industry in the West African region (and, in particular, within Nigeria) is intensely competitive. OER competes with other companies on bids to acquire oil and gas assets, the development of new markets, plants and infrastructure, the retention and acquisition of experienced and skilled management and oil professionals, and many other facets of the Nigerian oil business. Many of these competitors are global oil companies, which possess much greater technical and financial resources, such as Eni, Shell, Total, Chevron and ExxonMobil. If OER is unsuccessful in competing against other companies, it may materially adversely affect the operating results, financial condition or prospects of OER.

OER's exploration and development activities may not result in economically viable oil or gas production

OER's crude oil and gas exploration program may result in dry wells, unproductive wells or wells that are not economically feasible to produce. Future oil and gas exploration may involve unprofitable efforts from both dry wells and those 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 guarantee a profit on the investment or recovery of drilling, completion and operating costs. Also, 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. There is a need for substantial future exploration and development activities in order to meet forecast production estimates, as well as to benefit from substantial investments in respect of most of OER's offshore and other non-producing assets. A failure to complete such activities, in whole or in part, or a deferment of such activities, or a failure to achieve the rate of success expected from such activities, could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER is involved in a highly speculative industry

Exploration, appraisal and development of oil and gas reserves is a speculative business and involves a significant degree of risk. There is no guarantee that OER will continue to produce oil and gas, maintain assets with reserves,

establish new reserves or otherwise succeed in the industry. While OER has entered into agreements to acquire additional properties with production and reserves, there can be no assurance that these acquisitions will be completed. As a relatively new entrant to the oil industry, OER faces severe competition from competitors that are much larger and better capitalized. OER is particularly exposed to the risk of failure should its attributes no longer confer advantages upon it within Nigeria (e.g., should indigenous attributes no longer be given special treatment within the oil industry of Nigeria).

OER is subject to fluctuation in inflation rates

OER's operations are located principally in Nigeria and a majority of its operating costs are incurred in Nigeria. Since a significant portion of OER's general and administrative expenses in 2013 are denominated in Naira, inflationary pressures in Nigeria are a factor affecting OER's expenses. For example, employee and contractor wages, consumable prices and energy costs have been, and are likely to continue to be, particularly sensitive to monetary inflation in Nigeria. In an inflationary environment, OER may not be able to sufficiently increase the prices that it receives from the sale of oil and gas, which are generally linked to the US dollar-denominated prices of such products, in order to preserve existing operating margins.

OER is subject to fluctuations in exchange and interest rates

Exchange rate fluctuations may affect the costs that OER incurs in its operations. Since certain of OER's costs are incurred in Naira and Canadian dollars, yet oil is generally sold in U.S. dollars, the appreciation of those currencies against the U.S. dollar can increase OER's cost of oil production in U.S. dollar terms. In addition, since OER reports its financial statements in US dollars, OER faces currency translation risk because the assets, liabilities and expenses of OER denominated in currencies other than US dollars are translated into US dollars at the applicable exchange rate. Consequently, any increase or decrease in the value of the US dollar against other currencies, especially the Naira, will affect the value of these items in the financial statements. Although OER seeks to manage its foreign exchange risk in order to minimize any negative impact caused by exchange rate volatility, there can be no assurance that it will be able to do so successfully. Any movements in exchange rates could result in adverse effects on the operating results, financial condition or prospects of OER.

Certain of OER's credit facilities are subject to floating interest rates and, therefore, are subject to fluctuations in interest rates. Interest rate fluctuations are beyond OER's control and any movement in interest rates could result in adverse effects on the operating results, financial condition or prospects of OER.

OER may face drilling, production and technical delays, cost overruns, or work stoppages

Oil and gas exploration, development and production activities involve many risks. OER may incur cost overruns or be required to curtail, delay or cancel drilling operations because of many factors, such as unexpected drilling conditions, abnormal pressure or irregularities in geological formations, equipment failures or accidents and adverse weather conditions. In addition, offshore drilling operators are subject to perils particular to marine operations, including capsizing, grounding, collision and loss or damage from severe weather. The development, production and processing of oil and gas is also hazardous and subject to risks associated with natural disasters, fire, explosion, blowouts, cratering and oil spills. Each of these occurrences could result in substantial damage or injury to property and persons, including ecological disasters.

OER may not be able to market its expected hydrocarbon production as anticipated

The marketability of expected oil, gas and NGL production from OER's projects will be affected by numerous factors beyond OER's control, including, but not limited to, market fluctuations in prices, meeting minimum volume commitments, proximity and capacity of pipelines, the availability of upgrading and processing facilities, equipment availability and Nigerian Government regulations (including, without limitation, regulations relating to prices, taxes, royalties, allowable production, importing and exporting of oil, natural gas flaring and environmental protection). OER currently sells oil production to one or more third parties. If OER's agreements with third parties were to be terminated for any reason, OER could be unable to enter into a relationship with another purchaser of its crude oil on a timely basis or on acceptable terms.

OER may suffer financial loss related to hedging activities

The nature of OER's operations exposes it to fluctuations in commodity prices. OER uses, and may continue to use, financial instruments and physical delivery contracts to hedge its exposure to these risks. If product prices increase above those levels specified in future hedging agreements, OER could lose the cost of floors or ceilings, or a fixed price could limit OER from receiving the full benefit of commodity price increases. Additionally, hedging exposes OER to credit-related losses in the event of non-performance by counterparties to the financial instruments. OER may also 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 under its commodity hedging arrangements. In addition, OER may not be able to find pricing for hedging on suitable terms.

OER may not be able to keep pace with the adoption of new technologies in the oil and gas industry

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and gas companies may have greater financial, technical and personnel resources than OER that allow them to enjoy technological advantages and may in the future allow them to implement new technologies either before OER does so or in circumstances where OER is not able to do so. There can be no assurance that OER will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by OER or implemented in the future may become obsolete. If OER is unable to utilize the most advanced commercially available technology, this could have a material adverse effect on the operating results, financial condition or prospects of OER.

OER's operations are subject to significant health, safety and environmental regulations

OER is subject to laws and regulations relating to the protection of human health and safety and the environment, including relating to greenhouse gas emissions. Health and safety laws and regulations impose controls on the storage, handling and transportation of petroleum products, as well as restrict employee exposure to hazardous substances. Environmental legislation restricts or prohibits spills, releases or emissions of various substances produced in association with oil and natural gas operations and prescribes closure and reclamation procedures for terminated or abandoned wells and sites. In addition, regulations relating to greenhouse gas emissions may affect levels of future demand for hydrocarbon-based products.

OER incurs, and OER expects it to continue to incur, substantial capital and operating costs in order to comply with such health, safety and environmental laws and regulations. Any failure, whether inadvertent or otherwise, by OER to comply with applicable legal and regulatory requirements may give rise to significant liabilities and, in particular, a serious spill, even if accidental, could result in fines, penalties and civil damages that threaten the economic viability of OER. New laws and regulations, increasingly strict enforcement of, or new interpretations of, existing laws, regulations and licenses, or the discovery of previously unknown contamination may require further expenditures by OER. No assurance can be given that such regulations will allow for the continued profitable production of hydrocarbons, or at all, or otherwise in a manner so as not to adversely affect the operating results, financial condition or prospects of OER.

OER may be impacted by OPEC and other production quotas

Nigeria is a member of OPEC, which constrains, from time to time, its members' ability to produce oil through the imposition of production quotas. The NNPC allocates production quotas among the oil producers based on the aggregate technical production limits of all producing wells, which are negotiated between the producer and the Nigerian Government. Where technical production exceeds Nigeria's OPEC quota, the quota is allocated to the producers on a pro rata basis based on their respective technical production levels. If production allocations are exceeded, it is possible to apply for additional quotas from the Nigerian Government, but there can be no assurance that the additional quotas will be granted. Nigeria also has the power to implement export quotas. As a result, OER may be constrained in exporting oil through such quotas in the future, which could have a material adverse effect on the operating results, financial condition or prospects of OER.

Other Risks

Oando may be compelled to sell Common Shares

Oando currently owns a majority of the Common Shares (approximately 93%) and, even after giving effect to the sale of Securities, will continue to hold a substantial portion of OER's Common Shares. There can be no assurance that Oando will not, as a result of a default under a third party loan agreement, a condition to further finance or otherwise, be required to sell or liquidate Common Shares. Sales of a large number of the Common Shares in the public markets, or sales to private parties at a reduced price, or the potential for such sales, could decrease the trading price of the Common Shares and could also impair OER's ability to raise capital through future offerings of Common Shares.

The market for the Common Shares and OER 2012 Warrants may not develop to provide liquidity

The Common Shares and OER 2012 Warrants are listed on the TSX, however, trading in such securities is insufficiently active to produce a liquid trading market. OER cannot predict the extent to which investor interest in it will lead to the development of an active trading market in the Common Shares and OER 2012 Warrants or how liquid that market might become. An active and liquid market for the Common Shares and OER 2012 Warrants may not develop or, if developed, may not be maintained. If an active trading market does not develop, it may be difficult to sell such securities.

The price of the Common Shares and OER 2012 Warrants may fluctuate significantly

The securities of publicly traded companies, particularly oil and gas exploration and development companies, can experience a high level of price and volume volatility and the value of the Common Shares and OER 2012 Warrants can be expected to fluctuate depending on various factors, not all of which are directly related to the success of OER and its operating performance, underlying asset values or prospects. These include the risks described elsewhere in this "*Risk Factors*" section, as well as the following factors:

- market conditions in the broader stock market in general;
- actual or anticipated fluctuations in OER's results of exploration and operations;
- perceived prospects for OER's business and operations and results in operations and exploration and the oil and gas industry in general;
- issuance of new or changed securities;
- analysts' reports or recommendations;
- additions or departures of executive officers and other key personnel;
- changes in the economic performance or market valuations of or events affecting other companies that prospective purchasers deem comparable to OER;
- sales or perceived likelihood of sales of additional equity securities, whether from treasury or in the secondary market;
- litigation and governmental or regulatory investigations;
- worldwide economic and political conditions or events;
- changes in investor perceptions and confidence levels;
- significant acquisitions or business combinations, strategic partnerships, or capital commitments by or involving OER or its competitors; and
- trends, concerns, technological or competitive developments, changes in government policies, regulatory changes and other related issues in OER's business or target markets.

These and other factors may cause the market price and demand for the Common Shares and OER 2012 Warrants to fluctuate substantially, which may limit or prevent holders from being able to readily sell their Common Shares and OER 2012 Warrants and may otherwise negatively affect the liquidity of the Common Shares and OER 2012 Warrants.

The trading price of the Common Shares and OER 2012 Warrants may also decline in reaction to events that affect other companies in the same industry or that hold assets in the same country, even if these events do not directly affect OER. Financial markets have experienced significant price and volume fluctuations during the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. In addition, certain institutional prospective purchasers may base their investment decisions on consideration of OER's governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in the disposition of Common Shares and OER 2012 Warrants by those institutions, which could adversely affect the trading price of those securities.

OER does not pay dividends

OER has not declared or paid any dividends to date and does not intend to declare any dividends in the near future. Even if OER begins to pay dividends, the board has the discretion to determine the amount of dividends to be declared and paid to shareholders. OER may, subject to the requirements of applicable law and OER's constating documents, alter its dividend policies at any time and the continued payment of dividends will depend on, among other things, results of operations, financial condition, current and expected future levels of earnings, operating cash flow, liquidity requirements, market opportunities, income taxes, maintenance capital, growth capital expenditures, debt repayments, legal, regulatory and contractual constraints, working capital requirements, tax laws and other relevant factors. Additionally, OER's short and long term borrowings may prohibit OER from paying dividends at any time at which a default or event of default would exist under such debt, or if a default or event of default would exist as a result of paying the dividend.

Issuance of additional securities may dilute the interest of shareholders

The Board of Directors may issue an unlimited number of Common Shares or other securities of OER without any vote or action by OER's shareholders, subject to the rules of the TSX or any other stock exchange on which OER's securities may be listed from time to time. OER may make future acquisitions or enter into financings or other transactions involving the issuance of securities. OER will need to raise significant funds from time to time in the future and this may result in dilution to existing shareholders, which could be significant. In addition, OER may issue Common Shares under equity compensation arrangements and in connection with acquisitions. If OER issues any additional equity, the percentage ownership of existing shareholders will be reduced and diluted.

OER's operations involve substantial risks for which OER may not be insured

OER's business is subject to a number of risks and hazards, including adverse environmental conditions, industrial accidents, labour disputes, unusual or unexpected geological conditions, ground or slope failures, cave-ins, changes in the regulatory environment, inclement weather conditions, floods and earthquakes. Such occurrences could result in damage to oil and gas properties or production facilities, personal injury or death, environmental damage, and other damages and losses. Insurance may or may not be available to protect against such damages or losses, or such insurance may not be obtained by OER. In particular, insurance against risks such as environmental pollution or other hazards as a result of exploration and production is not generally available on acceptable terms. Losses from such occurrences could have a material adverse effect upon the operating results, financial condition or prospects of OER.

OER's directors and executive officers may be subject to conflicts of interest

Directors and senior management of OER hold positions with Oando and other companies, some of which operate in the oil and gas industry. Directors who have a material interest in any person or entity that is a party to a material contract or proposed material contract with OER are required under the CBCA, subject to certain exceptions, to disclose that interest and generally abstain from voting on a related resolution. In addition, directors and executive

officers are required to act honestly and in good faith with a view to the best interests of OER. In the past, OER has appointed committees of independent directors to evaluate opportunities where conflicts of interest exist or are perceived to exist, and OER expects to continue to deal with conflicts in this fashion.

Nevertheless, these other positions could create, or appear to create, potential conflicts of interest when these directors and senior management are faced with decisions that could have different implications for OER and their other business interests. Oando, in particular, is subject to several third party agreements, including loan agreements, that may compel it to seek dividends, loan repayments, cross-guarantees or other actions that are not in the best interests of OER at the time. There can be no assurance that directors with such conflicts will act in the best interest of OER, the failure of which could adversely affect the operating results, financial condition or prospects of OER.

It may not be possible to effect service of process and enforce judgments against OER or Oando outside of Canada

Oando and a number of OER's subsidiaries are incorporated or otherwise organized under the laws of foreign jurisdictions and a number of the directors and executive officers of OER, Oando and certain of the experts named in this AIF reside outside Canada. In addition, some or all of the assets of those persons and entities are located outside of Canada. Although the directors and officers of OER, as well as the directors and officers of Oando who have signed this AIF and the experts named in this AIF that reside outside of Canada have appointed agents for service of process in Canada, it may not be possible for investors to collect from or enforce judgments obtained in courts in Canada predicated on the civil liability provisions of securities legislation. Moreover, it may not be possible for investors to effect service of process within Canada upon the directors, executive officers and experts referred to above.

Investors face risks related to OER's holding company structure in the event of an insolvency, liquidation or reorganization of any of the subsidiaries of OER

OER holds all of its assets in its direct and indirect subsidiaries. In the event of the insolvency, liquidation or reorganization of any such subsidiaries, the holders of Common Shares may have no right to proceed against the assets of those subsidiaries or to cause the liquidation or bankruptcy of those subsidiaries under applicable bankruptcy laws. Creditors of OER's subsidiaries would be entitled to payment in full from such subsidiaries' assets before OER, as a shareholder, would be entitled to receive any distribution therefrom. Claims of creditors of OER's subsidiaries will have a priority with respect to the assets and earnings of these subsidiaries over the claims of OER, except to the extent that OER may itself be a creditor with recognized claims against such subsidiaries ranking at least *pari passu* with other creditors, in which case the claims of OER would still be effectively subordinate to any mortgage or other liens on the assets of such subsidiaries and would be subordinate to any indebtedness of such subsidiaries.

DIVIDENDS AND DISTRIBUTIONS

OER has not declared or paid any dividends to date and does not intend to declare any dividends in the near future. Any decision to pay dividends in the future will be at the discretion of the Board of Directors and will be take into account OER's earnings, financial requirements for OER's operations, and the satisfaction of solvency tests imposed by applicable corporate law and the instruments evidencing OER's indebtedness for the declaration and payment of dividends. See "*Risk Factors – Other Risks – OER does not pay dividends*."

DESCRIPTION OF SHARE CAPITAL

Common Shares

As at the date hereof there are 573,705,160 Common Shares issued and outstanding. OER is authorized to issue an unlimited number of Common Shares. Each Common Share entitles the holder to receive notice of and to attend all meetings of shareholders of OER and to one vote per Common Share at such meetings. Holders of Common Shares do not have cumulative voting rights with respect to the election of directors and, accordingly, holders of a majority of the Common Shares entitled to vote in any election of directors may elect all directors standing for election.

Holders of Common Shares are entitled to receive on a pro rata basis such dividends on the Common Shares, if any, as and when declared by the Board of Directors at its discretion from funds legally available therefor, and upon the liquidation, dissolution or winding up of OER are entitled to receive on a pro rata basis the net assets of OER after payment of debts and other liabilities, in each case subject to the rights, privileges, restrictions and conditions attaching to any other series or class of shares ranking senior in priority to or on a pro rata basis with the holders of Common Shares with respect to dividends or liquidation. The Common Shares do not carry any pre-emptive, subscription, redemption or conversion rights, nor do they contain any sinking or purchase fund provisions.

Warrants

As at December 31, 2013 and the date hereof there were 5,714,276 OER 2012 Warrants issued and outstanding. The OER 2012 Warrants were created pursuant to a warrant indenture dated July 24, 2012 between OER and Equity Financial Trust Company as warrant agent and were listed for trading on the TSX on July 30, 2012 under the symbol "OER.WT.A". These warrants entitle the holder to acquire one Common Share in consideration of C$2.00 and expire on July 24, 2014.

Prior to July 24, 2013, warrants were exercised to acquire 92 Common Shares at a price of C$1.50 per Common Share. On July 24, 2013, the remaining 5,713,984 warrants that were outstanding on such date expired unexercised. Each such warrant entitled the holder to acquire one Common Share in consideration of C$1.50. The warrants were listed for trading on the TSX under the symbol "OER.WT."

As at the date hereof there are 233,817,915 OER 2014 Warrants issued and outstanding. Each OER 2014 Warrant entitles the holder thereof to acquire one Common Share in consideration of C$2.00 and expire 24 months from the date of the closing of the COP Acquisition. If, after a period of six months from the closing of the COP Acquisition, the closing price of Common Shares on the TSX is greater than C$3.50 for a period of at least 10 consecutive trading days, the OER 2014 Warrants will expire within 30 days. The OER 2014 Warrants are not listed on any stock exchange or other public market. Under securities laws applicable in Canada the OER 2014 Warrants and the Common Shares issuable upon conversion thereof are subject to resale restrictions for a period of four months and a day after the issuance of the OER 2014 Warrants.

Stock Options

As at December 31, 2013 and the date hereof there were 7,810,000 stock options issued and outstanding under OER's stock option plan. Each stock option entitles the holder to acquire one Common Share. The stock options are exercisable at various prices and have a variety of expiry dates.

On February 7, 2014 stock options were exercised by a former director to acquire 15,709 Common Shares at a price of C$1.08 per Common Share.

Restricted Share Units

On July 24, 2012, 2,000,000 restricted share units ("**RSUs**") were granted to an officer of OER. The restricted share units vest as follows:

- 1/3 vested on July 24, 2013;
- 1/3 will vest on the July 24, 2014 provided that the closing price on the TSX of the Common Shares, during any consecutive five trading day period during the year between July 24, 2013and July 24, 2014, exceeds C$2.50; and
- all of the RSUs not already vested will vest on July 24, 2015 provided that the closing price on the TSX of the Common Shares, during any consecutive five trading day period during the year between July 24, 2014 and July 24, 2015, exceeds C$3.50.

2014 Oando Loan

The 2014 Oando Loan is convertible into Common Shares, subject to the limitation that Oando may not hold more than 94.6% of the outstanding Common Shares. Pursuant to the 2014 Oando Loan Documentation, each of Oando and OER are permitted to elect to convert amounts outstanding into equity securities of OER (other than interest accruing from February 26, 2014 which only Oando is permitted to elect to convert), based on:

a) the terms provided in a final prospectus of OER, in which case the price for conversion and nature of securities to be received shall be as set out under the offering;

b) where no final prospectus has been filed, the terms provided in an arm's length private placement, in which case the price for conversion and nature of securities to be received shall be as set out under the private placement agreement;

c) where there has been no prospectus or private placement offering, Common Shares of based on the 5-day volume weighted average price of the Shares as at the time of the completion or termination of the COP Acquisition; or

d) notwithstanding the foregoing, such terms as may be agreed by OER and Oando.

See "*Business of OER – Three Year History – Financing Activities – Oando Loan*".

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares and OER 2012 Warrants of OER are listed for trading on the TSX under the trading symbols "OER" and "OER.WT.A", respectively. The following tables set forth the reported price ranges and trading volume of the Common Shares and OER 2012 Warrants for the periods indicated (all amounts shown in Canadian dollars).

Common Shares

Common Shares (TSX:OER)

Month	Trading Price (C$)		Volume Traded
	High	Low	(# of Common Shares)
January 2013	1.70	1.22	169,079
February 2013	1.29	1.03	109,075
March 2013	1.49	0.75	209,427
April 2013	1.43	0.96	243,978
May 2013	1.59	1.01	205,452
June 2013	1.54	1.10	85,704
July 2013	1.49	1.19	79,623
August 2013	1.39	1.00	36,377
September 2013	1.85	1.07	356,538
October 2013	1.55	1.08	469,864
November 2013	1.40	1.12	57,614
December 2013	1.77	1.08	544,752
January 2014	1.90	1.45	331,501
February 2014	1.61	1.13	47,048
March 2014 (to March 28)	1.54	1.28	9,323

On March 25, 2014, being the last day on which the Common Shares traded prior to the date of this AIF, the closing price of the Common Shares on the TSX was C$ 1.31.

OER 2012 Warrants

OER 2012 Warrants (TSX: TSX:OER.WT.A)

Month	Trading Price (C$)		Volume Traded
	High	Low	(# of Warrants)
January 2013	$0.25	$0.14	71,895
February 2013	$0.14	$0.07	87,073
March 2013	$0.11	$0.08	13,635
April 2013	$0.16	$0.07	44,860
May 2013	$0.08	$0.06	7,067
June 2013	$0.10	$0.06	28,114
July 2013	$0.06	$0.06	18,705
August 2013	$0.05	$0.04	63,135
September 2013	$0.05	$0.02	48,631
October 2013	$0.01	$0.01	5,599
November 2013	$0.03	$0.02	7,267
December 2013	$0.02	$0.01	25,541
January 2014	$0.03	$0.02	21,861
February 2014	$0.05	$0.01	49,497
March 2014 (to March 28)	$0.01	$0.01	5,166

On March 25, 2014, being the last day on which the OER 2012 Warrants traded prior to the date of this AIF, the closing price of the OER 2012 Warrants on the TSX was C$ 0.01.

OER 2012 Warrants (TSX: TSX:OER.WT)

Month	Trading Price (C$)		Volume Traded
	High	Low	(# of Warrants)
January 2013	$0.20	$0.07	86,557
February 2013	$0.10	$0.04	141,061
March 2013	$0.05	$0.03	6,949
April 2013	$0.10	$0.03	60,579
May 2013	$0.06	$0.02	28,586
June 2013	$0.04	$0.01	48,445
July 2013 (to July 24)	$0.04	$0.01	8,495

Prior Sales

During the year ended December 31, 2013, OER issued 92 Common Shares at a price of C$1.50 per Common Share pursuant to the exercise of outstanding warrants.

On February 7, 2014 stock options were exercised by a former director to acquire 15,709 Common Shares at a price of C$1.08 per Common Share.

In February 2014 OER issued an aggregate 467,667,249 Common Shares and 233,817,915 OER 2014 Warrants. See *"Business of OER – Relevant Three Year History – Private Placement and 2014 Oando Loan Conversion and Description of Share Capital – Options."*

Escrowed Securities

As at December 31, 2013, the following securities of OER were held in escrow:

Name and municipality of residence of security holder	Number and designation of Escrowed Securities	Percentage of class
Oando PLC Lagos, Nigeria	25,084,763 Common Shares	23.65%

Notes:

(1) Pursuant to an escrow agreement between OER, Equity and Oando dated July 24, 2012, the securities of the corporation held by Oando were held in escrow by Equity Financial Trust Company and released from escrow as follows: 25% of the escrowed securities in were released on July 30, 2012 being OER's listing date on the TSX, 1/3 of the remaining escrowed securities were released on the 6 month anniversary of the listing date (January 30, 2013), ½ of the remaining escrowed securities were released on the 12 month anniversary of the listing date (July 30, 2013) and the remaining escrowed securities were released on the 18 month anniversary of the listing date (January 30, 2014).

As of the date hereof, to OER's knowledge, no securities of OER are held in escrow.

DIRECTORS AND OFFICERS

Biographies for Executive Officers and Directors

The following table sets forth, for each director and executive officer of OER: his name, place of residence, and principal occupation for the last five years. The directors are elected annually by the shareholders by ordinary resolution, or until their successors are appointed and hold office until the next annual meeting of OER.

Name and Place of Residence	Position Held	Director / Officer Since	Principal Occupation for the last five years
Jubril Adewale Tinubu Lagos, Nigeria	Chairman and Director	July 24, 2012	Group Chief Executive of Oando PLC
Omamofe Boyo[(2)] Lagos, Nigeria	Director	July 24, 2012	Deputy Group Chief Executive of Oando PLC
Olapade Durotoye [(4)] Lagos, Nigeria	President, Chief Executive Officer and Director	July 24, 2012	Chief Executive Officer of OER since July 24, 2010; Chief Executive Officer of Oando Exploration & Production Limited from June 2010 until July 2012; Chief Executive Officer of Ocean & Oil Holdings Limited from February 2007 to June 2010.
Christopher J.F. Harrop [(1)(3)] Ontario, Canada	Director	August 9, 2005	Chairman and Director, Canterbury Financial Service Limited, a merchant banking firm since May 1975; Chairman and Director, Blackheath Fund Management Inc., investment fund manager, from November 2008 to July 2012.
Bill Watson [(1)(4)(5)] Alberta, Canada	Director	October 17, 2012	Director of SilverWillow Energy Corporation (TSXV) since from February, 2012 until May 2013; Director, Silver Birch Energy Corporation (TSXV) from December 2010 until April 2012; Chief Operating Officer, S.E. Asia, Husky Energy from September 2007 until December 2010; Prior to that Vice President, Engineering, at Husky Energy from October 2004 until August 2007; Lead Officer at Husky Energy from October 2004 until December 2010.
John Orange [(2)(3)] Bury St Edmunds, Suffolk, United Kingdom	Director	July 24, 2012; Previously 2009-2010	Director of Vostok Energy Plc from September 2010 until December 2013; Director of Premier Oil Plc from February 1997 until May 2011; Director of Exile Resources Inc. from January 2009 until December 2010.

Name and Place of Residence	Position Held	Director / Officer Since	Principal Occupation for the last five years
Philippe Laborde[(1)(3)(5)] Abuja, Nigeria	Director	December 12, 2012	Current founder and Chief Executive Officer of Olaeum Energy, a venture capital company focused on oil and gas investments across Africa since October 2010; Co-founder and Chief Executive Officer for the Africa and Middle East region of DB Petroleum, an upstream joint venture between Dubai World and Benny Steinmetz Group, from August 2007 to June 2010.
Adeola Ogunsemi Lagos, Nigeria	Chief Financial Officer	July 24, 2012	Chief Financial Officer of OER since July 24, 2012. Chief Financial Officer of Oando Exploration & Production Limited from March 2009 until July 2012; Internal Control/Senior Analyst/Assistant Controller at British Petroleum (BP) America from May 2004 until February 2009.
Olanrewaju Adegbite Falade Lagos, Nigeria	Chief Operating Officer	July 24, 2012	Chief Operating Officer of OER since May 1, 2013; Head, Corporate Development and Integration Lead of OER from July 2012 to April 2013; Executive Director, Corporate Development of Oando Gas and Power from March 2009 to July 2012.
Ayotola Olubummi Jagun Lagos, Nigeria	Chief Governance & Compliance Officer	July 24, 2012	Chief Governance & Compliance Officer of OER since July 24, 2012; Company Secretary & Chief Compliance Officer of Oando Plc since November 2009; prior thereto General Counsel and Corporate Secretary, Capital G, an integrated financial services organization.
Krisztian Toth Ontario, Canada	Secretary	July 24, 2012	Partner, Fasken Martineau DuMoulin LLP, a law firm, since 2010; prior thereto Associate, Fasken Martineau DuMoulin LLP since 2003.

Notes:
(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Corporate Governance Committee
(4) Member of the Environmental, Health and Safety Committee
(5) Member of the Reserves and Resources Committee

Voting Securities

As of the date hereof and based upon filings made by each individual under applicable Canadian securities laws, the directors and officers of OER as a group beneficially own, or control or direct, directly or indirectly, 409,953 Common Shares, representing approximately 0.07% of the outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties and Sanctions

No director or executive officer of OER is, or within the ten years prior to the date hereof has been, a director or chief executive officer or chief financial officer of any company (including OER) that, (i) was subject to a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; (ii) was subject to a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days, that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

No director or executive officer of OER, or a shareholder holding a sufficient number of securities of OER to affect materially the control of OER, (i) is, or within ten years prior to the date hereof has been, a director or executive officer of any company (including OER) that, while the person was acting in that capacity, or within a year of that

person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceeding, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than John Orange, who was a director (until his resignation on December 8, 2013) of Vostok Energy Plc ("**Vostok**"), when it appointed an administrator under applicable UK bankruptcy laws on October 14, 2013 and when the UK Listing Authority cancelled the admission to the Official List of Vostok's convertible bonds (Vostok was subsequently sold to Zoltav Resources, a subsidiary of ARA Capital, a UK-based oil and gas producer); (ii) has, within ten years prior to the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder; or (iii) has entered into a settlement agreement with a securities regulatory authority or has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority, or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable shareholder in making an investment decision.

Conflicts of Interest

Except as disclosed in this AIF, to the best of OER's knowledge there are no known existing or potential conflicts of interest between OER and any director or officer of OER. However, there are potential conflicts of interest to which the directors and officers of OER will be subject to in connection with the operations of OER. In particular, certain of the directors and officers of OER are involved in managerial or director positions with Oando and other oil and natural gas companies whose operations may, from time to time, be in direct competition with those of OER or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of OER. Certain of the directors of OER have either other employment or other business or time restrictions placed on them and accordingly, these directors of OER will only be able to devote part of their time to the affairs of OER.

In accordance with the CBCA and OER's Corporate Governance Mandate, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with OER are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of OER. In appropriate cases, OER will establish a special committee of independent non-executive directors to review a matter in which one or more directors, or management, may have a conflict.

Except as disclosed in this AIF, to the best of OER's knowledge there are no other known existing or potential conflicts of interest between OER and any director or officer of OER, except that certain of the directors of OER serve as directors and officers of other public companies.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

This section summarizes material pending and existing legal proceedings in which OER is involved.

OML 125

OER (through OANDO OML 125 & 134) have commenced arbitration proceedings concerning the overlifting of oil by the NNPC in relation to OML 125. The dispute concerns the manner in which cost oil and profit oil has been computed, allocated and administered under the relevant PSC since 2006. NAE and OER take the position that, among other matters, they are entitled to deduct exploration costs associated with OML 134 from OML 125's production owing to unambiguous wording to this effect within the PSC. In October 2011, an arbitral tribunal (seated in Nigeria) found that the NNPC had overlifted and granted OER declaratory and injunctive relief with damages to be subsequently assessed.

Since the date of the arbitral award, the NNPC and the FIRS have separately sought to set aside the award in the Federal High Court of Nigeria (FHC). The NNPC obtained an interlocutory injunction restraining the parties to the arbitral proceedings from taking any further steps in those proceedings. NAE and OANDO OML 125 & 134 unsuccessfully appealed the interlocutory injunction. NAE forwarded an updated schedule of costs to enable the

tribunal to assess the damages to be awarded and NNPC has a deadline of March 26, 2014 to respond with its comments. Thereafter, the tribunal will proceed to complete the arbitration.

As at January 2010, the value of the overlift was estimated to be approximately $385 million (or $57.75 million net to OER) and OER believes that the value of the continued overlifting is currently in excess of $497 million. Any funds that may be ultimately recovered from the NNPC pursuant to the arbitration proceedings and accruing up to the date of the reverse takeover will be paid over by OER to Oando.

Additionally, OER (through Oando OML 125 & 134) and NAE are challenging various tax assessments made by FIRS in relation to OML 125 through the Tax Appeal Tribunal and the Federal High Court (the "**FHC**") in Nigeria. Certain of the tax assessment challenges relate to the over-lifting by the NNPC (see above) and therefore relate the same loss as the arbitration proceedings against the NNPC. The challenges were consolidated into one appeal in September 2012. The more material disputes are summarized below:

- Oando OML 125 & 134 and NAE believe that $312 million of FIRS' 2009 Petroleum Profits Tax assessment is tax refundable by the NNPC.
- Oando OML 125 & 134 and NAE believe that $120 million of FIRS' 2010 Petroleum Profits Tax assessment is tax refundable by the NNPC.

The Tax Appeal Tribunal ordered that the NNPC be joined to the proceedings, which order Oando OML 125 & 134 and NAE have appealed to the FHC. Pending the determination of this appeal, the FHC has issued an injunction on proceedings before the Tax Appeal Tribunal.

Two claims unrelated to the foregoing have been brought against NAE, as operator, in the FHC seeking, inter alia, an injunction restraining NAE from continuing exploration on OML 125 and damages for pollution and degradation to the environment. The first is a claim by The Most Rev Alademehin Claudis and others (suing as representatives of the Mahin, Etikan and Aheri kingdoms) for damages of ₦31 billion (approximately $200 million). The second is a claim by Lawrence Young Lemamu and others (suing for themselves and on behalf of members of the Ilaje Fishermen Association and Association of Ilaje Coastal Fishermen) for damages of ₦12,000,000,000 (approximately $75 million). If the claimants are ultimately successful in their suit, OER would effectively bear the cost in proportion to its working interest in OML 125. OER believes that these claims are without merit and unlikely to succeed.

OML 122

In September 2007, EEL 122 and Peak entered into the Bilabri Settlement Agreement to resolve a number of issues in respect of OML 122. Pursuant to the Bilabri Settlement Agreement, Peak undertook to settle certain invoices paid or payable by EEL 122 to third parties and, in exchange, EEL 122 agreed to reduce its interest in OML 122 to a carried interest of 5% of all crude oil production and a 12.5% interest in all natural gas. Peak failed to settle such invoices and, in February 2008, EEL 122 began arbitration proceedings. EEL was awarded $122.7 million in May 2008. Through separate legal proceedings before the FHC, Peak sought to prevent the arbitration proceedings from continuing and to prevent enforcement of the arbitral award. In November 2008, EEL 122 discontinued its application to register the arbitral award in Nigeria and, in September 2010, it petitioned the FHC to order the winding up of Peak. The winding up order was granted in November 2011. Peak has filed several appeals in respect of the winding up order and the appointment of the liquidator, and these are now pending before the Court of Appeal in Nigeria. There can be no guarantee that EEL 122 will be successful in recovering the Bilabri Settlement Agreement debt from the liquidator for Peak.

OPLs 321 and 323

In January 2009, the Nigerian Government purported to void KNOC's 60% interests in OPLs 321 and 323 and to re-allocate these in favour of the ONGC consortium (which includes OER and Owel Petroleum Services Nigeria). KNOC subsequently challenged the decision, instigating judicial review proceedings in the FHC in March 2009. The FHC found in favour of KNOC, however, Owel Petroleum Services Nigeria then had the judgment set aside on appeal to the Nigerian Court of Appeal. The matter is now pending before the Supreme Court. Parties to the dispute,

including OER, commenced settlement negotiations in respect of the dispute between KNOC and the Nigerian government in June 2013. OER understands that all parties involved in the negotiations have agreed in principle to restructure the working interests in order to accommodate the additional members into a new consortium to be formed as part of the negotiation. OER anticipates that settlement may be reached as early as mid-2014.

OER believes that its working interests remain unaffected and did request (and obtain) a refund from the Nigerian Government of its original signature bonuses ($161.7 million). OER intends to continue to invest in the blocks, however, it will weigh the merits of re-advancing the signature bonuses should the matter be settled as between the Nigerian Government and KNOC.

Regulatory Actions

To the knowledge of management of OER, no penalties or sanctions have been imposed by a court relating to securities legislation or by a securities regulatory body or by any other court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision, nor have any settlement agreements been entered into by OER with a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

AUDIT COMMITTEE

The Audit Committee Charter

The charter of the Audit Committee of the Board of Directors is attached to this AIF as Schedule "D".

Composition of the Audit Committee

The members of the Audit Committee are Chris Harrop, Bill Watson and Philippe Laborde. Each of the members of the Audit Committee is independent and "financially literate" (as defined in accordance with NI 52-110). In considering criteria for the determination of financial literacy, the board considered the member's ability to read and understand a balance sheet, an income statement and a cash flow statement of a public company, to understand the accounting principles used by OER to prepare its financial statements, to assess the general application of the accounting principles used to prepare such financial statements in connection with the accounting for estimates, accruals and reserves, the member's past experience in reviewing or overseeing the preparation of financial statements that present a breadth and level of complexity of issues that can reasonably be expected to be raised by OER's financial statements and the member's understanding of internal controls and procedures for financial reporting.

See "*Biographies for Directors*" above for biographies of each member of the Audit Committee, including each member's education and experience that is relevant to his responsibilities as a member of the Audit Committee.

Pre-Approval Policies and Procedures

The Audit Committee must pre-approve any non-audit services provided by the external auditor or the external auditor of any subsidiary of OER, provided that no approval shall be provided for any service that is prohibited under the rules of the Canadian Public Accountability Board, the Canadian Institute of Chartered Accountants or the Public Company Accounting Oversight Board.

Auditors' Fees

The following chart summarizes the aggregate fees billed by the external auditors of OER for professional services rendered to OER for audit and non-audit related services for each of the fiscal years ended December 31, 2012 and December 31, 2013.

Type of Work	Year Ended December 31, 2012	Year Ended December 31, 2013
Audit fees[1]	C$432,000	C$ 642,857.52
Audit-related fees[2]	C$116,000	C$ 449,995.76
Tax advisory fees[3]	C$25,000	C$ 220,889.13
All other fees	NIL	C$ 194,251.63
Total	**C$573,000**	**C$ 1,507,994.04**

Notes:
(1) Aggregate fees billed for OER's annual financial statements and services normally provided by the auditor in connection with OER's statutory and regulatory filings.
(2) Aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of OER's financial statements and are not reported as "Audit fees", including: assistance with aspects of tax accounting, attest services not required by state or regulation and consultation regarding financial accounting and reporting standards.
(3) Aggregate fees billed for tax compliance, advice, planning and assistance with tax for specific transactions.

PROMOTER

As of the date of this AIF, Oando beneficially owns, controls or directs 532,904,820 Common Shares, representing approximately 92.9% of the issued and outstanding Common Shares. In addition, Oando holds 216,282,884 OER 2014 Warrants.

Oando may be considered to be a promoter of OER under applicable Canadian securities laws because Oando played a key role in the formation of OER's business. See "*Business of OER – Relevant Three Year History*". Additional information related to Oando is available on Oando's website, www.oandoplc.com.

On April 30, 2012, OER indirectly acquired equity interests in OQI, a Nigerian company established to hold a 40% participating interest in Qua Ibo from Oando. Oando sold its interests in Qua Ibo under the terms of the Referral and Non-Competition Agreement for a purchase price of approximately $9.2 million. The purchase price represented reimbursement of all properly documented and commercially reasonable expenses incurred by Oando relating to its acquisition up to the closing date of the Qua Ibo acquisition plus an administrative fee of 1.75%. Oando acquired Qua Ibo on February 2, 2012 for a purchase price of approximately $10,000.

Oando entered into several agreements with OER as part of the Arrangement and to finance the COP Acquisition. See "*Incorporation and Organization – Intercorporate Relationships*" and "*Interests of Management and Oando in Material Transactions.*"

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as described below or as otherwise described in this AIF or the audited annual financial statements for the year ended December 31, 2013, neither Oando, nor any director or executive officer of OER, or to the knowledge of OER or any of their respective associates or affiliates, has engaged in any transaction with OER or its subsidiaries that has materially affected, or that could reasonably be expected to materially affect, OER. OER has entered into the following agreements with Oando:

Referral and Non-Competition Agreement

Pursuant to the Referral and Non-Competition Agreement, Oando is prohibited from competing with OER, except with respect to assets referred to such agreement, until the later of July 24, 2014 and such time as Oando owns less than 20% of the Common Shares. Oando is required to refer all upstream oil and gas opportunities to OER pursuant to this agreement. In addition, Oando was required to offer to OER any upstream assets acquired between September 27, 2011 and July 24, 2012 at a purchase price consisting of the amount paid, together with Oando's reasonable costs relating to such acquisition and a margin of 1.75%. OER has $7.6 million due to Oando under this agreement in respect of the COP acquisition

OER acquired Qua Ibo from Oando on April 30, 2013 for aggregate consideration of $9.2 million pursuant to the terms of the Referral and Non-Competition Agreement. See "*Business of OER – Relevant Three Year History – Qua Ibo Acquisition and Related Medium Term Facility.*"

ROFO Agreement

Under the terms of the ROFO Agreement, until Oando ceases to hold 20% of the Common Shares: (i) OER shall not consolidate, merge or enter into any similar business combination with another entity or liquidate, dissolve or wind-up OER without Oando's consent; and (ii) Oando shall have the right to nominate the CEO and chairman of the Board of Directors. OER agreed, as part of its TSX listing conditions, to nominate such number of independent directors as would ensure a majority of independent directors on the Board of Directors.

As well, the ROFO Agreement provided for a right of first offer in favour of OER in respect of three Licenses within Nigeria, which expired unexercised on September 27, 2013.

Cooperation and Services Agreement

Under OER and Oando entered into a Cooperation and Services Agreement Oando agreed to provide certain administrative and management services to OER, including corporate finance services, corporate communications services, legal and procurement services. The services are charged on the basis of cost plus a margin of ten percent or such other margin as may be agreed between Oando and OER. A majority of the independent directors of OER must approve such charges. The Cooperation and Services Agreement also requires cooperation with respect to the release of information, including financial statements. The term of the Cooperation and Services Agreement expires upon the later of (i) July 24, 2017; and (ii) such time as Oando owns less than 20% of the Common Shares. It is OER's intention to build its team internally and reduce the use of these services going forward. For the year ended December 31, 2013, OER was charged $6.8 million. It is expected that additional compensation will be paid to Oando during 2014 in connection with the COP Acquisition and related transactions, including its out-of-pocket costs.

Transitional Services Agreement

Pursuant to the Transitional Services Agreement, OER and Oando Servco agreed that Oando Servco would provide services to OEPL until January 24, 2014 for no more than 10% of the employees' normal working hours per month. OEPL is required to pay Oando Servco's costs of providing such services. OER has $7.3 million due from OEPL a subsidiary of Oando for services rendered during the year ended December 31, 2013.

Operating Associate Shareholder Agreements

Oando is a holder of certain interests in some of OER's subsidiaries in an effort to structurally embed indigenous participation, including in circumstances in which OER is no longer controlled by Oando. See "*Incorporation and Organization – Intercorporate Relationships*".

2014 Oando Loan Documentation

Oando has agreed to loan up to $1.2 billion to OER to finance the COP Acquisition at an annual interest rate of 4%. See "*Business of OER – Three Year History – Financing Activities – Oando Loan*".

TRANSFER AGENT AND REGISTRAR

The independent auditors of OER are PricewaterhouseCoopers LLP, at its offices located at 111 5th Ave SW, Suite 3100, Calgary, Alberta, Canada, T2P 5L3. PricewaterhouseCoopers LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

OER's transfer agent and registrar is Equity Financial Trust Company at its head office at 200 University Avenue, Suite 400, Toronto, Ontario, M5H 4H1.

MATERIAL CONTRACTS

There are no other contracts, other than those disclosed in this AIF, and those entered into in the ordinary course of OER's business, that are material to OER and which were entered into in the most recently completed fiscal year or which were entered into before the most recently completed fiscal year but are still in effect as of the date hereof.

INTEREST OF EXPERTS

All reserve and resource estimates contained in this AIF have been evaluated by Petrenel. As at the date hereof, the principals, directors, officers and associates of Petrenel, as a group, each owned, directly or indirectly, less than 1% of the outstanding Common Shares.

ADDITIONAL INFORMATION

Additional information about OER, including the financial information and material contracts and other documents described herein, may be found on SEDAR under OER's profile at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of OER's securities and securities authorized for issuance under equity compensation plans will be contained in OER's management information circular to be mailed in connection with the meeting of shareholders scheduled to be held in 2014.

Additional financial information is also provided in OER's annual audited consolidated financial statements and management's discussion and analysis for the year ended December 31, 2013. The audit report relating to those financial statements was prepared by each of PricewaterhouseCoopers LLP and PricewaterhouseCoopers Chartered Accountants Nigeria. PricewaterhouseCoopers LLP is independent of OER in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta. PricewaterhouseCoopers Chartered Accountants Nigeria is independent of OER in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Nigeria.

SCHEDULE "A" – FORM 51-101F1 STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

FORM 51-101 F1

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Oando Energy Resources Inc.

Period Ending: December 31, 2013

Report Prepared: March 28, 2014

This page is intentionally blank

CONTENT

CAUTIONARY STATMENTS 8

DEFINITIONS 10

PART 1: DATE OF STATEMENT 12

PART 2: DISCLOSURE OF RESERVES DATA 13

Item 2.3 Reserves Disclosure Varies with Accounting 26

Item 2.4 Future Net Revenue Disclosure Varies with Accounting 26

PART 3: PRICING ASSUMPTIONS 27

Item 3.1 Constant Prices Used in Supplemental Estimates 27

Item 3.2 Forecast Prices Used in Estimates 27

PART 4: RECONCILIATION OF CHANGES IN RESERVES 28

Item 4.1 Reserves Reconciliation (Forecast prices and costs) 28

PART 5: ADDITIONAL INFORMATION RELATING TO RESERVES DATA 31

Item 5.1 (a) Undeveloped Reserves 31

Item 5.3 Future Development Costs 32

PART 6: OTHER OIL AND GAS INFORMATION 33

Item 6.1 Oil and Gas Properties 33

Item 6.2 Properties With No Attributed Reserves 36

Item 6.5 Tax Horizon 37

Item 6.6 Costs Incurred 37

Item 6.7 Exploration & Development Activities 38

Item 6.8 Future Production Estimates 41

Item 6.9 Production History 42

This page is intentionally blank

CAUTIONARY STATEMENTS

In general, estimates of oil and gas reserves, resources, future net revenues and net present values are based upon forward-looking information and a number of variable factors and assumptions, such as the anticipated price of oil and gas, operating costs, well pressure, product characteristics and viscosity, production rates, ultimate reserve recovery, timing and amount of capital expenditures, location and capacity of local infrastructure, marketability of the oil and gas, royalty rates, tax rates and other economic factors, regulation by governmental and other regulatory agencies, and many other factors (including, for resources, discovery and commerciality). For those reasons, estimates of the oil reserves and resources attributable to any particular group of properties, as well as the classification of such reserves and resources (based on risk of recovery) and estimates of future net revenues associated with such reserves and resources prepared by different engineers (or by the same engineers at different times) may vary. The actual reserves and resources of OER may be greater or less than those estimated and such variation may be material.

In addition, OER's actual production, revenues, development, capital and operating expenditures, as applicable, with respect to its reserves and resources will vary from estimates thereof and such variations could be material. Any activities undertaken by OER to develop or permit the reclassification of its reserves and resources will be subject to the terms of the applicable contractual arrangement.

Statements relating to “net present value”, “future net revenues”, “reserves” and “resources” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future. Since Forward-looking information addresses future events and conditions, by its nature it involves inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital form internal and external sources and changes in tax, royalty and environmental legislations.

Contingent Resources - There is no certainty that it will be commercially viable to produce any portion of the contingent resources. Moreover, the volumes of contingent resources reported herein are sensitive to economic assumptions, including capital and operating costs and commodity pricing. Estimates of contingent resources have not been adjusted for risk based on the chance of development. There is no certainty as to the timing of any such development.

Prospective Resources - These are partially risked prospective resources that have been risked for chance of discovery, but have not been risked for chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Production information is commonly reported in units of barrel of oil equivalents or boes. Barrel of oil equivalents or boes may be misleading, particularly if used in isolation. Volumes of natural gas, in this report, have been converted to crude oil equivalent volumes assuming that 6 Mscf of natural gas is equivalent to one barrel of crude oil. A boe conversion ratio of 6 mscf: 1 bbl based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ration based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 ratio may be misleading as an indication of value.

NOTICE REGARDING RESERVES, RESOURCES, COST AND FINANCIAL INFORMATION

Reserves and Resources – The following terminology is used in respect of production, reserves and resources throughout this document:

- **'Gross'** or '**gross'** – when used in relation to production, reserves and resources means OER's working interest share of production, reserves and resources before deduction of royalties.
- **'Net'** or '**net'** – when used in relation to production, reserves and resources means either OER's working interest share of production, reserves and resources after deduction of royalties or OER's entitlement to production reserves and resources after deduction of royalties and tax oil (Petroleum Profits Tax) for Production Sharing Contracts. In relation to OER's interest in wells, "Net" or "net" means the number of wells obtained by aggregating OER's working interest in each of its gross wells. In relation to OER's interest in property, "Net" or "net" means the total area in which OER has an interest multiplied by the working interest owned by OER.

Unless otherwise stated, all contingent and prospective resources referred to herein have been presented on a Best Estimate basis.

Cost and Financial - Unless otherwise stated, all cost and financial information referred to herein have been expressed in Canadian dollars. An exchange rate of 1 US$ = 1.063915 CAN$ (based on the average value for December 2013 as published by the Bank of Canada) has been assumed in converting US$ to CAN$.

Please note that rounding errors may occur in the tables set forth below in the statement of reserves data and other oil and gas information.

INTRODUCTION

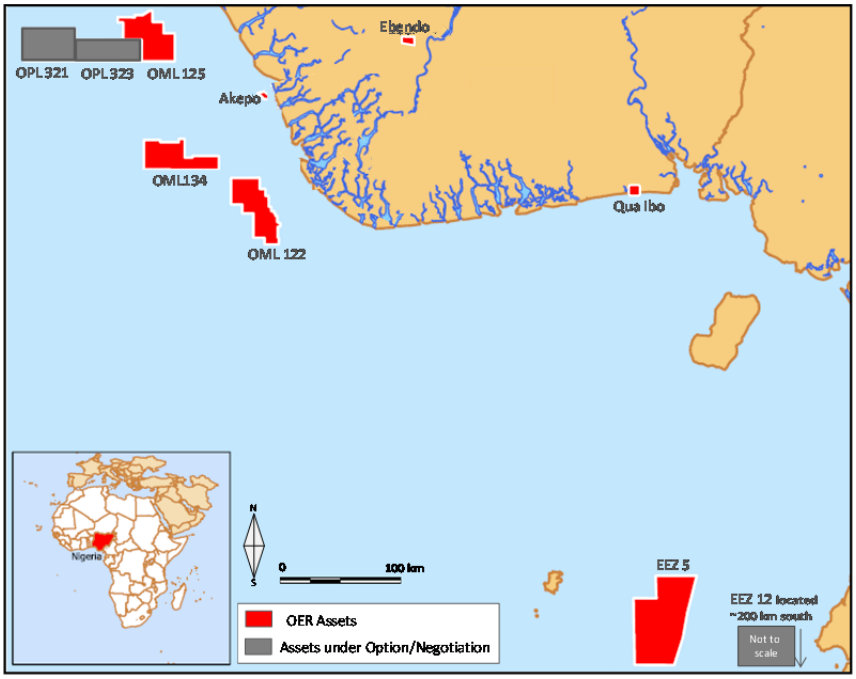
The Petroleum and Renewable Energy Company Limited ('Petrenel'), at the request of Oando Energy Resources Inc. ('OER' or 'Company'), has undertaken an independent assessment of the Company's petroleum reserves, resources, future net revenue and net present values.

This statement of reserves and other oil and gas information set forth below was issued on February 20, 2014 and is a summary of information contained in the Annual Petroleum Reserves Review Report, 2013 (the 'Petrenel Report'), which has an effective date of December 31, 2013 and was prepared using data up to December 31, 2013.

The Petrenel Report and information contained herein has been prepared in accordance with the standards and requirements contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ('NI 51-101') and complies with the Canadian Securities Administrators ('CSA') reporting requirements (October 2010), as stated in NI 51-101, its companion policy and the Canadian Oil and Gas Evaluation Handbook ('COGE Handbook'). The data for Petrenel's review were provided by OER or sourced from the public domain. Petrenel has relied on the data to be a comprehensive and representative dataset and has accepted, without independent verification, the completeness and validity of such data.

Readers are referred to NI 51-101 and to Canadian Securities Administrators Staff Notice 51-324 Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities for a glossary of terminology and definitions relating to the information included within this statement.

All of OER's reserves and resources associated with OER's assets referred to herein are located in Nigeria, both onshore and in Nigerian waters offshore (these include the following Licences: OML 125, OML 134, Ebendo (OML 56), Akepo (OML 90), Qua Ibo (OML 13), OML 122, OPL 321 and OPL 323. OER held Licences outside of Nigeria, in the Democratic Republic of Sao Tome and Principe, Zambia and Turkey, but as of December 31, 2013 OER exited Turkey and the Zambian license has been allowed to lapse.



OER's interests which are detailed in this statement are held as follows:

Property (Licence Area)	Interest Held By	OER Working Interest (WI)	Partners and Working Interests Held
OML 125	Oando OML 125 & 134 Limited	15%	Nigerian Agip Exploration (85%, operator)
Ebendo (OML 56)[4]	Oando Petroleum Development Company Limited	42.75%[1]	Energia Limited (55%, operator)
Akepo (OML 90)[4]	Oando Akepo Limited	40%	Sogenal (60%, operator)
Qua Ibo (OML 13)[4]	Oando Qua Ibo Limited	40%	Network Exploration & Production Nigeria ('NEPN') (60%, operator)
OML 134	Oando OML 125 & 134 Limited	15%	Nigerian Agip Exploration (85%, operator)
OML 122	Equator Exploration Nigeria 122 Limited	4.08% (oil) 10.2% (gas)	Peak Petroleum Industries Nigeria Limited (95% oil, 89.8% gas, operator)
OPL 321	Equator Exploration Nigeria 321 Limited	24.45%[3]	Korean National Oil Company (60%, operator) & Tulip Energy Resources (10%)
OPL 323	Equator Exploration Nigeria 323 Limited	24.45%[3]	Korean National Oil Company (60%, operator) & NJ Exploration (10%)

Notes:

1. OER hold a 95% equity interest in Oando Petroleum Development Company Limited, which holds a 45% Working Interest in Ebendo
2. OER hold a 81.50% equity interest in Equator Exploration Limited, which holds a 5% Working Interest in the oil in OML 122 and a 12.5% equity interest in the gas in OML 122
3. OER hold a 81.50% equity interest in Equator Exploration Limited, which holds a 30% Working Interest in OPL 321 and OPL 323
4. The Marginal fields have been carved out of existing Licences and are no longer part of the OML. However, the previous OML has been included in brackets for identification purposes.

Licences with Production

OML 125 (15% WI; operator NAE) is located offshore approximately 40 km from the western Nigerian coast in water depths ranging from 550 m to 1,100 m. The Licence covers an area of 1,983 km^2 (490,010 acres). The Licence includes one producing field (Abo field), one undeveloped discovery (Abo North) and 13 prospects. Production from the Abo field began in 2003 and the field currently has four producing wells (with a further producer shut-in awaiting flowline repairs), two water injection wells and two gas injection wells. In 2013, daily average production from the Abo field was 3,319 bbls/d of light to medium oil (gross, WI) and during that year the field produced a total of 1.21 MMbbls oil (gross, WI). As of December 31, 2013, OML 125 had (gross, WI) 2P reserves of 6.6 MMbbls oil, Best estimate Contingent resources of 5.1 MMboe (comprising 2.7 MMbbls oil and 14.5 Bscf of gas) and Best estimate Unrisked Prospective resources of 228.5 MMboe (comprising 189.2 MMbbls oil and 235.6 Bscf gas) (risked: 33.5 MMboe, comprising 27.8 MMbbls oil and 34.1 Bscf gas). OML 125 operates under a Production Sharing Contract.

Ebendo (42.75% WI; operator Energia), is located in the former OML 56 in the central Niger Delta, approximately 100 km north-west of Port Harcourt. The Licence covers an area of 65 km^2 (16,062 acres). The Licence includes two fields, the Ebendo field (producing) and the Obodeti field (undeveloped). Production from the Ebendo field began in 2009 and the field currently has three producing wells, and one which has been drilled but has yet to commence production. In 2013, daily average production from the Ebendo field was 860 bbls/d oil and 2,387 Mscf/d of sales gas (gross, WI) and during that year the field produced a total of 0.31 MMbbls oil and 0.87 Bscf gas (gross, WI). As of December 31, 2013, Ebendo had (gross, WI) 2P reserves of 10.8 MMboe (comprising 5.4 MMbbls oil and 32.8 Bscf gas) and Best Estimate Contingent resources of 6.2 MMboe (comprising 4.8 MMbbls oil and 8.3 Bscf gas). Ebendo operates under Marginal Field terms that benefit from advantageous fiscal terms.

Licences without Production

Akepo (40% WI and technical partner; operator Sogenal) is located in the former OML 90 in shallow water (<20 m) of the western Niger Delta. The Licence covers an area of 26 km^2 (6,425 acres). The Licence includes one undeveloped field (Akepo) and two prospects (A and B, collectively referred to as Akepo North). The Akepo field was discovered in 1993 and is currently being developed. The Akepo field is expected to commence production from a single well in Q3 2014, evacuating production through a barge to the terminal at Escravos. As of December 31, 2013, Akepo had (gross, WI) 2P reserves of 0.6 MMbbls oil, Best Estimate Contingent resources of 0.3 MMbbls oil and Best Unrisked Prospective resources of 3.9 MMboe (comprising of 3.3 MMbbls oil and 3.8 Bscf gas) (risked: 1.5 MMboe, comprising 1.2 MMbbls oil and 1.5 Bscf gas). Akepo operates under Marginal Field terms that benefit from advantageous fiscal terms.

Qua Ibo (40% WI and technical partner; operator NEPN) is located in onshore Nigeria near the mouth of the Qua Iboe River immediately adjacent to the ExxonMobil Qua Iboe Terminal. The Licence covers an area of 14 km^2 (3,459 acres) and includes one undeveloped field (Qua Ibo). The Qua Ibo field was acquired by OER during 2013, it is expected to commence production initially from a single well through an Early Production Facility in Q4 2014, with production from a further two wells to commence in Q1 2015 upon completion of the Group Gathering Facility. As of December 31, 2013, Qua Ibo had (gross, WI) 2P reserves of 0.9 MMbbls oil and Best Estimate Contingent resources of 2.9 MMbbls oil. Qua Ibo operates under Marginal Field terms that benefit from advantageous fiscal terms.

OML 134 (15% WI; operator NAE) is located offshore in water depths ranging from 550 m to 1,100 m approximately 80 km from the western Nigerian coast. The Licence covers an area of 1,132 km^2 (279,723 acres). The Licence includes three undeveloped discoveries (Oberan-1 fault block, Oberan-2 fault block and Minidiogboro), two single-well discoveries (Engule and Udoro) and nine prospects. There has been no production from OML 134 to date. As of December 31, 2013, OML 134 had (gross, WI) Best estimate Contingent resources of 12 MMboe (comprising 6.3 MMbbls oil and 34.2 Bscf gas) and Best estimate Unrisked Prospective resources of 73.9 MMboe (comprised 61.8 MMbbls oil and 72.9 Bscf gas) (risked: 16.7 MMboe, comprised 13.9 MMbbls oil and 16.8 Bscf gas).

OML 122 (4.08% oil WI and 10.2% gas WI; operator Peak) is located in the offshore Niger Delta, 40 km from the coastline of southern Nigeria, at a water depth of between 40 m to 300 m. The Licence covers an area of 1,599 km^2 (395,122 acres). The Licence is currently subject to a dispute between Peak and OER. The Licence includes three discoveries (Bilabri, Orobiri and Owanare). There has been no production from OML 122 to date. As of December 31, 2013, OML 122 had (gross, WI) Best Estimate Contingent resources of 11.4 MMboe (comprising 0.3 MMbbls oil and 66.8 Bscf gas).

OPL 321 and OPL 323 (24.5% WI; operator KNOC) are located adjacent to OML 125, offshore from the Nigerian coast, at a water depth of 950 m to 2,000 m. The Licences cover a combined area of 2,147 km^2 (530,535 acres). The Licences are presently the subject of a dispute between the operator, KNOC, and the Nigerian Government. Due to this ongoing dispute, since 2008 exploration on these Licences has not been possible and as a result, OER requested and received a refund of the aggregate signature bonus paid by OER in respect of the two Licences ($162 million). No wells have been drilled on the Licences to date. The Licence includes five sizeable prospects (Gorilla, Lobster, Octopus and Whale (OPL 323) and Elephant (OPL 321)). As of December 31, 2013, both Licences had (gross, WI) Best Unrisked Prospective resources of 1,089 MMboe (comprising 610.4 MMbbls oil and 2,689 Bscf gas) (risked: 229 MMboe, comprising 128.2 MMbbls oil and 604.5 Bscf gas). The probability of success given to these prospects range from 20% to 25%.

DEFINITIONS

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical, and engineering data; the use of established technology; specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

Reserve Categories:

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. There is at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Probable reserves are those reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable plus possible reserves. There is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves are those reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. There is at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves plus possible reserves.

Developed reserves are those reserves expected to be recovered from existing and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing:

Developed producing reserves are those reserves expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped reserves are reserves that are expected to be recovered from known accumulations with new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units directly offsetting development spacing areas that are reasonably certain of production when drilled unless reliable technology exists that establishes reasonable certainty of economic production at greater distances. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

Levels of Certainty for Reported Reserves - A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or lack of infrastructure or markets. It is also appropriate to classify as Contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

> ***Best estimate (2C)*** is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate.
>
> ***Low estimate (1C)*** is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty - a 90% confidence level - that the actual quantities recovered will equal or exceed the estimate.
>
> ***High estimate (3C)*** is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty - a 10% confidence level - that the actual quantities recovered will equal or exceed the estimate.

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.

> ***Best estimate*** is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate.
>
> ***Low estimate*** is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty (a 90% confidence level) that the actual quantities recovered will equal or exceed the estimate.
>
> ***High estimate*** is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty (a 10% confidence level) that the actual quantities recovered will equal or exceed the estimate.

PART 1: DATE OF STATEMENT

The *effective date* of the information being provided herein is December 31, 2013.

The *preparation date* of the information being provided herein is March 27, 2014.

PART 2: DISCLOSURE OF RESERVES DATA

The following is a summary of the oil and gas reserves and the net present values of future net revenue of OER's assets as evaluated by Petrenel. Petrenel is an independent, qualified reserves and resource evaluator appointed by the Company pursuant to NI 51-101 to prepare an Independent Annual Review of Petroleum Resources for OER with an effective date of December 31, 2013. Petrenel, in aggregate, evaluated or audited 100% of the future net revenue, calculated using a discount rate of 10%, attributable to proved plus probable reserves associated with OER's assets.

All evaluations of future net revenue are after deduction of royalties, development cost, production costs, abandonment costs and taxes (unless otherwise stated) but before consideration of indirect cost such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the estimates of future net revenue presented in the following tables represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Petrenel Report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the Petrenel Report. The recovery and reserve estimates attributed to the OER's properties described herein are estimates only. The actual reserves attributed to the OER's properties may be greater or less than those calculated. The range in estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as the range in estimates of reserves and future net revenue for all properties in combination, due to effects of aggregation.

The Proved, Probable and Possible reserves and Low, Best and High estimates of Contingent resources presented in this form are the arithmetic sum of estimates from multiple fields and/or reservoirs. The Proved plus Probable plus Possible estimates of reserves and the High estimate of Contingent resources for each field and/or reservoir is considered to represent a 10% percentile (P10) value (COGE Handbook Volume 1, Section 9). The Proved estimate of reserves and Low estimate of Contingent resources for each field and/or reservoir is considered to represent a 90% percentile (P90) value. Statistical principles indicate that the aggregated arithmetic sum of individual P90 values may have a higher probability of occurrence and the sum of the P10 values may have a lower probability of occurrence. Readers should give attention to the estimates of individual classes of Proved, Probable and Possible reserves and Low, Best and High estimates of Contingent resources and appreciate the differing probabilities associated with each class.

The Petrenel Report is based on certain factual data supplied by OER, including ownership, well data, production data, prices for product sold, revenues, operating costs, capital costs, contracts, and other relevant data. The supplied information was only relied upon where, in Petrenel's opinion, it appeared reasonable and consistent with its knowledge of the properties. No independent verification of the information provided by OER was made. Petrenel has also relied upon representations made by OER as to the completeness and accuracy of the data provided.

Please note that rounding errors may occur in the tables set forth below in the statement of reserves data and other oil and gas information.

Risks Related to Illegal Bunkering and Sabotage

Statements relating to production, reserves and resources, net present value and future net revenues attributed to Ebendo are negatively impacted by illegal bunkering (or theft) of oil and the sabotage of oil pipelines. The estimates of illegal bunkering and sabotage losses are based on information from the field operator, who currently pay a 27% charge to the pipeline operator (Nigerian Agip Oil Company) to cover these losses (latest data available up to July 2013). There is considerable uncertainty in the estimated losses, as oil production leaving the gathering stations is not accurately metered. The completion of a second pipeline at Ebendo, the Umugini pipeline (which leads to the Trans-Forcados pipeline), also has significant uncertainty over losses and these are forecast by Petrenel to be 17% in line with published data for the area. Trucking losses for Ebendo are taken to be zero, on the understanding that there is goods-in-transit insurance cover in-place; this will address any losses during custody transfer.

Item 2.1 Reserves Data

1. All Reserves (Forecast Prices and Costs)

All OER Assets (Abo (OML 125), Ebendo (OML 56), Qua Ibo (OML 13) and Akepo (OML 90))

	Light & Medium Oil[1]		Natural Gas[2]		Natural Gas Liquids		Oil Equivalent[3]	
Reserves Category	**Gross [4]**	**Net[5]**	**Gross[4]**	**Net[5]**	**Gross [4]**	**Net[5]**	**Gross[4]**	**Net[5]**
	(Mbbls)	*(Mbbls)*	*(MMscf)*	*(MMscf)*	*(Mbbls)*	*(Mbbls)*	*(Mboe)*	*(Mboe)*
Proved								
Developed Producing	4,016	3,118	7,615	7,205	-	-	5,285	4,319
Developed Non-Producing	1,455	1,203	7,868	7,445	-	-	2,766	2,444
Undeveloped	2,370	2,430	6,077	5,750	-	-	3,382	3,388
Total Proved	**7,841**	**6,752**	**21,559**	**20,400**	**-**	**-**	**11,434**	**10,152**
Probable	5,635	4,431	11,271	10,665	-	-	7,514	6,209
Total Proved Plus Probable	**13,476**	**11,183**	**32,830**	**31,065**	**-**	**-**	**18,948**	**16,361**
Possible[6]	4,997	3,854	17,907	16,944	-	-	7,981	6,678
Total Proved Plus Probable Plus Possible	**18,473**	**15,038**	**50,737**	**48,009**	**-**	**-**	**26,929**	**23,039**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs
2. Natural gas resources include both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, losses, and shrinkage
3. Natural gas has been converted to barrels of oil equivalent on the basis of six Mscf of natural gas being equal to one barrel of oil. The conversion is based on energy equivalency and does not necessarily represent a value equivalency at the wellhead
4. Gross – OER's share (WI) before deduction of royalties.
5. Net – OER's entitlement (WI) after deduction of royalties.
6. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
7. Numbers may not add up due to rounding

The following set of tables (A, B, C and D) shows the breakdown of reserves for each asset within OER's portfolio, as reflected in the above table.

A. Abo (OML 125)

	Light & Medium Oil[1]		Natural Gas		Natural Gas Liquids		Oil Equivalent	
Reserves Category	**Gross [3]**	**Net[4]**	**Gross[3]**	**Net[4]**	**Gross [3]**	**Net[4]**	**Gross[3]**	**Net[4]**
	(Mbbls)	*(Mbbls)*	*(MMscf)*	*(MMscf)*	*(Mbbls)*	*(Mbbls)*	*(Mboe)*	*(Mboe)*
Proved								
Developed Producing	2,439	1,582	-	-	-	-	2,439	1,582
Developed Non-Producing	402	181	-	-	-	-	402	181
Undeveloped	555	485	-	-	-	-	555	485
Total Proved	**3,397**	**2,247**	**-**	-	**-**	-	**3,397**	**2,247**
Probable	3,173	1,969	-	-	-	-	3,173	1,969
Total Proved Plus Probable	**6,570**	**4,217**	-	-	-	-	**6,570**	**4,217**
Possible[5]	1,990	916	-	-	-	-	1,990	916
Total Proved Plus Probable Plus Possible	**8,560**	**5,133**	-	-	-	-	**8,560**	**5,133**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs
3. Gross – OER's share (WI) before deduction of royalties.
4. Net – OER's entitlement (WI) after deduction of royalties.
5. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
6. Numbers may not add up due to rounding

B. Ebendo (OML 56)

Reserves Category	Light & Medium Oil[1]		Natural Gas[2]		Natural Gas Liquids		Oil Equivalent[3]	
	Gross [4]	Net[5]	Gross[4]	Net[5]	Gross [4]	Net[5]	Gross[4]	Net[5]
	(Mbbls)	*(Mbbls)*	*(MMscf)*	*(MMscf)*	*(Mbbls)*	*(Mbbls)*	*(Mboe)*	*(Mboe)*
Proved								
Developed Producing	1,577	1,536	7,615	7,205	-	-	2,846	2,737
Developed Non-Producing	1,052	1,023	7,868	7,445	-	-	2,364	2,264
Undeveloped	761	738	6,077	5,750	-	-	1,774	1,697
Total Proved	**3,391**	**3,298**	**21,559**	**20,400**	**-**	**-**	**6,984**	**6,698**
Probable	1,965	1,906	11,271	10,665	-	-	3,843	3,683
Total Proved Plus Probable	**5,355**	**5,203**	**32,830**	**31,065**	**-**	**-**	**10,827**	**10,381**
Possible[6]	2,193	2,112	17,907	16,944	-	-	5,178	4,936
Total Proved Plus Probable Plus Possible	**7,549**	**7,316**	**50,737**	**48,009**	**-**	**-**	**16,005**	**15,317**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs
2. Natural gas resources include both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, losses, and shrinkage
3. Natural gas has been converted to barrels of oil equivalent on the basis of six Mscf of natural gas being equal to one barrel of oil. The conversion is based on energy equivalency and does not necessarily represent a value equivalency at the wellhead
4. Gross – OER's share (WI) before deduction of royalties.
5. Net – OER's entitlement (WI) after deduction of royalties.
6. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
7. Numbers may not add up due to rounding

C. Akepo (OML 90)

Reserves Category	Light & Medium Oil[1]		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross [3]	Net[4]	Gross[3]	Net[4]	Gross [3]	Net[4]	Gross[3]	Net[4]
	(Mbbls)	*(Mbbls)*	*(MMscf)*	*(MMscf)*	*(Mbbls)*	*(Mbbls)*	*(Mboe)*	*(Mboe)*
Proved								
Developed Producing	-	-	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	396	582	-	-	-	-	396	582
Total Proved	**396**	**582**	**-**	**-**	**-**	**-**	**396**	**582**
Probable	230	302	-	-	-	-	230	302
Total Proved Plus Probable	**625**	**884**	**-**	**-**	**-**	**-**	**625**	**884**
Possible[5]	439	470	-	-	-	-	439	470
Total Proved Plus Probable Plus Possible	**1,065**	**1,355**	**-**	**-**	**-**	**-**	**1,065**	**1,355**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs
3. Gross – OER's share(WI) before deduction of royalties.
4. Net – OER's entitlement (WI) after deduction of royalties. Net entitlement is greater than gross entitlement because of carry arrangement with Sogenal
5. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
6. Numbers may not add up due to rounding

D. Qua Ibo (OML 13)

Reserves Category	Light & Medium Oil[1]		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross [3]	Net[4]	Gross[3]	Net[4]	Gross [3]	Net[4]	Gross[3]	Net[4]
	(Mbbls)	*(Mbbls)*	*(MMscf)*	*(MMscf)*	*(Mbbls)*	*(Mbbls)*	*(Mboe)*	*(Mboe)*
Proved								
Developed Producing	-	-	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	657	624	-	-	-	-	657	624
Total Proved	**657**	**624**	**-**	-	**-**	-	**657**	**624**
Probable	268	254	-	-	-	-	268	254
Total Proved Plus Probable	**925**	**879**	-	-	-	-	**925**	**879**
Possible[6]	375	356	-	-	-	-	375	356
Total Proved Plus Probable Plus Possible	**1,300**	**1,235**	-	-	-	-	**1,300**	**1,235**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs
3. Gross – OER entitlement (WI) before deduction of royalties.
4. Net – OER entitlement (WI) after deduction of royalties.
5. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
6. Numbers may not add up due to rounding

2. Net Present Value of Future Net Revenue (Forecast Prices and Costs)

The absolute and unit net present values of future net revenue, as defined by NI 51-101, net to OER's interest are shown below using Petrenel's forecast prices and costs.

All OER Assets (including Abo (OML 125), Ebendo (OML 56), Qua Ibo (OML 13) and Akepo (OML 90))

Reserves Category	Before Income Taxes[1] Discounted at (%/year)					After Income Taxes[1] Discounted at (%/year)					Unit Value[3] Before Income Tax Discounted at 10%/year
	0	5	10	15	20	0	5	10	15	20	
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*($/boe)*
Proved											
Developed Producing	183.0	169.4	157.8	147.9	139.3	101.3	92.8	85.7	79.7	74.6	29.9
Developed Non-Producing	108.6	94.8	83.7	74.6	67.0	56.2	49.3	43.7	39.1	35.3	30.3
Undeveloped	128.2	107.8	91.4	78.0	67.0	90.4	77.4	66.9	58.1	50.8	27.0
Total Proved	**419.9**	**372.0**	**332.9**	**300.5**	**273.2**	**247.8**	**219.5**	**196.3**	**177.0**	**160.7**	**29.1**
Probable	349.9	289.1	243.6	208.9	181.7	173.9	145.6	124.3	107.8	94.7	32.4
Total Proved Plus Probable	**769.8**	**661.1**	**576.5**	**509.3**	**454.9**	**421.7**	**365.2**	**320.6**	**284.7**	**255.4**	**30.4**
Possible[2]	373.8	287.6	228.1	185.7	154.5	176.9	138.5	111.8	92.5	78.2	28.6
Total Proved Plus Probable Plus Possible[2]	**1,143.6**	**948.7**	**804.7**	**695.0**	**609.4**	**598.6**	**503.7**	**432.4**	**377.3**	**333.6**	**29.9**

Notes:
1. The estimated value of future net revenue does not represent the fair market value of OER's reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
3. Unit values are expressed as net present value before tax divided by gross WI share of oil equivalent reserves.
4. Numbers may not add up due to rounding

The following set of tables (A, B, C and D) shows the breakdown of net present value of future revenue for each asset within OER's portfolio.

A. Abo (OML 125)

	Before Income Taxes[1] Discounted at (%/year)					After Income Taxes[1] Discounted at (%/year)					Unit Value[3] Before Income Tax Discounted at 10%/year
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*($/boe)*
Proved											
Developed Producing	117.7	111.0	105.2	100.1	95.6	54.7	51.2	48.2	45.6	43.3	43.1
Developed Non-Producing	29.4	26.2	23.6	21.3	19.4	12.1	10.8	9.7	8.8	8.0	58.7
Undeveloped	1.0	(1.9) [4]	(4.2) [4]	(6.1) [4]	(7.7) [4]	2.3[4]	0.6	(0.7) [4]	(1.8) [4]	(2.7) [4]	(7.6) [4]
Total Proved	**148.1**	**135.4**	**124.6**	**115.3**	**107.2**	**69.0**	**62.6**	**57.2**	**52.6**	**48.6**	**36.7**
Probable	162.2	137.1	117.6	102.3	90.1	75.0	63.6	54.6	47.6	41.9	37.1
Total Proved Plus Probable	**310.3**	**272.5**	**242.2**	**217.6**	**197.3**	**144.0**	**126.2**	**111.8**	**100.1**	**90.5**	**36.9**
Possible[2]	151.8	116.4	91.7	74.1	61.2	67.1	52.0	41.3	33.7	28.0	39.0
Total Proved Plus Probable Plus Possible[2]	**462.2**	**388.9**	**334.0**	**291.7**	**258.5**	**211.2**	**178.1**	**153.2**	**133.8**	**118.5**	**39.0**

Notes:
1. The estimated value of future net revenue does not represent the fair market value of OER's reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
3. Unit values are expressed as net present value before tax divided by gross WI share of oil equivalent reserves.
4. Negative values are presented in brackets
5. Numbers may not add up due to rounding

B. *Ebendo (OML 56)*

	Before Income Taxes[1] Discounted at (%/year)					After Income Taxes[1] Discounted at (%/year)					Unit Value Before[3] Income Tax Discounted at 10%/year
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*($/boe)*
Proved											
Developed Producing	65.3	58.3	52.6	47.8	43.7	46.6	41.7	37.6	34.2	31.3	33.4
Developed Non-Producing	79.3	68.6	60.1	53.2	47.5	44.1	38.5	34.0	30.3	27.3	57.1
Undeveloped	63.3	52.6	44.2	37.7	32.4	30.2	24.9	20.8	17.6	15.0	58.1
Total Proved	**207.8**	**179.5**	**156.9**	**138.7**	**123.7**	**120.9**	**105.1**	**92.4**	**82.1**	**73.5**	**46.3**
Probable	141.3	111.9	90.9	75.5	63.9	70.6	57.1	47.3	40.0	34.5	46.3
Total Proved Plus Probable	**349.2**	**291.4**	**247.8**	**214.2**	**187.6**	**191.5**	**162.1**	**139.7**	**122.1**	**108.1**	**46.3**
Possible[2]	169.0	126.0	97.3	77.4	63.2	83.4	63.7	50.3	41.0	34.2	44.4
Total Proved Plus Probable Plus Possible[2]	**518.1**	**417.4**	**345.1**	**291.6**	**250.8**	**275.0**	**225.8**	**190.0**	**163.1**	**142.2**	**45.7**

Notes:
1. The estimated value of future net revenue does not represent the fair market value of OER's reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
3. Unit values are expressed as net present value before tax divided by gross WI share of oil equivalent reserves.
4. Negative numbers are presented in brackets
5. Numbers may not add up due to rounding

C. *Akepo (OML 90)*

Reserves Category	Before Income Taxes[1] Discounted at (%/year) 0	5	10	15	20	After Income Taxes[1] Discounted at (%/year) 0	5	10	15	20	Unit Value Before[3] Income Tax Discounted at 10%/year
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*($/boe)*
Proved											
Developed Producing	-	-	-	-	-	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	41.7	38.6	35.9	33.4	31.2	39.5	36.6	34.0	31.7	29.7	90.6[4]
Total Proved	**41.7**	**38.6**	**35.9**	**33.4**	**31.2**	**39.5**	**36.6**	**34.0**	**31.7**	**29.7**	**90.6[4]**
Probable	24.9	22.2	19.8	17.8	16.1	18.7	16.7	15.0	13.5	12.3	86.3[4]
Total Proved Plus Probable	**66.7**	**60.8**	**55.7**	**51.2**	**47.4**	**58.3**	**53.3**	**49.0**	**45.3**	**42.0**	**89.0[4]**
Possible[2]	21.3	18.7	16.6	14.7	13.2	13.0	11.7	10.5	9.5	8.6	37.7[4]
Total Proved Plus Probable Plus Possible[2]	**88.0**	**79.5**	**72.2**	**66.0**	**60.5**	**71.3**	**65.0**	**59.6**	**54.8**	**50.6**	**67.8[4]**

Notes:

1. The estimated value of future net revenue does not represent the fair market value of OER's reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
3. Unit values are expressed as net present value before tax divided by gross WI share of oil equivalent reserves.
4. High unit value is due to the carry arrangement
5. Negative numbers are presented in brackets
6. Numbers may not add up due to rounding

D. *Qua Ibo (OML 13)*

Reserves Category	Before Income Taxes[1] Discounted at (%/year) 0	5	10	15	20	After Income Taxes[1] Discounted at (%/year) 0	5	10	15	20	Unit Value Before[3] Income Tax Discounted at 10%/year
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*($/boe)*
Proved											
Developed Producing	-	-	-	-	-	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	22.2	18.5	15.5	13.1	11.0	18.4	15.2	12.7	10.6	8.9	23.6
Total Proved	**22.2**	**18.5**	**15.5**	**13.1**	**11.0**	**18.4**	**15.2**	**12.7**	**10.6**	**8.9**	**23.6**
Probable	21.4	18.0	15.3	13.2	11.6	9.5	8.3	7.4	6.6	6.0	57.2
Total Proved Plus Probable	**43.6**	**36.5**	**30.8**	**26.3**	**22.6**	**27.9**	**23.6**	**20.1**	**17.2**	**14.8**	**33.3**
Possible[2]	31.7	26.5	22.5	19.4	17.0	13.3	11.2	9.6	8.4	7.4	60.1
Total Proved Plus Probable Plus Possible[2]	**75.3**	**63.0**	**53.4**	**45.8**	**39.6**	**41.2**	**34.8**	**29.7**	**25.6**	**22.3**	**41.1**

Notes:

1. The estimated value of future net revenue does not represent the fair market value of OER's reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
3. Unit values are expressed as net present value before tax divided by gross WI share of oil equivalent reserves.
4. Negative numbers are presented in brackets
5. Numbers may not add up due to rounding

3. Additional Information Concerning Future Net Revenue (Forecast Prices and Costs)

The revenue, royalties, costs and taxes associated with the estimate of future net revenue for all OER's Assets using Petrenel's forecast prices and costs at zero discount rate, are shown below.

All OER Assets (Abo (OML 125), Ebendo (OML 56), Qua Ibo (OML 13) and Akepo (OML 90))

Reserves Category	Revenue	Royalties	Levies & Duties	Operating Costs	Development Costs	Abandonment & Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes(1)	Future Net Revenue After Income Taxes
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*
Proved Reserves	888.2	56.5	19.1	258.6	98.0	36.1	419.9	172.1	247.8
Proved Plus Probable Reserves	1,502.6	100.1	32.0	461.7	96.2	43.1	769.8	348.1	421.7
Proved Plus Probable Plus Possible Reserves(1)	2,031.5	140.2	43.4	570.5	96.5	38.1	1,143.6	545.0	598.6

Notes:
1. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
2. Numbers may not add up due to rounding

The following set of tables (A, B, C and D) shows the revenue, royalties, costs and taxes associated with the estimate of net revenue breakdown for each asset within OER's portfolio, as reflected in the above table.

A. Abo (OML 125)

Reserves Category	Revenue	Royalties	Levies & Duties	Operating Costs	Development Costs	Abandonment & Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes(1)	Future Net Revenue After Income Taxes
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*
Proved Reserves	358.1	30.1	8.7	96.3	53.3	21.5	148.1	79.1	69.0
Proved Plus Probable Reserves	692.1	58.2	16.3	225.1	53.5	28.6	310.3	166.3	144.0
Proved Plus Probable Plus Possible Reserves(1)	899.2	76.2	20.7	263.1	52.7	24.3	462.2	251.0	211.2

Notes:
1. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
2. Numbers may not add up due to rounding

B. Ebendo (OML 56)

Reserves Category	Revenue	Royalties	Levies & Duties	Operating Costs	Development Costs	Abandonment & Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes(1)	Future Net Revenue After Income Taxes
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*
Proved Reserves	380.2	20.2	8.7	107.0	31.2	5.1	207.8	86.9	120.9
Proved Plus Probable Reserves	607.3	33.5	13.6	174.2	31.5	5.4	349.2	157.6	191.5
Proved Plus Probable Plus Possible Reserves(1)	864.4	52.9	18.9	237.4		5.4	518.1	243.2	275.0

Notes:
1. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
2. Numbers may not add up due to rounding

C. Akepo (OML 90)

Reserves Category	Revenue	Royalties	Levies & Duties	Operating Costs	Development Costs	Abandonment & Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes[1]	Future Net Revenue After Income Taxes
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*
Proved Reserves	78.3	2.7	1.7	22.3	5.8	4.1	41.7	2.2	39.5
Proved Plus Probable Reserves	101.9	3.4	2.1	22.9	3.4	3.6	66.7	8.4	58.3
Proved Plus Probable Plus Possible Reserves[1]	125.3	4.0	3.8	23.4	4.0	2.9	88.0	16.7	71.3

Notes:
1. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
2. Numbers may not add up due to rounding

D. Qua Ibo (OML 13)

Reserves Category	Revenue	Royalties	Levies & Duties	Operating Costs	Development Costs	Abandonment & Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes[1]	Future Net Revenue After Income Taxes
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*
Proved Reserves	71.7	3.6	0.0	32.9	7.7	5.3	22.2	3.8	18.4
Proved Plus Probable Reserves	101.2	5.1	0.0	39.4	7.8	5.4	43.6	15.7	27.9
Proved Plus Probable Plus Possible Reserves[1]	142.6	7.1	0.0	46.5	8.2	5.4	75.3	34.1	41.2

Notes:
1. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

The net present value of future net revenue and on a unit value basis for each production group is shown below. All values are net to OER and calculated using forecast prices and costs and calculated using a discount rate of 10%,

All OER Assets (Abo (OML 125), Ebendo (OML 56), Qua Ibo (OML 13) and Akepo (OML 90))

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted by 10%/year) (mm$)	Unit Value Before Income Taxes ($/bbls)/($/Mscf)
Proved Reserves	Light and medium crude oil (including solution gas and other by-products)	328.2	41.9
	Heavy oil (including solution gas and other by-products)	-	-
	Natural gas (including by-products but excluding solution gas from oil wells)	4.7	0.2
	Non-conventional oil and gas activities	-	-
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)	569.8	42.3
	Heavy oil (including solution gas and other by-products)	-	-
	Natural gas (including by-products but excluding solution gas from oil wells)	6.7	0.2
	Non-conventional oil and gas activities	-	-
Proved Plus Probable Plus Possible Reserves[1]	Light and medium crude oil (including solution gas and other by-products)	794.5	43.0
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural gas (including by-products but excluding solution gas from oil wells)	10.1	0.2
	Non-conventional oil and gas activities	-	-

Notes:
1. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
2. Numbers may not add up due to rounding

Item 2.2 Supplementary Disclosure of Reserves Data

1. Constant Prices and Costs

No evaluation using contact prices and costs has been undertaken.

2. Contingent Resources

Contingent resources in respect of oil and gas for OER's interests are listed below. 1C, 2C and 3C refer to the three risk categories of Low, Best and High cases as defined in the COGE Handbook. The reported figures are unrisked gross WI numbers only; net numbers are not included here as not all assets have been economically evaluated and thus any net number would be misleading.

	Contingent Resources by Economic Status and Resource Category (Gross, WI)				
Reserves Category	**Light & Medium Oil[1]**	**Heavy Oil**	**Natural Gas[2]**	**Natural Gas Liquids**	**Oil Equivalent[3]**
	(Mbbls)	(Mbbls)	(MMscf)	(Mbbls)	(Mboe)
Low (1C)	**9,752**	**2,140**	**76,754**	**-**	**24,685**
Economic	5,501	2,140	-	-	7,641
Sub-Economic [6]	3,706	-	33,726	-	9,327
Undetermined[4]	545	-	43,028	-	7,716
Best (2C)	**14,525**	**2,979**	**123,875**	**-**	**38,150**
Economic	7,235	2,979	-	-	10,214
Sub-Economic[6]	6,331	-	54,518	-	15,417
Undetermined[4]	959	-	69,358	-	12,519
High (3C)	**19,609**	**3,817**	**197,905**	**-**	**56,410**
Economic	8,989	3,817	-	-	12,806
Sub-Economic[6]	9,242	-	99,139	-	25,765
Undetermined[4]	1,379	-	98,765	-	17,839

	Contingent Resources by Asset and Resource Category				
Reserves Category	**Light & Medium Oil[1]**	**Heavy Oil**	**Natural Gas[2]**	**Natural Gas Liquids**	**Oil Equivalent[3]**
	(Mbbls)	(Mbbls)	(MMscf)	(Mbbls)	(Mboe)
Low (1C)	**9,752**	**2,140**	**76,754**	**-**	**24,685**
OML 125	2,598	0	8,002	-	3,932
OML 56	2,979	0	5,937	-	3,968
OML 90	327	0	0	-	327
OML 122	142	0	41,866	-	7,120
OML 134	3,706	0	20,948	-	7,197
Qua Ibo	0	2,140	0	-	2,140
Best (2C)	**14,525**	**2,979**	**123,875**	**-**	**38,150**
OML 125	2,713	0	14,518	-	5,133
OML 56	4,842	0	8,305	-	6,226
OML 90	327	0	0	-	327
OML 122	312	0	66,840	-	11,452
OML 134	6,331	0	34,213	-	12,033
Qua Ibo	0	2,979	0	-	2,979
High (3C)	**19,609**	**3,817**	**197,905**	**-**	**56,410**
OML 125	3,191	0	23,433	-	7,097
OML 56	6,545	0	10,834	-	8,350
OML 90	162	0	0	-	162
OML 122	469	0	94,555	-	16,228
OML 134	9,242	0	69,083	-	162
Qua Ibo	0	3,817	0	-	16,228

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs
2. Natural gas resources include both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, losses, and shrinkage
3. Natural gas has been converted to barrels of oil equivalent on the basis of six Mscf of natural gas being equal to one barrel of oil. The conversion is based on energy equivalency and does not necessarily represent a value equivalency at the wellhead
4. Includes properties that were not economically evaluated due to project immaturity
5. Numbers may not add up due to rounding
6. Includes properties that are not economic at current forecast costs and prices to achieve economic viability.

The future net revenue for the net, economic contingent resources is shown in the table below. These are associated only with Abo, Ebendo, Akepo and Qua Ibo; an economic evaluation has not been undertaken for any additional contingent resources.

	Before Income Taxes[1] Discounted at (%/year)					After Income Taxes[1] Discounted at (%/year)					Unit Value Before[3] Income Tax Discounted at 10%/year
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	
	(mm$)	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*(mm$)*	*($/boe)*
Low estimate (1C)	**411.9**	**306.9**	**234.1**	**182.1**	**144.1**	**174.9**	**129.8**	**98.2**	**75.5**	**58.8**	**30.6**
Best estimate (2C)	**689.9**	**498.7**	**370.8**	**282.6**	**220.0**	**286.3**	**205.0**	**150.5**	**112.9**	**86.2**	**36.3**
High estimate (3C)	**938.2**	**666.4**	**489.8**	**370.6**	**278.5**	**394.9**	**277.7**	**201.6**	**150.4**	**114.7**	**38.2**

Notes:

1. The estimated value of future net revenue does not represent the fair market value of OER's contingent resources.

2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
3. Unit values are expressed as net present value before tax divided by gross WI share of oil equivalent resources.
4. Numbers may not add up due to rounding

Certain petroleum resources within OER's assets have been classified as contingent resources. The future classification of these resources as petroleum reserves is contingent upon the following:

Ebendo (OML 56)

Contingent resources in respect of oil and gas in the Ebendo field are located in nine reservoir sands. These resources include the additional oil and gas recovery associated with the implementation of water injection in the field targeted at the XV, XVI, XVII, XVIIIa, XVIIIb, XIX and XXa reservoirs and further infill drilling (Ebendo-8) targeted at the XIIc and XIII reservoirs. Future classification of these resources as petroleum reserves is contingent upon

- further technical studies and subsequent approval of an updated development plan for the field
- confirmation that there is a market for the additional gas.

The possible recovery from the Obodeti field has been classified as Contingent Resources. The recoverable volumes in this field are small and currently considered to be non-commercial at forecast prices and costs. Future classification of these resources as petroleum reserves is contingent upon

- further technical studies leading to either the identification of additional recoverable volumes or a reduction in development costs.

Akepo (OML 90)

Contingent resources in respect of oil are located in one reservoir sand, D-06 associated with the possible implementation of gas lift, which will depend on rate of decline and timing of water breakthrough. Future classification of these resources as petroleum reserves is contingent upon

- the performance of the existing well once it is put on production to establish the need for artificial lift
- further technical studies and subsequent approval of an updated development plan for the field.

OML 122

The Bilabri field contains contingent resources in respect of gas in seven reservoir sands, and contingent resources in respect of oil within a single reservoir. The future classification of these resources as petroleum reserves is contingent upon

- the resolution of a commercial dispute between the partners (see below),
- further technical studies to demonstrate that commercial development is possible,
- preparation and approval of a field development plan,
- unitisation of the field where it extends into the adjacent northern Licence.

The Orobiri field contains contingent resources in respect of gas in three reservoir sands and contingent resources in respect of oil within a single reservoir. The future classification of these resources as petroleum reserves is contingent upon

- the resolution of a commercial dispute between the partners (see below),
- further technical studies to demonstrate that commercial development is possible,
- an increase in oil and or gas prices or reconfiguration of the development concept to reduce development costs,
- preparation and approval of a field development plan.

The Owanare field contains contingent resources in respect of gas in two reservoir sands. The future classification of these resources as petroleum reserves is contingent upon

- the resolution of a commercial dispute between the partners (see below),
- development of a gas market,
- further technical studies to demonstrate that commercial development the gas resources within the Licence and proximal areas is possible,
- preparation and approval of an integrated development plan.

<u>Commercial dispute</u>

In September 2009, Equator Exploration 122 Limited ('EEL') and Peak Petroleum Industries Nigeria ('Peak Petroleum') entered into the Bilabri Settlement Agreement to resolve a number of issues in respect of OML 122. Pursuant to the Bilabri Settlement Agreement, Peak Petroleum undertook to settle invoices paid or payable by EEL to third parties and, in exchange, EEL agreed to reduce its interest in OML 122 to 5% of all crude oil production and 12.5% interest in all natural gas. Peak Petroleum failed to settle such invoices and, in February 2008, EEL began arbitration proceedings. It was awarded $122.7 million in May 2008. Through separate legal proceedings before the Federal High Court of Nigeria, Peak Petroleum sought to prevent the arbitration proceedings from continuing and prevent enforcement of the arbitral award. In November 2008, EEL discontinued its application to register the arbitral award in Nigeria and, in September 2010, it petitioned the Federal High Court of Nigeria to order the winding up of Peak Petroleum. The winding up order was granted in November 2011. Peak Petroleum has filed several appeals in respect of the winding up order, and these are now pending before the court of Appeal in Nigeria. There can be no guarantee that EEL will be successful in recovering the Bilabri Settlement Agreement debt from the liquidator for Peak Petroleum.

OML 125

Contingent resources in respect of oil at Abo are associated with better reservoir management and additional production or injection wells to increase the oil recovery from the B200, B207, B209 and Anom01 sands, from which there is established production, and from the as yet undrained A188, A197, A199, B203 and B248 reservoirs. Gas that has been reinjected into the Abo field and that is technically recoverable in the future has been classified as contingent resources. The future classification of these resources as petroleum reserves is contingent upon

- further technical studies to demonstrate that further development of the field is technically possible and commercially viable,

- preparation and approval of an updated development plan,
- establishment of a gas market.

The small quantities of discovered and recoverable oil and gas in the Abo North field have been classified as contingent resources. These resources are subcommercial at forecast oil and gas prices and the future classification of these resources as petroleum reserves is contingent upon

- further technical studies leading to either the identification of additional recoverable volumes or a reduction in development costs.
- a significant rise in oil price or a reduction in development costs.

OML 134

The technically recoverable oil and gas located in seven discovered reservoir sands in the Oberan-1 fault block, Oberan-2 fault block, and Minidiogboro has been classified as Contingent Resources. Future classification of these resources as reserves is contingent upon:

- further technical studies to confirm recoverable volumes and firm up the development concept,
- development of a commercial outlet for the gas,
- preparation and approval of a field development plan.

Qua Ibo (OML 13)

Qua Ibo contains contingent resources in respect oil and gas. The C4 reservoir, which contains heavy (18°API) oil, requires recompletion and testing, as it has so far failed to flow at commercial oil rates because of sand production, and there are no fields within OML 13 that are producing from the C4 reservoir to provide a suitable analogy for Qua Ibo. There are also contingent resources in respect of oil in the C2 and C3 reservoirs, which have been found by well logging, but the fluid type and reservoir productivity is unknown or uncertain, and there are no plans to develop these reservoirs at present. It is reasonably certain, based on the logs and a comparison with underlying reservoirs that have been tested, that these reservoirs contain hydrocarbons and that they will produce oil and gas. The uncertainty is in what proportion of oil and gas will be produced. Future classification of these resources as reserves is contingent upon:

- demonstration of commercial flow rates from the C4 reservoir.
- testing and confirming hydrocarbon fill of the C2 and C3 reservoirs
- development of a gas market.

Significant Factors or Uncertainties Affecting Contingent Resources Data

There are significant uncertainties that affect the contingent resources data. There are a number of technical uncertainties that apply to most of the Contingent Resources including the quantity of the petroleum initially in place, the recovery factor, fluid properties, and the number and productivity of future oil and gas wells. Commercial uncertainties include receipt of government and regulatory approvals, the price of the petroleum products, the cost of developing the fields and operating the wells and facilities, applicable fiscal terms, and the timing and scope of future developments. Specific uncertainties over and above these generic factors include:

- The future level of crude oil theft associated with export of crude from Ebendo (assumed to be 27% (NAOC pipeline) or 17% (Umugini pipeline)), Akepo (assumed to be zero) and Qua Ibo (assumed to be zero).
- Transportation and processing tariffs applied to Ebendo production exported through the Forcados system.
- Future performance of the Akepo well (pressure and water production levels) and the need for artificial lift.
- Timing of the resolution of the commercial dispute associated with OML 122.
- Timing of further technical studies by the operator of OML 134 and OML 125.

Specific significant positive factors which may affect the contingent resources data contained herein are: (i) maturation of development plans and the supporting technical work for certain oil and gas pools could potentially increase the expected recovery; (ii) a reduction in bunkering and sabotage activities that affect Ebendo could increase resources; (iii) the application of new technology and secondary and tertiary flooding could increase resources ; and (iv) reduction in development costs and or changes in development concepts could potentially increase value and the quantity of economically recoverable resources.

Specific significant negative factors which may affect the contingent resources data contained herein are: (i) an increase in bunkering and sabotage activities that affect Ebendo, Akepo and Qua Ibo could reduce the resources; (ii) excessive gas production from oil rim reservoirs could reduce oil recovery; (iii) reduced gas or water injection in Abo could reduce oil recovery; and (iv) changes in fiscal terms and conditions and product prices upon Licence renewal or contract extension could reduce value and the quantity of economically recoverable resources.

3. Prospective Resources

OER holds an interest in a total of 28 prospects and leads within its Licences. Twenty-seven of these are located offshore in deep water (500 meters – 2000 meters), with the remaining one prospect in shallow water (10 meters). The aforementioned are a combination of drill ready and low maturity prospects.

These are partially risked prospective resources that have been risked for chance of discovery, but have not been risked for chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

There are a number of technical risks associated with any prospect including, but not limited to, presence of a source, reservoir, seal and trap, type and quantity of fluid present, timing of trap formation, lateral continuity of reservoir and seal and pressure/ temperature regime.

The total prospective resources in which OER hold an interest are shown in the table below.

	Unrisked Best Estimate Prospective Resources[1] (gross, WI)			**Risked Best Estimate Prospective Resources[1] (gross, WI)**			
Licence	**Oil**	**Gas**	**Total**	**POS[3]**	**Oil**	**Gas**	**Total**
	(Mbbls)	***(MMscf)***	***(Mboe)***	**(%)**	***(Mbbls)***	***(MMscf)***	***(Mboe)***
OML 125	189,195	235,603	228,462	14%	27,793	34,124	33,480
Ebendo (OML 56)	0.0	0.0	0.0	0%	0.0	0.0	0.0
Akepo (OML 90)	3,322	3,758	3,948	33%	1,215	1,450	1,457
Qua Ibo	0.0	0.0	0.0	0%	0.0	0.0	0.0
OML 134	61,761	72,872	73,906	23%	13,917	16,768	16,712
OML 122	0.0	0.0	0.0	0%	0.0	0.0	0.0
Sub-total	**254,278**	**312,233**	**306,316**		**42,925**	**52,342**	**51,649**
OPL 321[2]	229,918	491,815	311,887	20%	45,524	97,379	61,754
OPL 323[2]	380,511	2,377,439	776,750	22%	82,655	507,118	167,175
TOTAL	**864,707**	**3,181,487**	**1,394,953**		**171,104**	**656,839**	**280,578**

Notes:
1. Prospective resources carry discovery and development risks. There is no certainty that it will be economically viable to produce any portion of the resources.
2. Assets Under Option/Negotiation – these assets are subject to ongoing litigation between the operator (Korean National Oil Company) and the Nigerian Government.
3. Probability of Success (Technical)
4. Numbers may not add up due to rounding

OML 125

There are a total of 13 prospects in leads in OML 125 (Abo North Deep, Abo Intermediate, Abo Saddle, Abo South East, Abo South, Abo North West, Abo Deep, A151, B254, Ovoro Deep, Obra Deep, Eba and Aboribo). Many of these prospects and leads contain potential hydrocarbons in reservoirs that are being produced by the Abo field (in particular, the B200 reservoir). Elements of risk include poor trapping mechanisms and Amplitude Versus

Offset responses which may not be indicative of hydrocarbons. These prospects and leads have been given a chance of discovery ranging from 8% to 25%.

OML 134

In addition to the discoveries within OML 134, there are a total of ten prospects and leads (Oberan North, Oberan South East, Oberan North A, Oberan East A, Oberan East B, Oberan East D, Udoro Deep, Engule Deep, Onegun and Ologure). Many of these prospects and leads are highly compartmentalised individual fault blocks, with a risk of shallow gas (as was observed in the Minidiogboro exploration well, drilled Q4 2013). A review of the prospectivity in OML 134 should be undertaken, based on the results of recent seismic acquisition and processing and the five exploration wells. The prospects and leads in OML 134 are given a chance of discovery of between 12% and 30%.

OPL 321

There is a single prospect in OPL 321, Elephant, which is a large up-thrown three-way fault closure against a south-east trending normal fault, and is associated with a shale diapir. The prospect is identified from seismic and has a total of seven prospective reservoirs. Elephant has been given a chance of discovery of 22%.

OPL 323

There are four prospects in OPL 323; Gorilla, a series of stacked turbidites in a south-east to north-west oriented sub-basin, Octopus, a highly fault segmented shale cored anticline, Lobster and Whale, which are adjacent anticlines separated by a structural syncline, interpreted to contain turbidite sequences. The Gorilla, Octopus, Lobster and Whale prospects have been given a chance of discovery of 24%, 20%, 27% and 27%, respectively.

Akepo (OML 90)

There are prospective resources associated with those sands in Akepo which are untested and where the fluid type and reservoir productivity are unknown and uncertain. These sands have been given a chance of discovery of 50%.

In addition, there is an unproved fault block, Akepo North, which is adjacent to the Akepo discovery. The prospect is structurally similar to Akepo; both are three-way dip closed, fault bounded accumulations within individual fault blocks. Akepo North, which has been given a chance of discovery of 33%, is not included as part of the Akepo marginal field Licence and further agreement is required between the original farmor and Akepo field partners before exploration drilling can be undertaken.

Item 2.3 Reserves Disclosure Varies with Accounting

There are no accounts issued by the reporting issuer with respect to the Assets.

Item 2.4 Future Net Revenue Disclosure Varies with Accounting

There are no accounts issued by the reporting issuer with respect to the Assets.

PART 3: PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used in Supplemental Estimates

None.

Item 3.2 Forecast Prices Used in Estimates

Oil Prices applied to crude oil sold or planned to be sold from Akepo (via Escravos Terminal), Abo (via an FPSO), Ebendo (via Brass Terminal) and Qua Ibo (via the Qua Ibo Terminal) have been obtained by uplifting Petrenel's Brent crude marker forecast (dated January 1, 2014) by a 2% premium. The premium uplift applied to the Nigerian crude as a result of API gravity differences; the adjustment was based on historical price differentials. Petrenel's Brent oil price forecast was obtained by considering a number of sources including ICE forward prices, the EIA annual price forecast, recent historic trends and an assessment of short to medium term market factors.

The valuation has been carried out using the following oil and gas prices, and cost inflation indices.

	Oil and Condensate					Gas	Inflation	
Date	**Brent**	**Qua Ibo**	**Escravos**	**Abo Blend**	**Brass Light**	**Ebendo Gas**	**CAPEX**	**OPEX**
	(US$/bbls)	*(US$/bbls)*	*(US$/bbls)*	*(US$/bbls)*	*(US$/bbls)*	*US$/Mscf*	*(%)*	*(%)*
2013[1]	**108.62**	**N/A**	**N/A**	**110.23**	**110.60**	**0.30**	**N/A**	**N/A**
2014	106.27	108.40	108.40	108.40	108.40	0.30	2.5	2.5
2015	102.00	104.04	104.04	104.04	104.04	0.31	2.5	2.5
2016	98.87	100.84	100.84	100.84	100.84	0.32	2.5	2.5
2017	98.09	100.05	100.05	100.05	100.05	0.33	2.5	2.5
2018	99.48	101.47	101.47	101.47	101.47	0.34	2.5	2.5
2019	101.49	103.52	103.52	103.52	103.52	0.34	2.5	2.5
2020	103.54	105.61	105.61	105.61	105.61	0.35	2.5	2.5
2021	105.63	107.74	107.74	107.74	107.74	0.36	2.5	2.5
2022	107.76	109.92	109.92	109.92	109.92	0.37	2.5	2.5
2023	109.94	112.14	112.14	112.14	112.14	0.38	2.5	2.5
2024	112.16	114.40	114.40	114.40	114.40	0.39	2.5	2.5
2025	114.43	116.71	116.71	116.71	116.71	0.40	2.5	2.5
2026	116.74	119.07	119.07	119.07	119.07	0.41	2.5	2.5
2027	119.10	121.48	121.48	121.48	121.48	0.42	2.5	2.5
2028	121.50	123.93	123.93	123.93	123.93	0.43	2.5	2.5

Notes:

1.Historical data.

2.Only partial data available

3.All prices are in Money of the day and in US$

PART 4: RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation (Forecast prices and costs)

The following table provides a reconciliation of OER's gross reserves of oil and natural gas for the year ended December 31, 2013, using forecast prices and costs.

All OER Assets (including Abo (OML 125), Ebendo (OML 56), Qua Ibo (OML 13) and Akepo (OML 90))

Reserves Category	Light & Medium Oil[1]		Natural Gas[2]		Natural Gas Liquids		Oil Equivalent[3]	
	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]
	(Mbbls)	(Mbbls)	(Mscf)	(Mscf)	(Mbbls)	(Mbbls)	(Mboe)	(Mboe)
December 31, 2012	**8,143**	**12,262**	**13,630**	**16,730**	**-**	**-**	**8,145[5]**	**12,265[5]**
Exploration Discoveries	-	-	-	-	-	-	-	-
Drilling Extensions	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-
Technical Revisions	627	1,056	8,799	16,730	0	0	2,093[6]	3,884[6]
Discoveries	-	-	-	-	-	-	-	-
Acquisition	657	925	-	-	-	-	657[6]	925[6]
Disposition	-	-	-	-	-	-	-	-
Economic Factors	(144)	676	0	0	0	0	2,126[6]	3,462[6]
Production[6]	(1,443)	(1,443)	(870)	(870)	-	-	(1,588)[7]	(1,588)[7]
December 31, 2013	**7,841**	**13,476**	**21,559**	**32,830**	**-**	**-**	**11,434[7]**	**18,948[7]**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs.
2. Natural gas resources include both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, losses, and shrinkage.
3. Volumes of natural gas have been converted to crude oil equivalent volumes assuming 6 Mscf of natural gas is equivalent to 1 barrel of crude oil. The conversion is based on energy equivalency and does not necessarily represent a value equivalency at the wellhead.
4. 2P equals to Proved plus Probable (Probable equals 2P minus Proved)
5. Natural gas has been converted to barrels oil equivalent using other than six Mscf of natural gas (assumed different energy equivalency)
6. Production volumes are sales figures after deduction of losses and shrinkage, but before deduction of royalty.
7. Natural gas has been converted to barrels oil equivalent using six Mscf of natural gas being equal to one barrel of oil.
8. Negative revisions are in brackets.
9. Numbers may not add up due to rounding.

The following set of tables (A, B, C and D) shows the reconciliation of OER's gross reserves for each asset within OER's portfolio, as reflected in the above table.

A. Abo (OML 125)

Reserves Category	Light & Medium Oil[1]		Natural Gas[2]		Natural Gas Liquids		Oil Equivalent[3]	
	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]
	(Mbbls)	(Mbbls)	(Mscf)	(Mscf)	(Mbbls)	(Mbbls)	(Mboe)	(Mboe)
December 31, 2012	**4,391**	**6,681**	**-**	**-**	**-**	**-**	**4,391**	**6,681**
Exploration Discoveries	-	-	-	-	-	-	-	-
Drilling Extensions	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-
Technical Revisions	117	240	-	-	-	-	117	240
Discoveries	-	-	-	-	-	-	-	-
Acquisition	-	-	-	-	-	-	-	-
Disposition	-	-	-	-	-	-	-	-
Economic Factors	100	859	-	-	-	-	100	859
Production[5]	(1,211)	(1,211)	-	-	-	-	(1,211)	(1,211)
December 31, 2013	**3,397**	**6,570**	**-**	**-**	**-**	**-**	**3,397**	**6,570**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs.
2. Natural gas resources include both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, losses, and shrinkage.
3. Volumes of natural gas have been converted to crude oil equivalent volumes assuming 6 Mscf of natural gas is equivalent to 1 barrel of crude oil. The conversion is based on energy equivalency and does not necessarily represent a value equivalency at the wellhead.
4. 2P equals to Proved plus Probable (Probable equals 2P minus Proved)
5. Production volumes are sales figures after deduction of losses and shrinkage, but before deduction of royalty.
6. Negative revisions are in brackets.
7. Numbers may not add up due to rounding.

B. *Ebendo (OML 56)*

Reserves Category	Light & Medium Oil[1]		Natural Gas[2]		Natural Gas Liquids		Oil Equivalent[3]	
	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]
	(Mbbls)	(Mbbls)	(Mscf)	(Mscf)	(Mbbls)	(Mbbls)	(Mboe)	(Mboe)
December 31, 2012	**3,052**	**4,453**	**13,630**	**16,730**	**-**	**-**	**5,597[5]**	**7,241[5]**
Exploration Discoveries	-	-	-	-	-	-	-	-
Drilling Extensions	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-
Technical Revisions	133	670	8,799	16,970	-	-	2,064[6]	3,934[6]
Discoveries	-	-	-	-	-	-	-	-
Acquisition	-	-	-	-	-	-	-	-
Disposition	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-
Production	(233)	(233)	(870)	(870)	-	-	(377) [6]	(377) [6]
December 31, 2013	**3,391**	**5,355**	**21,559**	**32,830**	**-**	**-**	**6,984[6]**	**10,827[6]**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs.
2. Natural gas resources include both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, losses, and shrinkage.
3. Volumes of natural gas have been converted to crude oil equivalent volumes assuming 6 Mscf of natural gas is equivalent to 1 barrel of crude oil. The conversion is based on energy equivalency and does not necessarily represent a value equivalency at the wellhead.
4. 2P equals to Proved plus Probable (Probable equals 2P minus Proved)
5. Natural gas has been converted to barrels oil equivalent using other than six Mscf of natural gas (assumed different energy equivalency)
6. Production volumes are sales figures after deduction of losses and shrinkage, but before deduction of royalty.
7. Natural gas has been converted to barrels oil equivalent using six Mscf of natural gas being equal to one barrel of oil.
8. Negative revisions are in brackets.
9. Numbers may not add up due to rounding.

C. *Akepo (OML 90)*

Reserves Category	Light & Medium Oil[1]		Natural Gas[2]		Natural Gas Liquids		Oil Equivalent[3]	
	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]
	(Mbbls)	(Mbbls)	(Mscf)	(Mscf)	(Mbbls)	(Mbbls)	(Mboe)	(Mboe)
December 31, 2012	**727**	**1,128**	**-**	**-**	**-**	**-**	**727**	**1,128**
Exploration Discoveries	-	-	-	-	-	-	-	-
Drilling Extensions	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-
Technical Revisions	(88)	(320)	-	-	-	-	(88)	(320)
Discoveries	-	-	-	-	-	-	-	-
Acquisition	-	-	-	-	-	-	-	-
Disposition	-	-	-	-	-	-	-	-
Economic Factors	(244)	(183)	-	-	-	-	(244)	(183)
Production	-	-	-	-	-	-	-	-
December 31, 2013	**396**	**626**	**-**	**-**	**-**	**-**	**396**	**626**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs.
2. Natural gas resources include both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, losses, and shrinkage.
3. Volumes of natural gas have been converted to crude oil equivalent volumes assuming 6 Mscf of natural gas is equivalent to 1 barrel of crude oil. The conversion is based on energy equivalency and does not necessarily represent a value equivalency at the wellhead.
5. Natural gas has been converted to barrels oil equivalent using other than six Mscf of natural gas (assumed different energy equivalency)
6. Natural gas has been converted to barrels oil equivalent using six Mscf of natural gas being equal to one barrel of oil.
7. Negative revisions are in brackets.
8. Numbers may not add up due to rounding.

D. Qua Ibo (OML 13)

Reserves Category	Light & Medium Oil[1]		Natural Gas[2]		Natural Gas Liquids		Oil Equivalent[3]	
	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]	Proved	2P[4]
	(Mbbls)	(Mbbls)	(Mscf)	(Mscf)	(Mbbls)	(Mbbls)	(Mboe)	(Mboe)
December 31, 2012	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Exploration Discoveries	-	-	-	-	-	-	-	-
Drilling Extensions	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-
Acquisition	657	925	-	-	-	-	657	925
Disposition	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-
December 31, 2013	**657**	**925**	**-**	**-**	**-**	**-**	**657**	**925**

Notes:
1. Light & medium oil includes condensate produced from non-associated gas reservoirs.
2. Natural gas resources include both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, losses, and shrinkage.
3. Volumes of natural gas have been converted to crude oil equivalent volumes assuming 6 Mscf of natural gas is equivalent to 1 barrel of crude oil. The conversion is based on energy equivalency and does not necessarily represent a value equivalency at the wellhead.
5. Natural gas has been converted to barrels oil equivalent using other than six Mscf of natural gas (assumed different energy equivalency)
6. Natural gas has been converted to barrels oil equivalent using six Mscf of natural gas being equal to one barrel of oil.
7. Negative revisions are in brackets.
8. Numbers may not add up due to rounding.

PART 5: ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 (a) ***Undeveloped Reserves***

The following table presents changes in undeveloped reserves attributable to opportunities that were not identified in the preceding period and those revisions attributed to conversion from undeveloped to developed reserves categories as result of development drilling over the preceding year. The proved and probable undeveloped reserves were based on the accepted engineering and geological practices as defined under NI 51-101 (including the determination of reserves based on the presence of a commercial test rate from production tests, or extension of known accumulations supported by a combination of geological, geophysical and engineering data).

These reserves are expected to be recovered, with a reasonable degree of certainty, either from new wells on previously undrilled acreage with tested reservoirs or from existing wells that require major capital expenditure to bring them on production. Further details are included below the tables.

	Light & Medium Oil (gross, WI)	**Natural Gas (gross, WI)**	**Oil Equivalent (gross, WI)**
Proved Undeveloped Reserves	(Mbbls)	(MMscf)	(Mboe)
Prior to Dec 31, 2012	0	0	0
Dec 31, 2012	3,594	1,900	3,597[(1)]
Dec 31, 2013	(1,224)	4,177	(215)[(1)]
Current Total	**2,370**	**6,077**	**3,382[(2)]**

Notes:
1. Natural gas has been converted to barrels oil equivalent using other than six Mscf of natural gas (assumed different energy equivalency)
2. Natural gas has been converted to barrels oil equivalent using six Mscf of natural gas being equal to one barrel of oil.
3. Negative revisions are in brackets.
4. Numbers may not add up due to rounding.

	Light & Medium Oil (gross, WI)	**Natural Gas (gross, WI)**	**Oil Equivalent (gross, WI)**
Probable Undeveloped Reserves	(Mbbls)	(MMscf)	(Mboe)
Prior to Dec 31, 2012	0	0	0
Dec 31, 2012	1,670	900	3,597
Dec 31, 2013	878	249	(858)
Current Total	**2,548**	**1,149**	**2,739**

Notes:
1. Natural gas has been converted to barrels oil equivalent using other than six Mscf of natural gas (assumed different energy equivalency)
2. Natural gas has been converted to barrels oil equivalent using six Mscf of natural gas being equal to one barrel of oil.
3. Negative revisions are in brackets.
4. Numbers may not add up due to rounding.

5.1 (b)

OML 125

Undeveloped oil reserves in the Abo field are associated the Anom01 and Anom02 reservoirs that are to be drained by the Abo-8 and Abo-12 wells (from Q3 2014 and Q2 2015, respectively), as part of the phase three field development. Currently, there are no undeveloped gas reserves, as there are no near term plans to capture and sell the associated gas.

Ebendo (OML 56)

Undeveloped oil and gas reserves are associated with the XVIIIb reservoir that is to be drained by the Ebendo-6 well (from Q3 2014) and the XVI and XVII reservoirs that are to be drained by the Ebendo-7 well (from Q4 2014).

Akepo (OML 90)

Undeveloped oil reserves are associated with the C-01, D-01 and D-06 reservoirs that are to be drained by the Akepo-1ST sidetrack from Q2 2014. Currently there are no undeveloped gas reserves, as there are no near term plans to capture and sell the associated gas.

Qua Ibo (OML 13)

Undeveloped oil reserves are associated with the D5 reservoir that is to be drained by the Qua Ibo-3ST (from Q4 2014). Currently there are no undeveloped gas reserves, as there are no near term plans to capture and sell the associated gas.

Item 5.2 Significant Factors Or Uncertainties Affecting Reserves Data

There are significant uncertainties that affect the reserves data. Technical uncertainties include the quantity of the petroleum initially in place, the recovery factor, fluid properties, and the number and productivity of future oil and gas wells. Commercial uncertainties include the price of the petroleum products, the cost of developing the fields and operating the wells and facilities and the timing and scope of future developments.

Specific significant positive factors which may affect the reserves data contained herein are: (i) the maturation of development plans and the supporting technical work for certain oil and gas pools will enable a reclassification of some contingent resources as reserves; (ii) a reduction in bunkering and sabotage activities that affect Ebendo could increase reserves; and (iii) reduction in development costs could potentially increase value and the quantity of economically recoverable reserves.

Specific significant negative factors which may affect the reserves data contained herein are: (i) an increase in bunkering and sabotage activities that affect Ebendo could reduce the reserves; (ii) reduced gas or water injection in Abo could reduce oil recovery.

Item 5.3 Future Development Costs

A summary of the estimated development cost deducted in the estimation of future net revenue attributed to various reserves categories and prepared under forecast prices and costs, calculated using no discount, is presented in the following table. The planned expenditure is based on the operator's development plans for 2014 and Petrenel's assumptions thereafter.

It is understood that OER will pay for these development costs from production revenues.

Summary of Future Development Costs (gross, WI)

	Reserve Category		
Date	**Proved (1P)**	**Proved and Probable**	**Proved, Probable and Possible**
	(mm$)	(mm$)	(mm$)
Q1 2014	33.4	33.4	33.4
Q2 2014	15.7	15.7	15.7
Q3 2014	10.3[(5)]	7.1[(5)]	7.1[(5)]
Q4 2014	10.8	10.8	10.8
2014 Total	**70.2[(5)]**	**67.0[(5)]**	**67.0[(5)]**
2015	17.32	17.32	17.32
2016	3.22	3.22	3.22
2017	3.22	3.22	3.22
2018	0.05	0.49	0.49

Notes:

1. All values presented in this table are gross (WI).
2. All prices are in Real Term (December 31, 2013)
3. Cost associated with Contingent resource activities are reported separately.
4. Numbers may not add up due to rounding.
5. Proved future development costs are higher than Proved and Probable because of the inclusion of a partial workover of Abo-3ST in the Proved case only
6. All costs are expressed in CAN$

PART 6: OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties

The following section outlines the Company's important properties, plants, facilities, pipeline and installations. All OER's properties are located in Nigeria.

1. Properties

The Properties are restricted to Ebendo (OML 56), Akepo (OML 90), Qua Ibo (OML 13), OML 125, OML 134, OML 122, OPL 321 and OPL 323. Of these, Ebendo (OML 56) is onshore (on land) in Niger Delta, Nigeria, Qua Ibo (OML 13) is onshore (swamp), Akepo (OML 90) is in shallow offshore waters of the Nigerian coastal area, and OML 125, OML 134, OML 122, OPL 321 and OPL 323 are located in deep offshore waters in the Nigerian coastal area.

There are no mandatory relinquishments, surrenders, back-ins or changes in ownership with respect to any of the Assets. OER has an option over OPL 321 and OPL 323 and will need to repay the signature bonus to exercise this option.

Developed non-producing reserves associated with the Abo-3ST well (OML 125) have been shut-in since October 2013 due to a sand blockage in the flowline. Remediation work is to be undertaken and the well is expected to recommence production in Q2 2014. Developed non-producing reserves associated with the B209 reservoir in Abo-10 and Abo-11 have been shut-in since July 2013 – recommencement of production from this reservoir is pending permits from the Nigerian Department of Petroleum Resources ('DPR') for commingled production, expected to be Q1 2015.

Developed non-producing reserves associated with the Ebendo-6 well (OML 56) have been shut-in since October 2013. Although the well has been tested and completed, recommencement of production from this reservoir is pending completion of additional evacuation options, which are currently under construction; the Umugini pipeline will run directly from Ebendo.

2. Plant and Facilities

Name	Type	OML	Onshore/ Offshore	Collects Production From	Description – Other Notes
Ebendo	Flowstation	Ebendo	Onshore	Ebendo	10,000 bbls/d capacity, connected to gathering facility at Umusadege through a 6inch diameter, 8.5 km pipeline
Qua Ibo	Group Gathering Facility	Qua Ibo	Onshore	Qua Ibo & other Marginal Fields	Construction ongoing, due for completion Q3 2014. Will route production to ExxonMobil Qua Ibo Terminal located directly east of the field
	Flowstation	Qua Ibo	Onshore	Qua Ibo	Planned in 2015. Front-end-engineering has started.
Abo FPSO	FPSO	125	Offshore	Abo	Currently leased, with an option to buy in 2022. Includes production and test manifolds, separators, fuel gas processing and water treatment facilities. Oil production capacity of 40,000 bbls/d, gas production capacity of 114 MMscf/d and a water production capacity of 9 Mbbls/d. Also has capacity to reinject up to 30 Mbbls/d of water and 12 MMscf/d of gas.

<u>Ebendo</u>

Oil and gas produced at Ebendo is processed at a Flowstation owned by OER and its partners (capacity 10,000 bbls/d). The oil flows to a third party gathering facility at Umusadege and then, via the Kwale-Akri pipeline, to the NAOC JV crude oil transportation infrastructure for export at the Brass River Terminal. A second third-party pipeline, the Umugini pipeline (design capacity 45,000 bbls/d), is expected to be completed in the fourth quarter of 2014 and will provide a second export route through the Forcados Terminal and potentially increase oil export capacity. Trucking will be used as a short term evacuation option until completion of the Umugini pipeline. Gas is sold to Xenergi (a local Nigerian energy company) for further processing and utilization.

Qua Ibo

Oil and gas processing facilities and an export pipeline to the nearby ExxonMobil Qua Iboe Terminal are currently being constructed and are expected to be operational in the second quarter of 2014. The design capacity (5,000 bbls/d) is expected to be sufficient for the future development of the field.

OML 125

Oil produced from OML 125 is processed via the Abo FPSO, which is designed to treat 40 Mbbls/d of oil and 44 MMcf/d of gas and also serves as an export terminal. The Abo FPSO is held under a long-term lease.

Akepo

Akepo is to be produced through a leased Mobile Production Unit and barges.

3. Wells

The summary of the total number of wells is presented in the table below. Note that these are all oil wells - there are no gas wells on the Assets (with the exception of 2 gas injectors at Abo).

	Gross No. Wells [1]							
	Producing	**Injectors**	**Suspended**	**Shut-in**	**Plugged & Abandoned**	**Total**	**OER WI**	**Net No. Strings/Wells[2]**
Ebendo (OML 56)	3	0	0	1	1	5	42.75%	2.14
Akepo (OML 90)	0	0	0	1	0	1	40.00%	0.40
Qua Ibo (OML 13)	0	0	1	1	2	4	40.00%	1.6
OML 125	4	4	1	1	4	14	15.00%	2.1
OML 134	0	0	1	0	4	5	15.00%	0.75
OML 122	0	0	3	0	5	8	4.08%	0.33
OPL 321	0	0	0	0	0	0	24.45%	0.00
OPL 323	0	0	0	0	0	0	24.45%	0.00
Total	**7**	**4**	**6**	**4**	**16**	**37**		**7.32**

Notes:
1. Gross in this instance represents the total number of wells
2. Net in this instance represents the gross working interest (or total number of wells multiplied by the working interest)
3. Numbers may not add up due to rounding.

A more detailed breakdown of the total number of wells is presented in the table below.

Licence/ Field	Gross Wells[1]	Gross Strings[1]	OER WI	Net Wells[2]	Net Strings[2]	Country	Location	Type/ Status
Ebendo (OML 56)								
Ebendo-1		1			0.4275	Nigeria	Onshore (Land)	Producing
Ebendo-2		1			0.4275	Nigeria	Onshore (Land)	Abandoned
Ebendo-4	5	2	42.75%	2.14	0.855	Nigeria	Onshore (Land)	Producing
Ebendo-5		2			0.855	Nigeria	Onshore (Land)	Producing
Ebendo-6		2			0.855	Nigeria	Onshore (Land)	Shut-in
Qua Ibo (OML 13)								
Qua Ibo-1		1			0.4	Nigeria	Onshore (Swamp)	Abandoned
Qua Ibo-2		1			0.4	Nigeria	Onshore (Swamp)	Abandoned
Qua Ibo-3	4	1	40.00%	1.60	0.4	Nigeria	Onshore (Swamp)	-
Qua Ibo-3ST		1			0.4	Nigeria	Onshore (Swamp)	Suspended
Qua Ibo-4		1			0.4	Nigeria	Onshore (Swamp)	Shut-In
Akepo (OML 90)								
Akepo-1	1	1	40.00%	0.40	0.4	Nigeria	Offshore (Shallow Water)	-
Akepo-1ST		2			0.8	Nigeria	Offshore (Shallow Water)	Shut-In
OML 125								
Abo-1		1			0.15	Nigeria	Offshore (Deep Water)	Exploration
Abo-2		1			0.15	Nigeria	Offshore (Deep Water)	Producing
Abo North-1		1			0.15	Nigeria	Offshore (Deep Water)	Abandoned
Abo-3		1			0.15	Nigeria	Offshore (Deep Water)	-
Abo-3ST		1			0.15	Nigeria	Offshore (Deep Water)	Shut-In
Abo-4		1			0.15	Nigeria	Offshore (Deep Water)	-
Abo-4ST		1			0.15	Nigeria	Offshore (Deep Water)	Producing
Abo-5	14	1	15.00%	2.10	0.15	Nigeria	Offshore (Deep Water)	Gas Injector
Abo-6		1			0.15	Nigeria	Offshore (Deep Water)	Water Injector
Abo-7		1			0.15	Nigeria	Offshore (Deep Water)	Water Injector
Abo-8		1			0.15	Nigeria	Offshore (Deep Water)	Suspended
Abo-9		1			0.15	Nigeria	Offshore (Deep Water)	Gas Injector
Abo-10		1			0.15	Nigeria	Offshore (Deep Water)	Producing
Abo-11		1			0.15	Nigeria	Offshore (Deep Water)	Producing
Abo North-2		1			0.15	Nigeria	Offshore (Deep Water)	Abandoned
Okodo		1			0.15	Nigeria	Offshore (Deep Water)	Abandoned
OML 134								
Engule-1X		1			0.15	Nigeria	Offshore (Deep Water)	Abandoned
Udoro-1		1			0.15	Nigeria	Offshore (Deep Water)	Abandoned
Oberan-1	5	1	15.00%	0.75	0.15	Nigeria	Offshore (Deep Water)	Abandoned
Oberan-2		1			0.15	Nigeria	Offshore (Deep Water)	Abandoned
Minidiogboro		1			0.15	Nigeria	Offshore (Deep Water)	Suspended
OML 122								
Bilabri-1		1			0.04	Nigeria	Offshore (Deep Water)	Abandoned
Bilabri-2		1			0.04	Nigeria	Offshore (Deep Water)	Abandoned
Bilabri-DX1		1			0.04	Nigeria	Offshore (Deep Water)	Suspended
Bilabri-D2	8	1	4.08%	0.33	0.04	Nigeria	Offshore (Deep Water)	Suspended
Bilabri-D3		1			0.04	Nigeria	Offshore (Deep Water)	Abandoned
Bilabri-D4		1			0.04	Nigeria	Offshore (Deep Water)	Suspended
Owanare-1		1			0.04	Nigeria	Offshore (Deep Water)	Abandoned
Orobin-1		1			0.04	Nigeria	Offshore (Deep Water)	Abandoned
Total	**37**	**45**		**7.32**	**10.10**			

Notes:

1. Gross in this instance represents the total number of wells
2. Net in this instance represents the gross working interest (or total number of wells multiplied by the working interest)
3. Numbers may not add up due to rounding.

4. Pipelines

Pipeline From	Pipeline To	Location	Current Status	Type	Length (km)	Diameter (inch)
Umusadege	Eriemu (Midwestern) Flowstation[1]	Land	Being installed	Oil	51	12
Total				**Oil/Gas**	**51**	**12**

Note:
1, Eriemu flowstation is owned by NPDC (recently purchased from Shell JV)
2. The Umugini pipeline will provide a second independent export pipeline for Ebendo field. The pipeline's total transportation capacity will be approximately 45,000 bbls/d and it will connect to the Trans Forcados export pipeline. The Trans Forcados export pipeline will deliver crude oil to the Forcados export terminal operated by Shell.

Item 6.2 Properties With No Attributed Reserves

There are four properties in which OER hold an interest that are unproved (undrilled) and to which no reserves are attributed, OPL 321, OPL 323, OML 122 and OML 134.

Property (Licence Area)	Prospects	Acres (Net[2], WI)	Location	Work Commitments
OML 134	Oberan North, Oberan SE, Oberan East A, Oberan East B, Oberan East D, Olugure, Oberan North A, Engule Deep and Udoro Deep	41,958	Nigeria	None outstanding
OML 122	Oware	16,121[1]	Nigeria	None outstanding
OPL 321	Elephant	62,599	Nigeria	None outstanding
OPL 323	Gorilla, Lobster, Octopus, Whale	67,382	Nigeria	None outstanding

Note:
1. Gross, WI using oil WI of 4.08% (gas WI is 10.2%)
2. Net in this instance represents the gross working interest (or total number of wells multiplied by the working interest)

Significant Factors or Uncertainties Relevant to Properties With No Attributable Reserves

The resources of OPL 321 and OPL 323 are considered prospective since there has been no drilling activity to log for, or prove the presence of hydrocarbons on the Licences. Significant factors or uncertainties relevant to properties with no attributable reserves with regards to OML 122 and OML 134 are covered under Item 2.2 (2).

Item 6.3 Forward Contracts

OER is not bound by any forward contract agreements.

Item 6.4 Additional Information Concerning Abandonment And Reclamation Costs

In assessing the future value of OER's petroleum resources, Petrenel has included the following abandonment costs. These have been included as lump sum expenditure at the end of the economic field life.

Licence	OML 125	Ebendo (OML 56)	Akepo (OML 90)	Qua Ibo (OML 13)	Total
Gross Wells[1]	14	5	1	4	26
OER WI	15%	42.75%	40%	40%	
Net Wells [2]	2.1	2.14	0.40	0.80	5.44
Abandonment Costs					
Discount Rate 0%	28.65	5.42	3.62	5.38	43.07
Discount Rate 10%	21.25	3.68	2.65	3.48	31.05
Proportion Not Deducted in Calculating Future Net Revenue	-	-	-	-	-
Proportion Expected to pay in next 3 financial years (from reference date to end 2016)	52%	42%	66%	33%	49%
Amount Expected to pay in next 3 financial years (from reference date to end 2016)	14.90	2.29	2.37	1.76	21.32

Note:

1. Gross in this instance represents the total number of wells
2. Net in this instance represents the gross working interest (or total number of wells multiplied by working interest)
3. All prices are in Real Term (December 31, 2013)
4. Abandonment costs are for Reserves related projects only. Costs associated with Contingent resource activities are reported separately.
5. All costs assumed to be expended in the year after Licence expiry.
6. Numbers may not add up due to rounding.

Item 6.5 Tax Horizon

OER is not required to pay income and corporate tax for its most recently completed Financial Year. However, it pays Petroleum Profit Tax ('PPT') in connection with production from existing fields (excluding Ebendo, which has been awarded Pioneer Status until July 2015, meaning that the field is exempt from PPT for a five year period from the planned commencement of production).

Item 6.6 Costs Incurred

The following costs were incurred by OER for the 12 months ended December 31, 2013 (all properties in Nigeria and OER WI).

	Acquisition Costs		Exploration Costs		
Licence	Proved	Unproved	Proved	Unproved	**Development Costs**
			(mm$)		
Ebendo (OML 56)	-	-	-	-	24.31[1]
Akepo (OML 90)	-	-	-	-	0.04
Qua Ibo (OML 13)	9.85	-	-	-	23.25
OML 125	-	-	-	-	71.92
OML 134	-	-	-	7.77	-
OML 122	-	-	-	-	-
OPL 321	-	-	-	-	-
OPL 323	-	-	-	-	-
Total	**9.85**	-	-	**7.77**	**119.52**

Note:

1. MD&A capital expenditure excludes investment cost for Umugini pipeline.
2. All values presented in this table are gross (WI).
3. Numbers may not add up due to rounding.

Item 6.7 Exploration & Development Activities

Exploration and Development Wells in 2013

Activity Type	Gross [1]	Net[2]
Exploration		
Dry Holes	-	-
Oil Wells	-	-
Gas Wells	1	0.15
Total Exploration Wells	**1**	**0.15**
Development		
Dry Holes	-	-
Oil Wells (incl. sidetracks)	4	0.88
Gas Wells	-	-
Work-over Wells	-	-
Total Development Wells	**4**	**0.88**

Note:

1. Gross in this instance represents the total number of wells
2. Net in this instance represents the gross working interest (or total number of wells multiplied by working interest)
3. Individual numbers may not add up due to rounding

OML 125

No exploration wells were drilled on OML 125 during 2013.

As part of the phase three field development, in 2013 Abo-8 was re-completed as an oil producer on the Anom01 and Anom02 reservoirs, the sidetrack Abo-3ST was drilled and completed on the B200 reservoir and the sidetrack Abo-4ST was drilled and completed on the B207 reservoir.

Abo-4ST was producing at a rate of 1,380 bbls/d oil (gross, WI) on 31 December, 2013. Abo-3ST flowed only for ~72 hours during testing in Q3 2013, with production subsequently shut-in due to a significant sand blockage in the flowline, on which repairs are pending. Production has not recommenced from Abo-8 as the required flow line is a long lead item, delivery of which is expected to be Q3 2014.

A workover of the gas injection well, Abo-9, commenced in 2012 and was completed in the first quarter of 2013, with gas injection successfully restored in Q1 2014. This will provide pressure support for the Anom01 and Anom02 producing reservoirs.

Ebendo

No exploration wells were drilled on Ebendo during 2013.

Ebendo-6 was drilled in Q2 2013 to appraise a number of shallower sands (X – XIIc) and produce two deeper sands, XV and XVI. Testing of the well was ongoing in Q4 2013 and production is expected to commence in Q1 2014.

The Umugini pipeline will provide a second export line for the Ebendo field and it expected to result in a significant increase in crude offtake from the field. Construction operations of the Umugini pipeline are currently being delayed due to weather conditions and heavy rains in the area. However, it is Petrenel's understanding that the completion of the 51 km pipeline is expected in the first quarter of 2014 and that it will be fully operational by second quarter of 2014. The Umugini pipeline's gross transportation capacity will be approximately 45,000 bbls/d and it will connect the Ebendo field to the Trans Forcados export pipeline. The Umugini pipeline and Trans Forcados export pipeline will deliver crude oil from the Ebendo field to the Forcados export terminal operated by Shell. Negotiations regarding the crude handling agreement with the Trans Forcados export pipeline and Forcados export terminal operators are ongoing.

Akepo

No exploration wells were drilled on Akepo during 2013.

There have been revisions to the field development plan, which will now involve barging the oil instead of a pipeline to Beniboye. As a result of these revisions, production from the field has been deferred and is now expected to commence in Q3 2014.

Qua Ibo

No exploration wells were drilled on Qua Ibo during 2013.

The Qua Ibo-4 well was drilled and completed on the C4 reservoir, with a gravel pack for sand control, a single production string and an electrical submersible pump. Commercial oil flow from the C4 reservoir has yet to be demonstrated.

Construction of the group gathering facility began in 2013, which will gather crude from Qua Ibo and other marginal fields in the area. Front-end-engineering for Qua Ibo's own production station began in 2013.

OML 134

An exploration well was drilled into the Minidiogboro prospect in Q4 2013, with the well location defined from the new seismic data. A number of shallow (H245, H310, H350, H355) and intermediate (H520, H522, H524) sands were targeted, with an average probability of success of 26%. The target sands were found to be gas-bearing (shallow) or water-bearing (intermediate) and the well has been suspended as a gas discovery.

No further exploration or appraisal work was undertaken on the Oberan field during 2013.

OML 122

No exploration or development activities were undertaken for this Licence during 2013.

OPL 321

No exploration or development activities were undertaken for this Licence during 2013.

OPL 323

No exploration or development activities were undertaken for this Licence during 2013.

Future Exploration Activities

OML 125

An exploration tail is planned for Abo-12, which will target the Anom03 sand. The well is to be drilled during Q1/ Q2 2014. Until the re-processed seismic data for OML 125 has been reviewed, and prospectivity re-assessed, there are no plans to drill exploration wells on any of the other prospects in OML 125 until 2015 onwards.

Ebendo

Further development drilling on Ebendo will include an element of exploration of the shallower reservoirs, with a total of three wells anticipated to explore the IVa to X sands. These wells are all planned during 2014.

Akepo

There are no plans for further exploration activity on this Licence at this time.

Qua Ibo

In order to better understand the geological structure of the Qua Ibo field, seismic acquisition is to be undertaken on the field during 2014.

OML 134

There are no plans for further exploration activity on this Licence at this time.

OML 122

There are no plans for further exploration activity on this Licence at this time.

OPL 321

There are no plans for exploration activity on this Licence until the resolution of commercial disputes between the partners.

OPL 323

There are no plans for exploration activity on this Licence until the resolution of commercial disputes between the partners.

Future Development Activities

OML 125

The Abo field is in phase three of its development, and the drilling of Abo-8, Abo-3ST and Abo-4ST has already been completed as part of this. Abo-12, which will be completed on the Anom02 and A197 reservoir sands, is to be drilled in Q1/ Q2 2014 and commence production Q1 2015 following installation of the flowline. Stimulation of the producing wells will continue in 2014 and thereafter as required.

Plans to dry-dock the Abo FPSO to allow for refurbishment have been dropped. Instead, between 2014 and 2018 the refurbishment will be undertaken in situ, utilising planned production shut-downs to carry out the work, and thus minimising any interruption to production operations.

Ebendo

There are plans for three further production wells at Ebendo – Ebendo-7, Ebendo-8 and Ebendo-9. Ebendo-7 will be drilled onto the crest of the structure and is proposed to target the XVI and XVII reservoir sands, in addition to exploring the shallower sands (IVa to X).

Although the operator has identified the potential need for pressure support into several of the reservoirs at Ebendo, there are not yet any firm plans for gas or water injection wells.

Akepo

Production from Akepo is due to commence from the Akepo-1ST well in Q3 2014, following mobilisation and installation of the leased production facilities.

Qua Ibo

First oil from Qua Ibo is scheduled to be in Q3 2014, with Qua Ibo-3ST producing the D5 reservoir through the EPF. Production from the C4 reservoir will commence in Q1 2015, following completion of OER's own production station, and pending a demonstration of commercial oil flow from the C4 reservoir.

OML 134

Further appraisal of Oberan is needed before the field can be developed. There are no plans for any appraisal or development at this time.

OML 122

There are no plans for development activity on this Licence until the resolution of commercial disputes between the partners.

OPL 321

This Licence is not yet at the development stage.

OPL 323

This Licence is not yet at the development stage.

Item 6.8 Future Production Estimates

Production estimates (gross, WI) are summarized in table and charts below.

Category		2014	2015	2016	2017	2018
Light and Medium Crude Oil						
Abo	(bbls/d)	3,203	3,717	2,963	2,286	1,724
Ebendo (OML 56)	(bbls/d)	1,469	2,383	2,229	2,079	1,736
Akepo (OML 90)	(bbls/d)	135	689	529	360	0
Qua Ibo (OML 13)	(bbls/d)	135	538	474	392	323
Total	**(bbls/d)**	**4,942**	**7,328**	**6,195**	**5,116**	**3,783**
Sales Natural Gas						
Abo	(Mscf/d)	-	-	-	-	-
Ebendo (OML 56)	(Mscf/d)	6,284	12,686	12,758	12,825	10,874
Akepo (OML 90)	(Mscf/d)	-	-	-	-	-
Qua Ibo (OML 13)	(Mscf/d)	-	-	-	-	-
Total	**(Mscf/d)**	**6,284**	**12,686**	**12,758**	**12,825**	**10,874**
Oil Equivalent						
Abo	**(boe/d)**	3,203	3,717	2,963	2,286	1,724
Ebendo (OML 56)	**(boe/d)**	2,517	4,497	4,356	4,216	3,549
Akepo (OML 90)	**(boe/d)**	135	689	529	360	0
Qua Ibo (OML 13)	**(boe/d)**	135	538	474	392	323
Total	**(boe/d)**	**5,989**	**9,442**	**8,322**	**7,254**	**5,596**

Notes:

1. All values presented in this table are gross (WI).
2. Numbers may not add up due to rounding.

Item 6.9 Production History

2013 average (gross, WI) daily production from the Company's producing fields is shown in the table below. The average 2013 production rate was 4,179 bbls/d oil (gross, WI) and 2,387 Mscf/d (gross, WI) of sales natural gas.

		Three Months Ended				
Category		**31-Mar-13**	**30-Jun-13**	**30-Sep-13**	**31-Dec-13**	**LTM Total**
Light and Medium Crude Oil						
Abo	(bbls/d)	2,988	3,475	3,162	3,649	3,319
Ebendo (OML 56)	(bbls/d)	659	893	1,089	800	860
Akepo (OML 90)	(bbls/d)	-	-	-	-	-
Qua Ibo (OML 13)	(bbls/d)	-	-	-	-	-
Total	**(bbls/d)**	**3,647**	**4,368**	**4,251**	**4,449**	**4,179**
Sales Natural Gas						
Abo	(Mscf/d)	-	-	-	-	-
Ebendo (OML 56)	(Mscf/d)	1,632	2,380	3,524	2,012	2,387
Akepo (OML 90)	(Mscf/d)	-	-	-	-	-
Qua Ibo (OML 13)	(Mscf/d)	-	-	-	-	-
Total	**(Mscf/d)**	**1,632**	**2,380**	**3,524**	**2,012**	**2,387**
Oil Equivalent						
Abo	**(boe/d)**	2,988	3,475	3,162	3,649	3,319
Ebendo (OML 56)	**(boe/d)**	931	1,290	1,677	1,135	1,258
Akepo (OML 90)	**(boe/d)**	-	-	-	-	-
Qua Ibo (OML 13)	**(boe/d)**	-	-	-	-	-
Total	**(boe/d)**	**3,919**	**4,765**	**4,839**	**4,784**	**4,577**

Notes:
1. All values presented in this table are gross (WI)
2. Numbers may not add up due to rounding
3. LTM means last twelve months
4. Reported historical production is before losses and before deduction of royalties.

The following table sets forth information in respect of 2013 average daily oil 4. Values may differ from MD&A, which provides data for Oando Petroleum Development Company, which holds a 45% working interest in Ebendo (OML 56). OER holds a 95% equity interest in Oando Petroleum Development Company.production (gross, WI), prices received, royalties paid, production costs and the resulting netback per unit of volume. Gas net back data is not available, but gas revenue (approximately 0.2% of the Company total revenue) and incremental gas production costs are very small.

Total Company – 2013 oil production, operating expenses, royalties, and netback

2013 average daily production (gross, WI) (1)	4,179	bbls/d
2013 average daily sales (gross, WI) (2)	3,958	bbls/d
Price received (3,4)	117.34	$/bbl(5)
Royalties paid (3,4)	7.43	$/bbl(5)
Production costs (excluding G&A) (3,4)	21.98	$/bbl(5)
Netback (3,4)	87.93	$/bbl(5)

Notes:
1. Oil production before deduction for losses and changes in inventory/storage.
2. Sales production after deduction for losses and changes in inventory/storage, but before deduction for over-lifting by NNPC (OML 125).
3. Information provided by the Company have not been independently verified.
4. Values may differ from MD&A, which provides data for Oando Petroleum Development Company, which holds a 45% working interest in Ebendo (OML 56). OER holds a 95% equity interest in Oando Petroleum Development Company.
4. Oil price received is in Canadian Dollars.

GLOSSARY OF TERMS

Technical Abbreviations

Crude Oil and Natural Gas Liquids

$/bbls	dollars per barrel
Bbls or bbls	Barrel
Bbls or bbls	Barrels
Bbls/d or bbls/d	barrels per day
Mbbls	thousand barrels
Mbbls/d	thousand barrels per day
MMbbls	million barrels
MMbbls/d	million barrels per day

Natural Gas

$/Mscf	dollars per thousand standard cubic feet
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
GIIP	gas initially in place
Mscf	thousand cubic feet
Mscf/d	thousand cubic feet per day
MMscf	million standard cubic feet
MMscf/d	million standard cubic feet per day
scf/stb	standard cubic feet per stock tank barrel
Tcf	trillion standard cubic feet

Others

$	Canadian dollars (unless advised otherwise)
mm$	Million of dollars
%	percent
2C	best estimate contingent resources as defined in the COGE Handbook
2P	proved plus probable reserves
API	American Petroleum Institute and, in the context of a gravity measurement of crude oil, refers to an inverted scale for denoting the 'lightness' or 'heaviness' of crude oils and other liquid hydrocarbons
Boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
km	Kilometres
km^2	square kilometres
m	Metres
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
MMboe/d	million barrels of oil equivalent per day

SCHEDULE "B" – FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESOURCES EVALUATOR

Form 51-101F2
Report on Reserves Data
by
Independent Qualified Reserves
Evaluator or Auditor

Report on Reserves Data

To the board of directors of Oando Energy Resources Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Reserve Classification	Net Present Value of Future Net Revenue Before Tax (10% Discount Rate)			
				Audited (CAN$ Millions)	**Evaluated** (CAN$ Millions)	**Reviewed** (CAN$ Millions)	**Total** (CAN$ Millions)
Petrenel	Independent Annual Review of Petroleum Resources for Oando Energy Resources, Preparation Date February 28, 2014	Nigeria	Proved	-	332.9	-	332.9
			Probable	-	243.6	-	243.6
			Proved Plus Probable	-	576.5	-	576.5

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. Executed as to our report referred to above:

The Petroleum & Renewable Energy Company Limited (Petrenel)
Units 2&3
Silwood Business Centre

Silwood Park
Ascot
United Kingdom
SL5 7PW

February 28, 2014

Stewart L. Whiteley
MSc DIC CEng MEI
Chartered Engineer
Registrant 351493 of the Engineering Council (UK)

Stewart L. Whiteley, BSc (Hons)., MSc., DIC, FGS, SPE, MEI, C.Eng.
Managing Director

Report on Resources Data
by
Independent Qualified Reserves
Evaluator or Auditor

Report on Resources Data

To the board of directors of Oando Energy Resources Inc. (the "Company"):

1. We have prepared an evaluation of the Company's resources data as at December 31, 2013. The resources data are estimates of low, best and high estimates of contingent and prospective resources as at December 31, 2013. The future net revenue, as at December 31, 2013, has been evaluated for part of the contingent resources using forecast prices and costs.

2. The resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the resources data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the resources data are free of material misstatement. An evaluation also includes assessing whether the resources data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue of the Company (before deduction of taxes) attributed to best estimate contingent resources for those properties that have been economically evaluated, using forecast prices and costs and calculated using a discount rate of 10 percent:

Independent Qualified Reserves Evaluator or Auditor	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (Country)**	**Resource Classification**	**Unrisked Net Contingent Cash Flow Before Tax (10% Discount Rate)**			
				Audited (CAN$ Millions)	**Evaluated** (CAN$ Millions)	**Reviewed** (CAN$ Millions)	**Total** (CAN$ Millions)
Petrenel	Independent Annual Review of Petroleum Resources for Oando Energy Resources, Preparation Date February 28, 2014	Nigeria	Low estimate (1C)	-	234.1	-	234.1
			Best estimate (2C)	-	370.8	-	370.8
			High estimate (3C)	-	489.8	-	489.8

5. An updated evaluation or audit of the potential quantity of prospective resources has been undertaken for all identified prospects and leads. However the potential future net revenues associated with these prospective resources has either not been assessed or not updated.

6. In our opinion, the resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the resources data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our estimates of resources referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

8. Because the resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

9. Contingent oil resources evaluated in this report are potentially recoverable using established technology and are considered to be economically recoverable based on the Forecast Case price and cost parameters used in this report. A Field Development Plan is required to classify a discovery as reserves, and in this case is dependent on undertaking further reservoir studies and delineation drilling as well as preparations of development plans and facility designs to determine the commerical viability of these contingent oil resources.

Executed as to our report referred to above:

The Petroleum & Renewable Energy Company Limited (Petrenel)
Units 2&3
Silwood Business Centre
Silwood Park
Ascot
United Kingdom
SL5 7PW

March, 28 2014

Stewart L. Whiteley, BSc (Hons)., MSc., DIC, FGS, SPE, MEI, C.Eng.
Managing Director

SCHEDULE "C" – FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Oando Energy Resources Inc. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and resources data which are estimates of proved reserves and probable reserves and contingent resources and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated and reviewed the Company's reserves data and resources data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves and Resources Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) (reviewed the reserves and resources data with management and the independent qualified reserves evaluator.

The Reserves and Resources Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves and Resources Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves and resources data and other oil and gas information;

(b) the filing of Forms 51-101 F2 which are the reports of the independent qualified reserves evaluator on the reserves and resources data; and

(c) the content and filing of this report.

Because the reserves and resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) Olapade Durotoye

Olapade Durotoye
Chief Executive Officer

(signed) Adeola Ogunsemi

Adeola Ogunsemi
Chief Financial Officer

(signed) Bill Watson
Bill Watson
Director and Chair of Reserves and Resources Committee

(signed) Philippe Laborde
Philippe Laborde
Director and Member of Reserves and Resources Committee

March 31, 2013

SCHEDULE "D" – AUDIT COMMITTEE CHARTER

CHARTER OF THE AUDIT COMMITTEE OF OANDO ENERGY RESOURCES INC.

1. PURPOSE

The Audit Committee (the "**Audit Committee**") shall provide assistance to the board of directors (the "**Board**") of Oando Energy Resources Inc. (the "**Company**") in fulfilling its oversight function with respect to:

(a) the quality and integrity of the Company's financial statements;

(b) determining the Company's financial accounting policies;

(c) the Company's compliance with legal and regulatory requirements relating to financial matters;

(d) the External Auditor's (as defined below) qualifications, performance and independence;

(e) the performance of the Company's senior finance employees, internal audit function, and, if applicable, the External Auditor;

(f) internal controls and disclosure controls;

(g) the review of principal risks of the Company's business and the implementation of appropriate risk management systems;

(h) the preparation of audit committee reports, if any, to be included in the Company's annual proxy statement, circular or annual report; and

(i) oversight, preparation and review of reports in compliance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Companies.

2. COMMITTEE MEMBERSHIP

2.1 Number and Appointment of Members

The Audit Committee will be comprised of no fewer than three directors and shall be appointed by the Board on recommendation of the Corporate Governance Committee (the "**CG Committee**").

2.2 Independence of Members

Subject to any exemptions in applicable securities laws, each member of the Audit Committee will be independent for the purposes of all applicable regulatory and stock exchange requirements as in effect from time to time and in accordance with such additional criteria for independence as the Board may establish.

2.3 Committee Chair

The Chair of the Audit Committee shall be appointed by the Board following receipt of the recommendation of the CG Committee.

The fundamental responsibility of the Chair of the Audit Committee is to be responsible for the management and effective performance of the Committee and provide leadership to the Committee in fulfilling its mandate and any other matters delegated to it by the Board. To that end, the Chair of the Audit Committee's responsibilities shall include:

(a) providing leadership to the Committee and presiding over Committee meetings;

(b) facilitating the flow of information to and from the Committee and fostering an environment in which Committee members may ask questions and express their viewpoints;

(c) reporting to the Board with respect to the significant activities of the Committee and any recommendations of the Committee;

(d) leading the Committee in annually reviewing and assessing the adequacy of its mandate and evaluating its effectiveness in fulfilling its mandate; and

(e) taking such other steps as are reasonably required to ensure that the Committee carries out its mandate

2.4 Financial Literacy

All members of the Audit Committee shall be "financially literate" (at the time of appointment or within a reasonable time thereafter if the Board has determined that this will not materially adversely affect the ability of the Audit Committee to satisfy the requirements of National Instrument 52-110 of the Canadian Securities Administrators), meaning that all members of the Audit Committee have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements. In addition, at least one member of the Audit Committee must have accounting or related financial management expertise, as the Board interprets such qualification in its own business judgment, provided that any member of the Audit Committee that satisfies the requirements of Section 2.5 below shall be deemed to satisfy this requirement.

2.5 Audit Committee Financial Expert

(a) **Attributes of the Audit Committee Financial Expert.** To the extent possible, the Board will appoint to the Audit Committee at least one Director who has the following attributes (the "**Audit Committee Financial Expert**"):

(i) an understanding of International Financial Reporting Standards ("**IFRS**") and financial statements;

(ii) ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;

(iii) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Company's financial statements, or experience actively supervising one or more persons engaged in such activities;

(iv) an understanding of internal controls and procedures for financial reporting; and

(v) an understanding of audit committee functions.

(b) **Experience of the Audit Committee Financial Expert.** To the extent possible, the attributes described above will have been acquired through:

(i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that

involve the performance of similar functions (or such other qualification as the Board interprets such qualification in its business judgment);

(ii) experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions;

(iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or

(iv) other relevant experience.

2.6 Appointment and Removal of Members and Chair

The members of the Audit Committee and the Chair of the Audit Committee shall be appointed annually by the Board at the first meeting of the Board following a meeting of the Company's shareholders at which directors are elected, provided that if such appointments are not so made, any Director who is then serving as a member of the Audit Committee or as the Chair of the Audit Committee shall continue to so serve until his or her successor is appointed.

No member of the Audit Committee shall be removed except by majority vote of the directors that are independent for the purposes of all applicable regulatory and stock exchange requirements as well as by majority vote of all directors.

3. AUTHORITY OF THE COMMITTEE

3.1 Retaining and Compensating Advisors

The Audit Committee shall have the authority to engage independent counsel, experts and other advisors as the Audit Committee may deem appropriate in its sole discretion and to set and pay the compensation for any advisors employed by the Audit Committee.

3.2 Subcommittees

The Audit Committee may form and delegate authority to subcommittees if deemed appropriate by the Audit Committee provided that no subcommittee shall consist of fewer than two members.

3.3 Funding

The Company shall provide appropriate funding, as determined by the Audit Committee, for payment of (i) compensation to any External Auditor, (ii) compensation to any independent counsel, experts and other advisors employed by the Audit Committee under the foregoing section, and (iii) ordinary administrative expenses of the Audit Committee that are necessary or appropriate in carrying out its duties.

3.4 Access to Management

The Audit Committee shall have unrestricted and direct access to the Company's management, employees, the Company's internal auditor, the External Auditor and the books and records of the Company.

4. REMUNERATION OF COMMITTEE MEMBERS

4.1 Remuneration of Audit Committee Members

Members of the Audit Committee and the Chair of the Audit Committee shall receive such remuneration for their service on the Audit Committee as the Compensation Committee may determine from time to time.

4.2 Directors' Fees

No member of the Audit Committee may earn fees from the Company or any of its subsidiaries other than directors' fees (which fees may include cash and/or shares or options or other share-based awards or other in-kind consideration ordinarily available to directors, as well as all of the regular benefits that other directors receive), including fees paid to directors for service on a committee of the Board or as the Chair of any committee of the Board (including pursuant to Section 4.1 above), and pensions or deferred compensation, if any, for prior service on the Board that is not contingent on future service on the Board. For greater certainty, no member of the Audit Committee shall accept, directly or indirectly, any consulting, advisory or other compensatory fee from the Company.

5. RESPONSIBILITIES

The Audit Committee shall have the functions and responsibilities set out below as well as any other functions that are specifically delegated to the Audit Committee by the Board and that the Board is authorized to delegate by applicable laws and regulations. In addition to these functions and responsibilities, the Audit Committee shall perform the duties required of an audit committee by any exchange upon which securities of the Company are traded, or any governmental or regulatory body exercising authority over the Company, as are in effect from time to time (collectively, the "**Applicable Requirements**").

The Audit Committee is responsible for overseeing the Company's financial statements and financial disclosures. Management is responsible for the preparation, presentation, quality and integrity of the Company's financial statements and financial disclosures and for the appropriateness of the accounting principles and the reporting policies used by the Company. The External Auditor is responsible for auditing the Company's annual consolidated financial statements and for reviewing the Company's unaudited interim financial statements. In addition, the Audit Committee is responsible for the oversight, preparation and review of reports in compliance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Companies.

5.1 Integrity of Financial Statements and Financial Disclosure

(a) **Annual Financial Statements.** The Audit Committee shall meet to review and discuss with management and the External Auditor, the Company's audited annual financial statements and Management's Discussion and Analysis ("**MD&A**") of such financial statements prior to their filing with the applicable securities regulators, including the use and presentation of non-international financial reporting standards ("**non-IFRS**") financial measures, if any, relating to the Company's annual financial results, together with the report of the External Auditor thereon and the associated press release and, if appropriate, recommend to the Board that it approve the audited annual financial statements, MD&A and associated press release.

(b) **Interim Financial Statements.** The Audit Committee shall meet to review and discuss with management and the External Auditor, the Company's interim unaudited financial statements and MD&A of such financial statements prior to their filing with the applicable securities regulators, including the use and presentation of non-IFRS financial measures, if any, relating to the Company's interim financial results, together with the associated press release, and, if appropriate, recommend to the Board that it approve the interim unaudited financial statements, interim MD&A and associated press release.

(c) **Annual Information Form.** The Audit Committee shall review the Company's Annual Information Form ("**AIF**") and, if appropriate, recommend to the Board that it approve the AIF.

(d) **Material Public Financial Disclosure.** The Audit Committee shall review and discuss with management and the External Auditor and, where appropriate or required, approve, or recommend to the Board that it approve:

(i) the types of information to be disclosed and the type of presentation to be made in connection with earnings press releases;

(ii) financial information and earnings guidance (if any) provided to analysts and rating agencies;

(iii) press releases containing financial information (paying particular attention to the use, if any, of non-IFRS financial measures or information); and

(iv) financial information or financial statements in a prospectus or other securities offering document, or any other document required to be disclosed or filed by the Company, before its public disclosure or filing with regulatory authorities in Canada.

(e) **Procedures for Review.** The Audit Committee shall be satisfied that adequate procedures are in place for the review of the Company's disclosure of financial information extracted or derived from the Company's financial statements (other than financial statements, MD&A and earnings press releases, which are dealt with elsewhere in this Charter) and shall periodically assess the adequacy of those procedures.

(f) **General.** The Audit Committee shall review and discuss with management and the External Auditor:

(i) the quality of, and not just the acceptability of, the accounting principles applied in respect of the financial statements and the clarity of the disclosures in the financial statements;

(ii) major issues regarding accounting principles and financial statement presentations, including any significant changes in the Company's selection or application of accounting principles;

(iii) major issues as to the adequacy of the Company's internal controls over financial reporting and any special audit procedures adopted in light of material control deficiencies;

(iv) analyses prepared by management and/or the External Auditor setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative IFRS methods on the financial statements and the degree of aggressiveness or conservatism of the Company's accounting principles and critical accounting estimates;

(v) the effect on the Company's financial statements of: regulatory and accounting initiatives; off-balance sheet transactions; structures, obligations (including contingent obligations) and other relationships of the Company with unconsolidated entities or other persons that have a material current or future effect on the Company's financial condition, changes in financial condition, results of operations, liquidity, capital resources, capital reserves or significant components of the Company's revenues or expenses;

(vi) the extent to which changes or improvements in financial or accounting practices, as approved by the Audit Committee, have been implemented;

(vii) any financial information or financial statements in prospectuses and other offering documents;

(viii) the factors identified by management as factors that may affect future financial results;

(ix) the management certifications of the financial statements as required under applicable securities laws in Canada or otherwise;

(x) disclosures made by the Company's Chief Executive Officer and Chief Financial Officer during their certification process in connection with the Company's financial statements about (a) any significant deficiencies or material weaknesses in the design or operation of disclosure controls and procedures and internal controls which could adversely affect the Company's ability to record, process, summarize and report financial data, and (b) any fraud involving management or other employees who have a significant role in the Company's internal controls, and shall ensure that any such deficiencies, weaknesses or fraud, the risks associated therewith and the Company's plans to remediate such deficiencies, weaknesses or fraud, if any, are appropriately disclosed in the MD&A;

(xi) conclusions from whistleblower complaints or concerns, in accordance with the Company's Whistleblower Policy;

(xii) any litigation, claim or contingency that could have a material effect on the financial statements;

(xiii) any other relevant reports or financial information submitted by the Company to any governmental body, or the public; and

(xiv) pension plan financial statements, if any.

5.2 **<u>External Auditor</u>**

(a) **Authority with Respect to External Auditor.** As a representative of the Company's shareholders, the Audit Committee shall be directly responsible for the appointment (through nomination to the Company's shareholders), compensation, retention and oversight of the work of any registered public accounting firm engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Company (the "**External Auditor**"). Each External Auditor shall report directly to the Audit Committee. In the discharge of this responsibility, the Audit Committee shall:

(i) have sole responsibility for recommending to the Company's shareholders the firm to be proposed for appointment as the External Auditor for the above described purposes and determining at any time whether the Board should recommend to the Company's shareholders whether the incumbent External Auditor should be removed from office;

(ii) review the scope and terms of the External Auditor's engagement, discuss the audit fees with the External Auditor and be solely responsible for pre approving such audit services fees; and

(iii) require the External Auditor to confirm in its engagement letter each year that the External Auditor is accountable to the Board and the Audit Committee as representative of shareholders.

(b) **Audit Plan.** At least annually, the Audit Committee shall review a summary of the External Auditor's annual audit plan. The Audit Committee shall consider and review with the External Auditor any material changes to the scope of the plan and satisfy itself that the audit plan is risk based and covers all relevant activities over a measurable cycle and that the work of the External Auditor and the internal auditor is coordinated.

(c) **Audit and Review Reports.** The Audit Committee shall review the audit report and review reports prepared by the External Auditor in respect of the Company's audited financial statements and unaudited financial statements, respectively.

(d) **Relationship with External Auditor.** The Audit Committee shall develop a relationship with the External Auditor that allows for full, frank and timely discussion of all material issues.

(e) **Independence.** The Audit Committee shall satisfy itself as to the independence of the External Auditor. As part of this process the Audit Committee shall:

(i) assure the regular rotation of the lead audit partner as required by law and consider whether, in order to ensure continuing independence of the External Auditor, the Company should rotate periodically, the audit firm that serves as External Auditor;

(ii) require the External Auditor to submit on a periodic basis, at least annually, to the Audit Committee, a formal written statement that they are objective and independent within the meaning of the applicable Rules of Professional Conduct/Code of Ethics adopted by the provincial institute or order of chartered accountants to which it belongs and delineating all relationships between the External Auditor and the Company; actively engage in a dialogue with the External Auditor with respect to any disclosed relationships or services that may impact the objectivity and independence of the External Auditor; and take appropriate action in response to the External Auditor's written statements to satisfy itself of the External Auditor's independence; and

(iii) review and approve the policy setting out the restrictions on the Company hiring partners, employees and former partners and employees of the Company's current or former External Auditor.

(f) Issues Between External Auditor and Management. The Audit Committee shall:

(i) review and discuss any problems or difficulties experienced by the External Auditor in conducting the audit, including any restrictions on the scope of the External Auditor's activities or any access to requested information, and management's response thereto;

(ii) review any significant disagreements with management and, to the extent possible, resolve any disagreements between management and the External Auditor;

(iii) review all material correspondence between the External Auditor and management related to audit findings;

(iv) review with the External Auditor:

(A) any accounting adjustments that were proposed by the External Auditor, but were not made by management;

(B) any communications between the audit team and audit firm's national office regarding auditing or accounting issues arising from the engagement;

(C) any management or internal control letter issued, or proposed to be issued (in draft) by the External Auditor to the Company and subsequent follow-up of any identified deficiencies;

(D) the performance, responsibilities, budget and staffing of the Company's internal auditor; and

(E) any correspondence between the Company and any public accounting firm other than the External Auditor related to auditing or accounting issues.

(g) Non-Audit Services.

(i) The Audit Committee shall:

(A) pre-approve any non-audit services provided by the External Auditor or the external auditor of any subsidiary of the Company to the Company (including its subsidiaries) provided that no approval shall be provided for any service that is prohibited under the rules of the Canadian Public Accountability Board, the Canadian Institute of Chartered Accountants or the Public Company Accounting Oversight Board; and

(B) adopt specific pre-approval policies and procedures for the engagement of non-audit services, provided that such pre-approval policies and procedures are detailed as to the particular service, the Audit Committee is informed of each non-audit service and the procedures do not include delegation of the Audit Committee's responsibilities to management.

(ii) The Audit Committee may delegate to one or more members of the Audit Committee the authority to pre-approve non-audit services in satisfaction of the requirement in the previous section, provided that such member or members of the Audit Committee must present any non-audit services so approved to the Audit Committee at its first scheduled meeting following such pre-approval.

(iii) The Audit Committee shall instruct management to promptly bring to its attention any services performed by the External Auditor which were not recognized by the Company at the time of the engagement as being non-audit services.

(h) **Evaluation of External Auditor.** The Audit Committee shall evaluate the External Auditor each year, and present its conclusions to the Board. In connection with this evaluation, the Audit Committee shall:

(i) review and evaluate the performance of the lead partner of the External Auditor;

(ii) obtain the opinions of management and of the persons responsible for the Company's internal audit with respect to the performance of the External Auditor; and

(iii) obtain and review a report by the External Auditor describing:

(A) the External Auditor's internal quality-control procedures;

(B) any material issues raised by the most recent internal quality control review, or peer review, of the External Auditor's firm or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, regarding one or more independent audits carried out by the External Auditor's firm, and any steps taken to deal with any such issues; and

(C) all relationships between the External Auditor and the Company (to be set out in the formal written statement described in Section 5.2(e)(ii)).

(i) **Review of Management's Evaluation and Response.** The Audit Committee shall review the External Auditor's recommendations, and review management's response to and subsequent follow-up on any identified weaknesses.

(j) Financial Risk Assessment or Review. The Audit Committee shall:

(i) discuss policies with respect to risk assessment and risk management, and receive regular reports from management and receive comments from the External Auditor, if any, on:

(A) the Company's principal financial risks;

(B) the systems implemented to monitor those risks; and

(C) the strategies (including hedging strategies) in place to manage those risks; and

(ii) recommend to the Board whether any new material strategies presented by management to manage the Company's principal financial risks should be considered appropriate and approved.

5.3 Risk Management

(a) **Review of Policies and Practices.** The Audit Committee shall periodically review the policies and practices of the Company regarding cash management, financial derivatives, financing, credit, insurance, taxation, commodities trading and related matters.

(b) **Risk Management Governance Model.** The Audit Committee shall oversee the Board's risk management governance model by conducting periodic reviews with the objective of appropriately reflecting the principal risks of the Company's business in the mandate of the Board and its committees.

(c) **Security Risks.** The Audit Committee shall review on a summary basis any significant physical security management, IT security or business recovery risks and strategies to address such risks.

(d) **Standards of Business Conduct.** The Audit Committee shall periodically review the Company's Corporate Code of Business Conduct and Ethics and provide recommendations to the Board concerning its compliance with applicable disclosure, legal and Stock Exchange listing requirements.

5.4 Pension Plan

The Audit Committee shall review the assets, financial performance, funding status, investment strategy and actuarial reports of the Company's pension plan, if any, including the terms of engagement of the plan's actuary and fund manager.

5.5 Senior Finance Employees

The Audit Committee shall assist the Compensation Committee and the Board in their assessments of the performance of the Company's senior finance employees.

5.6 Review of Regulatory Correspondence

The Audit Committee shall discuss with management any correspondence with or published reports of regulators or governmental agencies which may have a material effect on the Company's financial statements or accounting policies.

5.7 Audit Committee Disclosure

The Audit Committee shall review and approve any audit committee reports mandated by Applicable Requirements for inclusion in the Company's annual information form, management information circular, annual report or any other disclosure document.

6. MEETINGS

6.1 Committee Meetings

The Audit Committee will meet regularly at times necessary to perform the duties described above in a timely manner, but not less than quarterly in advance of filing quarterly reports and at any time deemed appropriate by the Audit Committee. In addition, the Chair of the Audit Committee, any member of the Audit Committee, the External Auditor, the Chairman of the Board or Lead Director, if applicable, or the Chief Executive Officer or Chief Financial Officer may call a special meeting of the Audit Committee at any time by notifying the Company's Corporate Secretary who will notify the members of the Audit Committee. Unless otherwise resolved by the Board, no fewer than a majority of the members of the Audit Committee shall constitute a quorum to transact business and such meetings may be telephonic or by video conferencing. Notice of at least 48 hours shall be provided for all meetings.

Members of the Audit Committee may participate in a meeting of the Audit Committee by means of telephone conference call or similar communications equipment by means of which all persons participating in the meeting can hear each other.

The affirmative vote of a majority of the members of the Audit Committee present at the time of such vote will be required to approve any action of the Audit Committee. Subject to the requirements of any applicable law, regulation or rule, any action required or permitted to be taken at a meeting of the Audit Committee may be taken without a meeting if a consent in writing, setting forth the action so taken, is signed by all of the members of the Audit Committee. Such written consent shall have the same force as a unanimous vote of the Audit Committee.

At the invitation of the Chair of the Audit Committee, other Board members, officers or employees of the Company, external legal counsel and other experts or consultants may attend any meeting of the Audit Committee. The External Auditor is entitled to attend and be heard at each meeting of the Audit Committee.

Minutes of every meeting shall be kept with the Company's corporate records. The minutes of Audit Committee meetings shall be in sufficient detail to convey the substance of all discussions held, and shall accurately record the decisions reached, as well as attendance of members of the Audit Committee at each meeting. The minutes of Audit Committee meetings will be kept by the Secretary of the Meeting and distributed to members of the Board with copies to the Chief Financial Officer and the External Auditor.

6.2 In Camera Meetings

As a part of each meeting of the Audit Committee at which the Audit Committee recommends that the Board approve the Company's annual audited financial statements and at which the Audit Committee approves the Company's unaudited interim financial statements, the Audit Committee shall meet separately with each of:

(a) management;

(b) the External Auditor; and

(c) the internal auditor.

The External Auditor will have direct access to the Audit Committee at their own initiative, shall receive notice of each meeting of the Audit Committee and shall be entitled to attend any such meeting at the Company's expense.

6.3 Regular Reporting

The Audit Committee shall report directly to the Board at the Board's next meeting the proceedings at the meetings of the Audit Committee and all recommendations made by the Audit Committee at such meetings.

In addition to reports of the Audit Committee provided at each Board meeting the Board shall receive regular reports from the Audit Committee with respect to the integrity of the Company's financial reporting system and its compliance with all regulatory requirements relating to financial reporting.

7. OTHER

7.1 Related Party Transactions

The Audit Committee shall review and approve all related party transactions in which the Company is involved or which the Company proposes to enter into.

7.2 Whistle Blowing

The Audit Committee shall make recommendations to the Board in respect of the Company's Whistleblower Policy and establish procedures for:

(a) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, auditing matters, violations of Canadian securities or other applicable laws, rules or regulations; and

(b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters, violations of any laws, rules or regulations, including but not limited to Canadian securities and other applicable laws and violations of the Company's Corporate Code of Business Conduct and Ethics.

The Audit Committee shall review and assess the adequacy of the Whistleblower Policy on an annual basis.

The Audit Committee shall oversee the administration and implementation of the Whistleblower Policy in accordance with its terms, including all required liaison with the Company's Chief Compliance Officer in accordance with the Whistleblower Policy.

The Audit Committee shall, on a quarterly basis, certify to the Chief Executive Officer and the Chief Financial Officer that, other than as disclosed to the Chief Executive Officer and the Chief Financial Officer, there have been no matters reported to the Audit Committee under the Whistleblower Policy that would impact the certifications to be provided by the Chief Executive Officer and the Chief Financial Officer under applicable securities legislation or stock exchange requirements.

7.3 Other

Perform such other functions as may be necessary or appropriate under law, the Company's articles, bylaws or as directed by the Board.

8. AUDIT COMMITTEE WORK PLAN

The Audit Committee shall annually develop a work plan to identify and set timeframes for the duties it is responsible for performing, including but not limited to determining the Company's financial accounting policies, evaluating internal and disclosure controls and oversight, preparing and reviewing of reports, including 51-101 reports. The Audit Committee shall regularly monitor its compliance with performing such duties within the timeframes specified in the work plan.

9. ANNUAL PERFORMANCE EVALUATION

On an annual basis, the Audit Committee shall follow the process established by the Board and overseen by the CG Committee for assessing the performance of the Audit Committee.

10. CHARTER REVIEW

The Audit Committee shall review and assess the adequacy of this Charter annually and recommend to the CG Committee any changes it deems appropriate.

This Charter is subject to the provisions of the Company's articles and by-laws and the Canada Business Corporations Act as amended from time to time. This Charter is a statement of broad policies and is intended as a component of the flexible governance framework within which the Board, assisted by its committees, directs the affairs of the Company. While it should be interpreted in the context of all applicable laws, regulations and listing requirements, as well as in the context of the Company's articles and by-laws, it is not intended to establish any legally binding obligations.