Oando Energy Resources

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2015

March 29, 2016

TABLE OF CONTENTS

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 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.
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.
2015 Financial Statements	means OER's audited annual consolidated financial statements for the years ended December 31, 2015 and 2014.
2015 MD&A	means management's discussion and analysis relating to the 2015 Financial Statements.
3D	means three dimensional.
51-101 Statement	means the report dated February 25, 2016 on Form 51-101F1 prepared by D&M and entitled "*Statement Of Reserves Data and Other Oil and Gas Information*" and attached hereto as Schedule "A".
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 Oando 131 Acquisition Agreement, ODENL Acquisition Agreement and OOL 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, 2015.
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.
API	means 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
BCBCA	*British Columbia Business Corporations Act* and the regulations thereunder, as amended from time to time.
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.
boe	means barrel of oil equivalent.
boe/d	means barrel of oil equivalent per day.
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.
bunkering	means the theft and trade of stolen oil and other petroleum products.
CBCA	means the *Canada Business Corporations Act* and the regulations thereunder, as amended from time to time.
CEO	means the Chief Executive Officer of OER.
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.
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.
Contingent Resources	means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or 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. When used herein, the terms "best estimate", "2C", "low estimate", "1C" and "high estimate", "3C" have the meanings ascribed thereto in the 51-101 Statement.

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 acquisition by OER of the COP Nigerian Business.
COP Nigerian Business	means the offshore business carried out by COP in Nigeria through its indirectly wholly-owned subsidiaries Oando 131 and ODENL and the onshore (or shallow water) business in Nigeria conducted by OOL.
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.
D&M	means DeGolyer and McNaughton, a "qualified reserves evaluator" which is "independent" of OER within the meanings of NI 51-101.
Domestic Supply Obligation	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, as carved out of OML 56.
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 a sea zone prescribed by the *United Nations Convention on the Law of the Sea* over which a state has special rights regarding the exploration and use of marine resources. It stretches from the baseline out to 200 nautical miles from the coast. In colloquial usage, the term may include the continental shelf. The term does not include either the territorial sea or the continental shelf beyond the 200 nautical mile limit.
EHS Policy	means environmental health and safety policy.
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.
Exile	means Exile Resources Inc.
Exile 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 "General Development of OER's Business – Relevant Three Year History – Reverse Takeover Involving Oando and OER."
Exile Restructuring	means the restructuring completed pursuant to the Exile Arrangement between OER and Oando, as more particularly described under the heading "*General Development of OER's Business – Relevant Three Year History – Reverse Takeover Involving Oando and 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.
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.
GMP	means the Nigerian Gas Master Plan, 2008.
Gross or gross	when used in relation to production, reserves, and resources means 100 percent of the field's production, reserves and resources.
Guidelines	means the *Guidelines for Farm-out and Operation of Marginal Fields* issued by the DPR from time to time.
HoldCo Subsidiary	has the meaning ascribed thereto under the heading "*Incorporation and Organization*."
IFRS	means International Financial Reporting Standards.
Institutional Shareholders	means M1 Petroleum Ltd., West African Investment Ltd. and Southern Star Shipping Company Inc.
IOC	means an international oil company (like COP, Chevron, Eni or ExxonMobil) 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.
JV	means joint venture.
Key Personnel	means certain of OER's officers, employees and service providers.
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	means the Kwale-Okpai independent power plant located in OML 60.
LIBOR	means the London interbank offered rate.
License	means OELs, OMLs and OPLs, or interests therein or interests in areas therein, whether held through a JV or PSC or 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).
LTIP	means the long term incentive plan approved by the Board of Directors on December 10, 2014.
Marginal Field	means a field defined as a "marginal field" in the Petroleum Act and Guidelines that the President of Nigeria may, from time to time, identity as a marginal field thereunder.
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 in relation to a specific bid round.
Medal Oil	means Medal Oil Company Limited.
MEND	means the Movement for the Emancipation of the Niger Delta.
mD	milliDarcy.
MD	measured depth.
Mboe	thousand barrels of oil equivalent.
Minority Shares	means the issued and outstanding Common Shares, excluding the Common Shares held by Oando PLC and those held by the Institutional Shareholders or Key Personnel who have agree, in connection with the Oando Arrangement, to receive common shares of the Purchaser in exchange for their Common Shares.
MMboe	million barrels of oil equivalent.
MMboe/d	million barrels of oil equivalent per day.
mss	metres subsea.
NAE	means Nigerian Agip Exploration Limited.
NAOC	means Nigerian Agip Oil Company Limited.

NAOC JOA	means the JOA with NNPC and NAOC dated July 17, 1991in respect of the NAOC JV.
NAOC JV	means the NAOC joint venture, comprised of Eni, the NNPC and OOL, in respect of which OOL 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 means either OER's working interest share of production, reserves and resources or OER's entitlement to production reserves and resources 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.
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.
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 SV Corporation, the Nigerian state-owned oil company.
NNPC Act	means the *Nigerian National Petroleum Corporation Act*, 2004 (Nigeria).
NPV	net present value.
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 131	means Oando 131 Limited, formerly 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.

Oando 131 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 Oando 131.
Oando Akepo	means Oando Akepo Limited.
Oando Arrangement	means the arrangement to be completed under the BCBCA in accordance with the terms of the Oando Arrangement Agreement.
Oando Arrangement Agreement	means the arrangement agreement dated December 22, 2015 between OER, Oando and the Purchaser.
Oando OML 125 & 134	means Oando OML 125& 134 Limited, a corporation incorporated under the laws of Nigeria.
OPDC2	means Oando Petroleum Development Company Ltd.
ODENL	means Oando Deepwater Exploration Nigeria Limited, formerly Phillips Deepwater Exploration Nigeria Limited, a corporation incorporated in under the laws of Nigeria, and holding OML 145.
ODENL 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 ODENL.
OEL	means an oil exploration licence.
OEPL	means Oando Exploration & Production Limited, a subsidiary of Oando, which is a corporation incorporated under the laws of Nigeria.
OER or the Corporation	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 Exile Arrangement.
OER 2012 Warrant	means one share purchase warrant exercisable to acquire one Common Share of OER at an exercise price of C$2.00 per share until July 24, 2014.
OER 2014 Warrant	means one share purchase warrant exercisable to acquire one Common Share of OER at an exercise price of US$1.80 per share until July 30, 2016, and includes any warrant exchanged therefor; provided that, if after February 28, 2015, the closing price of the Common Shares on the TSX is greater than $3.50 CAD for a period of at least 10 consecutive trading days, the OER 2014 Warrants will expire within 30 days.
OML	means oil mining lease.
OOL	means Oando Oil Limited, a corporation incorporated under the laws of Nigeria and resulting from the amalgamation of Oando Oil Limited and Oando Hydrocarbons Limited in December 2015, formerly Phillips Oil Company Nigeria Limited. References to "OOL" in relation to periods prior to such amalgamation are to Oando Hydrocarbons Limited.
OOL 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 OOL.
OPDC	means Oando Production and Development Company Limited, formerly Phillips

	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 Oando Akepo Limited, Oando Petroleum Development Company Limited, Oando OML 125&134 Limited, Oando Qua Ibo Limited, Oando Reservoir and Production Services Limited, Oando Oil Limited, Oando Deepwater Exploration Nigeria Limited, Medal Oil Company Limited and Oando 131 Limited.
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.
Peak	means Peak Petroleum Industries Nigeria Limited, a corporation incorporated under the laws of Nigeria.
Petroleum Act	means the *Petroleum Act*, 2004 (Nigeria).
Phillips Brass	means Phillips (Brass) Limited.
PIB	means *The Petroleum Industry Bill* (Nigeria).
PPT	means tax payable pursuant to the *Petroleum Profits Tax Act 1994* (Nigeria), as amended.
Prospective Resources	means 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. When used herein, the terms “best estinate”, “low estimate” and “high estimate” have the meanings ascribed thereto in the 51-101 Statement.
PSC	means production sharing contract.
Purchaser	means Oando E&P Holdings Limited, a private company incorporated under the laws of the Province of British Columbia and a wholly-owned subsidiary of Oando PLC.
Qua Ibo	means the Qua Ibo Marginal Field, as carved out of 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.
Reserves	means 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. When used herein, the terms "proved reserves", "probable reserves", "possible reserves", "developed reserves", "developed non-producing reserves" and "undeveloped reserves" have the meanings ascribed thereto in the 51-101 Statement.
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*."
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 São Tomé & Príncipe.
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.
Unit	Has the meaning ascribed thereto under "*Description of OER' Business – Relevant Three Year History – Private Placement.*"
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 NGL

$/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

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 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: 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, in circumstances where 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 to one, utilizing a boe conversion ratio of 6 Mcf of natural gas: 1 bbl of crude oil could be misleading as an indication of value.

INTERPRETATION

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

Financial information about OER including, information about covenants relating to the Corporate Facility and RBL OER's financial commodity contracts/hedging arrangements and related party transactions, should be read in conjunction with the 2015 Financial Statements and 2015 MD&A.

Information about the Nigerian oil and gas industry in the section entitled "*The Nigerian Oil and Gas Industry and Regulatory Framework – Overview"* is extracted from "Country Analysis Brief: Nigeria" (February 2015) published by the U.S. Energy Information Administration.

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 - Legislative Framework – Petroleum Act*."

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 gross 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 42.75%. 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.

Information concerning the number of securities of OER owned or held by OER's directors, officer or shareholders is based upon filings made by each individual under applicable Canadian securities laws, without independent verification by OER.

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.

The information contained in this AIF is dated as of December 31, 2015 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:

- expectations regarding the completion of the Oando Arrangement and its impact on the strategic, business, operational and financial affairs of OER;
- expectations regarding the impact of the COP Acquisition on the strategic, business, operational and financial affairs of OER;
- expectations regarding future acquisitions or dispositions and effects of the terms, timing, completion and integration of 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, development, production and other activities;
- OER's expectations of future fiscal terms, 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;
- 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.

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 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 Exile Arrangement. In connection with the Exile Arrangement, Oando transferred the majority of its oil and gas assets to OER. See "*General Development of OER's Business - Relevant Three Year History*."

Following the receipt of the required shareholder approvals at the annual and special meeting of shareholders held on June 11, 2015, OER was continued from the federal jurisdiction of Canada into the Province of British Columbia under the BCBCA with effect from August 31, 2015.

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 Exile Arrangement, the Common Shares were listed, and commenced trading, on the TSX on July 30, 2012 under the symbol "OER."

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's operations are conducted from of its Lagos office located at 8th Floor, 2, Ajose-Adeogun Street, Victoria Island, Lagos Nigeria. OER also has an office in Toronto located at Suite 1210, 333 Bay Street, Bay-Adelaide Centre, Toronto, Ontario, Canada, M5H 2R2.

Principal operating subsidiaries of the Corporation are included in the table below. The operations and country of incorporation for all entities listed below is Nigeria unless otherwise noted. The entities included are involved in the acquisition of petroleum and natural gas rights, the exploration for and development and production of oil and natural gas.

		Proportion of ordinary shares held by:		
Operating Subsidiary	**Nature of Business**	**OER**	**Oando**	**Non-Controlling Interests**
Oando Production and Development Company Limited[1]	Working interest in OML 56 (Ebendo Field), onshore property in the production stage	38%	57%	5%
Oando Oil Limited[3]	Working interest in OML 60, 61, 62, and 63, onshore properties in the production stage	100%	-	-

Oando OML 125 & 134 Limited[1]	Working interest in OML 125 (offshore, production stage) and OML 134 (offshore, development stage)	40%	60%	-
Oando Akepo Limited[1]	Working interest in OML 90 (Akepo Field), offshore property in the development stage	40%	60%	-
Oando Qua Ibo Limited[1]	Working interest in OML 13 (Qua Ibo), onshore property in the development stage	40%	60%	-
Equator Exploration Limited[2]	Working interest in OML 122 (offshore, development stage), OPL 321 and 323 (offshore, exploration stage) and JDZ Block 2, STP Block 5, and STP Block 12 (offshore, exploration)	81.5%	-	18.5%
Oando OML 131 Limited/Medal Oil Limited[1]	Working interests in OML 131, offshore property in the exploration stage	40%	60%	-
Oando Deepwater Exploration Nigeria Limited[1]	Working interest in OML 145, offshore property in the exploration stage	40%	60%	-
Oando Reservoir and Production Services Limited[1]	Reservoir and product ion services to oil and gas companies	40%	60%	-

[1] *The Corporation controls this entity through a shareholder agreement described below.*

[2] *The country of incorporation for Equator Exploration Limited is the British Virgin Islands.*

[3] *In December 2015, the Corporation amalgamated Oando Hydrocarbons Limited with Oando Oil Limited; Oando Oil Limited was the name given to the amalgamated entity.*

As described elsewhere in this AIF, OER's structure reflects its status as an indigenous company under applicable Nigerian legislation, such as the Petroleum Act and Local Content Act, and enjoy preferential status under Nigerian laws. Therefore, 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 1**") and Oando Akepo in respect of Oando Akepo;
  - Oando Netherlands Holding 3 BV ("**HoldCo 2**") and OPDC2 in respect of OPDC2;
  - Oando OML 125 & 134 (BVI) Limited ("**HoldCo 3**") and Oando OML 125 & 134 in respect of Oando OML 125 & 134; 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; and
- shareholder agreements dated July 31, 2014 were entered into between:
  - Oando, Oando Resources Limited ("**ORL**"), Oando OML 131 Holding BV ("**Holdco 7**") and Oando 131; and
  - Oando, ORL, Oando OPL 214 Holding BV ("**Holdco 8**") and ODENL.

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 appoints two directors to the board of each Operating Associate, and the HoldCo Subsidiary appoints 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, Oando can be compelled to sell its Class A Shares to the holders of the Class B 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.

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 the lenders under OER's Corporate Facility; (ii) restrictions on transfer of the Class A Shares contained in the Shareholder Agreements; (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 transfer of shares in companies which have interests in OMLs or OPLs. Pursuant to the Shareholders Agreements, the holder of the Class B Shares can acquire the Class A Shares for US$1**.**

See "*The Nigerian Oil and Gas Industry and Regulatory Framework – Legislative Framework – The Petroleum Act*" and "*Risk Factors – Risks Relating to OER's Operations – The Nigerian Government and third parties may contest OER's status as an indigenous company*."

GENERAL DEVELOPMENT OF OER'S BUSINESS

General

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 Exile Restructuring. Oando retained three Licenses with no reserves or production due to, among other matters, ongoing negotiations with governmental authorities.

On September 27, 2011, Exile entered into a definitive master agreement with Oando providing for the Exile Restructuring and including, among other matters, the transfer of the majority of Oando's upstream oil and gas assets for consideration of 100,339,052 Common Shares. The Exile Restructuring and Exile Arrangement were approved by shareholders at a special meeting held on December 29, 2011 and closed on July 24, 2012. The Exile Restructuring and Exile Arrangement were effected simultaneously to complete the following transactions, among other matters:

- a share consolidation of the existing shares of Exile 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 Exile Arrangement of two warrants for every approximate 16.28 existing shares of Exile held immediately prior to the Exile Arrangement: one 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 warrant exercisable to acquire one Common Share at an exercise price of C$2.00 per Common Share for a period of 24 months;
- 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 Exile 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*", **"***Interests of Management and Oando in Material Transactions – ROFO Agreement" and "Interests of Management and Oando in Material Transactions – Referral and Non-Competition Agreement*."

Today, OER is an indigenous Nigerian energy company with a portfolio of oil and gas Licenses and related facilities and infrastructure concentrated in Nigeria and STP. 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 STP. Oil and gas revenue is generated by the production and sale of crude oil, natural gas, and NGL from OER's interest in OMLs 60 - 63 (onshore), Ebendo (onshore), Qua Ibo (onshore) and OML 125 (offshore), all located in Nigeria. OER also generates oil transportation tariff revenue as a result of its interest in various pipelines and revenues from the sale of power generated at the Kwale-Okpai IPP. For the year ended December 31, 2015, OER produced an aggregate 19.9 MMboe of crude oil, natural gas, and NGL and generated $455 million in revenue (net of royalties) See "*Description of OER's Business – Overview*."

OER, together with its subsidiaries, has employees located in Nigeria, England and Canada. As a result of the ongoing integration of the COP Acquisition, the anticipated completion of the Oando Arrangement and current industry conditions, OER is evaluating the human resources requirements necessary for it to achieve its plans for future growth and development.

Relevant Three Year History

Oando Arrangement

On December 22, 2015, OER entered the Oando Arrangement Agreement under which the Purchaser would acquire all of the Minority Shares, pursuant to a plan of arrangement for cash consideration of US$1.20 per Common Share, subject to the receipt of lender consent and the necessary shareholder, court and regulatory approvals. Common Shares owned by Oando PLC, the Institutional Shareholders and the Key Personnel will be exchanged for common shares of the Purchaser on a one for one basis.

OER's shareholders approved the Plan of Arrangement on February 25, 2016 and the Supreme Court of British Columbia approved the Plan of Arrangement on February 26, 2016. Completion of the Oando Arrangement is subject to satisfaction or waiver of certain conditions precedent, including the consent of certain lenders of OER and Oando. The consent required of the lenders under the RBL has been obtained. Consents required from lenders under the Corporate Facility and lenders to Oando have not yet been obtained. The outside closing date for completion of the Oando Arrangement is April 29, 2016.

After completion of the Oando Arrangement, the Common Shares will be delisted from the TSX and an application will be made for OER to cease to be a reporting issuer or its equivalent under applicable Canadian securities laws.

Further details of the Oando Arrangement Agreement and the Oando Arrangement are set out in the Corporation's Management Information Circular dated January 19, 2016 a copy of which is available under the Corporation's profile on SEDAR at www.sedar.com.

Sale of OMLs 125 and 134

In December 2015, OER entered into an agreement to sell its interest in OMLs 125 and 134 to the project's operator for cash proceeds of $5.5 million and the assumption by the operator of $84.5 million in cash call liabilities payable by OER to the joint venture. Completion of the transaction remains subject to the receipt of lender and government consent. OER has retained all rights to amounts owed by NNPC to OER on account of oil overlifted at OML 125.

COP Acquisition

The COP Acquisition was completed on July 31, 2014 for total consideration, after adjustments, of $1.5 billion (inclusive of $550 million in deposits paid prior to closing). Through this transaction, OER acquired all of the issued share capital of OOL, Oando 131 and ODENL. OOL holds a 20% non-operating interest in the NAOC Joint Venture, which holds OMLs 60, 61, 62, and 63 (each of which is producing) as well as related infrastructure and

facilities. The other co-venturers are NNPC (60% interest) and NAOC (20% and operator). Oando 131 holds a 95% operating interest (Medal Oil, another subsidiary of OER holds the remaining 5%) in OML 131 (non-producing) located 70 km offshore in water depths of 500m to 1,200m. ODENL holds a 20% non-operating interest in OML 145 (non-producing) located 110 km offshore in water depths of 800m to 1,800m. See "*Description of OER's Business*."

At the time of acquisition, the assets of the NAOC JV included forty discovered oil and gas fields, of which twenty-four were producing, approximately forty identified prospects and leads, twelve production stations, approximately 1,490 km of pipelines, three gas processing plants, the Brass River Oil Terminal, the Kwale-Okpai IPP and associated infrastructure.

OER filed a business acquisition report on Form 51-102F4 under its profile on SEDAR on August 14, 2014.

Medal Oil Acquisition

On July 11, 2014, OER completed the acquisition of Medal Oil. The $5 million purchase price was satisfied through the issuance of 3,491,082 Units at a deemed price of C$1.57 per Unit, the terms of which are described below under "*— Financing Activities – Private Placement.*" At the time of its acquisition, Medal Oil held a 5% interest in OML 131. In connection with the completion of the COP Acquisition later in July 2014, OER acquired the remaining 95% interest in OML 131. Accordingly, OER currently holds a 100% interest in OML 131.

Qua Ibo Acquisition

On April 30, 2013, OER acquired the Class B Shares of OQI and ORPS, from Oando for a purchase price of $9.2 million. Upon the receipt of all consents and approvals described below, OER will own a 40% participating interest in Qua Ibo located onshore in Nigeria. The field is operated by NEPN and OER, through its subsidiary ORPS, is technical services provider. OER purchased its interests in Qua Ibo under the terms of the 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 – Onshore Assets – Qua Ibo*" and "*Interests of Management and Others in Material Transactions - Referral and Non-Competition Agreement.*"

The transfer of the interest remains subject to Nigerian governmental consent. Approval of the DPR 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 was to finance working capital requirements and capital expenditures with respect to the development of Qua Ibo. The Diamond Bank Loan was repaid in 2014.

EEZ Block 5 and EEZ Block 12

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. EEL is seeking a 12 month

extension to the deadline for completing is Phase I exploration activities. See "*Description of OER's Assets – Licenses without Production – Blocks 5 and 12 EEZ of STP*."

In December 2015, EEL entered into farmout agreements under which, subject to satisfaction of certain conditions precedent, it has agreed to farm out: (i) a 65% participating interest in Block 5 for $7.4 million with a 50% of carry up to $9.0 million for each of exploration Phases II and III and (ii) a 65% participating interest in Block 12 with a carry of the first $2.0 million of OER's portion of project costs. The Government of STP holds 15% and 12.5% carried interests in Blocks 5 and 12, respectively. Closing of the transaction is subject to satisfaction or waiver of government approvals and certain other standard conditions precedent and is expected to occur during the second quarter of 2016.

Financing Activities

Oando Loans

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.

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 had the ability borrow up to an aggregate $1.2 billion on or before December 31, 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 as well as an additional $599 million.

The purpose of the 2014 Oando Loan was to fund the COP Acquisition and other general corporate requirements. The maturity date of the 2014 Oando Loan was December 31, 2015 and the 2014 Oando Loan bore interest at the rate of 4% per annum. Also pursuant to the 2014 Oando Loan Documentation OER agreed to pay a $48 million facility fee to Oando.

On February 26, 2014, outstanding principal and interest in the aggregate amount of $614.4 million was converted into 432,565,768 Units. On July 9, 2014, outstanding principal and interest in the aggregate amount of $170 million and the $48 million facility fee was converted into 150,075,856 Units. On August 21, 2014, outstanding principal and interest in the aggregate amount of $98 million was converted into 68,144,115 Units. Outstanding principal and interest in the aggregate amount of $41 million was repaid in cash later in 2014.

No amounts are outstanding under the 2014 Oando Loan and no further amounts may be drawn under the 2014 Oando Loan subsequent to December 31, 2014.

See *"– Private Placement."*

Corporate Facility

OER signed an agreement dated January 17, 2014, amended January 31, 2014, with a consortium of lenders to establish the Corporate Facility. The full $350 million was drawn in July 2014 to (a) repay existing bank loans and (b) finance the COP Acquisition. Interest is charged at 3 month LIBOR plus 9.5% per annum for the first fifty-seven months of the Corporate Facility, with an increase of 1% for the remaining life. Amounts due under the Corporate Facility are repayable quarterly. The Corporate Facility has a final maturity date of June 30, 2020 and is secured by OER's interest in OML 125, OML 134, OML 56, and OML 90 including all fields and facilities.

OER is required to hedge a certain portion of crude oil production (see "— *Hedging Arrangements*") received from assets, other than assets comprising the COP Nigerian Business. The Corporate Facility also requires OER to maintain aggregate cash balances of at least $50 million in two accounts with the lenders (the cost reserve account

and a debt service reserve account) within one year from the date the facility is drawn; provided that the amount maintained in the debt service reserve account from time to time shall not be less than the amount required to satisfy the next payment of interest and other non-principal costs, hedging receipts payable (if any) and applicable taxes. The Corporate Facility has a cash sweep provision which obliges OER to apply 40% of its excess cash flows (other than cash flows from OOL) to prepayment of the Corporate Facility at the end of every quarter.

The Corporate Facility contains various covenants which, among other things, require OER to refrain from: disposing of assets other than in the ordinary course of business or otherwise permitted under the Corporate Facility; incurring financial indebtedness other than as permitted; paying dividends or other distributions unless certain conditions are satisfied; providing guarantees or certain types of indemnities; or engage in any mergers or similar transactions which would adversely impact OER's ability to discharge its obligations under the facility.

The Corporate Facility contains financial covenants as follows:

- debt service coverage ratio of not less than 1.3 times;
- field life coverage ratio of not less than 1.5 times; and
- loan life coverage ratio of not less than 1.4 times.

Events of default include breach of OER's obligations under the Corporate Facility, default under other financial indebtedness, insolvency or the occurrence of one or more events which could reasonably be expected to have a material adverse effect on OER or its ability to fulfill its obligations in respect of the Corporate Facility.

In 2015, the Corporation used proceeds from early settlement and reset arrangements on financial commodity contracts and available cash to repay $50.8 million of the Corporate Facility.

As a result of the cash deposits restricted by the lenders under the RBL, the Corporation did not pay its quarterly interest and principal payment of $21.7 million in December 2015 which triggered a default under the Corporate Facility. In February 2016, the Corporation paid $5.9 million of overdue interest on the Corporate Facility. In March 2016, the Corporation paid the overdue principal but failed to make a principal and interest payment of $19.6 million that was due in March, again due to restrictions imposed by the RBL lenders. The Corporation remains in default on the loan. The default gives the lenders the ability to accelerate the maturity of amounts due under the Corporate Facility. While the lenders have not exercised these acceleration rights, there can be no assurances that they will not do so at a future date. See "*Risk Factors – Risks Relating to OER – OER is a leveraged business.*"

African Export-Import Bank Facility

On June 6, 2014, OER signed an agreement with African Export-Import Bank to obtain a one year $100 million subordinated structured debt facility. The full $100 million, less prepaid interest at the rate of at 3 month LIBOR plus 7% per annum, was drawn in July 2014 to finance a portion of the COP Acquisition. The loan is secured by a stand-by letter of credit (the "**SBLC**") which is guaranteed by Oando PLC. Pursuant to applicable capitalization guidelines, the bank which provided the SLBC required that Oando PLC provide cash collateral of $50 million, which amount was provided by OER. The loan was repaid in October, 2015.

RBL

OER entered into agreements dated January 31, 2014 and July 31, 2014 with a syndicate of lenders to provide for a loan of $450 million known as the RBL. The full $450 million was drawn in July 2014 to fund the COP Acquisition.

In February 2015, the Corporation used proceeds from early settlement and reset arrangements on financial commodity contracts and available cash to repay $187.3 million of the Senior Secured Facility. See "*— Hedging Arrangements*."

In October 2015, the Corporation increased its borrowing capacity under the RBL by $90.7 million and used this amount, together with additional cash, for the purposes of repaying outstanding principal and accrued interest owed to African Export-Import Bank. See "*-- African Export-Import Bank Facility*."

Interest is charged on the RBL at 3 month LIBOR plus 8.5% per annum and interest payments are due at the end of each quarterly period. Amounts due under the RBL are repayable quarterly in accordance with a repayment schedule. In addition to regular repayments. The RBL has a cash sweep provision which obliges OOL to apply 25% of any excess cash from the proceeds of sales of crude oil, natural gas liquids and electric power from OOL's various operations against outstanding principal at the end of every quarter. The RBL has a final maturity date of June 30, 2019 and is secured by OER's 20% interest in the NAOC JV including all fields, facilities and the Kwale-Okpai IPP.

OER is required to hedge a certain portion of its crude oil production (see "— *Hedging Arrangements*") received from the COP Nigerian Business. The RBL requires OER to maintain aggregate cash balances of at least $40 million with the lenders and such amount may not be withdrawn without the approval of the lenders.

The RBL contains various covenants which, among other things, require OER to refrain from: disposing of assets other than as permitted under the terms of the RBL; incurring financial indebtedness other than as permitted; providing guarantees or certain types of indemnities; or engage in any mergers or similar transactions which would adversely impact OER's ability to discharge its obligations under the facility.

Following an agreement reached in September 2015 to eliminate a current ratio covenant, the RBL contains financial covenants as follows:

- interest coverage ratio equal or greater than 4.0:1; and
- leverage ratio equal to or less than 3.0:1.

Events of default include breach of OER's obligations under the RBL, default under other financial indebtedness, insolvency or the occurrence of one or more events which could reasonably be expected to have a material adverse effect on OER or its ability to fulfill its obligations in respect of the RBL.

In December 2015 the Corporation amalgamated two of its subsidiaries, without receiving lender consent. This triggered a default and prompted lenders to exercise their right to oblige OER to seek their consent prior to the disbursement of funds from cash deposits held on account with RBL lenders. OER's default gives the lenders the ability to accelerate the maturity of amounts due under the Corporate Facility. While the lenders have not exercised these acceleration rights, there can be no assurances that the lenders will not do so at a future date. See "*Risk Factors – Risks Relating to OER – OER is a leveraged business.*"

Among other expenditures, the lenders prohibited OER from making certain payments of principal and interest due under the Corporate Facility, with the result that OER is currently in default of its obligations under the Corporate Facility. See " – *Corporate Facility*."

In February 2016, the Corporation completed the annual borrowing base calculations required under the RBL. As a result of a reduction of the borrowing base, OER is required to Corporation to prepay $12 million of the amount outstanding under the RBL.

Hedging Arrangements

In connection with the RBL and Corporate Facility, OER was required to enter into financial commodity contracts. Certain of these commodity contracts, which relate to the RBL and which expire in July 2017, had the effect of fixing the price received by OER for 8,000 bbl/day of oil produced from the COP Nigerian Business at $97/bbl until the benchmark price of dated Brent crude oil reached $110.55/bbl. Once the benchmark price of dated Brent crude oil price exceeded $110.55/bbl OER would have received the incremental price above $110.55/bbl.

The remaining commodity contracts, which relate to the Corporate Facility and which expire in January 2019, had the effect of fixing the price received by OER for 2,223 bbl/day of oil produced from OER's other assets at an average price of $91/bbl until the benchmark price of dated Brent crude oil reached cap prices ranging from $95/bbl to $115/bbl. Once the benchmark price of dated Brent crude oil price exceeded the applicable cap prices OER would have received the incremental price above the cap price.

During the first quarter of 2015 OER realized $234 million by resetting the prices of its financial commodity contracts. The proceeds from this transaction (in addition to $4 million from cash in hand) were applied to prepay the RBL and Corporate Facility as detailed below:

- $188 million to the repayment of amounts due under the RBL, resulting in a balance of $227 million outstanding after such repayment; and
- $51 million to the repayment of amounts due under the Corporate Facility, resulting in a balance of $287 million outstanding after such repayment.

The effect of the reset financial commodity contracts associated with the RBL is to fix the price of oil that the Corporation receives, on the specific volumes at $65/bbl until the benchmark price of dated Brent crude oil reaches $75/bbl; when dated Brent crude oil price exceeds $75/bbl the Corporation will receive the incremental price above $75/bbl. These hedges account for 8,000 bbls/day.

The effect of the reset financial commodity contracts associated with the Corporate Facility is to fix the price of oil that the Corporation receives, on the specific volumes at an average price of $65/bbl until the benchmark price of dated Brent crude oil reaches the cap price (which ranges from $75/bbl to $85/bbl); when dated Brent crude oil price exceeds the cap price the Corporation will receive the incremental price above cap price. These hedges account for an average of 1,617 bbls/day.

Provisions of the financial commodity contracts permit the counterparties to terminate those contracts in the event of certain defaults under the Corporate Facility and RBL, respectively. See "—RBL", "—Corporate Facility" and "*Risk Factors – Risks Relating to OER – OER is a leveraged business.*"

Private Placement

On February 26, 2014 OER completed a private placement of 35,070,063 Common Shares and 17,535,031 warrants (each Common Share and one-half of one warrant being a "**Unit**") at a price of C$1.57 per Unit. 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. Each warrant entitled 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.

On December 31, 2014, the warrants issued pursuant to the private placement and conversion of amounts owing under the 2014 Oando Loan were exchanged for OER 2014 Warrants. The most noteworthy impacts of such exchange were that (i) the exercise price of the warrants changed from C$2.00 to $1.80 (reflecting the C$/US$ exchange rates as of the date of closing of the private placement) with the corresponding effects on OER's financial statements as described therein and (ii) the OER 2014 Warrants were listed for trading through the facilities of the TSX whereas the warrants exchanged therefor were not so listed.

Loans to EEL

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 present, Oando has 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. Approximately $12.3 million in principal and interest outstanding under these advances is reflected in the 2015 Financial Statements.

INTRODUCTION TO NIGERIA

Nigeria has approximately 177 million inhabitants. Located on the Gulf of Guinea on Africa's western coast, Nigeria covers an area of approximately 924,000 km^2. English is Nigeria's official language, although many local languages such as Hausa, Yoruba, Igbo and Ijaw are also spoken. 50% of the population is Muslim, 40% is Christian and 10% practice indigenous beliefs. Nigeria's currency is the Naira.

Nigeria achieved independence from Britain in 1960. Nigeria is a federal republic 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 are based primarily on English common law. Nigeria is currently experiencing its longest period of civilian rule since independence.

Nigeria became a member of OPEC in 1971 and is the seventh largest oil and gas producer in 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 establishes production ceilings and quotas for individual members. The NNPC has historically allocated Nigeria's production quota 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.

Following an April 2014 statistical "rebasing" exercise, Nigeria emerged as Africa's largest economy, with 2015 GDP estimated at US$ 1.1 trillion. Oil has been a dominant source of government revenues since the 1970s, although the new government elected in March 2015 has announced plans to diversify the economy away from oil. Regulatory constraints and security risks have limited new investment in oil and natural gas, and Nigeria's oil production has contracted every year since 2012. In 2015 GDP growth fell to 3% (2014: 6.3% (est)) largely due to lower oil prices. The non oil sector also contracted. Fiscal authorities pursued countercyclical policies in 2011-2013, significantly reducing the budget deficit. Monetary policy has also been responsive and effective. Following the 2008-9 global financial crises, the banking sector was effectively recapitalized and regulation enhanced. Despite its strong fundamentals, oil-rich Nigeria has been hobbled by inadequate power supply, lack of infrastructure, delays in the passage of legislative reforms, an inefficient property registration system, restrictive trade policies, an inconsistent regulatory environment, a slow and ineffective judicial system, unreliable dispute resolution mechanisms, insecurity, and pervasive corruption.

THE NIGERIAN OIL AND GAS INDUSTRY AND REGULATORY FRAMEWORK

Overview

Oil

According to the Oil & Gas Journal, Nigeria has an estimated 37 billion barrels of proved crude oil reserves as of January 2015—the second-largest amount in Africa after Libya. The majority of reserves are found along the country's Niger River Delta and offshore in the Bight of Benin, the Gulf of Guinea, and the Bight of Bonny. Current exploration activities are mostly focused in the deep and ultra-deep offshore. NNPC had undertaken onshore exploration activities in northeast Nigeria, within the Chad basin, but the lack of discoveries and the presence of the militant group Boko Haram have stalled exploration. Exploration activities in the onshore Niger Delta have decreased because of the rising security problems related to bunkering and pipeline sabotage.

Nigeria produces mostly light, sweet (low sulfur) crude oil of which the vast majority is exported to global markets. Crude oil production in Nigeria reached its peak of 2.44 million bbl/d in 2005, but began to decline significantly as violence from militant groups surged, forcing many companies to withdraw staff and shut in production. The lack of transparency of oil revenues, tensions over revenue distribution, environmental damages from oil spills, and local ethnic and religious tensions created a fragile situation in the oil-rich Niger Delta. By 2009, crude oil production plummeted by more than 25% to average 1.8 million bbl/d.

In late 2009, amnesty was declared, and the militants came to an agreement with the Nigerian government whereby they handed over weapons in exchange for cash payments and training opportunities. The rise in oil production after 2009 was partially because of the reduction in attacks on oil facilities following the implementation of the amnesty program, which allowed companies to repair some damaged infrastructure and bring some supplies back online.

Another major factor that contributed to the upward trend in output at this time was the continued increase in new deepwater offshore production. The government took measures to attract investment in deepwater acreage in the 1990s to boost production capacity and to diversify the location of the country's oil fields. To encourage investments in deepwater areas, which involve higher capital and operating costs, the government offered PSCs in which IOCs received a greater share of revenue as the water depth increased.

In 2014, Nigeria produced 2.4 million bbl/d of petroleum and other liquids, of which 2.0 million bbl/d was crude oil and the remainder was condensate, natural gas plant liquids, and refinery processing gains. Nigeria's 2014 production was slightly higher than in 2013 because of fewer supply disruptions but still lower than previous years.

There are several planned deepwater projects in Nigeria that have been repeatedly pushed back because of the delayed passing of the PIB and the uncertainty that new fiscal/regulatory terms will impose on the oil industry. The latest drafts of the PIB have also prompted questions about the commercial viability of deepwater projects under the proposed changes to fiscal terms. Deepwater projects have typically included more favorable fiscal terms than onshore/shallow water projects, but the PIB, if passed into law, is expected to increase the government's share of production revenue coming from deepwater projects. As a result of the uncertainty, only two of nine planned deepwater oil projects have been sanctioned by IOCs, while the rest have not received a final investment decision to develop. The planned deepwater oil projects have the potential to bring online 1.1 million bbl/d of new production over the next five or more years, however, only 23% (260,000 bbl/d) reached the critical development milestone. Additionally, global crude oil prices have fallen substantially since mid-2014. If global crude oil prices remain low, this could exacerbate project delays in Nigeria.

Nigeria has extensive export infrastructure, particularly for crude oil. In 2014, Nigeria exported 2.05 million bbl/d of crude oil and condensate. Nigeria in the past has been an important oil supplier to the United States, but the absolute volume and the share of U.S. imports from Nigeria have fallen substantially as U.S. light, sweet crude oil production from the Bakken and Eagle Ford has reduced the need for imports of crude grades of similar quality, such as Nigeria's crude oil. The United States imported an average 60,000 bbl/d of crude oil from Nigeria for the first 11 months of 2014, the lowest amount since the United States started importing Nigerian crude in 1973 and more than a 90% drop from the average volume imported in 2010. As a result, Nigeria fell from being the 5th-largest foreign oil supplier to the United States in 2011 (accounting for 9% of U.S. crude imports) to the 10th in 2014 (accounting for less than 1% of U.S. crude imports).

The United States traditionally had been the largest importer of Nigerian oil until the last few years. The United States went from being the largest importer of Nigerian oil in 2012 to the 10th largest in 2014. India is now the largest country importer of Nigeria's oil, purchasing about 370,000 bbl/d or 18% of Nigeria's total crude exports in 2014. Europe continued to be the largest regional importer of Nigerian oil, importing slightly more than 900,000 bbl/d or 45% of the exports in 2014. European imports of Nigerian crude and condensate increased year-over-year by more than 40% in 2011 and by 30% in 2012, making Europe the largest regional importer of Nigerian oil by far. The European embargo on Iranian crude imports and sporadic supply disruptions in Libya contributed to Europe's increased oil imports from Nigeria.

Historically prominent in the oil and gas industry in Nigeria, IOCs have begun to face a number of challenges, including illegal bunkering, sabotage and security issues, particularly in relation to onshore assets. As well, some IOCs have announced intentions to spend capital on larger projects, which tend to be predominantly offshore. In response to these challenges and larger opportunities several major IOCs have divested from their onshore assets, as COP did in respect of the COP Nigerian Business. OER believes that IOCs will continue to withdraw from onshore interests over time. In recent years, with incentives such as its Marginal Fields program, the Nigerian Government has taken steps to increase the involvement of indigenous Nigerian companies, including OER’s subsidiaries, particularly with respect to onshore opportunities.

Natural Gas

Most of Nigeria’s natural gas reserves are located in the Niger Delta. Nigeria had an estimated 180 Tcf of proved natural gas reserves as of January 2015, making it the ninth-largest natural gas reserve holder in the world and the largest in Africa. Despite holding a global top-10 position for proved natural gas reserves, Nigeria produced only 1.35 Tcf of dry natural gas in 2013. Natural gas production is constrained by the lack of infrastructure to monetize

the natural gas that is currently being flared. The natural gas industry is affected by similar security and regulatory issues that pertain to the oil industry.

Dry natural gas production in Nigeria grew for most of the past decade until Shell declared a force majeure on natural gas supplies to the Soku gas-gathering and condensate plant in November 2008. The Soku plant provides a substantial amount of feed gas to Nigeria's sole LNG facility. Shell shut down the plant to repair damages to a pipeline connected to the Soku plant that was sabotaged by local groups siphoning condensate. The plant reopened nearly five months later, but it was shut down again for most of 2009 for operational reasons. As a result, the plant's closure led to a reduction in Nigeria's natural gas production, particularly from Shell's fields in the Niger Delta, and a decline in LNG exports in 2009. Natural gas production gradually grew after 2009, and it reached its highest level of 1.5 Tcf in 2012. In 2013, production fell by 10% to 1.35 Tcf because of supply disruptions and a temporary blockade on Nigeria's LNG shipments, which also led to a corresponding fall in exports and, to a lesser extent, domestic consumption. Nigeria consumed 490 Bcf of dry natural gas in 2013, about 36% of its production.

A significant amount of Nigeria's gross natural gas production is flared because some of Nigeria's oil fields lack the infrastructure needed to capture the natural gas produced with oil, known as associated gas. In 2013, Nigeria flared 428 Bcf of its associated gas production, or 15% of its gross production. According to the U.S. National Oceanic and Atmospheric Administration, natural gas flared in Nigeria accounted for 10% of the total amount flared globally in 2011.

The amount of gas flared in Nigeria has decreased in recent years, from 540 Bcf in 2010 to 428 Bcf in 2013. According to Shell, one of the largest gas producers in the country, the impediments to decreasing gas flaring have been the security situation in Niger Delta and the lack of partner funding that has slowed progress on projects to capture associated gas. Shell recently reported that it was able to reduce the amount of gas it flared in 2012 because of improved security in some Niger Delta areas and stable co-funding from partners, which allowed Shell to install new gas-gathering facilities and repair existing facilities damaged during the militant crisis of 2006 to 2009. Shell also plans to develop the Forcados Yokri Integrated Project and the Southern Swamp Associated Gas Gathering Project to reduce gas flaring.

The Nigerian government has been working to end gas flaring for several years, but the deadline to implement the policies and fine oil companies has been repeatedly postponed, with the most recent deadline being December 2012. In 2008, the Nigerian government developed the Gas Master Plan to promote investment in pipeline infrastructure and new gas-fired power plants to help reduce gas flaring and provide more gas to fuel much-needed electricity generation. However, progress is still limited because security risks in the Niger Delta have made it difficult for IOCs to construct infrastructure that would support gas monetization.

Nigeria exports the vast majority of its natural gas in the form of LNG. Nigeria exported about 800 Bcf of LNG in 2013, ranking Nigeria among the world's top five LNG exporters, along with Qatar, Malaysia, Australia, and Indonesia. Estimates of Nigeria's LNG exports vary among sources, with the BP 2014 Statistical Review of World Energy placing it at almost 800 Bcf in 2013 and the OPEC Annual Statistical Bulletin estimating it at 866 Bcf in 2013. Nigeria's LNG exports accounted for about 7% of globally traded LNG. Japan is the largest importer of Nigerian LNG and imported 23% of the total in 2013, followed by South Korea (17%) and Spain (14%).

Trade patterns for Nigerian LNG have changed over the past few years. Most notably, Nigeria's LNG exports to Europe have decreased significantly. In 2010, Europe imported about 67% of total Nigerian LNG exports, but in 2013, that share dropped to 31%. Nigeria has increased its LNG exports to Asia, namely Japan, following the Fukushima nuclear incident in March 2011. Japan's imports of Nigerian LNG were six times the 2010 level by 2013.

U.S. LNG imports from Nigeria have declined substantially, similar to the trend in U.S. crude oil imports. U.S. imports from Nigeria peaked at 57 Bcf in 2006 and fell to 2 Bcf in 2011, mostly as a result of growing U.S. natural gas production. In 2012, the United States did not import LNG from Nigeria for the first time since 1999. In 2013, the U.S. resumed imports from Nigeria, receiving 2.5 Bcf of LNG.

The LNG facility on Bonny Island is Nigeria's only operating LNG plant. It is operated by Nigeria LNG Limited (NLNG) and its partners include NNPC (49%), Shell (25.6%), Total (15%), and Eni (10.4%). NLNG currently has six liquefaction trains with a production capacity of 22 million tons per year (1,056 Bcf/y) of LNG and 4 million

tons per year (80,000 bbl/d) of liquefied petroleum gas. A seventh train is planned to increase the facility's LNG capacity to more than 30 million tons per year (1,440 Bcf/y).

Brass LNG Limited, a consortium made up of NNPC, Total, and Eni, is developing the Brass LNG Liquefaction Complex. The Brass LNG facility is expected to have two liquefaction trains with a total capacity of 10 million tons per year (480 Bcf/y). The project is in the early engineering phase.

Nigeria exports a small amount of its natural gas via the West African Gas Pipeline, which began commercial operations in 2011. The 421-mile pipeline carries natural gas from Nigeria's Escravos region to Togo, Benin, and Ghana, where it is mostly used for power generation. The pipeline links into the existing Escravos-Lagos pipeline and moves offshore at an average water depth of 35 meters. The pipeline has the nameplate capacity to export 170 MMcf/d (62 Bcf/y) of natural gas, although its actual throughput (21 Bcf in 2013) is about one-third of its capacity.

Legislative Framework

Under the Nigerian constitution, the regulation of petroleum is a matter for the federal government. However, the oil and gas industry is also subject to a variety of federal, state and local laws and regulations, including those relating to taxation and the environment, health and safety. The primary laws applicable to the oil and gas industry are described below.

The Petroleum Act

The Petroleum Act covers the definition of petroleum, title to petroleum, licencing of upstream and downstream operations and other issues relating to the Nigerian petroleum industry. The Petroleum Act empowers the Minister of Petroleum Resources with the right to exercise general supervision over all operations carried on under licences and leases granted under the act. The Minister exercises these rights in conjunction with the DPR. The DPR is charged with the responsibility of supervising, regulating and monitoring petroleum activities in Nigeria through the enforcement of policies relating to all petroleum matters, licensing of all petroleum operations, including issuance of permits, and setting standards and guidelines for safe, efficient and effective control of such operations.

The Petroleum Act provides for the different Licences that must be obtained in order to carry out petroleum operations in Nigeria, including OELs, OPLs and OMLs. An OEL confers on the grantee the non-exclusive right to undertake petroleum exploration activities in the specified OEL area. An OEL terminates on the 31 December following the date it was granted and may be renewed for one year subject to the fulfillment of conditions imposed. An OPL confers on the grantee the exclusive right to prospect for, carry away and dispose of hydrocarbons in the specified OPL area. The duration of an OPL is five years, inclusive of any period of renewal. An OML confers on the grantee the exclusive right to search for, win, work, carry away and dispose of all petroleum in, under or throughout the area covered by the OML. In essence, this translates as having the title to the oil or gas produced in the concession or the proceeds thereof. An OML confers essentially the same rights as an OPL but the duration of an OML is 20 years and may be renewed. The applicant for an OML must be a holder of an OPL who has discovered crude oil in commercial quantity. Commercial quantity is deemed to have been achieved if the OPL holder can satisfy the authorities that a production of Mbbls/d of crude oil can be obtained from the OPL area. 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. The rights granted to the holder of an OPL or OML apply both to crude oil as well as gas. The Minister is empowered to revoke an OML where the lessee is controlled directly or indirectly by a citizen of, or a company organized in, a country that does not permit Nigerians to acquire, hold or operate petroleum concessions. The Minister also has the power to revoke any OML where the lessee is not conducting operations: continuously; in accordance with the approved basic work program or good oil field practices; where the lessee has failed to comply with the provisions of the Petroleum Act; where the lessee has failed to pay its royalties; or where the lessee has failed to furnish the Minister with the necessary reports of its operations.

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.

In 1996, the Petroleum Act was amended to give the Nigerian government the power to order the farm-out of Marginal Fields to Nigerian companies in exchange for farm-out fees and royalty payments. This amendment was part of measures and initiatives that were implemented by the Nigerian government with the following objectives: (i) expanding oil reserves; (ii) reducing the rates of abandonment of depleting fields; (iii) maintaining tax and royalty revenues from fields which would otherwise have become unproductive; and (iv) encouraging indigenous companies to develop the required technical and managerial competence required to participate successfully in the exploration and production sector. Marginal fields are defined in the *Guidelines for Farm-out and Operation of Marginal Fields* as fields that have reserves reported annually to the DPR which have remained unproduced for over 10 years. Marginal fields have some or all of the following characteristics:

- are not considered by Licence holders for development because of assumed economics under prevailing fiscal and market conditions;
- have had at least one successful exploratory well drilled on the structure and have been reported as oil and gas discoveries for more than 10 years, with no follow-up appraisal or development effort;
- have crude oil characteristics different from current streams, which cannot be profitably produced through conventional methods or current technology;
- have high gas and low oil reserves;
- have been abandoned by the leaseholders for upwards of three years for economic reasons; and
- the present License holders may consider farming out due to portfolio rationalization.

NNPC Act

The NNPC is a state-owned petroleum company established under the NNPC Act. The NNPC, which is chaired by the Minister of Petroleum Resources, is authorised to engage in commercial activities pertaining to the petroleum industry. In addition to its exploration activities, NNPC was given powers and operational interests in refining, petrochemicals and products transportation as well as marketing. The duties of NNPC include:

- exploring and prospecting for, working, winning or otherwise acquiring, possessing and disposing of petroleum;
- purchasing and marketing petroleum, its products and by-products; and
- engaging in activities that enhance the petroleum industry in the overall interest of Nigeria.

The NNPC typically conducts its exploration and production activities through participation in joint ventures and PSCs with foreign and indigenous oil companies. Most of Nigeria's major onshore/shallow water oil and natural gas projects, like the NAOC JV, are funded through JVs between NNPC and oil companies, where NNPC is the majority shareholder. PSCs are the fiscal regime typically, but not always, governing deepwater projects. PSC terms on deepwater projects tend to contain more attractive terms than those in JV arrangements in order to incentivize the development of deepwater projects.

In March 2016, the Nigerian press reported that President Muhammadu Buhari has approved the restructuring of the NNPC into seven new divisions. Under the new structure, NNPC is expected to have five core new divisions comprising the upstream, downstream, refining group, gas and power, as well as the ventures' groups. The other two

divisions will be finance and services groups. The restructuring has not yet been effected and there can be no assurance as to its final structure or the effect of that structure on OER's activities and joint venture interests. As well, certain Nigerian legislators have suggested that NNPC can only be altered, changed or otherwise amended only by an act of the National Assembly since the NNPC was established under the NNPC Act.

Local Content Act

The Local Content Act introduced significant reforms in the Nigerian oil and gas industry. The act aims to increase the level of indigenous participation in the oil and gas industry. Oil and gas arrangements, contracts and operations are now required to comply with minimum Nigerian content standards and thresholds. All oil and gas agreements, contracts or memoranda of understanding relating to any operation or transaction in the Nigerian oil and gas industry entered into after the enactment of the Local Content Act are required to comply with the provisions of the act.

The scope of this act is extensive and all operators, contractors, sub-contractors and other entities carrying out projects, operations, activities or transactions in the Nigerian oil and gas industry are required to adhere to the provisions of the act as an essential factor in their project conceptualization, development and management. Nigerian independent contractors shall be given first consideration in the award of oil blocks, oil field licences, oil lifting licences and all projects for which contracts are to be awarded in the Nigerian oil and gas industry. In addition, indigenous Nigerian persons shall be given first consideration for employment and training in any project executed by any operator or project promoter in the Nigerian oil and gas industry. The act also requires that exclusive consideration is given to Nigerian indigenous service companies that demonstrate ownership of equipment, Nigerian personnel and capacity to execute such work, or to bid on land or swamp operating areas of the Nigerian oil and gas industry for specific contracts and services.

The promotion of ''Nigerian Content'' as provided by the Local Content Act is required to be a major consideration for the award of licenses, permits and any other interest or operation in the Nigerian oil and gas industry. The ''Nigerian Content'' of a company is defined as the quantum of composite value added to or created in the Nigerian economy by a systematic development of capacity and capabilities through the deliberate utilization of Nigerian human, material resources and services in the Nigerian oil and gas industry. The minimum ''Nigerian Content'' in any project to be executed in the industry is required to be consistent with the levels set out in a schedule attached to the Local Content Act showing the proposed rates and measured units for listed activities. The schedule also shows the required percentages of Nigerian resources to be utilized, expressed in terms such as manpower, industry spend, tonnage or volume for each specified project item.

Although the Local Content Act does not appear to place emphasis on the nationality of the shareholders of a company operating in the Nigerian oil and gas industry as the basis of local content, it does stipulate an ownership threshold to determine what constitutes a ''Nigerian company''. Section 106 of the Local Content Act defines a ''Nigerian company'' as a company with not less than 51% of its shares held by Nigerians.

GMP

The GMP came into effect in 2008 as an aggregate policy framework that includes the Gas Infrastructure Blueprint, Gas Pricing Policy and Domestic Gas Supply Obligation. Nigeria holds the seventh largest natural gas reserves in the world and with the GMP, the Nigerian government aims to leverage this resource base to meet the target of growing the economy at 10% per annum.

The GMP is expected to drive the monetization of gas in order to substantially reduce gas flaring, provide a more efficient and cheaper source of fuel for power and industrial production, and provide an alternative revenue source for the Nigerian government.

The main objectives of the GMP include:

- developing and entrenching a sustainable commercial framework for the Nigerian domestic gas market;

- maximizing the multiplier effect of gas in the domestic economy through the facilitation of gas utilization in the domestic economy and the stimulation of broad gas-based industrialization;

- optimizing Nigeria's share and competitiveness in high-value export markets, through selective participation in high-value markets and strategic positioning for growth; and

- assuring long-term gas security for Nigeria.

Following the approval of the GMP, the Nigerian government issued the National Gas Supply and Pricing Policy and the National Domestic Gas Supply and Pricing Regulation 2008. Both provide for the imposition of a domestic gas supply obligation on all upstream companies and require a pre-determined portion of their gas production to be set aside for supply to the domestic market. The GMP also has the goal of creating an integrated gas gathering, processing and distribution network in the Niger Delta and across Nigeria through the implementation of a ''gas infrastructure blueprint'' in an attempt to significantly increase the amount of gas used domestically, to in turn promote private sector participation and to standardize gas specification.

Alongside the GMP, the Nigerian government is also implementing an accelerated gas development and utilization program to enable domestic investors to take advantage of the opportunities in Nigeria's gas industry. It involves the installation of supplementary gas treatment and processing plants between existing gas plants and power plants.

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 December 2008. 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 proposes to replace the PPT with the NHT, 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 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 the Petroleum Host Communities Fund (the "**PHCF**") as 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 PHCF, 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.

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*." 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.

Contractual Framework and Fiscal Regime

Overview

There are five primary legal arrangements for crude oil production currently in force in Nigeria:

- *Concession/sole risk* — an independent company with a concession bears the full risk and costs of exploration, development and production, has interests over the crude oil produced and is liable for all royalties and PPT payments. Currently, concessions in respect of OMLs are only awarded to Nigerian companies that have at least 51% of their shares held by Nigerian citizens.

- *JVs* — Most JVs apply in the onshore or shallow offshore area of Nigeria. JVs currently account for the majority of Nigeria's total oil production. Under a JV, one or more oil companies enter into a joint venture with the NNPC whereby the oil companies and the NNPC (who usually holds a majority, accessible, non-operating stake) agree to jointly explore for, develop and produce petroleum pursuant to the terms of a License jointly held by them. JVs 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. 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.

  For JV partners, PPT 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. 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 transportation 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. In respect of PCSs involving the Nigerian Government, 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 through oil lifted by the NNPC ("Royalty Oil") and then splits the resulting 'Profit Oil' in an agreed proportion with the NNPC. The rate of PPT is 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 subsequent Licensing rounds (2005 and thereafter) applied a cost ceiling of 80%.

- *Marginal Fields* — Fields currently located within OMLs may be carved out of the OML and acquired under the Marginal Fields Development Program where they are "marginal" under the provisions of the Petroleum Act and the Guidelines. In the broadest sense, an oil field is "marginal" if the field that may not produce enough net income to make it worth developing at a given time and/or which has not been exploited for a period of 10 years. OML holders may voluntarily, or as compelled by the President of Nigeria in certain circumstances, dispose of Marginal Fields to Nigerian companies (i.e. companies incorporated in Nigeria and that are at least 51% Nigerian owned) under farmout agreements. Under the fiscal incentives provided by the DPR, parties who acquire Marginal Fields will enjoy fiscal terms that are more favourable than would have normally applied to onshore and shallow water projects. See "— *Advantages to Indigenous Companies – Marginal Fields Development Program*."

- *Service contracts* — an arrangement pursuant to which the OML holder enters into a contract with a contractor that provides risk capital for exploration and production. If no commercial discovery is made, the contract is then terminated with no further obligation on either party. If a commercial discovery is made, the contractor is entitled to recover its costs and receive some additional remuneration.

The three arrangements relevant to OER are JVs, PCSs and marginal fields arrangements. Each has different fiscal implications. 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 and in OER's financial statements and management's discussion and analysis relating thereto.

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

Joint Ventures[1]					Deepwater PSCs[2]		Marginal Fields[3]	
	$/bbl		**$/Mcf**	**$/boe**		**$/bbl**		**$/bbl**
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)	Less Capital Allowance	–	–	Less Capital Allowance	(4.00)	Less Capital Allowance	(4.00)
Less ITA	(1.00)	Less ITA					Less ITA	(1.00)
= 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*."

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.

Advantages to Indigenous Oil Companies

Marginal Field Development Program

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. See "*—Legislative Framework – The Petroleum Act*."

The following documents are relevant to an understanding of the Marginal Field Development Program: (i) The Petroleum Act; (ii) the Guidelines; and (iii) a letter dated July 12, 2006 from the DPR (the "**DPR Letter**"), in which certain incentives were granted to Marginal Fields operators. This legislation and interpretive materials are supplemented by the relevant farmout agreements under which the Marginal Fields operators acquire their interests in the relevant Licenses. The Guidelines and Petroleum Act define marginal fields as fields that have been deemed to be such by the President of Nigeria or 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. Under the Petroleum Act, the holder of an OML may, with the consent of and on such terms and conditions as may be approved by the President, farmout any Marginal Field which lies within the leased area. Alternatively, as occurred in "bid rounds" in 2003, the President may cause the farmout of a Marginal Field if such Field has been left unattended for a period of not less than 10 years from the date it was first discovered. Regardless of whether the farm-out is voluntary or mandated by the President, only Nigerian companies (i.e. companies incorporated in Nigeria and that are at least 51% Nigerian owned) which can demonstrate upstream oil and gas experience and have the technical capability to evaluate and develop the asset are permitted to apply for, or operate Marginal Fields. Non-Nigerian companies are not permitted to be technical partners but their equity participation is limited to 40%. Once a preferred bidder has been selected, it must enter into a farmout agreement with the vendor, with the terms of such agreement being subject to the approval of the President. In addition to the terms of the farmout agreement, the DPR granted certain fiscal incentives to the Marginal Field, including: (i) a PPT rate of 55%; (ii) ITA at 20%; (iii) royalties based on production rather than water depth (at rates ranging from 2.5% for 5,000 bbls/d to 18.5% for 15,000 bbls/d); (iv) and various other fees, rents and royalties payable to the vendor. Once an operator acquires a Marginal Field, it has all of the rights of the original OML leaseholder in respect of the Marginal Field and must deal with the DPR and other governmental authorities for lease renewals and other matters.

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. At least nine 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. 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).

Other Matters Affecting the Nigerian Oil and Gas Industry

Security, Bunkering and Pipeline Sabotage

Since the mid-2000s, Nigeria has experienced increased pipeline vandalism, kidnappings, and militant takeovers of oil facilities in the Niger Delta. In the past, MEND was one of the main groups attacking or threatening attacks on oil infrastructure for political objectives, claiming to seek a redistribution of oil wealth and greater local control of the oil sector. Security concerns led some oil services firms to pull out of the country and oil workers' unions to threaten strikes over security issues. The instability in the Niger Delta has also resulted in shut-in production at onshore and shallow offshore fields, forcing companies to frequently declare force majeure on oil shipments. The amnesty program implemented in 2009 led to fewer attacks and supply disruptions in 2009-10, and some companies were able to repair damaged oil infrastructure.

The NAOC JV, in which OER holds a 20% interest, was subjected to two incidents of in 2015. See "*Description of OER's Business – Licenses with Production – OMLs 60-63 – Overview*."

Despite measures taken to ameliorate the causes of militant attacks, there has been an increased level of bunkering and other attacks in recent years. Nigeria's oil theft and trade business is based on a complex system of networks comprised of domestic, regional, and international actors. Oil is stolen at various stages of the production process from upstream to downstream operations—wellheads, manifolds, pipelines, and storage tanks at export terminals. Most bunkering operations typically involve tapping or siphoning oil from a pipeline by a hose and pumping the oil onto barges or small tankers. Some stolen crude oil is taken to illegal refineries along the Niger Delta's swampy bush areas and the refined products are then sold domestically and regionally. However, the bulk of the crude oil makes its way to international markets. Most of that oil is sold to world markets directly from Nigeria's export terminals, which is known as white collar theft. White collar theft entails filling tankers (or topping them off) with stolen oil at export terminals or stealing crude from storage tanks and loading it onto trucks. A portion of the global illegally traded oil also involves the transfer of crude oil from small tankers to larger tankers waiting further offshore, also known as ship-to-ship transfers.

National estimates of stolen crude oil vary and can reach as high as 400,000 bbl/d, but some believe that estimate is too high and may include the volume lost in oil spills. It is difficult to measure the volume of stolen crude oil because metering systems are usually at export terminals and, therefore, oil stolen between the wellhead and pipelines is not easily detected. Furthermore, IOCs do not collectively report volumes stolen, so there is no authoritative source for total volumes stolen.

Environmental Damage

The Niger Delta region suffers from environmental damage caused by pipeline sabotage, bunkering and spills from illegal refineries. Additionally, pipelines have contributed to oil spills as old or poorly maintained pipelines can rupture when they corrode. The amounts spilled because of bunkering or sabotage versus aging infrastructure and/or operational failures are highly debated among oil companies and environmental and human rights groups. Oil spills have caused land, air, and water pollution and decreased fish stocks.

Piracy

Piracy in West Africa has increased over the past few years, affecting the region's oil industry and naval transportation. Security experts say that the West African coast has become the most dangerous in the world as the amount of piracy incidents has surpassed those in East Africa (particularly around offshore Somalia) and several piracy attacks have resulted in the injury or deaths of crew members. The International Maritime Bureau, an agency that tracks piracy incidents, believes that piracy occurrences are underreported in West Africa's waters because of a fear of more attacks, potential increased insurance costs, and the proprietary information about vessels.

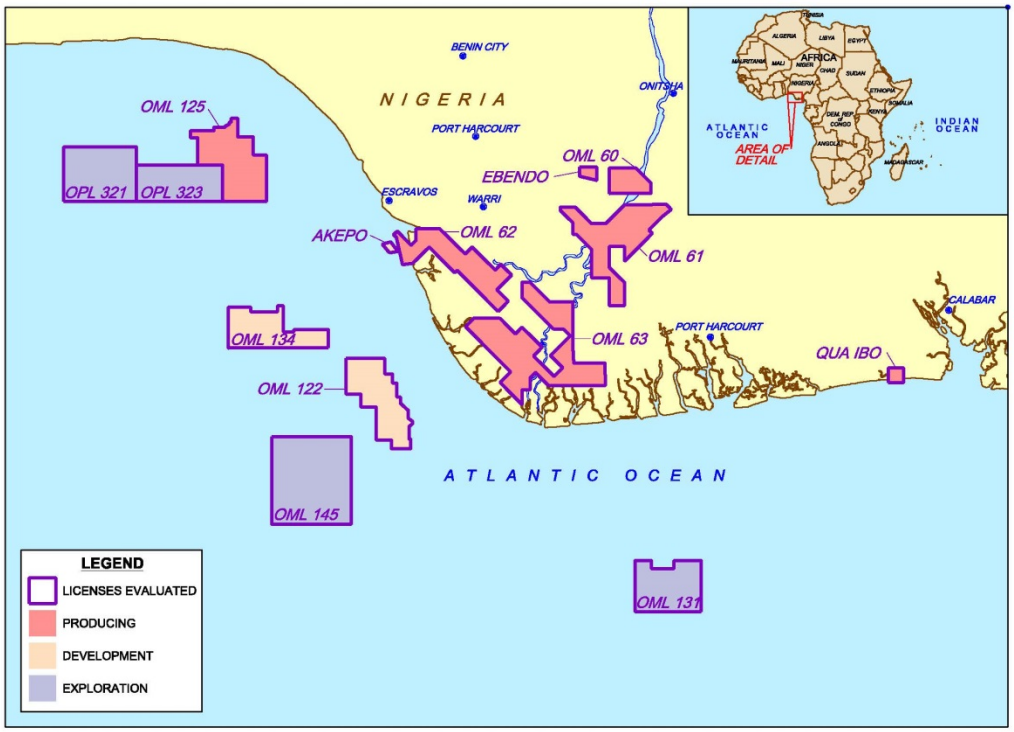
Piracy attacks include armed robbery, kidnapping for ransom, boarding offshore oil platforms, and stealing tankers or siphoning oil from tankers. Piracy in West Africa has focused more on crude oil and refined product theft compared with piracy in East Africa, which mostly involves kidnapping for ransom. Some oil companies have reported stolen cargoes of crude oil. Some analysts believe that the pirates are from Nigerian militant groups such as MEND. One of the major impediments to reducing piracy incidents, particularly those offshore Nigeria, is that the Nigerian government does not allow foreign armed guards in its waters, which was a successful tactic used to curtail piracy in East Africa. According to the United Nation's Operational Satellite Applications Program, the number of piracy-related attacks in offshore West Africa, particularly the Gulf of Guinea, shows no signs of decreasing, and the attacks have become more violent.

Certain of OER’s deep water assets have suffered from disruptions due to piracy in the past and there can be no assurance that they will not be attacked in the future.

DESCRIPTION OF OER’S BUSINESS

Overview

OER is involved in the acquisition of petroleum and natural gas rights, the exploration for, and development and production of, oil and natural gas. 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 Licenses: OMLs 60-63, Ebendo (OML 56), Qua Ibo (OML 13), OML 125, OML 122, OML 131, OML 134, Akepo (OML 90), OML 145, OPL 321 and OPL 323; the locations of which are shown on the map below.



Oil and gas revenue is generated by the production and sale of crude oil, natural gas, and NGLs from the Corporation's interest in OMLs 60 to 63 (onshore), OML 125 (offshore), Ebendo (in OML 56, onshore), and Qua Ibo (in OML 13, onshore), all located in Nigeria. The Corporation also generates oil transportation tariff revenue from third parties by the Corporation's interest in various pipelines and revenues through the sale of power generated at the Kwale-Okpai IPP. The Corporation's major customers include subsidiaries of international oil companies and other joint ventures in Nigeria. The Corporation earned the majority of its revenue from Eni Trading and Shipping S.p.A, Vitol SA and Nigeria Liquefied Natural Gas Limited.

Important plants, facilities and installations in which OER has an interest include 14 flowstations, one oil processing centre (Ebocha, OML 61), one gathering facility (F.U.N, OML 13), one oil export terminal (Brass, NAOC JV), three gas plants (Kwale, Ob-Ob and Ogbainbiri), one power plant (the Kwale-Okpai IPP) and associated infrastructure including, roads, power stations and heliports. The majority of these properties are based onshore. There is a leased FPSO for the Abo field in OML 125.

There are approximately 1,250 km of pipelines transporting oil and gas from flowstations to oil centres/gas plants and the oil and gas export terminals. Approximately 1,190 km of these pipelines are associated with NAOC JV. Some of the NAOC JV's main export pipelines are used by third parties and agreements are in place for transportation and processing. In addition, some gas is supplied from the Akri field to the Oguta plant owned by the Shell JV.

A breakdown of OER's revenue for the years ended December 31, 2015 and 2014 is as follows:

	2015	2014
Crude oil	396,361	389,720
NGLs	12,754	5,594
Natural gas	97,955	66,617

Gross oil and gas sales	507,070	461,931
Less: royalties	(71,421)	(55,592)
Oil and gas sales, net of royalties	435,649	406,339
Oil transportation tariffs and other	6,110	4,932
Kwale-Okpai power sales	13,206	10,151
Revenue, net of royalties	454,965	421,422

In 2015 the average daily production (Gross) from OER's interest in producing fields is shown in the table below as taken from the 51-101 Statement. OER's Gross average 2015 production rate was 20,740 bbls/d of oil, 162,067 Mscf/d of sales gas, and 3,332 bbls/d of natural gas liquids.

		Three Months Ended				
Product Type		**31-Mar-15**	**30-Jun-15**	**30-Sep-15**	**31-Dec-15**	**LTM Total**
Light and Medium Crude Oil						
OMLs 60, 61, 62, & 63	(bbls/d)	15,593	16,443	16,094	14,127	15,561
OML 125	(bbls/d)	2,767	2,969	3,839	3,663	3,313
Ebendo (OML 56)	(bbls/d)	2,021	1,319	1,907	1,580	1,706
Qua-Ibo (OML 13)	(bbls/d)	320	957	935	869	772
Total	**(bbls/d)**	**20,702**	**21,687**	**22,775**	**20,239**	**21,353**
Conventional Natural Gas (Sales)						
OMLs 60, 61, 62, & 63	(Mscf/d)	167,179	173,244	154,134	145,861	160,030
OML 125	(Mscf/d)	0	0	0	0	0
Ebendo (OML 56)	(Mscf/d)	11,662	8,261	13,782	10,417	11,034
Qua-Ibo (OML 13)	(Mscf/d)	0	0	0	0	0
Total	**(Mscf/d)**	**178,841**	**181,505**	**167,915**	**156,278**	**171,064**
Natural Gas Liquids						
OMLs 60, 61, 62, & 63	(bbls/d)	3,745	3,725	2,605	3,265	3,332
OML 125	(bbls/d)	0	0	0	0	0
Ebendo (OML 56)	(bbls/d)	0	0	0	0	0
Qua-Ibo (OML 13)	(bbls/d)	0	0	0	0	0
Total	**(bbls/d)**	**3,745**	**3,725**	**2,605**	**3,265**	**3,332**
Oil Equivalent						
OMLs 60, 61, 62, & 63	(boe/d)	47,201	49,042	44,388	41,702	45,565
OML 125	(boe/d)	2,767	2,969	3,839	3,663	3,313
Ebendo (OML 56)	(boe/d)	3,965	2,695	4,204	3,316	3,545
Qua-Ibo (OML 13)	(boe/d)	320	957	935	869	772
Total	**(boe/d)**	**54,253**	**55,663**	**53,366**	**49,550**	**53,196**

Notes:
1. All values presented in this table are Company Gross.
2. Liquid production volumes are sales figures after deduction of losses and shrinkage, but before deduction of royalty.
3. Natural gas production includes both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, flaring, losses and shrinkage, but before deduction of royalty.
4. Natural gas has 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. LTM means last twelve months.
6. Numbers may not add up due to rounding.

The following table, taken from the 51-101 Statement, sets forth information in respect of 2015 volumes produced and sold.

Total Company- 2015 Production, Operating Expenses, Royalties, and Netback

	Light & Medium Oil (M bbls)	Conventional Natural Gas (MMscf)	Natural Gas Liquids (Mbbls)	Oil Equivalent [1] (Mboe)
2015 Net Sales Volumes	7,761	58,411	1,216	18,712
Average price unit volume received (US$)	51.07	1.68	10.49	27.10
Royalties paid per unit volume (US$)	8.13	0.12	0.73	3.80
Production costs per unit volume (US$) [2]				11.99
Netback per unit volume before taxes (US$)				11.31

Notes:
1. 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.
2. Allocation of production costs is not easily attributable between multiple product types due to nature of operations. Resulting netbacks are thus disclosed on the basis of units of equivalency between oil and gas.
3. Liquid production volumes are sales figures after deduction of losses and shrinkage, but before deduction of royalty.
4. Natural gas production includes both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, flaring, losses and shrinkage, but before deduction of royalty.
5. Numbers may not add up due to rounding.

Per unit volume, netbacks have been calculated by subtracting royalties and production (operating) costs from revenues. Where revenues per unit volume equals average price received for a given product type over the financial year.

Licenses with Production

OMLs 60-63

Overview

The NAOC JV is OER's most material asset. The NAOC JV (20% WI; NAOC 20% and operator; NNPC 60%) holds OMLs 60, 61, 62 and 63, located onshore in the Niger Delta and the Licenses have an expiry date of June 14, 2027.

The terms of the NAOC JOA govern the NAOC JV. Under the NAOC JOA, NAOC acts as operator of the JV but there is provision for the eventual assumption by the NNPC of operatorship over portions of the NAOC JV. An operating committee, comprised of six members appointed by the NNPC, two members appointed by NAOC and two members appointed by OOL oversees the activities of the NAOC JOA. Decisions of the operating committee require unanimous approval of the members. The NAOC JOA requires any party who receives an offer to acquire any of its interest in the NAOC JV to provide the other parties with a 30 day right of first refusal to acquire such interest. The NAOC JV also provides, among other things, for the rights of the parties to receive information about the business and affairs of the JV, access to the JV and its books and records, the obligations of the parties to fund their proportionate interests of the NAOC JV and replacement of the operator.

OER's gross share of total production sold from NAOC JV in 2015 was 16.6 MMboe (comprised of 5.7 MMbbls of oil, 58.5 Bscf of gas and 1.2 MMbbls of natural gas liquids). Therefore, in 2015, OER's gross share of daily production sold from NAOC JV averaged 45,565 Mboe per day (consisting of 15,561 bbls/d of oil, 160,030 MMscf/d of gas and 3,332 bbls/d of natural gas liquids).

As of December 31, 2015, OER held a net share in the NAOC JV 2P reserves of 427 MMboe (comprised of 152.3 MMbbls of oil, 12.5 MMbbls of natural gas liquids and 1,573.6 Bscf of gas), gross Best estimate unrisked Contingent resources of 78.2 MMboe, gross Best estimate of risked (defined as risk for chance of development) Contingent resources of 19.1 MMboe, gross Mean estimate unrisked Prospective resources of 51.5 MMboe and gross Mean estimate of risked (defined as risk for chance of geologic success) Prospective resources of 19.5 MMboe.

A fire incident started on June 28, 2015 when saboteurs ignited an explosive device which started a fire involving two of the NAOC JV's crude storage tanks located at the Ebocha Oil Centre in Rivers State. In the early hours of 30th June 2015, a third tank collapsed after suffering structural damages due to the fire outbreak. The Ebocha Oil Centre is the default hub for most of the land area oil production in the NAOC JV, collecting and stabilizing land area crude from 4 Flow Stations/Processing Facilities. The fire was extinguished with no injuries, fatalities, or environmental spills. Most production in the land area was initially shut-in, leading to July production from crude oil, NGLs and natural gas production being reduced by approximately 10,000 boe/day net during the month. Production was restored near the end of July by the combination of installing booster pumps at the Ebocha terminal and reconfiguring lines to bypass the storage facility, along with redirecting production along existing pipelines. As a result of the incident, OER incurred impairment charges of $6.7 million relating to its share of the infrastructure and facilities damaged. As well, the incident resulted in approximately 10% of pre-incident natural gas volumes being constrained behind pipe due to back-pressure issues. The operator has increased the level of security in and around the Ebocha terminal in conjunction with OER.

On July 9, 2015 there was an explosion/fire which occurred at one of the pipelines operated by NAOC which resulted in 14 fatalities. The incident occurred when a contractor's inspection and repair team were working on the 10" Clough Creek-Tebidaba pipeline, which had been damaged by suspected oil thieves who had spilled an oil and gas mixture into the environment. Ignition of the spilled hydrocarbons at a point that was away from the repair point and pipeline resulted in a fast-moving fire that engulfed the inspection and repair team and killed 12 people initially. Two other members of the team later succumbed to their injuries; 4 members of the team survived. The line was fully repaired and brought back on-stream during the third quarter of 2015 with minimal interruption to production.

Producing Fields

OML 60 covers an area of 358 km^2 (88,464 acres). The License includes nine fields; Agwe, Akri-Oguta (unitized with SPDC), Asemoke, Ashaka, Beniku, Kwale, Odugri, Okpai, and Oniku. Production from OML 60 began in 1971 and the fields have 18 gross producing wells.

OML 61 covers an area of 1,499 km^2 (370,410 acres). The License includes sixteen fields; Alinso, Ebegoro, Ebegoro South, Ebocha, Idu, Irri-Oleh, Isoko South, Manuso, Mbede, Obaifu-Obrikom, Ogbogene, Omoku West, Oshi-Ubie (unitized with SPDC), Samabri-Biseni (unitized with SPDC), Taylor Creek, and Umuoru. Production from OML 61 began in 1970 and the fields have 70 gross producing wells.

OML 62 covers an area of 1,221 km^2 (301,715 acres). The License includes three fields; Beniku, Tuomo, and Tuomo West. Production from OML 62 began in 1985; all the producers are currently shut in.

OML 63 covers an area of 2,246 km^2 (554,998 acres). The License includes ten fields; Azuzuama, Clough Creek, Ekedai, Emette, Nimbe South, Obama, Ogbainbiri, Osiama Creek South, Pirigbene, and Tebidaba. Production from OML 63 began in 1975 and the fields have 36 gross producing wells.

Undeveloped Reserves

Undeveloped oil, gas and NGL reserves are associated with ongoing field development in multiple reservoirs, involving wells in Akri, Beniku, Kwale, Okpai, Odugri, and Oniku as part of the extended drilling program. Twenty-two wells are scheduled to be drilled in OML 60 between 2018 and 2037.

Undeveloped oil, gas and NGL reserves are associated with ongoing field development in multiple reservoirs, involving wells in Ebegoro South, Ebocha, Idu, Irri-Oleh, Isoko South, Manuso, Mbede, Obiafu-Obrikom, Ogbogene, Omoku West, Oshi-Ubie, and Samabri Biseni as part of the extended drilling program. Eighty-two wells are scheduled to be drilled in OML 61 between 2016 and 2037.

Undeveloped oil reserves are associated with ongoing field development in multiple reservoirs, involving wells in Tuomo and Tuomo West as part of the extended drilling program. Seven wells are scheduled to be drilled in OML 62 between 2019 and 2035.

Undeveloped oil, gas and NGL reserves are associated with ongoing field development in multiple reservoirs, involving wells in Azuzuama, Clough Creek, Ekedai, Emette, Nimbe South, Obama, Ogbainbiri, and Pirigbene as part of the extended drilling program. Seventeen wells are scheduled to be drilled in OML 63 between 2019 and 2037.

There are 128 wells scheduled to be drilled in OMLs 60, 61, 62 and 63 between 2016 and 2037.

Capital Projects and Budgeted Capital Expenditure

During 2015 capital expenditures on OMLs 60 to 63 totalled $41.3 million. Capital expenditures during the period included $11.7 million spent on development drilling and completion activities in the Ogbainbiri Deep 4 well, $27.5 million was spent on pipeline and facility upgrades and $2.1 million was spent on geophysical exploration studies and other assets. The reduction of capital spending in 2015 compared to the budgeted amount was due to project delays and a reduction of spending as a result of the lower crude oil and natural gas price environment.

In 2016, the Corporation estimates that a total of $60.0 million will be spent at OMLs 60 to 63, consisting of $44.4 million directed to facilities for asset integrity, water disposal and flare down, and $15.6 million on drilling three development wells and a workover.

Ebendo

Overview

Ebendo Marginal License (42.75% WI; Energia, an indigenous company and operator, 55% WI), was carved from OML 56 in the central Niger Delta, approximately 100 km north-west of Port Harcourt. The License covers an area of 65 km^2 (16,062 acres). The License includes two fields, the Ebendo field (producing), Obodeti field (undeveloped) and one prospect, Ebendo North. Ebendo operates under Marginal Field terms that benefit from advantageous fiscal terms. The Obodedi field was not evaluated for the 51-101 Statement.

OER's gross share of total production sold from Ebendo in 2015 was 1.294 MMboe (consisting of 0.623 MMbbls of oil and 4.027 Bscf of gas), hence OER's company gross share of daily production sold from Ebendo averaged 3,545 Mboe per day (consisting of 1,706 bbls/d of oil and 11,034 MMscf/day of gas).

As of December 31, 2015, the Ebendo License held net 2P reserves of 8.8 MMboe (comprised 5.4 MMbbls oil and 20.3 Bscf of gas), gross Best estimate unrisked Contingent resources of 1.4 MMboe, gross Best estimate of risked Contingent resources of 1.0 MMboe, gross Mean estimate unrisked Prospective resources of 2.4 MMboe and gross Mean estimate of risked Prospective resources of 1.2 MMboe.

Producing Fields

Ebendo is situated in the eastern part of the License. Production from the Ebendo field began in 2009 and the field currently has four producing wells and three shut in wells.

Undeveloped Reserves

Undeveloped oil and gas reserves are associated with the XVI and XVIIIa reservoirs to be drained by Ebendo-8, and the XIII and XVII reservoirs to be drained by Ebendo-10. The wells are scheduled to be drilled in 2017 and 2018.

Capital Projects and Budgeted Expenditure

During 2015, the Corporation incurred $1.7 million in capital expenditures at Ebendo, which included the pipeline facility enhancements and drilling site preparation costs.

Throughout 2016, the Corporation has estimated $6.7 million in capital expenditures for five well workovers, a storage tank and Umugini pipeline upgrades.

Qua Ibo

Overview

Qua Ibo (40% WI and technical partner; NEPN, an indigenous company, 60% WI and operator) is located in onshore Nigeria, near the mouth of the Qua Iboe River, immediately adjacent to the ExxonMobil Qua Ibo Terminal. The License covers an area of 14 km^2 (3,459 acres) and includes one producing field (Qua Ibo). The Qua Ibo License was acquired by OER during 2013 and it operates under Marginal Field terms that benefit from advantageous fiscal terms. Production from the Qua Ibo field began in 2015 and the field currently has two producing wells and one shut in well.

OER's gross share of total production sold from Qua Ibo in 2015 was 0.282 MMbbls of oil, hence OER's gross share of daily production sold from OML 125 averaged 772 bbls/d of oil.

As of December 31, 2015, Qua Ibo License held net 2P reserves of 3.7 MMbbls of oil, gross Best estimate unrisked Contingent resources of 0.3 MMboe and gross Best estimate risked Contingent resources of 0.2 MMboe.

In its capacity as technical services provider, ORPS oversees, together with NEPN, the operations on Qua Ibo. ORPS agreed to fund certain of NEPN's costs on Qua Ibo until first oil, following which ORPS will be entitled to 90% of NEPN's sales proceeds from its 60% share of crude oil production until NEPN's obligation plus a 10% fee is paid in full.

Producing Fields

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. There are currently two wells producing via three strings.

Undeveloped Reserves

Undeveloped oil reserves are associated with the C4 reservoir, which is the target of a three-well development plan. The Qua Ibo-5, Qua Ibo-6 and Qua Ibo-7 are scheduled to be drilled in 2018 and 2019.

Capital Projects and Budgeted Capital Expenditure

In 2015, the Corporation incurred capital expenditures of $3.8 million at Qua Ibo on pipeline and crude oil facility costs. The Qua Ibo field commenced production late February 2015 and realized its first sales from production in the second quarter of 2015. The Corporation revised its 2015 budgeted from $0.6 million capital spending to $3.5 million to account for additional facility requirements for water handling, in addition to the previously planned facility enhancements.

In 2016, the Corporation has budgeted $0.9 million to be spent on gathering facilities and water treatment facilities.

OML 125

Overview

OML 125 (15% WI; Eni, operator, 85% WI) is located approximately 40 km offshore from the western Nigerian coast in water depths ranging from 550 m to 1,100 m. The License covers an area of 1,983 km^2 (490,010 acres). The License includes one producing field (Abo field), one undeveloped discovery (Abo North) and 13 prospects, of which 6 were evaluated for the 51-101 Statement. OML 125 operates under a Production Sharing Contract.

Production from the Abo field began in 2003 and the field currently has four producing wells, two other wells are shut-in pending flowline repairs while another is waiting on arrival of a Xmas tree. In addition there are two water injection wells and two gas injection wells.

OER's gross share of total production sold from OML 125 in 2015 was 1.2 MMbbls of oil, hence OER's gross share of daily production sold from OML 125 averaged 3,313 bbls/d of oil.

As of December 31, 2015, OML 125 held net 2P reserves of 5.8 MMbbls of oil, gross Best estimate unrisked Contingent resources of 1.1 MMboe, gross Best estimate of risked Contingent resources of 0.6 MMboe, gross Mean estimate unrisked Prospective resources of 16.6 MMboe and gross Mean estimate of risked Prospective resources of 7.0 MMboe.

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. Production from the Abo field began in 2003 and the field currently has five producing wells; five other wells are shut-in. In addition there is one injection well.

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%.

Capital Projects and Budgeted Capital Expenditure

The Corporation incurred $36.4 million of capital expenditures during 2015 at OML 125 related to gathering and transportation infrastructure enhancements and facility maintenance. The enhancements included $23.1 million spent on Abo phase 3 gathering and transportation construction, $4.2 million on well completion costs at Abo 12, $5.6 million on its FPSO on capital maintenance, and $3.5 million on other capital maintenance projects. The significant reduction of capital spending in 2015 compared to the budgeted amount was primarily due to delaying planned projects as a result of the lower crude oil and natural gas price environment to ration capital spending.

The Corporation has an agreement to divest of the OML 125 property in 2016. Therefore, no capital spending has been budgeted in 2016 at OML 125.

Licenses without Production

Akepo

Akepo Marginal License (40% WI and technical partner; Sogenal, operator, 60% WI) was carved from OML 90 and located in shallow waters (<20m) of the western Niger Delta. The License covers an area of 26 km^2 (6,425 acres). The License includes one undeveloped field (Akepo) and two prospects (A and B, collectively referred to as Akepo North). The Akepo field is expected to commence production from a single well in 2017, evacuating production through a barge to the Escravos terminal. Akepo operates under Marginal Field terms that benefit from advantageous fiscal terms.

As of December 31, 2015, the Akepo License held gross Best estimate unrisked Contingent resources of 3.8 MMboe, gross Best estimate of risked Contingent resources of 2.6 MMboe, gross Mean estimate unrisked Prospective resources of 3.7 MMboe and gross Mean estimate of risked Prospective resources of 1.2 MMboe.

OML 134

OML 134 (15% WI; NAE operator, 85% WI) is located offshore in water depths ranging from 550 m to 1,100 m approximately 80 km from the western Nigerian coast. The License covers an area of 1,132 km^2 (279,723 acres). The License includes three undeveloped discoveries (Oberan-1 fault block, Oberan-2 fault block and Minidiogboro), two single-well discoveries (Engule and Udoro) and nine prospects, of which six were evaluated for the 51-101 Statement. There has been no production from OML 134 to date.

As of December 31, 2015, OML 134 held gross Best estimate unrisked Contingent resources of 1.6 MMboe, gross Best estimate of risked Contingent resources is 0.9 MMboe, gross Mean estimate of unrisked Prospective resources of 16.9 MMboe and gross Mean estimate of risked Prospective resources of 5.3 MMboe.

In December 2015 OER agreed to sell its interests in OMLs 134 and 125 to the operator. See "*Relevant Three Year History – Sale of OMLs 125 and 134.*"

OML 145

OML 145 (20% WI; ExxonMobil operator, 80% WI) is located offshore in water depths ranging from 1000 to 1,500 m, approximately 110 km from the western Nigerian coast. OER acquired interests in OML 145 as part of the acquisition of ConocoPhillips's Nigerian business in July 2014. The License covers an area of 1,293 km^2 (319,507.5 acres) and includes two undeveloped discoveries (Uge and Uge North), two single-well discoveries (Nza and Orso) and five prospects. There has been no production from OML 145 to date.

As of December 31, 2015, OML 145 held gross Best estimate unrisked Contingent resources of 42.7 MMboe, gross Best estimate of risked Contingent resources of 24.4 MMboe, gross Mean estimate of unrisked Prospective resources of 39.8 MMboe and gross Mean estimate of risked Prospective resources of 19.6 MMboe.

OML 122

OML 122 (12.5% gas WI and 5.0% oil WI; Peak, an indigenous company, 87.5% gas WI and 95.0% 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 to 300 m. The License covers an area of 1,599 km^2 (395,122 acres). The License includes three discoveries (Bilabri, Orobiri and Owanare) of which, only Bilabri was evaluated for the 51-101 statement. There has been no production from OML 122 to date.

As of December 31, 2015, OML 122 held gross Best estimate unrisked Contingent resources of 7.7 MMboe and gross Best estimate risked Contingent resources of 4.8 MMboe. See "Legal Proceedings and Regulatory Actions – OML 122".

OML 131

OML131 (100% WI; operator OER) is located offshore in water depths ranging from 500 to 1,200 m approximately 70 km from the western Nigerian coast. The License is expected to be unitized with OML 135 with a resulting unit share of 51% for OML 131. OML 131 covers an area of 1,204 km^2 (301,000 acres) and includes two undeveloped discoveries (Bolia-Chota and Ebitemi) and two prospects (Pulolulu and Chota East). There has been no production from OML 131 to date.

As of December 31, 2015, OML 131 held gross Best estimate unrisked Contingent resources of 71.6 MMboe, gross Best estimate of risked Contingent resources of 40.9 MMboe, gross Mean estimate of unrisked Prospective resources of 165.9 MMboe and gross Mean estimate of risked Prospective resources of 41.5 MMboe.

Blocks 5 and 12, EEZ of STP

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 STP awarded OER Blocks 5 and 12, located within the country's EEZ. Block 5 has an area of 2,844 km^2 and the water depth within the block ranges from 2000 to 2500 m. Existing 2D seismic data over the block were reprocessed in 2014 and interpreted to identify several prospects. In 2015, 3D seismic data was acquired over an area of 1400 km^2. The processing of the newly acquired 3D seismic data was completed in December 2015 and interpretation of the 3D is currently ongoing to further mature identified prospects for exploration drilling in 2017.

In December 2015, EEL agreed to farm out 65% of its participating interest in Block 5 for $7.4 million to equalize past costs and will retain a 20% participating interest, with a 50% carry up to $9.0 million each for both Phases II

and III. EEL also entered into an agreement to farm out 65% of its participating interest in Block 12, retaining a 22.5% participating interest with a carry of the first $2.0 million of OER's portion of project costs. The farm-out for Block 12 is yet to be completed. The government of STP (through its national petroleum agency) will retain 15% and 12.5% carried interests in Blocks 5 and 12, respectively. Closing of the transaction is subject to satisfaction or waiver of government approvals and certain other standard conditions precedent and is expected to occur during the second quarter of 2016.

As of December 31, 2015, the EEZ Block 5 held gross Mean estimate unrisked Prospective resources of 1,474.7 MMboe and gross Mean estimate risked.

OPL 321 and OPL 323

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 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 this ongoing dispute, since 2008 exploration on these Licenses 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 Licenses ($162 million). See "*Legal Proceedings and Regulatory Matters – OPLs 321 and 323*."

No wells have been drilled on the Licenses to date. The License includes five sizeable prospects (Gorilla, Lobster, Octopus and Whale (OPL 323) and Elephant (OPL 321)).

As of December 31, 2015, OPLs 321 and 323 jointly held gross Mean estimate unrisked Prospective resources of 826.5 MMboe and gross Mean estimate risked Prospective resources of 197.2 MMboe.

Capital Projects and Budgeted Capital Expenditure

Other than as set forth above, asset capital expenditures include spending on OML 131, OML 134 and EEL. During 2015 the Corporation spent $4.7 million to advance exploration of the respective properties with geological and technical studies.

In 2016, the Corporation estimates that $5.7 million will be expended on exploration projects and corporate assets. The exploration is focused on OML 131, OML 145 and Block 5, to assess the geological and geophysical aspects of the project areas, along with the environmental impacts through technical studies and seismic acquisition.

Fiscal Terms of OER's Licenses

OER holds its material Licenses pursuant to JVs. Its other producing Licenses are held pursuant to PSCs (OML 125) and Marginal Fields (Ebendo and Qua Ibo). In addition to the terms of those Licenses, 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 "*The Nigerian Oil and Gas Industry and Regulatory Framework – Contractual Framework and Fiscal Regime*" for a detailed description of the general fiscal terms of each License type.

JVs

The following is a summary of the key terms of the JOA relating to OMLs 60 - 63:

	OMLs 60 - 63
Contract:	JV

	OMLs 60 - 63
OER Working Interest:	20%
License Expiry Date:	2027
Royalty:	
Oil (deductible against PPT)	20%
Gas (deductible against CITA)	7%
Investment Tax Allowance[(1)]:	5%
CITA:	30%
Annual Capital Allowances:	
Years 1-4	20%
Years 5+	19%
PPT:	85%
Other Taxes/Fees:	
VAT[(2)]	5%
NDDC Levy[(3)]	3%
Education Tax[(4)]	2%

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 "*The Nigerian Oil and Gas Industry and Regulatory Framework – Contractual Framework and Fiscal Regime*."

(2) VAT is levied at 5% on all capital and operating costs.

(3) 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.

(4) Education Tax is levied at 2% 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.

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 and financial terms of the PSCs relating to OMLs 125 and 134.

	OML 125	OML 134
Contract:	PSC	PSC
OER Working Interest:	15%	15%
License Expiry Date:	2023	2023

	OML 125	OML 134
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
CITA		
Annual Capital Allowances:		
Years 1-4	20%	20%
Years 5+	19%	19%
Available Cost Pool (OER)[(2)] ($million):	$53.6[(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 "*The Nigerian Oil and Gas Industry and Regulatory Framework — Contractual Framework and Fiscal Regime*."

(2) As at December 31, 2015.

(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% 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 Field Licenses

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

- **Term and relinquishment:** 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. The License for Ebendo will expire at the end of the field life. The Licenses for Qua Ibo and Akepo were each renewed on March 15, 2011 for a period of 4 years. Applications for renewal of those Licenses have been filed and OER anticipates that renewals will be granted in due course. OER expects that the renewed License for Qua Ibo will expire at the end of the field life.
- **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 services provider 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 services provider 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 Limited prior to the Exile 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 services provider 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). Also pursuant to the JOA, OER is permitted to charge $4 million per annum for general and administrative costs prior to first oil and, thereafter, such amount as may be actually incurred. In its capacity as technical services provider, ORPS oversees, together with NEPN, the operations on Qua Ibo. ORPS agreed to fund certain of NEPN's costs on Qua Ibo until first oil, following which ORPS will be entitled to 90% of NEPN's sales proceeds from its 60% share of crude oil production (after periodic repayment of loans taken by NEPN) until NEPN's obligation plus a 10% fee is paid in full.
- **Bonus payments:** 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 tax holiday of up to five years. Pioneer status, which confers a tax holiday of up to five years, was conferred on Ebendo (which status expired on June 30, 2015); however, in February, 2015 OER received a letter from FIRS stating that FIRS will not honour the final two years

of the tax holiday. OER received pioneer status at Qua Ibo for a period of three years commencing on February 1, 2015. In June 2015, the Corporation received pioneer status for natural gas development at OMLs 60 to 63 for a period of three years commencing on January 1, 2014. 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	March 15, 2015[7]	March 15, 2015[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):	$64.70	$38.6	$60.0
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, 2015.

(3) Legally, PPT is 65.75% for the first five years of production and 85% thereafter, 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% 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. Applications for renewal of the Licenses for Qua Ibo and Akepo have been filed and OER anticipates that a renewal for life of field will be granted for Qua Ibo and a further 4 year renewal will be granted for Akepo.

Other Corporate Matters

Environmental, Health, Safety, Security and Community

In respect of those Licenses where OER is not the operator or technical services provider, 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, take steps to 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.

EHS Policy

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 services provider. OER has implemented policies and operates an 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.

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 Risks Related to OER's Operations – OER may be subject to substantial fines for gas flaring*."

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. OER has 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.

OER uses full time employees and community consultants to pursue its corporate social responsibility initiatives. Additionally, OER sometimes temporarily locates 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 host communities in order to improve the economic conditions of those communities.

Ethics and Integrity

In accordance with the BCBCA, 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 Corporate Governance 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 Corporate Governance Committee by the Board of Directors.

In addition, OER has adopted a Related Party Transaction Policy in order to identify, notify, review, evaluate and disclose related party transactions.

Ethics Policy

The Ethics Code applies to all of OER's directors, officers, managers, employees and persons rendering and providing services. 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.

Anti-Corruption and Anti-Bribery Policy

The principles of respect, integrity and professionalism in all business dealings are entrenched in OER's Ethics Code. Corruption has been identified as one of the single greatest obstacles to these principles. OER has adopted an 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 a gifts and benefits policy that applies to the giving and acceptance of gifts and/or benefits, 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) not 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 its value is below C$150.

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

D&M prepared the 51-101 Statement in accordance with the requirements of NI 51-101. The 51-101 Statement is attached as Schedule "A" to this AIF. Form 51-101F2 "Report of Independent Qualified Reserves Evaluator" of D&M and Form 51-101F3 "Report of Management on Oil and Gas Disclosure", both prepared in accordance with the requirements of National Instrument 51-101, are attached to this AIF respectively as Schedule "B" and Schedule "C."

DESCRIPTION OF SHARE CAPITAL

Common Shares

As at the date hereof there are 796,049,213 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.

OER 2014 Warrants

As at December 31, 2013 and the date hereof there are 344,673,441 OER 2014 Warrants issued and outstanding. The OER 2014 Warrants are governed by a warrant indenture dated December 31, 2014 between OER and Equity Financial Trust Company as warrant agent and are listed for trading on the TSX under the symbol "OER.WT." Each OER 2014 Warrant entitles the holder to acquire one Common Share for consideration of US$1.80. The OER 2014 Warrants will expire on July 30, 2016.

Stock Options

As at December 31, 2015 and the date hereof there were 9,410,000 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. See the 2015 Financial Statements for a summary of options granted, exercised and expired during 2015. Under the terms of the Oando Arrangement,

options will be cancelled and the holder of each in-the-money option will be entitled to receive a cash payment equal to a cash amount equal to the amount, if any, by which $1.20 exceeds the exercise price of each option.

Long Term Incentive Plan

OER has implemented the LTIP and reserved for issuance thereunder a number of Common Shares equal to ten percent of the Common Shares issued and outstanding from time to time less the number of Common Shares reserved for issuance pursuant to stock options and RSUs.

Under the LTIP a participant is granted a conditional share award over a number of Common Shares (the "**Share Unit**"), which is a right to receive such number of Common Shares in the future, provided certain conditions are met. A participant will normally receive his or her Common Shares on or after the third anniversary of the grant of the relevant Share Units, provided he or she remains an employee, officer or consultant and the performance condition described below have been satisfied. Participants are also required to hold their Common Shares for a mandatory two year holding period measured from the time of vesting.

There are outstanding 2,747,829 Share Units outstanding.

Share Units are subject to a performance condition based on the ranking of OER's total shareholder return ("**TSR**") against a comparator group of other exploration and production companies who possess characteristics, such as size and exposure to Africa, which the Board of Directors have determine appropriate for the purposes of comparison to OER. OER's TSR will be measured over a period of three financial years, beginning with the financial year in which the Share Units were granted (the "**Performance Period**"). The extent of vesting of the Share Units will be determined as follows:

Rank of OER's TSR against the TSR of the members of the Comparator Group	% of Share Units that vests (i.e. expressed as a percentage of the total number of Common Shares originally subject to the Share Units)
Upper quartile or above	100%
Between upper quartile and median	On a straight line basis between 25% and 100%
Median	25%
Below median	0%

The vesting of the Share Units is also subject to an overriding discretion for the Compensation Committee to reduce (including to zero) or increase the level of vesting of the Share Units that would otherwise result by reference to the performance condition alone by such extent as it considers appropriate in the event that the Compensation Committee determines that OER's TSR performance is not reflective of OER's underlying financial performance over the Performance Period.

In addition, the Compensation Committee has the discretion to reduce (including to zero) the level of vesting of the Share Units that would otherwise result by reference to the performance Condition alone by such extent as it considers appropriate in the event that the Compensation Committee determines that there has been a negative health, safety and/or environmental event during the Performance Period.

The Compensation Committee, acting fairly and reasonably, may vary the performance condition if an event occurs and it considers it appropriate to do so, provided the amended performance condition is not materially less difficult to achieve. Under the terms of the Oando Arrangement, Share Units will be cancelled and the holders thereof will be entitled to receive a cash payment equal to a cash amount equal to $1.20 for each Share Unit.

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 and 630,000 Common Shares were issued in January 2015 to satisfy OER's obligation, net of withholding tax calculated at $42,166.59, to deliver 666,667 Common Shares;
- 1/3 expired on July 24, 2014 when the conditions precedent to their vesting failed to be satisfied; and
- 1/3 expired on July 24, 2015 when the conditions precedent to their vesting failed to be satisfied.

MARKET FOR SECURITIES

The Common Shares and OER 2014 Warrants are listed for trading on the TSX under the trading symbols "OER" and "OER.WT", respectively. The following tables set forth the reported intra-day price ranges and trading volume of the Common Shares and OER 2014 Warrants on the TSX for the periods indicated (all amounts shown in Canadian dollars). **[NTD: Complete table below based on March 28 trading.]**

Common Shares

Common Shares			
Month	**Trading Price (C$)**		**Volume Traded**
	High	**Low**	**(# of Common Shares)**
January 2015	1.30	0.75	31,940
February 2015	1.29	0.89	49,615
March 2015	1.55	1.00	81,432
April 2015	2.03	1.47	102,471
May 2015	1.62	1.38	28,957
June 2015	1.36	1.09	2,802
July 2015	1.54	0.79	121,409
August 2015	1.05	0.63	43,461
September 2015	0.83	0.63	16,200
October 2015	0.66	0.39	20,859
November 2015	0.80	0.60	78,614
December 2015	1.56	0.38	343,682
January 2016	1.77	1.47	534,710
February 2016	1.66	1.41	1,176,384
March 2016 (to March 28)	1.46	1.26	211,441

On March 18, 2016, 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$ 1.26.

OER 2014 Warrants

The OER 2014 Warrants have not traded since the date of listing on January 8, 2015.

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*."

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)(5)] Lagos, Nigeria	President, Chief Executive Officer and Director	July 24, 2012	Chief Executive Officer of OER since July 24, 2012; 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.
Philippe Laborde[(1)(2)(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.
John Orange[(2)(3)(4)] 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
Ronald Royal[(1)(3)(4)] Abbotsford, British Columbia, Canada	Director	April 1, 2015	Private Businessman since April, 2007; Director of Valeura Energy Inc. (TSX) since 2010; Director of Gran Tierra Energy Inc. (TSX) since 2015; Director of Caracal Energy Inc. (TSX) from July 2011 to July 2014.
Bill Watson[(1)(3)(5)] Calgary, Alberta, Canada	Lead Director	October 17, 2012	Director of Mitra Energy Inc. (TSX) from December 2010 to March 2015; Director of SilverWillow Energy Corporation (TSXV) 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.

Name and Place of Residence	Position Held	Director / Officer Since	Principal Occupation for the last five years
Yannis Korakakis Lagos, Nigeria	Chief Operating Officer	September 1, 2014	Chief Operating Officer of OER since September 1, 2014; Chief Operating Officer of Atlantic Energy from May 2012 to May 2014; Deputy Managing Director of Addax Petroleum Development Nigeria Ltd. from May 2007 to May 2012.
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.
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.

Notes:

(1) Member of the Audit and Risk 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, 4,176,412 Common Shares, representing approximately 0.5% 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; or (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 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 BCBCA 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 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.

AUDIT AND RISK COMMITTEE

Audit and Risk Committee Charter

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

Composition of the Audit and Risk Committee

The members of the Audit and Risk Committee are Messrs. Laborde, Watson and Royal. Each of the members of the Audit and Risk 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 Executive Officers and Directors*" for biographies of each member of the Audit and Risk Committee, including each member's education and experience that is relevant to his responsibilities as a member of the Audit and Risk Committee.

Pre-Approval Policies and Procedures

The Audit and Risk 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, 2014 and December 31, 2015.

Type of Work	**Year Ended December 31, 2014**	**Year Ended December 31, 2015**
Audit fees[(1)]	C$ 1,523,313	C$ 1,100,400
Audit-related fees[(2)]	--	--
Tax advisory fees[(3)]	C$ 154,635	C$ 49,557
All other fees	C$ 15,990	C$ 31,301
Total	**C$ 1,693,938.15**	**C$ 1,181,259**

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.

LEGAL PROCEEDINGS

From time to time, OER is the subject of litigation arising out of its operations. Damages claimed under such litigation, including the litigation discussed below, may be material or may be indeterminate and the outcome of such litigation may materially impact OER's financial condition or results of operations. While OER assesses the merits of each lawsuit and defends itself accordingly, it may be required to incur significant expenses or devote significant resources to defend itself against such litigation.

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.

The following is a summary of the material pending and existing legal proceedings in which OER is involved.

OML 125

NAE and OER (through Oando OML 125 & 134) 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.

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. On July 9, 2014 a final award was issued by the arbitration tribunal in favour of NAE and OER entitling NAE and OER to collect amounts overlifted

by the NNPC. The arbitration tribunal assessed damages suffered by NAE and OER as at January 31, 2014. OER's share of the damages awarded under the final award is $72.9 million plus interest on damages, legal and expert costs, interest on legal and expert costs, and additional interest from the date the award was granted until payment.

NNPC has not complied with the final award and continues to overlift. On August 25, 2014, NAE and OER filed an action at the Federal High Court for the recognition and enforcement of the partial and final awards. On October 2, 2014, NNPC filed a motion asking the court to dismiss that action. The matter remains pending before the courts.

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 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 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). OER believes that these claims are without merit and unlikely to succeed. If the claimants are ultimately successful in their suit, OER would effectively bear the cost in proportion to its working interest in OML 125.

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. In May 2015, EEL 122 enter into a Settlement Agreement with Peak pursuant to which Peak was required to pay $52.5 million to EEL 122 Peak prior to November 25, 2015 as full and final settlement of the sums owed by Peak. To date, Peak remains in default of its obligation to pay the settlement amount. There can be no guarantee that EEL 122 will be successful in recovering the any amounts from 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, but the judgment was set aside by the Nigerian Court of Appeal. The matter is now pending before the Nigerian Supreme Court with the next anticipated hearing date scheduled for April 2016.

Parties to the dispute, including OER, commenced settlement negotiations in respect of the dispute between KNOC and the Nigerian government in June 2013. Settlement discussions are ongoing.

OER believes that its working interests remain unaffected and obtained a $161.7 million refund of its original signature bonuses from the Nigerian Government. OER intends to weigh the merits of re-advancing the signature bonuses should the matter be settled as between the Nigerian Government and KNOC.

OOL Tax Litigation

For tax years 2008 through 2011 OOL filed PPT returns and claimed tax offsets against its Education Tax liability in accordance with the provisions of the Memorandum of Understanding ("**MOU**") signed in 2000. The FIRS rejected this treatment on the basis that the MOU had been terminated in January 2008 and assessed the Corporation with additional Education Tax liability of $21,095,049 for tax years 2008-2011. OOL appealed this issue to the Tax Appeal Tribunal (the "**TAT**") but the appeal was denied in March 2015. Under the terms of the COP Acquisition documents, COP assumed the defense and costs of these proceedings; however the liability is not subject to indemnification. OOL has further appealed this matter to the Federal High Court.

For tax years 2006 through 2011 OOL filed its PPT returns and claimed deductions for intercompany interest expense and exemptions from dividend withholding tax on gas profits. On November 4, 2013, the FIRS disagreed with OOL's position and issued notices of assessment of $5,270,332, $39,986,520 and $940,859 being additional assessments on withholding tax on dividends from gas income, disallowed interest on intercompany loan and attendant Education Tax on the intercompany loan interest, respectively. On January 30, 2014, FIRS subsequently issued a notice of refusal to amend the assessments. OOL appealed these issues to the TAT. On December 12, 2014 the TAT ruled against OOL, on the dividend withholding tax on gas income matter and ordered OOL to make payment in respect thereof. On February 11, 2015 the TAT held in favour of OOL on the issues of intercompany interest expense and the attendant Education Tax assessment and dismissed the FIRS' assessments in that regard. Under the terms of the COP Acquisition documents, COP assumed the defense and costs of these proceedings and indemnified OOL for approximately $5.3 million paid to FIRS pursuant to the TAT's decision.

PROMOTER

As of the date hereof and based upon filings made by Oando under applicable Canadian securities laws, Oando beneficially owns, controls or directs (i) 746,107,838 Common Shares, representing approximately 93.7% of the issued and outstanding Common Shares and (ii) 325,382,569 OER 2014 Warrants, representing approximately 94.4% of the issued and outstanding OER 2014 Warrants. Assuming exercise of all such OER 2014 Warrants, Oando Plc would beneficially own, or exercise control or direction over, 1,071,490,407 Common Shares, representing approximately 95.6% of the Corporation's issued and outstanding Common Shares; however, Oando Plc is prohibited from exercising any OER 2014 Warrants where such exercise would result in its ownership of the Corporation exceeding 94.6%.

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. 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 Exile Arrangement and to finance the COP Acquisition. See "*Incorporation and Organization*" and "*Interests of Management and Oando in Material Transactions*."

A summary of related party balances between OER and Oando PLC as at December 31, 2015 and 2014 is set out in the 2015 Financial Statements and the 2015 MD&A under the heading "*Related Party 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, 2015, 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%.

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.

Cooperation and Services Agreement

Under the terms of the 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 Cooperation and Services Agreement will automatically terminate on the later of (i) July 24, 2017; and (ii) such time as Oando owns less than 20% of the Common Shares. At any time, OER may elect to terminate any of the services under the agreement provided such notice is effective only on December 31 or June 30 of any year and such notice has been given at least 60 days in advance. Once terminated, Oando shall have no further obligation to make available the services as have been so terminated and equitable adjustments shall be made as to the cost for the remaining services, if any, that are continued to be supplied.

During 2015, OER paid to Oando (ii) $23 million for services provided and (ii) $10.9 million in aviation costs to an entity associated with a director of the Corporation.

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 was required to pay Oando Servco's costs of providing such services.

Operating Associate Shareholder Agreements

Oando is a holder of certain interests in some of OER's subsidiaries under the terms of 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 including in circumstances in which OER is no longer controlled by Oando. See "*Incorporation and Organization*."

2014 Oando Loan Documentation

Between December 2012 and the closing of the COP Acquisition, OER borrowed an aggregate $908 million from Oando, which amount bore interest at an annual rate of 4%, plus a facility fee of $48 million. All amounts outstanding under such loan were repaid in 2014 and no further amounts may be borrowed under the Oando Loan. See "*General Development of OER's Business – Three Year History – Financing Activities – Oando Loan*."

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 exercises significant control over the affairs of OER

Oando currently owns a majority of the Common Shares (approximately 93.8% 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.

The concentration of ownership with Oando may have the effect of delaying or deterring a change in control of OER, could deprive shareholders of an opportunity to receive a premium for their Common Shares as part of a sale of OER and might affect the value of the Common Shares.

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.

Sales by Oando 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.

The Corporation has entered into the Oando Arrangement

The Corporation has entered into the Oando Arrangement Agreement with the Purchaser and Oando the Purchaser agreed to acquire all of the Minority Shares for $1.20 per Common Share pursuant to the Oando Arrangement (see "3. General Development of the Business – 3.1 Three Year History - The Oando Arrangement). Completion of the

Oando Arrangement remains subject to receipt of certain lender consents and certain other closing conditions customary in transactions of this nature, and has an outside closing date of April 29, 2016. If completed, the Oando Arrangement will result in the Corporation becoming an indirect subsidiary of Oando and the Common Shares will be delisted from the TSX.

As a result, the Oando Arrangement, if completed, will limit the gains that an investor may earn on an investment in Common Shares, and will result in a loss for investors who purchase (or who have already purchased) common shares of the Corporation for a price higher than US$1.20.

Each of the Corporation and the Purchaser has the right to terminate the Oando Arrangement Agreement and Oando Arrangement in certain circumstances. The completion of the Oando Arrangement is subject to a number of conditions precedent, certain of which are outside the control of the Corporation, including the lender consents. There can be no certainty, nor can the Corporation provide any assurance, that these conditions will be satisfied or, if satisfied, when they will be satisfied. Accordingly, there is no certainty, nor can the Corporation provide any assurance, that the Oando Arrangement will be completed, or that it will be completed on the terms currently set out in the Oando Arrangement Agreement.

The failure to complete the Oando Arrangement, or to complete it on the terms currently set out in the Oando Arrangement Agreement, could adversely affect the Corporation's reputation and the prevailing market prices for its Common Shares. A decline in the market prices of the Common Shares could impair the Corporation's ability to raise additional capital through the sale of securities should it desire to do so and could impair the ability or desirability of a sale of common shares by other shareholders.

If the Exile Arrangement is not completed and OER decides to seek another merger, arrangement or similar transaction with a third party, Oando or the Purchaser, there can be no assurance that it will be able to find a party willing to pay an equivalent or more attractive price than the total consideration to be paid pursuant to the Exile Arrangement. The presence of a controlling shareholder, Oando PLC, limits the price that an acquiror might be willing to pay in the future for the Common Shares, and it may have the effect of preventing or delaying a change of control or other acquisition of the Corporation.

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 and provided guarantees in connection with OER's loan facilities. There is no assurance that Oando will continue to support OER in the future. Shareholders 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 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 is a leveraged business

OER has borrowed substantial amounts. OER is subject to certain financial and other restrictive covenants under the terms of its indebtedness that limit its ability to borrow or otherwise restrict the manner in which it operates. OER's ability to meet the financial covenants and certain other 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 potentially lead to cross default under other 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.

At December 31, 2015 and the date hereof, the Corporation is in breach of certain covenants under the RBL facility and Corporate Facility. These defaults give the respective lenders the right to accelerate payment of all amounts under their respective Facilities. In the event of such acceleration, OER will be obliged to make immediate payment of all principal and interest. If OER does not have sufficient cash on hand to make such payment, it will be obliged to take steps necessary to fund the repayment of the principal and interest. Such steps may include the sale of assets, resetting financial commodity contracts (or otherwise deriving value from the early settlement therefrom) or the raising of additional cash by way of debt or equity (assuming market conditions permit).

OER has granted security over substantially all of its assets for the purposes of securing its obligations under its loan facilities. As a result of OER's defaults under the terms of its facility agreements, the lenders thereunder may seek to enforce any the security in accordance with the terms of the relevant loan agreements and related security documentation. Such enforcement would have a material adverse effect on OER's business, prospects, financial condition or results of operations.

The terms of OER's financial commodity contracts permit the counterparties thereto to terminate the commodity contracts in the certain event of default under each of the RBL and Corporate Facility. In the event of any such termination, counterparty's obligation to pay OER a fixed price of $65/bbl for specified quantities of oil will cease and among other things the fair value of, and OER's ability to reset or otherwise derive value from, those financial commodity contracts may be negatively and materially affected. See the 2015 Financial Statements and 2015 MD&A.

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

During 2014, OER reported weaknesses in its internal controls over financial reporting and its disclosure control procedures. 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 further weaknesses, 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 intentional 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's business involves significant capital expenditure and it may require external debt and further equity financing in order to fund expenditures and investments in facilities, infrastructure, technology and other capital expenditures to generate, improve, maintain or preserve revenues. These expenditures may require significant capital in addition to its existing cash resources, 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, its cash resources will be reduced and 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. The failure or inability on the part of OER or its partners to fund capital expenditures may result in declining production and reserves in subsequent years, which could have a material adverse effect on OER. OER may also seek funds for its business by selling part of its operations and/or by assigning certain rights to its assets under farm-out arrangements.

OER is not the operator of any development or producing project in which it holds an interest

OER is not the operator on any of its projects which are under development or in production. On each of such projects, OER does not have the right to make unilateral decisions with respect to development and operation activities. Such activities are conducted jointly by the operator and the joint venture partners in accordance with work programs which are proposed by the operator and approved by the joint venture partners in accordance with relevant agreements. OER's preferred strategies for operating and developing a project and the interests of OER may not always be aligned with those of the operator or any other joint venture partner, each of whom have the right to vote in their sole discretion for the approval of operating plans and other matters. As a non-operator, OER is required to co-operate and agree with the operator in respect of the extent and timing of activities related to the joint venture and OER's ability to direct or control the activities of the operator will be limited to its participation in and by the powers given to the operating committee under the joint venture. This may mean that the assets may not be developed in the manner, or in the timeframe, preferred by OER, which may mean that its expected return is diminished or delayed. Conversely, OER may be required to fund development earlier than anticipated, or in amounts greater than expected, which may strain existing operations and could materially and adversely affect OER's business, financial condition, results of operations and prospects.

As a joint venture partner in the NAOC JV, NNPC is required to fund its portion of operations and expenses on that joint venture and other joint venture partners are exposed to the risk that NNPC may be delayed in, or fail to make, such payments. In the past, NNPC has been delayed in making certain of such payments. In the case of continued delays or any failure by NNPC to make such payments, capital expenditures and/or operating expenditures may be adversely affected and thereby have a material adverse effect on OER's business, prospects, financial condition, results of operations and cash flows.

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. OER requires 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 COP Nigerian Business or any acquired assets or business into its own business 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. If OER fails to consummate or integrate acquisitions successfully, it may have to scale back its expansion strategy and not realize the increase in reserves and related revenues as anticipated. 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. OER's expansion strategy may not be successful and OER may not be able to invest its capital directly or indirectly to acquire assets on attractive terms or at all.

Although OER 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) finance the acquisition on acceptable terms, if at all; (ii) develop efficient and integrated managerial and support systems, (iii) standardize technology and operational development, (iv) control costs, (v) maintain effective quality controls while expanding OER's internal information, accounting and management systems, (vi) attract, assimilate and retain additional qualified personnel and (vii) 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.

OER assumed 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 after January 1, 2012, 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. 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, COP 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

Investing in securities in emerging markets such as Nigeria generally involves a high degree of risk

Investing in securities of issuers in emerging markets, such as Nigeria, generally involves a higher degree of risk than investments in securities of issuers from more developed countries and carries risks that are not typically associated with investing in more mature markets. These risks include, but are not limited to, greater political risk, a narrow export base, budget deficits, lack of adequate infrastructure necessary to sustain economic growth and changes in the political and economic environment.

Oil and gas companies operating in West Africa, and more specifically Nigeria, may be particular targets of criminal or militant actions. Criminal, corrupt or militant action against OER, its properties or facilities could have a material adverse effect on OER's business, prospects, financial condition or results of operations.

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 – Legislative Framework – PIB*."

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 under civilian governments.

Although recent elections have been conducted peacefully and credibly, prior to the final announcement of the results of the 2011 election, 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. There can be no assurance that the outcome of future elections will not be accompanied by unrest, militancy, violence or allegations of corruption.

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 and death can be substantial, such as in April 2014 when the group kidnapped nearly 300 schoolgirls from Chibok, Borno State and January 2015 when its attacks on the Nigerian towns of Baga and Doron Baga resulted in claims varying from 150 up to 2,000 people killed.

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 organizations 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 near some of the projects in which it holds interests. 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.

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 NAOC JV, in which OER holds a 20% interest, was subjected to two incidents of in 2015. See "*Description of OER's Business – Licenses with Production – OMLs 60-63 – Overview*."

Nigeria experiences high incidence of bunkering 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. 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.

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.

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.

Nigeria's oil and natural gas industry typically accounts for a significant percentage of government revenue and total export revenue. Historically, some of this revenue has been used to subsidize gasoline prices. In 2012, efforts to eliminate these subsidies led to national strikes and public protests. 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. 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.

The interpretation of applicable regulations and the outcome and duration of court proceedings in Nigeria could differ significantly from those in other jurisdictions in which shareholders are based or elsewhere.

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. Instances of corruption by government officials and misuse of public funds could affect the ability of companies within such markets to operate their businesses efficiently.

The Nigerian Government has indicated that it takes corruption seriously and has been conducting an ongoing corruption investigation into the oil industry in Nigeria. In 2012, the 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.

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 jeopardize its existing assets, including its PSCs, and its personnel, thereby materially adversely affecting its operating results, financial condition or prospects.

In addition to other applicable anti-corruption legislation, OER is subject to the *Corruption of Foreign Public Officials Act* (Canada). OER's Code of Business Conduct and Ethics, whistleblower, Anti-Corruption and Anti-Bribery, and 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 laws or policies. Failure to detect or prevent any breach of such laws or policies may expose OER to potential civil or criminal penalties under relevant applicable law and to reputational damage, which may have a material adverse effect on OER's business, prospects, financial condition or results of operations.

Seasonal weather conditions and flooding that may affect OER's operations

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.

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. Bunkering 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.

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 expenditures 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.

Risks Relating to OER's Operations

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

OER is involved in proceedings to recover revenues related to the overlifting of oil from OML 125 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. The NNPC has continued to lift production volumes that exceed its entitlement, despite an arbitration award in favour of OER which requires it to cease. There can be no assurance that the NNPC will stop overlifting from OML 125, or that it will not 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 – OML 125*."

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 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 OPDC, OQI 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. OER's production is derived from projects 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 contest OER's status 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 Domestic Supply Obligation). Although the enforcement of Domestic Supply 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 regulations governing Domestic Supply Obligations. 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. 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 and involve the application of judgment on the part of the people performing the estimate. 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, engineering 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 51-101 Statement.

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. 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. Contingent resource estimates are estimates only and should not be construed as being exact quantities. The probability that contingent resources will be economically developed or that prospective resources will be discovered, or be economically recoverable, is considerably lower than for proven, probable and possible reserves.

Prospective resources are speculative in respect of their inferred presence and uncertain in respect of their inferred volume range. Volumes and values associated with prospective resources should be considered highly speculative.

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'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. 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.

OER's decommissioning funds may prove to be insufficient

OER sets aside funds for decommissioning assets based on estimates of the decommissioning costs, which are based on current requirements, technology and price levels and are computed based on the latest assumptions as to the scope and method of abandonment. However, because decommissioning estimates are based only on those facts and circumstances known at the time of estimation and assumptions which might later prove to be inaccurate, such provisions may not prove to be sufficient to cover actual decommissioning costs. Furthermore, the PIB, if and when enacted, may include new regulations for the decommissioning of installations, structures, wells and pipelines, which may require OER to set aside additional decommissioning funds.

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 bunkering 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, the production and marketing of oil and gas, the procurement of rigs and equipment necessary for exploration and production operations, 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.

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.

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

The exploration business, which relies on the discovery and extraction of hydrocarbons, is dependent upon geological and seismic surveys prior to exploration drilling. Such surveys and operations are costly and such costs may ultimately prove higher than anticipated depending on a number of factors encountered during the exploration phase, in particular, unforeseen practical difficulties arising from the explored areas and/or soil and the cost and availability of rigs and long-lead items. As well, operations of this type make it possible to decide on the location of exploration drilling, when to transition to the production start-up phase or whether or not to pursue exploration. The hydrocarbons estimated either when exploration or production licences are obtained or at the commencement of drilling operations may ultimately not be present or, if present, they may be insufficient or incapable of extraction or their exploitation may not be commercially viable. Consequently, OER cannot guarantee a return on any investments that are, or that will be, made with respect to future exploration, or that current exploration activities will be profitable.

OER cannot guarantee that new hydrocarbon resources will be discovered in adequate quantities to replace existing reserves or to allow OER to recover all the capital invested in exploration activities and to ensure a return on the investments made. An inability to discover adequate quantities of new resources will increase OER's dependency on the conversion from contingent to prospective reserves. The conversion may not be achieved with respect to all or any of OER's contingent resources and the failure to achieve such conversion could have a material adverse effect on OER's business, prospects, financial condition, results of operations and cash flows.

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. 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 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

The market for the Common Shares and OER 2014 Warrants may not develop to provide liquidity

The Common Shares and OER 2014 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 2014 Warrants or how liquid that market might become. An active and liquid market for the Common Shares and OER 2014 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 2014 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 2014 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:

- fluctuations in the prices of oil, gas and other petroleum products;
- 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;
- 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;
- economic and political conditions or events, particularly in Nigeria;
- changes in applicable laws, rules and regulations;
- 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 2014 Warrants to fluctuate substantially, which may limit or prevent holders from being able to readily sell their Common Shares and OER 2014 Warrants and may otherwise negatively affect the liquidity of the Common Shares and OER 2014 Warrants.

The trading price of the Common Shares and OER 2014 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 2014 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 borrowings prohibit OER from paying dividends in certain circumstances. See "*General Development of OER's Business – Relevant Three Year History – Financing Activities*."

Issuance of additional securities may dilute the interest of 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, 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. 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 BCBCA, 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.

Shareholders 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 through 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.

AUDITORS, TRANSFER AGENT AND REGISTRAR

OER's auditors 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 D&M. As at the date hereof, the principals, directors, officers and associates of D&M, as a group, each owned, directly or indirectly, less than 1% of the outstanding Common Shares. D&M is "independent" of OER within the meaning of NI 51-101.

ADDITIONAL INFORMATION

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

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 2016.

Additional financial information is also provided in the 2015 Financial Statements and 2015 MD&A.

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, 2015

Report Prepared: March 29, 2016

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CONTENT

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GLOSSARY OF TERMS

Technical Abbreviations

Standard imperial units are used in this report

Crude Oil and Natural Gas Liquids

$/bbls	dollars per 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
Bscf	billion standard 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

U.S.$	United States dollars (unless advised otherwise)
mm$	Millions 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

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. Any values presented herein should not be considered as equivalent to fair market value of the subject properties.

Contingent Resources – There is uncertainty 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 herein have been presented before and after adjustment for risk based on the estimated probability of development. There is no certainty as to the timing of any such development.

Prospective Resources – These are risked prospective resources that have been risked for chance of discovery, and have been presented before and after adjustment for risk based on the estimated probability 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 uncertainty that it will be commercially viable to produce any portion of the resources.

Production information is commonly reported in units of barrels of oil equivalents or “boes”. Barrels 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 thousand standard cubic feet (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 100 percent of the field's production, reserves and resources.

'Company Gross' or 'company gross' when used in relation to production, reserves, and resources means the product of OER's working interest and gross quantities**.**

'Net' or '**net'** when used in relation to production, reserves, and resources means either OER's working interest share of production, reserves and resources or OER's entitlement to production reserves and resources 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.

'Risked' or 'risked' when used in relation to contingent resources means risked for chance of development and when used in relation to prospective resources means risked for chance of geologic success.

Imperial Units – we are using standard imperial units which used in relation to production, reserves and resources means liquids measured in thousands of barrels (Mbbls) and millions of barrels (MMbbls) and gas measured in millions of standard cubic feet (MMscf) and billions of standard cubic feet (Bscf).

Cost and Financial – Unless otherwise stated, all cost and financial information referred to herein have been expressed in United States dollars (U.S.$). The term 'Income Taxes' as used herein includes all Nigerian taxes paid and does not include any Canadian or United States taxes.

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

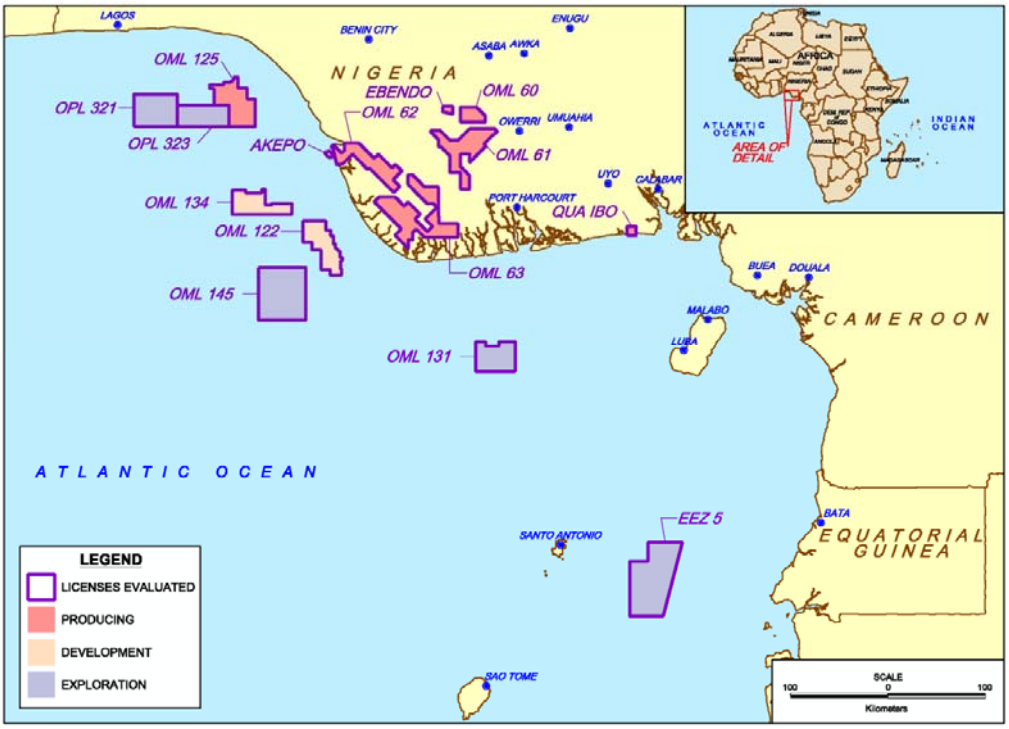
DeGolyer and MacNaughton (D&M), at the request of Oando Energy Resources Inc. ('OER' or 'Company'), has undertaken an independent assessment of the Company's petroleum reserves, resources, future net revenue, and net present values.

This statement of reserves and other oil and gas information set forth below was issued on February 22, 2016 and is a summary of information contained in the "Report as of December 31, 2015 on Reserves and Associated Revenue and Contingent Resources attributable to Oando Energy Resources Inc. for Certain Properties in Nigeria" (the 'D&M Report'), which has an effective date of December 31, 2015 and was prepared using data up to December 31, 2015.

The D&M 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 (December 2014), as stated in NI 51-101, its companion policy, CSA Staff Notice 51-327 *Revised Guidance on Oil and Gas Disclosure*, and the Canadian Oil and Gas Evaluation Handbook ('COGE Handbook'). The data for D&M's review were provided by OER or sourced from the public domain. D&M 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 Licenses: OML 60, OML 61, OML 62, OML 63, OML 122, OML 125, OML 131, OML 134, Ebendo (OML 56), Akepo (OML 90), Qua Ibo (OML 13), OML 145, OPL 321, OPL 323, and the EEZ Block 5 in Sao Tome.



OER's interests which have been independently evaluated by DeGolyer and MacNaughton and detailed in this statement are held as follows:

Property (License Area)	Interest Held By	OER Working Interest (WI)	Partners and Working Interests Held
OML 60	Oando Oil Limited [1]	20%	Nigerian Agip Oil Company (20% Operator), Nigerian National Petroleum Corporation (60%)
OML 61	Oando Oil Limited [1]	20%	Nigerian Agip Oil Company (20% Operator), Nigerian National Petroleum Corporation (60%)
OML 62	Oando Oil Limited [1]	20%	Nigerian Agip Oil Company (20% Operator), Nigerian National Petroleum Corporation (60%)
OML 63	Oando Oil Limited [1]	20%	Nigerian Agip Oil Company (20% Operator), Nigerian National Petroleum Corporation (60%)
OML 122	Equator Exploration Nigeria 122 Limited	5.0% (oil) 12.5% (gas) [2]	Peak Petroleum Industries Nigeria Limited (95% oil, 89.8% gas, Operator)
OML 125	Oando OML 125 & 134 Limited	15%	Nigerian Agip Exploration (85% Operator)
OML 131	Oando 131 Limited	100%	Oando Energy Resources (100% Operator)
OML 134	Oando OML 125 & 134 Limited	15%	Nigerian Agip Exploration (85% Operator)
OML 145	Oando Deepwater Exploration Nigeria Limited	21.05%	ExxonMobil (21.05% Operator), Chevron Nigeria Deepwater B Limited (21.05%), Svenska Petroleum Exploration AB (21.05%), and Nigerian Petroleum Development Company (15.79%)
Ebendo (OML 56) [5]	Oando Petroleum Development Company Limited	45% [3]	Energia Limited (55% Operator)
Akepo (OML 90) [5]	Oando Akepo Limited	40%	Sogenal (60% Operator)
Qua Ibo (OML 13) [5]	Oando Qua Ibo Limited	40%	Network Exploration & Production Nigeria ('NEPN') (60% Operator)
OPL 321	Equator Exploration Nigeria 321 Limited	30% [4]	Korean National Oil Company (60% Operator) & Tulip Energy Resources Nigeria Limited (10% Operator)
OPL 323	Equator Exploration Nigeria 323 Limited	30% [4]	Korean National Oil Company (60% Operator) & NJ Exploration (10% Operator)
EEZ Block 5	Equator Exploration STP Block 5 Ltd	100% [6]	Oando Energy Resources (100% Operator)

Notes:

1. Effective December 2015, Oando Oil Limited (OOL) is a successor company to Oando Hydrocarbons Limited (OHL) as the interest holder of OMLs 60, 61, 62, and 63.
2. OER holds 81.50% equity interest in Equator Exploration Limited (EEL), which holds a 5% Working Interest in the oil in OML 122 and a 12.5% equity interest in the gas in OML 122. Resources other than Reserves disclosed for OML 122 pertain to EEL's consolidated interest of 5% and 12.5% for oil and gas respectively.
3. OER holds 95% equity interest in Oando Petroleum Development Company Limited (OPDC), which holds a 45% Working Interest in Ebendo. OER files consolidated financial statements for OPDC, thus, Reserves and Resources other than Reserves disclosed for Ebendo pertain to OPDC's consolidated interest of 45%.
4. OER holds 81.50% equity interest in Equator Exploration Limited, which holds a 30% Working Interest in OPL 321 and OPL 323. Resources other than Reserves disclosed for OPLs 321 & 323 pertain to EEL's consolidated interest of 45%.
5. The Marginal fields have been carved out of existing Licenses and are no longer part of the OML. However, the previous OML has been included in brackets for identification purposes.
6. OER also holds 81.5% equity interest in Equator Exploration limited, which holds a 100% Working Interest in the oil in EEZ Block 5. Resources other than Reserves disclosed for EEZ Block 5 pertain to EEL's consolidated interest of 100%.

Licenses with Production

OMLs 60, 61, 62 and 63 (20% WI; operator NAOC). The Licenses are collectively called the Nigeria Agip Oil Company Joint Venture ('NAOC JV'). OER acquired interests in this License as part of the acquisition of ConocoPhillips's Nigerian business in July 2014. NAOC JV currently represents OER's most material asset and is strategically located onshore in the Niger Delta, across land and swampy terrain, covering a total area of 5,324 km^2 (1,315,587 acres). Oil and gas production began September 1970 and the current status of each License is summarized below.

> **OML 60** (20% WI; operator NAOC) is located in the northern Niger Delta. The License covers an area of 358 km^2 (88,464 acres). The License includes nine fields; Agwe, Akri-Oguta (unitized with SPDC), Asemoke, Ashaka, Beniku, Kwale, Odugri, Okpai, and Oniku. Production from OML 60 began in 1971 and the fields have 18 gross producing wells.
>
> **OML 61** (20% WI; operator NAOC) is located in the northern Niger Delta. The License covers an area of 1,499 km^2 (370,410 acres). The License includes sixteen fields; Alinso, Ebegoro, Ebegoro South, Ebocha, Idu, Irri-Oleh, Isoko South, Manuso, Mbede, Obaifu-Obrikom, Ogbogene, Omoku West, Oshi-Ubie (unitized with SPDC), Samabri-Biseni (unitized with SPDC), Taylor Creek, and Umuoru. Production from OML 61 began in 1970 and the fields have 70 gross producing wells.
>
> **OML 62** (20% WI; operator NAOC) is located in the central Niger Delta. The License covers an area of 1,221 km^2 (301,715 acres). The License includes three fields; Beniku, Tuomo, and Tuomo West. Production from OML 62 began in 1985; all the producers are currently shut in.
>
> **OML 63** (20% WI; operator NAOC) is located along the coastal swamp area of the Niger Delta. The License covers an area of 2,246 km^2 (554,998 acres). The License includes ten fields; Azuzuama, Clough Creek, Ekedai, Emette, Nimbe South, Obama, Ogbainbiri, Osiama Creek South, Pirigbene, and Tebidaba. Production from OML 63 began in 1975 and the fields have 36 gross producing wells.

OER's company gross share of total production sold from NAOC JV in 2015 was 16.6 MMboe (comprised of 5.7 MMbbls of oil, 58.5 Bscf of gas and 1.2 MMbbls of natural gas liquids). Therefore, in 2015, OER's company gross share of daily production sold from NAOC JV averaged 45,565 Mboe per day (consisting of 15,561 bbls/d of oil, 160,030 MMscf/d of gas and 3,332 bbls/d of natural gas liquids).

As of December 31, 2015, OER held a net share in the NAOC JV 2P reserves of 427 MMboe (comprised of 152.3 MMbbls of oil, 12.5 MMbbls of natural gas liquids and 1,573.6 Bscf of gas), company gross Best estimate unrisked Contingent resources of 78.2 MMboe, company gross Best estimate of risked (defined as risk for chance of development) Contingent resources of 19.1 MMboe, company gross Mean estimate unrisked Prospective resources of 51.5 MMboe and company gross Mean estimate of risked (defined as risk for chance of geologic success) Prospective resources of 19.5 MMboe.

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. OML 125 covers an area of 1,983 km^2 (490,010 acres) and the License includes one producing field (Abo field), one undeveloped discovery (Abo North) and 13 identified prospects, of which 6 were evaluated for this report. Production from the Abo field began in 2003 and the field currently has five producing wells; five other wells are shut-in. In addition there is one injection well. OML 125 operates under a Production Sharing Contract.

OER's company gross share of total production sold from OML 125 in 2015 was 1.2 MMbbls of oil, hence OER's company gross share of daily production sold from OML 125 averaged 3,313 bbls/d of oil.

As of December 31, 2015, OML 125 held net 2P reserves of 5.8 MMbbls of oil, company gross Best estimate unrisked Contingent resources of 1.1 MMboe, company gross Best estimate of risked Contingent resources of 0.6 MMboe, company gross Mean estimate unrisked Prospective resources of 16.6 MMboe and company gross Mean estimate of risked Prospective resources of 7.0 MMboe.

Ebendo Marginal Field (45% WI; operator Energia) was carved from OML 56 in the central Niger Delta, approximately 100 km north-west of Port Harcourt. The License covers an area of 65 km^2 (16,062 acres) and

includes two fields, the Ebendo field (producing) and the Obodeti field (undeveloped), and one prospect, Ebendo North. The Obodeti field was not evaluated for this report. Production from the Ebendo field began in 2009 and the field currently has four producing wells and three shut in wells. Ebendo operates under Marginal Field terms that benefit from advantageous fiscal terms.

OER's company gross share of total production sold from Ebendo in 2015 was 1.294 MMboe (consisting of 0.623 MMbbls of oil and 4.027 Bscf of gas), hence OER's company gross share of daily production sold from Ebendo averaged 3,545 Mboe per day (consisting of 1,706 bbls/d of oil and 11,034 MMscf/day of gas).

As of December 31, 2015, the Ebendo License held net 2P reserves of 8.8 MMboe (comprised 5.4 MMbbls oil and 20.3 Bscf of gas), company gross Best estimate unrisked Contingent resources of 1.4 MMboe, company gross Best estimate of risked Contingent resources of 1.0 MMboe, company gross Mean estimate unrisked Prospective resources of 2.4 MMboe and company gross Mean estimate of risked Prospective resources of 1.2 MMboe.

Qua Ibo Marginal Field (40% WI; operator NEPN) is located in onshore Nigeria, near the mouth of the Qua Ibo River, immediately adjacent to the ExxonMobil Qua Ibo Terminal. The License covers an area of 14 km^2 (3,459 acres) and includes one producing field (Qua Ibo). The Qua Ibo License was acquired by OER during 2013 and it operates under Marginal Field terms that benefit from advantageous fiscal terms. Production from the Qua Ibo field began in 2015 and the field currently has two producing wells and one shut in well.

OER's company gross share of total production sold from Qua Ibo in 2015 was 0.282 MMbbls of oil, hence OER's company gross share of daily production sold from OML 125 averaged 772 bbls/d of oil.

As of December 31, 2015, Qua Ibo License held net 2P reserves of 3.7 MMbbls of oil, company gross Best estimate unrisked Contingent resources of 0.3 MMboe and company gross Best estimate risked Contingent resources of 0.2 MMboe.

Licenses without Production

Akepo Marginal Field (40% WI and technical partner; operator Sogenal) was carved from OML 90 and is located in shallow waters (<20m) of the western Niger Delta. The License covers an area of 26 km^2 (6,425 acres). The License 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 studied for development. The Akepo field is expected to commence production from a single well in 2017, evacuating production through a barge to the Escravos terminal. Akepo operates under Marginal Field terms that benefit from advantageous fiscal terms.

As of December 31, 2015, the Akepo License held company gross Best estimate unrisked Contingent resources of 3.8 MMboe, company gross Best estimate of risked Contingent resources of 2.6 MMboe, company gross Mean estimate unrisked Prospective resources of 3.7 MMboe and company gross Mean estimate of risked Prospective resources of 1.2 MMboe.

OML 122 (5% oil WI and 12.5% gas WI; operator Peak) is located in the offshore Niger Delta, 40 km from the coastline of southern Nigeria, at a water depth of 40 to 300 m. The License covers an area of 1,599 km^2 (395,122 acres) and is currently subject to a dispute between Peak and OER. OML 122 includes three discoveries (Bilabri, Orobiri and Owanare) of which, only Bilabri was evaluated for this report. There has been no production from OML 122 to date.

As of December 31, 2015, OML 122 held company gross Best estimate unrisked Contingent resources of 7.7 MMboe and company gross Best estimate risked Contingent resources of 4.8 MMboe.

OML 131 (100% WI; operator OER) is located offshore in water depths ranging from 500 to 1,200 m approximately 70 km from the western Nigerian coast. The License is expected to be unitized with OML 135 with a resulting unit share of 51% for OML 131. OML 131 covers an area of 1,204 km^2 (301,000 acres) and includes two undeveloped discoveries (Bolia-Chota and Ebitemi) and two prospects (Pulolulu and Chota East). There has been no production from OML 131 to date.

As of December 31, 2015, OML 131 held company gross Best estimate unrisked Contingent resources of 71.6 MMboe, company gross Best estimate of risked Contingent resources of 40.9 MMboe, company gross Mean

estimate of unrisked Prospective resources of 165.9 MMboe and company gross Mean estimate of risked Prospective resources of 41.5 MMboe.

OML 134 (15% WI; operator NAE) is located offshore in water depths ranging from 550 to 1,100 m approximately 80 km from the western Nigerian coast. The License covers an area of 1,132 km^2 (279,723 acres) and includes three undeveloped discoveries (Oberan-1 fault block, Oberan-2 fault block and Minidiogboro), two single-well discoveries (Engule and Udoro) and nine prospects, six of which were evaluated for this report. There has been no production from OML 134 to date.

As of December 31, 2015, OML 134 held company gross Best estimate unrisked Contingent resources of 1.6 MMboe, company gross Best estimate of risked Contingent resources is 0.9 MMboe, company gross Mean estimate of unrisked Prospective resources of 16.9 MMboe and company gross Mean estimate of risked Prospective resources of 5.3 MMboe.

OML 145 (21.05% WI; operator ExxonMobil) is located offshore in water depths ranging from 1000 to 1,500 m, approximately 110 km from the western Nigerian coast. The License covers an area of 1,293 km^2 (319,507.5 acres) and includes two undeveloped discoveries (Uge and Uge North), two single-well discoveries (Nza and Orso) and five prospects. There has been no production from OML 145 to date.

As of December 31, 2015, OML 145 held company gross Best estimate unrisked Contingent resources of 42.7 MMboe, company gross Best estimate of risked Contingent resources of 24.4 MMboe, company gross Mean estimate of unrisked Prospective resources of 39.8 MMboe and company gross Mean estimate of risked Prospective resources of 19.6 MMboe.

OPL 321 and OPL 323 (30% 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 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 this ongoing dispute, since 2008 exploration on these Licenses 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 Licenses ($162 million). No wells have been drilled on the Licenses to date. The License includes five sizeable prospects (Gorilla, Lobster, Octopus and Whale (OPL 323) and Elephant (OPL 321)).

As of December 31, 2015, OPLs 321 and 323 jointly held company gross Mean estimate unrisked Prospective resources of 826.5 MMboe and company gross Mean estimate risked Prospective resources of 197.2 MMboe.

EEZ Block 5 (100% WI; operator Oando) is located in the exclusive economic zone of The Democratic Republic of Sao Tome & Principe (not more than 200 NM from its coast as per international maritime law). The area lies between latitudes 1o N and 1o 45' N and longitudes 80 E and 80 30' E. By this definition, the study area sits in the Atlantic area and lies close to the equator and has a close proximity to Equatorial Guinea and the Bight of Biafra. Block 5 has an area of 2,844 km^2 and the water depth within the block ranges from 2000 to 2500 m. Existing 2D seismic data over the block were reprocessed in 2014 and interpreted to identify several prospects. In 2015, 3D seismic data was acquired over an area of 1400 km^2. The processing of the newly acquired 3D seismic data was completed in December 2015 and interpretation of the 3D is currently ongoing to further mature identified prospects for exploration drilling in 2017.

As of December 31, 2015, the EEZ Block 5 held company gross Mean estimate unrisked Prospective resources of 1,474.7 MMboe and company gross Mean estimate risked Prospective resources of 384.2 MMboe.

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 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 commercially 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 at least 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 (at least 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 (at least 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 at least 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 (at least 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 (at least 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, 2015.

The *preparation date* of the information being provided herein is February 25, 2016.

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 D&M. D&M is an independent, qualified reserves and resources 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, 2015. D&M, in aggregate, evaluated 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 costs, 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 D&M Report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the D&M Report. The recovery and reserve estimates attributed to OER's properties described herein are estimates only. The actual reserves attributed to 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) quantity (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) quantity. Statistical principles indicate that the aggregated arithmetic sum of individual P90 values may have a higher level of confidence than 90 percent and the sum of the P10 values may have a lower level of confidence than 10 percent. Readers should give attention to the estimates of individual classes of proved, probable and possible reserves and Low, Best and High estimates of contingent and prospective resources and appreciate the differing probabilities associated with each class.

The D&M 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 D&M's opinion, it appeared reasonable and consistent with its knowledge of the properties. No independent verification of the information provided by OER was made. D&M 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 Key Uncertainties

Estimates of reserves, net present value and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue resources estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information. This includes; uncertainties in the quantities of Petroleum-Initially-in-Place related to structural mapping, fluid contact depths and fluid properties, uncertainty in recovery factors, especially for those reservoirs without adequate production history, and uncertainties around future product prices. Such exposure to effects of future market prices for oil or gas could positively or negatively impact the realized revenues from sales of crude oil, natural gas liquids (NGL) and gas.

Risks Related to Political, Legal, Economic and Military Developments in Nigeria

Estimates of reserves, net present value and future net revenue attributed to assets in Nigeria are subject to certain risks related to political, legal, economic and military developments in Nigeria. This includes uncertainty regarding the financing of NNPC's 60% share of costs in the NAOC JV, which impacts the fulfilment of the drilling and work program on which a significant portion of the reserves is based. Acts of political unrest, war or terrorism in the Niger Delta area may result in suspension of operations for prolonged periods. Also, there are uncertainties around the passing of the Petroleum Industry Bill (PIB) and the fiscal and regulatory terms that may apply.

Risks Related to Illegal Bunkering and Sabotage

Statements relating to production, reserves, net present value and future net revenues attributed to the undeveloped reserves in NAOC JV and reserves in 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. Losses in Ebendo are forecast by D&M to be 15% annually, then stepped down linearly from 2020 to 2025. For the NAOC JV, an anti-theft campaign is in place to reduce losses due to illegal bunkering (or theft). As a result of the anti-theft campaign, losses in NAOC JV are forecast by D&M to be 12% from 2016 to 2020, stepped down linearly from 2021 to 2025 and assumed to be zero beyond 2025. Both of these forecasts are in line with published data for the area.

For NAOC JV developed reserves, forecasts are based on historical production data after losses. Therefore D&M have not adjusted forecasts extrapolated from these for losses due to illegal bunkering and sabotage.

Risks Related to License Assumptions

OMLs 60, 61, 62 and 63 have a License expiration date of 2027, however reserves for these assets have been projected to an economic limit. The Nigerian Petroleum Act includes a provision for automatic renewal of an OML upon application by the operator, provided that the operator has paid all rents and royalties due and has otherwise performed all obligations under the terms of the lease. Reserves reported herein are projected beyond the current expiration dates and have been classified as proved, probable, and possible based on the assumption that the operator will apply for renewal of the OMLs and that OER expects that the operator will be in material compliance with all requirements for lease renewal.

Item 2.1 Reserves Data

1. All Reserves (Forecast Prices and Costs)

All OER Assets NAOC JV (OMLS 60, 61, 62, 63), Abo (OML 125), Ebendo (OML 56), and Qua Ibo (OML 13)

	Light & Medium Oil [1] (Mbbl)			Conventional Natural Gas [2] (MMscf)			Natural Gas Liquids (Mbbl)			Oil Equivalent [3] (Mboe)		
Reserves Category	**Gross [4]**	**Company Gross [5]**	**Net [6]**	**Gross [4]**	**Company Gross [5]**	**Net [6]**	**Gross [4]**	**Company Gross [5]**	**Net [6]**	**Gross [4]**	**Company Gross [5]**	**Net [6]**
Proved												
Developed Producing	211,613	42,673	42,111	2,334,755	474,272	474,272	60,705	12,141	12,141	661,444	133,859	133,297
Developed Non-Producing	146,781	29,000	28,736	1,176,776	235,353	235,353	0	0	0	342,910	68,226	124,112
Undeveloped	203,690	42,501	42,501	2,289,051	460,290	460,290	0	0	0	585,199	119,216	119,216
Total Proved	**562,084**	**114,174**	**113,348**	**5,800,582**	**1,169,915**	**1,169,915**	**60,705**	**12,141**	**12,141**	**1,589,553**	**321,301**	**320,475**
Probable	266,290	54,077	53,832	2,112,622	423,979	423,979	1,575	315	315	619,969	125,055	124,810
Total Proved Plus Probable	**828,374**	**168,251**	**167,180**	**7,913,204**	**1,593,894**	**1,593,894**	**62,280**	**12,456**	**12,456**	**2,209,521**	**446,356**	**445,285**
Possible [7]	309,999	62,662	62,281	1,713,986	345,215	345,215	1,575	315	315	597,238	120,513	120,132
Total Proved Plus Probable Plus Possible [7]	**1,138,373**	**230,913**	**229,461**	**9,627,190**	**1,939,109**	**1,939,109**	**63,855**	**12,771**	**12,771**	**2,806,760**	**566,869**	**565,417**

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, flaring, losses, and shrinkage.
3. Natural gas has 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. Gross – 100% of reserves.
5. Company Gross – the product of the company working interest and gross reserves.
6. Net – equivalent to the W.I. or the net entitlement as calculated in the Production Sharing Contract.
7. Possible reserves are those additional reserves that are less certain to be recovered than probable. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
8. Probable and possible reserves are presented as required by NI 51-101 and are not equivalent to proved reserves.
9. 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. OMLs 60, 61, 62, 63

	Light & Medium Oil [1] (Mbbl)			Conventional Natural Gas [2] (MMscf)			Natural Gas Liquids (Mbbl)			Oil Equivalent [3] (Mboe)		
Reserves Category	**Gross [4]**	**Company Gross [5]**	**Net [6]**	**Gross [4]**	**Company Gross [5]**	**Net [6]**	**Gross [4]**	**Company Gross [5]**	**Net [6]**	**Gross [4]**	**Company Gross [5]**	**Net [6]**
Proved												
Developed Producing	171,562	34,313	34,313	2,305,477	461,097	461,097	60,705	12,141	12,141	616,513	123,304	123,304
Developed Non-Producing	139,640	27,928	27,928	1,176,776	235,353	235,353	0	0	0	335,769	67,154	123,304
Undeveloped	195,525	39,105	39,105	2,279,136	455,828	455,828	0	0	0	575,381	115,076	115,076
Total Proved	**506,727**	**101,346**	**101,346**	**5,761,389**	**1,152,278**	**1,152,278**	**60,705**	**12,141**	**12,141**	**1,527,664**	**305,533**	**305,533**
Probable	254,770	50,954	50,954	2,106,802	421,360	421,360	1,575	315	315	607,479	121,496	121,496
Total Proved Plus Probable	**761,497**	**152,300**	**152,300**	**7,868,191**	**1,573,638**	**1,573,638**	**62,280**	**12,456**	**12,456**	**2,135,142**	**427,029**	**427,029**
Possible [7]	294,997	58,998	58,998	1,704,312	340,862	340,862	1,575	315	315	580,624	116,123	116,123
Total Proved Plus Probable Plus Possible [7]	**1,056,494**	**211,298**	**211,298**	**9,572,503**	**1,914,500**	**1,914,500**	**63,855**	**12,771**	**12,771**	**2,715,766**	**543,152**	**543,152**

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, flaring, losses, and shrinkage.
3. Natural gas has 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. Gross – 100% of reserves.
5. Company Gross – the product of the company working interest and gross reserves.
6. Net – equivalent to the W.I. or the net entitlement as calculated in the Production Sharing Contract.
7. Possible reserves are those additional reserves that are less certain to be recovered than probable. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
8. Probable and possible reserves are presented as required by NI 51-101 and are not equivalent to proved reserves.
9. Numbers may not add up due to rounding.

B. *Abo (OML 125)*

Reserves Category	Light & Medium Oil [1] (Mbbl)			Conventional Natural Gas [2] (MMscf)			Natural Gas Liquids (Mbbl)			Oil Equivalent [3] (Mboe)		
	Gross [4]	Company Gross [5]	Net [6]	Gross [4]	Company Gross [5]	Net [6]	Gross [4]	Company Gross [5]	Net [6]	Gross [4]	Company Gross [5]	Net [6]
Proved												
Developed Producing	32,023	4,803	4,241	0	0	0	0	0	0	32,023	4,803	4,241
Developed Non-Producing	7,141	1,072	808	0	0	0	0	0	0	7,141	1,072	808
Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0
Total Proved	**39,164**	**5,875**	**5,049**	**0**	**0**	**0**	**0**	**0**	**0**	**39,164**	**5,875**	**5,049**
Probable	6,446	967	722	0	0	0	0	0	0	6,446	967	722
Total Proved Plus Probable	**45,610**	**6,842**	**5,771**	**0**	**0**	**0**	**0**	**0**	**0**	**45,610**	**6,842**	**5,771**
Possible [7]	9,695	1,454	1,073	0	0	0	0	0	0	9,695	1,454	1,073
Total Proved Plus Probable Plus Possible [7]	**55,305**	**8,296**	**6,844**	**0**	**0**	**0**	**0**	**0**	**0**	**55,305**	**8,296**	**6,844**

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, flaring, losses, and shrinkage.
3. Natural gas has 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. Gross – 100% of reserves.
5. Company Gross – the product of the company working interest and gross reserves.
6. Net – equivalent to the W.I. or the net entitlement as calculated in the Production Sharing Contract.
7. Possible reserves are those additional reserves that are less certain to be recovered than probable. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
8. Probable and possible reserves are presented as required by NI 51-101 and are not equivalent to proved reserves.
9. Numbers may not add up due to rounding.

C. *Ebendo (OML 56)*

Reserves Category	Light & Medium Oil [1] (Mbbl)			Conventional Natural Gas [2] (MMscf)			Natural Gas Liquids (Mbbl)			Oil Equivalent [3] (Mboe)		
	Gross [4]	Company Gross [5]	Net [6]	Gross [4]	Company Gross [5]	Net [6]	Gross [4]	Company Gross [5]	Net [6]	Gross [4]	Company Gross [5]	Net [6]
Proved												
Developed Producing	6,926	3,116	3,116	29,278	13,175	13,175	0	0	0	11,806	5,312	5,312
Developed Non-Producing	0	0	0	0	0	0	0	0	0	0	0	0
Undeveloped	2,588	1,165	1,165	9,915	4,462	4,462	0	0	0	4,241	1,909	1,909
Total Proved	**9,514**	**4,281**	**4,281**	**39,193**	**17,637**	**17,637**	**0**	**0**	**0**	**16,046**	**7,221**	**7,221**
Probable	2,450	1,106	1,106	5,820	2,619	2,619	0	0	0	3,420	1,543	1,543
Total Proved Plus Probable	**11,964**	**5,387**	**5,387**	**45,013**	**20,256**	**20,256**	**0**	**0**	**0**	**19,466**	**8,763**	**8,763**
Possible [7]	1,821	816	816	9,674	4,353	4,353	0	0	0	3,433	1,542	1,542
Total Proved Plus Probable Plus Possible [7]	**13,785**	**6,203**	**6,203**	**54,687**	**24,609**	**24,609**	**0**	**0**	**0**	**22,900**	**10,305**	**10,305**

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, flaring, losses, and shrinkage.
3. Natural gas has 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. Gross – 100% of reserves.
5. Company Gross – the product of the company working interest and gross reserves.
6. Net – equivalent to the W.I. or the net entitlement as calculated in the Production Sharing Contract.
7. Possible reserves are those additional reserves that are less certain to be recovered than probable. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
8. Probable and possible reserves are presented as required by NI 51-101 and are not equivalent to proved reserves.
9. Numbers may not add up due to rounding.

D. Qua Ibo (OML 13)

Reserves Category	Light & Medium Oil [1] (Mbbl)			Conventional Natural Gas [2] (MMscf)			Natural Gas Liquids (Mbbl)			Oil Equivalent [3] (Mboe)		
	Gross [4]	Company Gross [5]	Net [6]	Gross [4]	Company Gross [5]	Net [6]	Gross [4]	Company Gross [5]	Net [6]	Gross [4]	Company Gross [5]	Net [6]
Proved												
Developed Producing	1,102	441	441	0	0	0	0	0	0	1,102	441	441
Developed Non-Producing	0	0	0	0	0	0	0	0	0	0	0	0
Undeveloped	5,577	2,231	2,231	0	0	0	0	0	0	5,577	2,231	2,231
Total Proved	**6,679**	**2,672**	**2,672**	**0**	**0**	**0**	**0**	**0**	**0**	**6,679**	**2,672**	**2,672**
Probable	2,624	1,050	1,050	0	0	0	0	0	0	2,624	1,050	1,050
Total Proved Plus Probable	**9,303**	**3,722**	**3,722**	**0**	**0**	**0**	**0**	**0**	**0**	**9,303**	**3,722**	**3,722**
Possible [7]	3,486	1,394	1,394	0	0	0	0	0	0	3,486	1,394	1,394
Total Proved Plus Probable Plus Possible [7]	**12,789**	**5,116**	**5,116**	**0**	**0**	**0**	**0**	**0**	**0**	**12,789**	**5,116**	**5,116**

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, flaring, losses, and shrinkage.
3. Natural gas has 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. Gross – 100% of reserves.
5. Company Gross – the product of the company working interest and gross reserves.
6. Net – equivalent to the W.I. or the net entitlement as calculated in the Production Sharing Contract.
7. Possible reserves are those additional reserves that are less certain to be recovered than probable. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
8. Probable and possible reserves are presented as required by NI 51-101 and are not equivalent to proved reserves.
9. 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 D&M's forecast prices and costs.

All OER Assets (including NAOC JV (OMLs 60, 61, 62, 63), Abo (OML 125), Ebendo (OML 56), and Qua Ibo (OML 13)

Summary of Net Present Values of Future Net Revenue, as of December 31, 2015, Based on Forecast Prices and Costs

Reserves Category	Before Income Taxes discounted at (%/Year)					After Income Taxes discounted at (%/Year)					Unit Value Before Income Tax [3] ($/boe)
	0 (mm$)	5 (mm$)	10 (mm$)	15 (mm$)	20 (mm$)	0 (mm$)	5 (mm$)	10 (mm$)	15 (mm$)	20 (mm$)	
Proved											
Developed Producing	1,407	1,197	1,020	879	768	374	417	403	374	344	7.7
Developed Non-Producing	1,232	673	371	204	109	289.6	114.7	25	(21)	(43)	3.0
Undeveloped	3,713	2,281	1,455	960	654	1,344.7	876.2	591	411	292	12.2
Total Proved	**6,351**	**4,150**	**2,845**	**2,043**	**1,531**	**2,008.0**	**1,407.4**	**1,019**	**764**	**593**	**8.9**
Probable	4,779	2,539	1,454	898	594	1,007.9	555.9	337	226	166	11.7
Total Proved Plus Probable	**11,130**	**6,690**	**4,299**	**2,940**	**2,125**	**3,015.9**	**1,963.3**	**1,356**	**990**	**759**	**9.7**
Possible [2]	5,642	2,757	1,517	930	623	1,107.8	531.1	291	185	133	12.6
Total Proved Plus Probable Plus Possible [2]	**16,772**	**9,446**	**5,816**	**3,870**	**2,748**	**4,123.7**	**2,494.4**	**1,647**	**1,175**	**892**	**10.3**

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. 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 net oil equivalent reserves.
4. Values associated with probable and possible reserves are presented as required by NI 51-101 and are not equivalent to values associated with proved reserves.
5. Numbers may not add up due to rounding.

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

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

All OER Assets (NAOC JV (OMLs 60, 61, 62, 63), Abo (OML 125), Ebendo (OML 56), and Qua Ibo (OML 13)

Reserves Category	Revenue (mm$)	Royalties (mm$)	Operating Costs [1] (mm$)	Development Costs (mm$)	Abandonment Costs (mm$)	Future Net Revenue Before Income Taxes (mm$)	Future Income Costs [2] (mm$)	Future Net Revenue After Income Taxes (mm$)
Proved	12,438	1,992	3,984	1,654	428	4,380	2,372	2,008
Proved Plus Probable	18,956	3,120	5,243	2,084	471	8,039	5,023	3,016
Proved Plus Probable Plus Possible [3]	26,448	4,448	6,653	2,478	512	12,357	8,233	4,124

Notes:
1. Operating costs include contribution to Niger Delta Development Commission (NDDC) fund.
2. Future income costs refer to Nigerian taxes. No consideration has been given to Canadian income taxes.
3. Possible reserves are those additional reserves that are less certain to be recovered than probable. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
4. Values associated with probable and possible reserves are presented as required by NI 51-101 and are not equivalent to values associated with proved reserves.
5. Numbers may not add up due to rounding.

Item 2.2 Supplementary Disclosure of Reserves Data

1. Constant Prices and Costs

No evaluation using constant prices and costs has been undertaken.

Item 2.3 Reserves Disclosure Varies with Accounting

For the Ebendo Marginal field, reserves disclosure varies with accounting. OER holds a significant majority interest of 95% in Oando Petroleum Development Company Limited (OPDC), which holds a 45% Working Interest in Ebendo. OER files consolidated financial statements for OPDC, thus, reserves and resources other than reserves disclosed for Ebendo pertain to OPDC's consolidated interest of 45%.

A consistent approach has been applied to OPL 321, OPL 323 and EEZ Block 5 which include reserves other than resources.

Item 2.4 Future Net Revenue Disclosure Varies with Accounting

For the Ebendo Marginal field, future net revenue disclosure varies with accounting. OER holds a significant majority interest of 95% in Oando Petroleum Development Company Limited (OPDC), which holds a 45% Working Interest in Ebendo. OER files consolidated financial statements for OPDC, thus, future net revenue disclosed for Ebendo pertain to OPDC's consolidated interest of 45%.

PART 3: PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used in Supplemental Estimates

Not applicable.

Item 3.2 Forecast Prices Used in Estimates

Oil Prices applied to crude oil sold or planned to be sold.

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

	Light and Medium Oil [2]	Conventional Natural Gas		Natural Gas Liquids	Inflation	
Date	Consensus (US $/bbl)	OMLs 60-63 (US $/Mscf)	Ebendo Gas (US $/Mscf)	Eleme (US $/bbl)	CAPEX (%)	OPEX (%)
2015 [1]	51.37	1.55	0.30	10.56		
2016	52.00	1.69	0.30	11.09	0.0	0.0
2017	60.10	1.82	0.30	11.52	0.0	0.0
2018	63.34	1.88	0.30	11.69	0.0	0.0
2019	69.86	1.98	0.30	12.04	0.0	0.0
2020	75.58	2.08	0.30	12.34	0.0	0.0
2021	80.41	2.16	0.30	12.60	0.0	0.0
2022	87.65	2.28	0.30	12.98	2.0	2.0
2023	89.40	2.31	0.30	13.08	2.0	2.0
2024	91.19	2.34	0.30	13.17	2.0	2.0
2025	93.01	2.37	0.30	13.27	2.0	2.0
2026	94.87	2.40	0.30	13.37	2.0	2.0
2027	96.77	2.43	0.30	13.47	2.0	2.0
2028	98.71	2.47	0.30	13.57	2.0	2.0
2029	100.68	2.50	0.30	13.68	2.0	2.0

Notes:
1. Weighted average historical prices from most recent financial year (2015).
2. Light & medium oil includes condensate produced from non-associated gas reservoirs.
3. All prices are Money-of-the-Day and in United States Dollars (US $).

The price forecast for light and medium oil is based on the December 2015 version of a price deck that is prepared and published by a consensus of Canadian operators and contractors, indexed to Brent, with the support of the Society of Petroleum Evaluation Engineers (SPEE).

Nearly eighty percent of future sales gas production from NAOC JV (OMLs 60, 61, 62 and 63) goes to Bonny LNG and the pricing formula specified in the sales gas contract is based on a netback from realised LNG prices. Actual realised prices from gas sales to Bonny LNG may be lower or higher than the assumed price.

Future prices for Ebendo gas are fixed at US$ 0.30 per thousand cubic feet and based on the gas sales agreement with the buyer, Xenergi.

Natural gas liquids (NGL) are sold to Eleme Petrochemical Plant and the contractual price formula is a netback based on prices of High-Density Polyethylene (HDPE) in South East Asia as published by Platt.

Zero escalation factors are applied to future capital and operating expenditures through 2021. In 2022 and beyond, future capital and operating expenditures are inflated at an annual rate of two percent, based on historical averages in the United States. These are applicable because prices and expenditures are incurred in United States Dollars.

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 company gross share reserves of oil and natural gas for the year ended December 31, 2015, using forecast prices and costs.

All OER Assets (including NAOC JV (OMLs 60, 61, 62, 63), Abo (OML 125), Ebendo (OML 56), and Qua Ibo (OML 13))

Summary of Reserves Reconciliation as of December 31, 2015 for Company Gross Reserves [1]

	Light & Medium Oil [2]		Natural Gas [3]		Natural Gas Liquids		Oil Equivalent [4]	
	Proved (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mscf)	Proved Plus Probable (Mscf)	Proved (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Proved Plus Probable (Mboe)
December 31, 2014	108,534	148,027	1,005,011	1,545,785	12,410	14,600	288,446	420,258
Extensions & Improved Recovery	-	-	-	-	-	-	-	-
Technical Revisions	17,137	29,545	567,971	153,404	906	(884)	112,705	54,228
Discoveries	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	(4,577)	(2,578)	(340,644)	(42,851)	0	0	(61,351)	(9,720)
Production [5]	(7,794)	(7,794)	(62,438)	(62,438)	(1,216)	(1,216)	(19,416)	(19,416)
December 31, 2015	113,300	167,200	1,169,900	1,593,900	12,100	12,500	320,383	445,350

Notes:

1. Company Gross is the product of OER's working interest and gross quantities. Note that OER's total *company gross* proved plus probable reserves aggregate to 446 MMboe, while OER's total *net* proved plus probable reserves aggregate to 445 MMboe.
2. Light & medium oil includes condensate produced from non-associated gas reservoirs.
3. Natural gas resources include both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, flaring, losses, and shrinkage.
4. 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. 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.

PART 5: ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

The following table presents undeveloped reserves attributable to opportunities that were first attributed in each of the most recent three financial years. 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 degree of certainty appropriate to its classification as proved or probable, 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 after the tables.

Proved Undeveloped Reserves	Light & Medium Oil (Net) (Mbbl)	Natural Gas (Net) (MMscf)	Natural Gas Liquids (Net) (Mbbl)	Oil Equivalent (Net) (Mboe) [1]
Prior to December 31, 2012 [2]	na	na	na	na
December 31, 2012	3,594	1,900	-	3,910
December 31, 2013 [3]	657	-	-	657
December 31, 2014 [4]	36,445	463,954	2,190	113,771
December 31, 2015 [5]	6,056	-	-	6,056

Probable Undeveloped Reserves	Light & Medium Oil (Net) (Mbbl)	Natural Gas (Net) (MMscf)	Natural Gas Liquids (Net) (Mbbl)	Oil Equivalent (Net) (Mboe) [1]
Prior to December 31, 2012 [2]	na	na	na	na
December 31, 2012	1,680	900	-	1,830
December 31, 2013 [3]	268	-	-	268
December 31, 2014 [4]	18,666	237,623	387	58,270
December 31, 2015 [5]	7,573	82,016	-	21,242

Notes:
1. Natural gas has been converted to barrels of oil equivalent using six Mscf of natural gas being equal to one barrel of oil.
2. Oando did not file Form 51-101 F1 prior to December 31, 2012.
3. Proved and Probable Undeveloped Reserves first attributed on December 31, 2013 pertain to acquisition of Qua Ibo License.
4. Proved and Probable Undeveloped Reserves first attributed on December 31, 2014 pertain to acquisition of OML 60, 61, 62, & 63.
5. Proved and Probable Undeveloped Reserves first attributed on December 31, 2015 pertain to technical revisions in OML 60, 61, 62, & 63.
6. Numbers may not add up due to rounding.

OML 60

Undeveloped oil, gas and NGL reserves are associated with ongoing field development in multiple reservoirs, involving wells in Akri, Beniku, Kwale, Okpai, Odugri, and Oniku as part of the extended drilling program. Twenty-two wells are scheduled to be drilled in OML 60 between 2018 and 2037.

OML 61

Undeveloped oil, gas and NGL reserves are associated with ongoing field development in multiple reservoirs, involving wells in Ebegoro South, Ebocha, Idu, Irri-Oleh, Isoko South, Manuso, Mbede, Obiafu-Obrikom, Ogbogene, Omoku West, Oshi-Ubie, and Samabri Biseni as part of the extended drilling program. Eighty-two wells are scheduled to be drilled in OML 61 between 2016 and 2037.

OML 62

Undeveloped oil reserves are associated with ongoing field development in multiple reservoirs, involving wells in Tuomo and Tuomo West as part of the extended drilling program. Seven wells are scheduled to be drilled in OML 62 between 2019 and 2035.

OML 63

Undeveloped oil, gas and NGL reserves are associated with ongoing field development in multiple reservoirs, involving wells in Azuzuama, Clough Creek, Ekedai, Emette, Nimbe South, Obama, Ogbainbiri, and Pirigbene as part of the extended drilling program. Seventeen wells are scheduled to be drilled in OML 63 between 2019 and 2037.

There are 128 wells scheduled to be drilled in OMLs 60, 61, 62 and 63 between 2016 and 2037.

Qua Ibo (OML 13)

Undeveloped oil reserves are associated with the C4 reservoir, which is the target of a three-well development plan. The Qua Ibo-5, Qua Ibo-6 and Qua Ibo-7 are scheduled to be drilled in 2018 and 2019.

Ebendo (OML 56)

Undeveloped oil and gas reserves are associated with the XVI and XVIIIa reservoirs to be drained by Ebendo-8, and the XIII and XVII reservoirs to be drained by Ebendo-10. The wells are scheduled to be drilled in 2017 and 2018.

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from on-going development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on recent production forecasts, prices and economic conditions. As circumstances change and additional data become available, reserves estimates may be revised due to technical factors and/or commercial factors.

Technical uncertainties include the quantity of the petroleum initially in place, the recovery factor, well performance, fluid properties, and the number and productivity of future oil and gas wells.

Commercial uncertainties include assumptions about extension of gas contract and License renewals, prices of the petroleum products, cost of developing the fields, cost of operating the wells and facilities, cost of abandonment and reclamation, 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 OMLs 60, 61, 62, and 63 and Ebendo could increase reserves; and (iii) reduction in development costs could potentially increase the value and the quantity of economically recoverable reserves.

Specific significant negative factors which may affect the reserves data contained herein are: (i) non-renewal of gas contracts and Licenses; (ii) reduction or termination of the ongoing drilling programs on OMLs 60, 61, 62 and 63; (iii) an increase in bunkering and sabotage activities that affect OMLs 60, 61, 62, and 63 and Ebendo could reduce reserves; (iv) reduced gas or water injection in Abo could reduce oil recovery.

This Statement of Reserves Data and Other Oil and Gas Information are estimates only and there is no assurance or guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than the estimates provided herein and such variances could be material.

Item 5.3 Future Development Costs

A summary of the estimated development costs 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 future development plans, following consultations with various operators and co-venturers.

OER expects to pay for these development costs through a combination of cash flow from operations, existing and future debt, and new equity financing or similar arrangements.

A summary of the estimated development costs 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 future development plans, following consultations with various operators and co-venturers.

OER expects to pay for these development costs through a combination of cash flow from operations, existing and future debt, and new equity financing or similar arrangements.

Summary of Estimated Undiscounted Future Development Costs
Attributable to Reserves Using Forecast Prices and Costs (Net)

	Reserves Category		
Date	**Total Proved (mm$)**	**Total Proved plus Probable (mm$)**	**Total Proved plus Probable plus Possible (mm$)**
2016	62	62	62
2017	189	189	189
2018	111	113	113
2019	145	145	145
2020	84	84	84

Notes:
1. All values in this table are Oando net.
2. All prices are in Real Term (December 31, 2015).
3. Costs associated with Contingent Resources are reported separately.
4. Numbers may not add up due to rounding.

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 NAOC JV (OMLs 60, 61, 62, and 63), Ebendo (OML 56), Akepo (OML 90), Qua Ibo (OML 13), OML 122, OML 125, OML 131, OML 134, OML 145, OPL 321m OPL 323 and EEZ Block 5. Of these, NAOC JV (OMLs 60, 61, 62, 63), Qua Ibo (OML 13) and Ebendo (OML 56) are onshore (on land) in the Niger Delta, Nigeria, Akepo (OML 90) is in shallow offshore waters of the Nigerian coastal area, while OML 122, OML 125, OML 131, OML 134, OML 145, OPL 321, OPL 323 and EEZ Block 5 are located in offshore waters in the Nigerian coastal area.

Developed non-producing reserves in OMLs 60, 61, 62 and 63 are associated with reservoirs behind pipe that can be produced from existing wells. A workover rig is scheduled for 2016 to commence remedial operations on these wells.

Developed non-producing reserves associated with Abo-2 and Abo-3ST wells (OML 125) have been shut-in since July and June 2014, respectively due to flow-line blockage. Remediation of both wells is planned for 2016.

There are no mandatory relinquishments, surrenders, back-ins or changes in ownership with respect to any of the Oil Mining Licenses (OML). For the Oil Prospecting Licenses (OPL), there is a requirement to relinquish approximately 50% of the block acreage during the process converting to an OML. Additionally, OER has an option over OPL 321 and OPL 323 and will need to repay the signature bonus to exercise this option.

2. Plant and Facilities

Important plants, facilities and installations in which OER has an interest include 14 flowstations, one oil processing centre (Ebocha, OML 61), one gathering facility (F.U.N, OML 13), one oil export terminal (Brass, NAOC JV), three gas plants (Kwale, Ob-Ob and Ogbainbiri), one power plant (Kwale-Okpai Independent Power Plant or "Kwale-Okpai IPP") and associated infrastructure including, roads, power stations and heliports. The majority of these properties are based onshore. There is a leased Floating Production Storage and Offloading vessel for the Abo field in OML 125.

Reserves have been attributed to Beniboye in OML 62, which is currently not producing. The wells and flowstation are capable of producing but production stopped in 2013 after the assets were vandalized. Prior to that incident, the field was producing about 2,000 barrels of oil per day, which was evacuated to Shell-operated Forcados Terminal 10 km away.

The following table summarizes plant and facilities in which OER holds an interest.

Name	Type	OML	Location	Collects Production From	Working Interest	Description – Other Notes
Abo FPSO	Floating Production Storage & Offloading Vessel	125	Offshore	Abo field	15%	Currently leased, with an option to buy in 2022. Includes production & test manifolds, separators, fuel gas processing & water treatment facilities. Oil production capacity of 40,000 bbls/d, gas production capacity of 114 MMscf/d, & water production capacity of 9 Mbbls/d. Also has capacity to reinject up to 30 Mbbls/d of water & 12 MMscf/d of gas.
Akri	Flowstation	60	Land	Akri, Odugri, & Agwe fields	20%	Approx. 35 km from Ebocha. The processed crude oil commingles with the crude oil stream from Kwale flowstation & flows to Ebocha Oil Centre.
Beniboye	Flowstation	62	Swamp	Beniboye field	20%	Located in North West of OML 62, approx. 2 km from Shell's Forcado terminal. Built on a small piece of land & surrounded by water.
Brass River	Export Terminal		Swamp	All NAOC-JV flowstations plus some 3rd party assets	20%	Located in Brass Island of Bayelsa State, 113 km southwest of Port Harcourt & with a storage capacity of 3,558,000 bbls.
Clough Creek	Flowstation	63	Swamp	Clough Creek field	20%	Approx. 150 km west of Port Harcourt. Existing flowstation on piled platform on branch of a river. Accommodation & new equipment on land.
Ebendo	Flowstation	Ebendo	Onshore	Ebendo field	45%	10,000 bbls/d capacity, connected to gathering facility at Umusadege through a 6 inch diameter, 8.5 km pipeline.
Ebocha	Oil Centre & Flowstation	61	Land	All flowstations in the Land area except from Idu & Oshi flowstations	20%	Approx. 100 km inland from Port Harcourt. First crude oil separation & gathering centre built by NAOC in Nigeria, 1970.
FUN Gathering Facilit	Gathering Facility	13	Onshore	Qua Ibo & other Marginal fields	13%	Group gathering facility jointly owned by marginal field operators; "Frontier", "Universal", & "Network", the FUN Group, to export oil production to Exxon Mobil's Qua Iboe Terminal. Commenced operatio in Q1 2015. OER holds interests through its co-venture with Network.
Idu	Flowstation	61	Land	Idu & unitized Samabri/Biseni fields	20%	Approx. 27 km from Ebocha. Shut down in 1982 & reopened later to cope with increased volumes of oil & gas from Idu & Samabri-Biseni.
Irri/Isoko	Flowstation	61	Land	Irri, Isoko, & Oleh fields	20%	Approx. 40 km from the Kwale plant. Upgraded for NLNG's train 6.
Kwale-Okpai	Plant & Flowstation	61	Land	Asemoke, Ashaka, Beriku, Kwale, & Okpai fields. Also from nearby 3rd party Marginal fields, including Ebendo	20%	480 MW combined cycle gas-fired Independent Power Plant. Approx. 110 km NNW from Port Harcourt. Also contains a gas plant & incorporates Okpai flowstation.
Obiafu Obrikom (Ob-(	Plant & Flowstation	61	Land	Obiafu, Omoku West, Obrikom, Ogbogene, Umuoru, & Ebegoro fields	20%	Gas hub for NAOC-JV network. Approx. 80 km NNW of Port Harcou Gas plant on land, incorporating old Obrikom & Ebegoro flowstations (no longer functional). Natural Gas Liquids are processed here & exported to buyers via Ebocha.
Obama	Flowstation	63	Swamp	Pirigbene, Nimbe South, Ekedei, Emette, & Obama fields	20%	Approx. 80 km WSW of Port Harcourt. Piled platform on branch of a river, accommodation for operations personnel on land.
Ogbainbiri	Flowstation & Gas Plant	63	Swamp	Ogbainbiri, Tuomo, & surrounding fields	20%	Approx. 92 km from Brass Terminal. Mounted on a small piece of land Flowstation upgraded in 2013 to increase capacity to 200 MMscf/d in view of making it the NAOC JV swamp area gas hub.
Oshi	Flowstation	61	Land	Oshi, Taylor Creek, & Manuso fields	20%	Approx. 70 km WNW from Port Harcourt. Flowstation on land.
Qua Ibo	Flowstation	Qua Ibo	Onshore	Qua Ibo field	40%	Early processing facility with 10,000 bbls/d capacity commissioned in Q4 2014.
Tebidaba	Flowstation	63	Swamp	Tebidaba field	20%	Approx. 57 km from Brass Terminal. Constructed as a platform on a branch of the river, with living accommodations on nearby land.

3. Pipelines

There are approximately 1,250 km of pipelines transporting oil and gas from flowstations to oil centres/gas plants and the oil and gas export terminals. Approximately 1,190 km of these pipelines are associated with NAOC JV. Some of the NAOC JV's main export pipelines are used by third parties and agreements are in place with ADDAX Petroleum, SPDC, AENR (Platform) and OER's marginal fields for transportation and processing. In addition, some gas is supplied from the Akri field to the Oguta plant owned by SPDC.

The table below summarizes the pipelines in which OER holds an interest.

Pipeline From	Pipeline To	Location	Type	Length (km)	Diameter (in)	Working Interest
Irri Flowstation	Kwale-Okpai Gas Plant	Land	Oil	39	10	20%
Kwale-Okpai Gas Plant	Akri Flowstation	Land	Oil	17.3	10	20%
Akri Flowstation	Ebocha Flowstation	Land	Oil	22	14	20%
Ob/Ob Gas Plant	Obrikom Site	Land	Oil	4	10	20%
Obrikom Site	Ebocha Flowstation	Land	Oil	11	10 & 6	20%
Ebocha Flowstation	Ogoda Manifold	Land	Oil	42.5	18	20%
Ebocha Flowstation	Eleme Petrochemicals	Land	NGL	87.5	8	20%
Samabri Cluster	Idu Flowstation	Land	Oil	18.7	14	20%
Idu Flowstation	Ogoda Manifold	Land	Oil	0.6	6	20%
Oshi Flowstation	Ogoda Manifold	Land	Oil	8	10	20%
Ogoda Manifold	Rumuekpe Booster Stn	Land	Oil	22.5	14	20%
Ogoda Manifold	Brass Terminal	Land	Oil	99	24	20%
Ogbainbiri Flowstation	Tebidaba Flowstation	Swamp	Oil	35	14	20%
Clough Creek Flowstation	Tebidaba Flowstation	Swamp	Oil	52	10	20%
Tebidaba Flowstation	Brass River Manifold	Swamp	Oil	44.7	18	20%
Obama Flowstation	Brass River Manifold	Swamp	Oil	26.5	18	20%
Brass River Manifold	Brass Terminal	Swamp	Oil	12.8	24	20%
Beniboye Flowstation	Forcados Terminal	Swamp	Oil	2	10	20%
Irri Flowstation	Kwale-Okpai Gas Plant	Land	Gas	39	18	20%
Kwale-Okpai Gas Plant	Ob/Ob Gas Plant	Land	Gas	49.3	24	20%
Kwale-Okpai Gas Plant	Okpai Power Plant	Land	Gas	12	18	20%
Akri Flowstation	Oguta (SPDC)	Land	Gas	8	12	20%
Ob/Ob Gas Plant	Eleme Petrochemicals	Land	Gas	87.5	8	20%
Ob/Ob Gas Plant	PG Rivers	Land	Oil	1.5	8 & 12	20%
Ebocha Flowstation	Ob/Ob Gas Plant	Land	Gas	29.5	14	20%
Ogbainbiri Flowstation	Kolo Creek Node	Swamp & Land	Gas	47.5	24	20%
Kolo Creek Node	Ob/Ob Gas Plant	Land	Gas	73	24	20%
Idu Flowstation	Ob/Ob Gas Plant	Land	Gas	22	18	20%
Oshi Flowstation	Ob/Ob Gas Plant	Land	Gas	42	14	20%
Oshi Flowstation	Ogoda Manifold	Land	Gas	8	18	20%
Ob/Ob Gas Plant	Ubeta	Land	Gas	59	24	20%
Ubeta	Rumuji	Land	Gas	32.9	24	20%
Ubeta	Rumuji	Land	Gas	32.9	28	20%
Rumuji	Bonny NLNG	Land	Gas	65.8	36	20%
Obama	Brass River Manifold	Land	Gas	26.5	4	20%
Brass River Manifold	Brass Terminal	Land	Gas	12.8	4	20%
Qua-Ibo Processing Facility	FUN Gathering Facility	Land	Oil	1	6	40%
FUN Gathering Facility	Qua Iboe Terminal	Land	Oil	1.5	6	13.33%
Ebendo	Umusadege Gathering Facility	Land	Oil	8.5	6	45%
Umusadege Gathering Facility	Eriemu Flow Station (NPDC)	Land	Oil	51	12	11.25%

Note: All values in this table are net to Oando.

4. Wells

The following table sets forth OER's wells for all assets as of December 31, 2015.

License	Producing	Shut-in/ Suspended	Injectors	Abandoned	Total	OER WI	Net Wells
OML 60	18	38	0	13	69	20.00%	13.8
OML61	70	113	1	22	206	20.00%	41.2
OML 62	0	19	0	7	26	20.00%	5.2
OML 63	36	38	0	17	91	20.00%	18.2
Ebendo (OML 56)	4	3	0	1	8	45.00%	3.6
Akepo (OML 90)	0	1	0	0	1	40.00%	0.4
Qua Ibo (OML 13)	2	1	0	1	4	40.00%	1.6
OML 122 (1)	0	0	0	8	8	5% (oil), 12.5% (gas)	0.4
OML 125	5	5	1	4	15	15.00%	2.3
OML 131	0	0	0	7	7	100.00%	7.0
OML 134	0	0	0	5	5	15.00%	0.8
OML 145	0	0	0	5	5	21.05%	1.1
OPL 321	0	0	0	0	0	30.00%	0.0
OPL 323	0	0	0	0	0	30.00%	0.0
EEZ Block 5	0	0	0	0	0	100.00%	0.0
Total	**135**	**218**	**2**	**90**	**445**		**95.5**

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. Net wells in OML 122 based on volume weighted average of oil in gas in oil equivalent terms.
4. Numbers may not add up due to rounding.

Item 6.2 Properties with No Attributed Reserves

There are eight properties for which OER holds an interest that have no attributed reserves (unproved properties). There are Akepo, OML 122, OML 131, OML 134, OML 145, OPL 321, OPL 323 and EEZ Block 5. Key details for these properties are summarized in the table below:

License Area	Fields *Prospects and Leads	Gross Area (Acres) [1]	Working Interest	Location	Country	Work Commitments
Akepo (OML 90)	Akepo Main *Akepo North	6,425	40%	Shallow Offshore	Nigeria	None Outstanding
OML 122	Bilabri, Owanere, Orobiri -	395,123	5% (oil), 12.5% (gas) [2]	Offshore	Nigeria	None Outstanding
OML 131	Bolia-Chota, Ebitemi *Pulolulu, East Chota	297,515	100%	Deep Offshore	Nigeria	None Outstanding
OML 134	Oberan South, Mindiogboro *Oberan North, North-A, South-East, Oberan East -A, -B, -C, -D	279,720	15%	Deep Offshore	Nigeria	None Outstanding
OML 145	Uge, Uge-North, Nza, Orsa *Ogazi Lead C, Uge Deep, Nza Deep, Ichokwu, Uge Block B/C	319,508	21.5%	Deep Offshore	Nigeria	None Outstanding
OPL 321	- *Elephant	312,995	30% [3]	Deep Offshore	Nigeria	None Outstanding
OPL 323	- *Gorilla, Whale, Lobster, Octopus -A, -B, -C, -D	275,591	30% [3]	Deep Offshore	Nigeria	None Outstanding
EEZ Block 5	*Pargo, Seriola, Atum, Espadim, Cavala, Barracuda	702,768	100% [5]	Ultra Deep Offshore	São Tomé & Príncipe	4 year work programme comprising seismic acquisition and studies

Notes:

1. Gross Area is 100% area of License.
2. OER holds 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 holds 81.50% equity interest in Equator Exploration Limited, which holds a 30% Working Interest in OPL 321 and OPL 323.
4. OER holds 81.50% equity interest in Equator Exploration Limited, which holds a 100% Working Interest in EEZ Block 5.

Item 6.3 Forward Contracts

OER is not a party to any forward contracts which are not disclosed as financial instruments in accordance with Sections 3280 and 3861 of the CICA Handbook.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

License	OML 125	Ebendo (OML 56)	OMLs 60-63	Qua Ibo (OML 13)	Total
Gross Wells [1]	15	8	392	4	419
OER WI	15%	45%	20%	40%	
Net Wells [2]	2.25	3.60	78.40	1.60	85.85
Abandonment Costs					
Discount Rate 0%	40.34	47.25	368.39	14.63	470.61
Discount Rate 10%	29.34	16.56	45.50	3.18	94.58
Proportion Not Deducted in Calculating Future Net Revenue	-	-	-	-	-
Proportion Expected to pay in next 3 financial years (from reference date to end 2018)	56%	-	-	-	-
Amount Expected to pay in next 3 financial years (from reference date to end 2018)	22.41	0.00	0.00	0.00	22.41

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 working interest).
3. All prices are in Real Term (December 31, 2015).
4. Abandonment costs are for Reserves related projects only and include the costs of future wells. Costs associated with Contingent resource activities are reported separately.
5. Numbers may not add up due to rounding.

Item 6.5 Tax Horizon

OER was required to pay income taxes for its most recently completed financial year on all its assets. Details of taxes paid are disclosed in OER's Financial Statement for its most recently completed financial year.

Pioneer Status is a tax holiday granted to qualified (or eligible) industries anywhere in Nigeria. The grant of pioneer status to a company in Nigeria is aimed at enabling such a company operating within the pioneer industry to make significant capital expenditure and a reasonable level of return of profit within its formative years without having to pay company taxes. For the evaluation of future net revenue associated with reserves at an effective date of December 31, 2015, pioneer status is applied to Oando Oil Limited (OOL), Oando Petroleum Development Company (OPDC) Limited, and Oando Qua Ibo Limited (OQIL). The pioneer status for OOL, which holds a 20% interest in OMLs 60, 61, 62, and 63, only applies to the gas, and was effective on Jan 1, 2014 and is valid for three years. The pioneer status for OPDC Limited, which holds a 45% interest in Ebendo field had an effective date of July 1, 2010 and was valid for five years and ended on June 30, 2015. The pioneer status for OQIL, which holds a 40% interest in Qua Ibo was effective on February 1, 2015 and is valid for three years.

Item 6.6 Costs Incurred

The following costs were incurred by OER for the 12 months ended December 31, 2015. All properties are based in Nigeria and values reflect OER company gross.

License	OER Company Gross				
	Acquisition Costs		Exploration Costs		Development Costs [3]
	Proved [1]	Unproved [2]	Proved [1]	Unproved [2]	
	(mm$)	(mm$)	(mm$)	(mm$)	(mm$)
Ebendo (OML 56)	-	-	0.4	-	2.49
Akepo (OML 90)	-	-	-	-	0.11
Qua Ibo (OML 13)	-	-	-	-	3.75
OML 60, 61, 62, & 63	-	-	1.98	-	39.33
OML 122	-	-	-	-	-
OML 125	-	-	0.37	-	36.01
OML 131	-	-	-	1.13	-
OML 134	-	-	1.04	-	-
OML 145	-	-	-	0.12	-
OPL 321	-	-	-	-	-
OPL 323	-	-	-	-	-
EEZ Block 5	-	-	-	1.68	-
OER Total	**0.0**	**0.0**	**3.79**	**2.93**	**81.69**

Notes:
1. Proved property - a property or part of a property to which reserves have been specifically attributed.
2. Unproved property - a property or part of a property to which no reserves have been specifically attributed.
3. Development costs are capital expenditures unrelated to exploration incurred in last financial year for oil and gas development activities.

Across all OER assets, a total of US$ 88.41 million was incurred on exploration and development capital expenditures in 2015 for drilling and completion activities, construction of gathering systems and facilities, and capital maintenance projects.

Item 6.7 Exploration & Development Activities

Exploration and Development Wells in 2015

Activity Type	Gross	Net [2]
Exploration		
Dry Holes	-	-
Oil Wells	-	-
Gas Wells	-	-
Total Exploration Wells	**0**	**0.00**
Development		
Dry Holes	-	-
Oil Wells (incl. sidetracks)	-	-
Gas Wells (incl. sidetracks) [1]	0.45	0.09
Total Development Wells	**0.45**	**0.09**
Workovers		
Dry Holes	-	-
Oil Wells (incl. sidetracks)	-	-
Gas Wells (incl. sidetracks)	-	-
Total Workovers	-	-

Notes:
1. Value shown represents proportion of well drilled and completed in 2015, based on time spent.
2. Net wells are equal to company gross wells. Net wells are equity weighted based on applicable properties within each category.
3. Individual numbers may not add up due to rounding.

Exploration and development activities undertaken in 2015 are summarized below by OER properties.

Akepo

No exploration or development wells were drilled on Akepo during 2015.

Ebendo

No exploration wells were drilled on Ebendo during 2015.

Qua Ibo

No exploration wells were drilled on Qua Ibo during 2015.

OML 60, 61, and 62

No exploration or development wells were drilled on OML 60, 61, and 62 in 2015.

OML 63

No exploration wells were drilled on OML 63 in 2015. One development well in OML 63, Ogbainbiri Deep 4, was spudded in 2014 but concluded and completed in 2015.

OML 122

No exploration or development activities were undertaken for this License during 2015.

OML 125

No exploration or development wells were drilled on OML 60 in 2015.

OML 131

No exploration or development activities were undertaken for this License during 2015.

OML 134

No further exploration or appraisal work was undertaken in OML 134 field during 2015.

OML 145

No exploration or development activities were undertaken for this License during 2015.

OPL 321

No exploration or development activities were undertaken for this License during 2014.

OPL 323

No exploration or development activities were undertaken for this License during 2015.

EEZ Block 5

No exploration or development wells were drilled on EEZ Block 5 in 2015**.**

Future Exploration Activities

Akepo

Although one prospect has been identified, there are no plans for further exploration activity on this License at this time.

Ebendo

Further development drilling on Ebendo will include an element of exploration of the shallower reservoirs by two wells, Ebendo 8 and Ebendo 10, which are anticipated to explore the IVa to X sands. The wells are scheduled to be drilled in 2017 and 2018.

There are studies ongoing to evaluate and drill an exploration well in the Ebendo North prospect (Ebendo 9) in 2017.

Qua Ibo

Undeveloped oil reserves are associated with the C4 reservoir, which is the target of a three-well development plan. The wells are scheduled to be drilled in 2018 and 2019.

In order to better understand the geological structure of the Qua Ibo field, seismic acquisition is to be undertaken on the field during 2017.

OML 60

There are no exploration and appraisal wells planned in this License, based on the drilling sequence as of December 31, 2015.

OML 61

There are no exploration and appraisal wells planned in this License, based on the drilling sequence as of December 31, 2015.

OML 62

There are two exploration and appraisal wells planned in this License, based on the drilling sequence as of December 31, 2015. Two wells are to be drilled, one in 2021 and one in 2022.

OML 63

There are five exploration and appraisal wells planned in this License, based on the drilling sequence as of December 31, 2015. One well is to be drilled in 2018, three in 2020 and one in 2022.

OML 122

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

OML 125

Aboribo and Abo Deep prospects have been identified as upcoming exploration targets, however no firm plan currently exists to drill an exploration well.

OML 131

Although there are several prospects identified, there are no firm plans for further exploration activity on this License at this time.

OML 134

Although there are several prospects identified, there are no plans for further exploration activity on this License at this time.

OML 145

Although there are several prospects identified, there are plans to reprocess existing 3 dimensional (3D) seismic data in 2016/2017 in order to properly image deeper targets for the possibility of identifying new leads and prospects.

OPL 321

Although there is one significant prospect identified, there are no plans for exploration activity on this License until the resolution of commercial disputes between the partners.

OPL 323

Although there are several prospects identified, there are no plans for exploration activity on this License until the resolution of commercial disputes between the partners.

EEZ Block 5

Although there are several prospects identified with 2 dimensional (2D) seismic data, there are plans to interpret the newly acquired 3D seismic data in 2016 with an exploration planned for 2017.

Future Development Activities

Akepo

Plans for standalone development using a leased floating production facility have been aborted due to its sub-economic outlook. The current development concept involves a tie-back to a nearby facility (Britannia-U FPSO). Technical studies and negotiations are ongoing with expectation of commencing production in 2018.

Ebendo

There are plans for two further production wells at Ebendo – Ebendo-8 and Ebendo-10. Ebendo-8 is proposed to target the XVI and XVIIa reservoir sands, while Ebendo-10 is proposed to target the XIIc, XIII and XVII sands. The wells are scheduled to be drilled in 2017 and 2018 and will commence production through existing facilities right after completion.

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.

Qua Ibo

There are plans for three further production wells at Qua Ibo, which are proposed to target the C4 reservoir. The wells are scheduled to be drilled in 2018 and 2019 and will commence production through existing facilities right after completion.

OML 60

There are 22 wells planned for future development in this License area, based on the drilling sequence as of December 31, 2015. The wells are to be drilled in six fields from 2018 to 2037. All wells are expected to commence production through existing facilities right after completion.

OML 61

There are 82 wells planned for future development in this License, based on the drilling sequence as of December 31, 2015. The wells are to be drilled in twelve fields from 2016 to 2037. All wells are expected to commence production through existing facilities right after completion

OML 62

There are 7 wells planned for future development in this License, based on the drilling sequence as of December 31, 2015. The wells are to be drilled in two fields from 2019 to 2035. All wells are expected to commence production through existing facilities right after completion

OML 63

There are 17 wells planned for future development in this License, based on the drilling sequence as of December 31, 2015. The wells are to be drilled in eight fields from 2019 to 2037. All wells are expected to commence production through existing facilities right after completion.

OML 122

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

OML 125

There are no plans for future development activity on this License.

OML 131

The Chota discovery is being unitized with Shell's Bolia field in OML 135. Development studies are ongoing for Bolia-Chota, which Shell operates on behalf of the unit. There are plans for a joint development with the Shell operated Nwa-Doro fields (OML 135 and OML 129) using an FPSO with multiple producers and injectors (gas or water) on the Bolia-Chota unit. There are several options being evaluated for commercialization of gas from these assets, including gas evacuation to nearby facilities. Project execution is expected to start after 2020 with first oil expected around 2025.

OML 134

Further appraisal of Oberan and Mindiogboro is needed before these fields can be developed. There are no firm plans for any appraisal or development at this time.

OML 145

Development plans are being progressed for the Uge field in OML 145 by operator ExxonMobil. The plan involves an FPSO, nine producers and nine injectors. Project execution has been delayed to 2018 with production expected to commence in 2025.

OPL 321

This License is not yet at the development stage.

OPL 323

This License is not yet at the development stage.

EEZ Block 5

This License is not yet at the development stage.

Item 6.8 Future Production Estimates

The volume of production estimated for the first year reflected in the estimates of company gross share proved and probable reserves are summarized in table below. Realization of future production estimates is dependent on the execution of the work program underpinning the evaluation. All future production pertains to assets in Nigeria.

		2016	
Product Type		**Proved**	**Probable**
Light and Medium Crude Oil			
OMLs 60, 61, 62, & 63	(bbls/d)	17,370	1,027
OML 125	(bbls/d)	3,673	418
Ebendo (OML 56)	(bbls/d)	2,707	175
Qua Ibo (OML 13)	(bbls/d)	518	74
Total	**(bbls/d)**	**24,268**	**1,695**
Conventional Natural Gas (Sales)			
OMLs 60, 61, 62, & 63	(Mscf/d)	168,027	7,137
OML 125	(Mscf/d)	0	0
Ebendo (OML 56)	(Mscf/d)	9,192	88
Qua Ibo (OML 13)	(Mscf/d)	0	0
Total	**(Mscf/d)**	**177,219**	**7,225**
Natural Gas Liquids			
OMLs 60, 61, 62, & 63	(bbls/d)	3,696	96
OML 125	(bbls/d)	0	0
Ebendo (OML 56)	(bbls/d)	0	0
Qua Ibo (OML 13)	(bbls/d)	0	0
Total	**(bbls/d)**	**3,696**	**96**
Oil Equivalent			
OMLs 60, 61, 62, & 63	(boe/d)	49,070	2,313
OML 125	(boe/d)	3,673	418
Ebendo (OML 56)	(boe/d)	4,239	190
Qua Ibo (OML 13)	(boe/d)	518	74
Total	**(boe/d)**	**57,500**	**2,995**

Notes:
1. All values presented in this table are Company Gross share.
2. Liquid production volumes are sales figures after deduction of losses and shrinkage, but before deduction of royalty.
3. Natural gas production includes both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, flaring, losses and shrinkage, but before deduction of royalty.
4. Natural gas has 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. Numbers may not add up due to rounding.

Important disclosure pertaining to reported future production estimates

The volume of production estimated for 2016 presented under item 6.8 originates from D&M's independent reserves evaluation, which was based on data provided to D&M by OER up until December 2015. The drilling program provided by OER in November 2015 included a multiple rig drilling and workover program from 2016 through 2025. The drilling program was revised in December 2015 by D&M, which included a reduced number of rigs, starting with two wells in 2016, then drilling six wells per year from 2017 through 2037 and completing six workovers per year from 2016 through 2027. These plans were reviewed and supported by OER Management.

Item 6.9 Production History

In 2015 the average daily production (Company Gross) from OER's producing fields is shown in the table below. OER's Company Gross average 2015 production rate was 20,740 bbls/d of oil, 162,067 Mscf/d of sales gas, and 3,332 bbls/d of natural gas liquids.

		Three Months Ended				
Product Type		**31-Mar-15**	**30-Jun-15**	**30-Sep-15**	**31-Dec-15**	**LTM Total**
Light and Medium Crude Oil						
OMLs 60, 61, 62, & 63	(bbls/d)	15,593	16,443	16,094	14,127	15,561
OML 125	(bbls/d)	2,767	2,969	3,839	3,663	3,313
Ebendo (OML 56)	(bbls/d)	2,021	1,319	1,907	1,580	1,706
Qua-Ibo (OML 13)	(bbls/d)	320	957	935	869	772
Total	**(bbls/d)**	**20,702**	**21,687**	**22,775**	**20,239**	**21,353**
Conventional Natural Gas (Sales)						
OMLs 60, 61, 62, & 63	(Mscf/d)	167,179	173,244	154,134	145,861	160,030
OML 125	(Mscf/d)	0	0	0	0	0
Ebendo (OML 56)	(Mscf/d)	11,662	8,261	13,782	10,417	11,034
Qua-Ibo (OML 13)	(Mscf/d)	0	0	0	0	0
Total	**(Mscf/d)**	**178,841**	**181,505**	**167,915**	**156,278**	**171,064**
Natural Gas Liquids						
OMLs 60, 61, 62, & 63	(bbls/d)	3,745	3,725	2,605	3,265	3,332
OML 125	(bbls/d)	0	0	0	0	0
Ebendo (OML 56)	(bbls/d)	0	0	0	0	0
Qua-Ibo (OML 13)	(bbls/d)	0	0	0	0	0
Total	**(bbls/d)**	**3,745**	**3,725**	**2,605**	**3,265**	**3,332**
Oil Equivalent						
OMLs 60, 61, 62, & 63	(boe/d)	47,201	49,042	44,388	41,702	45,565
OML 125	(boe/d)	2,767	2,969	3,839	3,663	3,313
Ebendo (OML 56)	(boe/d)	3,965	2,695	4,204	3,316	3,545
Qua-Ibo (OML 13)	(boe/d)	320	957	935	869	772
Total	**(boe/d)**	**54,253**	**55,663**	**53,366**	**49,550**	**53,196**

Notes:
1. All values presented in this table are Company Gross.
2. Liquid production volumes are sales figures after deduction of losses and shrinkage, but before deduction of royalty.
3. Natural gas production includes both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, flaring, losses and shrinkage, but before deduction of royalty.
4. Natural gas has 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. LTM means last twelve months.
6. Numbers may not add up due to rounding.

The following table sets forth information in respect of 2015 volumes produced and sold.

Total Company- 2015 Production, Operating Expenses, Royalties, and Netback

	Light & Medium Oil (M bbls)	Conventional Natural Gas (MMscf)	Natural Gas Liquids (Mbbls)	Oil Equivalent [1] (Mboe)
2015 Net Sales Volumes	7,761	58,411	1,216	18,712
Average price unit volume received (US$)	51.07	1.68	10.49	27.10
Royalties paid per unit volume (US$)	8.13	0.12	0.73	3.80
Production costs per unit volume (US$) [2]				11.99
Netback per unit volume before taxes (US$)				11.31

Notes:

1. 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.
2. Allocation of production costs is not easily attributable between multiple product types due to nature of operations. Resulting netbacks are thus disclosed on the basis of units of equivalency between oil and gas.
3. Liquid production volumes are sales figures after deduction of losses and shrinkage, but before deduction of royalty.
4. Natural gas production includes both associated and non-associated gas (combined) and are sales quantities after deduction of gas for own use, flaring, losses and shrinkage, but before deduction of royalty.
5. Numbers may not add up due to rounding.

Per unit volume, netbacks have been calculated by subtracting royalties and production (operating) costs from revenues. Where revenues per unit volume equals average price received for a given product type over the financial year.

APPENDIX

OER has chosen to report resources other than reserves, inclusive of discovered contingent resources and undiscovered prospective resources.

PART 7: OPTIONAL DISCLOSURE OF CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA

Item 7.1 Contingent Resources

There is uncertainty 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 herein have been presented before and after adjustment for risk based on the estimated probability of development. There is no certainty as to the timing of any such development.

Contingent resources hereby disclosed have been rigorously evaluated using standard industry practices. All contingent resources reported herein have been subject to independent evaluation by qualified assessors, DeGolyer and MacNaughton (D&M).

Specific Definitions Pertaining to Contingent Resources

Contingent resources are sub-classified according to project maturity as follows:

> ***Development pending***, where resolution of the final conditions for development is being actively pursued (high chance of development). If a project cannot be developed within a reasonable timeframe consideration should be given to classification as development on hold.
>
> ***Development on hold,*** where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.
>
> ***Development unclarified,*** when the evaluation is incomplete, and there is ongoing activity to resolve any risks or uncertainties.
>
> ***Development not viable***, where no further data acquisition or evaluation is currently planned, and hence, there is a low chance of development.

For ***Resources other than Reserves***, the degree to which a project scenario has been developed can range from very basic with limited data and analysis, to a fully developed analysis that is suitable for a final project decision. The three levels of development of a project scenario are described below when conducting an evaluation and reporting its results:

> ***Development study*** is the most detailed step in the development of a project evaluation scenario. It is based on detailed geological and engineering study and economic analysis of information on the specific project, and provides sufficient information for the creation of a development plan, from which a development decision can be made.
>
> ***Pre-development study*** is an intermediate step in the development of a project evaluation scenario. The amount of information that is available for the reservoir of interest is greater than for a conceptual study. In particular, the petroleum initially-in-place has been reasonably well defined and the remaining uncertainty lies largely in the recovery factor and the economic viability. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision or for seeking outside major financing.
>
> ***Conceptual (scoping) study*** is the initial stage of the development of a project scenario with limited detail and is typically based on limited information.

Contingent resources in respect of oil and gas for OER's interests are listed below. 1C, 2C and 3C refer to the three probability categories of Low, Best and High cases as defined in the COGE Handbook. The estimates are reported as unrisked and risked gross and company gross quantities only; net numbers are not included here as not all assets have been economically evaluated (required for entitlement calculations), and thus, any net quantities could be misleading. However, net quantities will be equal-to or less-than the company gross quantities.

Summary of Unrisked Oil, NGL and Gas Contingent Resources as of December 31, 2015 based on Forecast Prices and Costs

		Light and Medium Oil		Natural Gas Liquids		Conventional Natural Gas		Oil Equivalent[1]	
Contingent Resources Project Maturity Sub-Class	**License**	**Gross[2] (Mbbl)**	**Comp Gross[3] (Mbbl)**	**Gross[2] (Mbbl)**	**Comp Gross[3] (Mbbl)**	**Gross[2] (MMscf)**	**Comp Gross[3] (MMscf)**	**Gross[2] (Mboe)**	**Comp Gross[3] (Mboe)**
Low (1C)									
Development Unclarified	Akepo (OML 90)	4,436	1,774	0	0	2,098	839	4,786	1,914
Development Unclarified	Ebendo (OML56)	1,062	478	0	0	2,943	1,324	1,553	699
Development Unclarified	Qua Ibo (OML 13)	0	0	0	0	3,901	1,560	650	260
Development Unclarified	OMLs 60-63	39,387	7,878	0	0	684,281	136,856	153,434	30,687
Development on Hold	OML 122	10,015	501	0	0	268,250	33,531	54,723	6,090
Development not Viable	OML 125	2,645	292	0	0	2,462	273	3,055	338
Development Unclarified	OML 131	10,770	10,770	0	0	116,662	116,662	30,214	30,214
Development not Viable	OML 134	1,173	176	0	0	6,074	911	2,185	328
Development Unclarified	OML 145	14,931	3,143	0	0	52,748	11,103	23,722	4,994
	Total OER	**84,419**	**25,012**	**0**	**0**	**1,139,419**	**303,059**	**274,322**	**75,522**
Best (2C)									
Development Unclarified	Akepo (OML 90)	8,902	3,561	0	0	4,052	1,621	9,577	3,831
Development Unclarified	Ebendo (OML56)	2,067	930	0	0	5,727	2,577	3,022	1,360
Development Unclarified	Qua Ibo (OML 13)	0	0	0	0	4,161	1,664	694	277
Development Unclarified	OMLs 60-63	64,737	12,949	20,760	4,151	1,831,906	366,384	390,815	78,164
Development on Hold	OML 122	14,021	701	0	0	334,082	41,760	69,701	7,661
Development not Viable	OML 125	8,606	953	0	0	8,695	962	10,055	1,113
Development Unclarified	OML 131	31,915	31,915	0	0	238,298	238,298	71,631	71,631
Development not Viable	OML 134	8,374	1,256	0	0	14,443	2,166	10,781	1,617
Development Unclarified	OML 145	169,802	35,744	0	0	197,497	41,573	202,718	42,673
	Total OER	**308,424**	**88,009**	**20,760**	**4,151**	**2,638,861**	**697,005**	**768,994**	**208,328**
High (3C)									
Development Unclarified	Akepo (OML 90)	11,560	4,624	0	0	5,238	2,095	12,433	4,973
Development Unclarified	Ebendo (OML56)	2,663	1,198	0	0	7,379	3,321	3,893	1,752
Development Unclarified	Qua Ibo (OML 13)	0	0	0	0	4,422	1,769	737	295
Development Unclarified	OMLs 60-63	103,527	20,703	70,960	14,192	3,954,285	790,856	833,535	166,704
Development on Hold	OML 122	18,027	901	0	0	356,998	44,625	77,527	8,339
Development not Viable	OML 125	22,220	2,459	0	0	20,612	2,281	25,655	2,839
Development Unclarified	OML 131	51,260	51,260	0	0	471,576	471,576	129,856	129,856
Development not Viable	OML 134	12,804	1,921	0	0	36,685	5,502	18,918	2,838
Development Unclarified	OML 145	314,803	66,267	0	0	345,509	72,730	372,388	78,389
	Total OER	**536,864**	**149,333**	**70,960**	**14,192**	**5,202,704**	**1,394,755**	**1,474,941**	**395,984**

Notes:

1. Natural gas has 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.
2. Gross - 100% of contingent resources.
3. Company Gross - the product of OER's working interest and gross quantities.
4. 3C is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. There is a 10% probability that the quantities actually recovered will equal or exceed the 3C resource estimate.
5. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.
6. Includes properties that are sub-economic at current forecast costs and prices.
7. Includes properties that were not economically evaluated due to project immaturity.
8. Numbers may not add up due to rounding.

Summary of Risked Oil, NGL and Gas Contingent Resources as of December 31, 2015 based on Forecast Prices and Costs

Contingent Resources Project Maturity Sub-Class	License	Chance of Development[2]	Light and Medium Oil Gross[3] (Mbbl)	Light and Medium Oil Comp Gross[4] (Mbbl)	NGL Gross[3] (Mbbl)	NGL Comp Gross[4] (Mbbl)	Conventional Natural Gas Gross[3] (MMscf)	Conventional Natural Gas Comp Gross[4] (MMscf)	Oil Equivalent[1] Gross[3] (Mboe)	Oil Equivalent[1] Comp Gross[4] (Mboe)
Low (1C)										
Development Unclarified	Akepo (OML 90)	69%	3,061	1,224	0	0	1,448	579	3,302	1,321
Development Unclarified	Ebendo (OML56)	74%	786	354	0	0	2,178	980	1,149	517
Development Unclarified	Qua Ibo (OML 13)	59%	0	0	0	0	2,302	920	384	153
Development Unclarified	OMLs 60-63	76%	29,934	5,987	0	0	520,054	104,011	116,610	23,322
Development on Hold	OML 122	63%	6,309	316	0	0	168,998	21,125	34,475	3,837
Development not Viable	OML 125	57%	1,508	166	0	0	1,403	156	1,742	192
Development Unclarified	OML 131	58%	6,247	6,247	0	0	67,664	67,664	17,524	17,524
Development not Viable	OML 134	53%	622	93	0	0	3,219	483	1,159	174
Development Unclarified	OML 145	57%	8,511	1,792	0	0	30,066	6,329	13,522	2,847
	Total OER		**56,978**	**16,179**	**0**	**0**	**797,332**	**202,247**	**189,867**	**49,887**
Best (2C)										
Development Unclarified	Akepo (OML 90)	69%	6,142	2,457	0	0	2,796	1,118	6,608	2,643
Development Unclarified	Ebendo (OML56)	74%	1,530	688	0	0	4,238	1,907	2,236	1,006
Development Unclarified	Qua Ibo (OML 13)	59%	0	0	0	0	2,455	982	409	164
Development Unclarified	OMLs 60-63	76%	49,200	9,841	15,778	3,155	1,392,249	278,452	297,020	59,405
Development on Hold	OML 122	63%	8,833	442	0	0	210,472	26,309	43,912	4,827
Development not Viable	OML 125	57%	4,905	543	0	0	4,956	548	5,731	634
Development Unclarified	OML 131	58%	18,511	18,511	0	0	138,213	138,213	41,547	41,547
Development not Viable	OML 134	53%	4,438	666	0	0	7,655	1,148	5,714	857
Development Unclarified	OML 145	57%	96,787	20,374	0	0	112,573	23,697	115,549	24,324
	Total OER		**190,346**	**53,522**	**15,778**	**3,155**	**1,875,607**	**472,374**	**518,725**	**135,406**
High (3C)[5]										
Development Unclarified	Akepo (OML 90)	69%	7,976	3,191	0	0	3,614	1,446	8,578	3,432
Development Unclarified	Ebendo (OML56)	74%	1,971	887	0	0	5,460	2,458	2,881	1,297
Development Unclarified	Qua Ibo (OML 13)	59%	0	0	0	0	2,609	1,044	435	174
Development on Hold	OMLs 60-63	76%	78,681	15,734	53,930	10,786	3,005,257	601,051	633,487	126,695
Development not Viable	OML 122	63%	11,357	568	0	0	224,909	28,114	48,842	5,254
Development Unclarified	OML 125	57%	12,665	1,402	0	0	11,749	1,300	14,623	1,619
Development not Viable	OML 131	58%	29,731	29,731	0	0	273,514	273,514	75,317	75,317
Development Unclarified	OML 134	53%	6,786	1,018	0	0	19,443	2,916	10,027	1,504
Development Unclarified	OML 145	57%	179,438	37,772	0	0	196,940	41,456	212,261	44,681
	Total OER		**328,605**	**90,303**	**53,930**	**10,786**	**3,743,495**	**953,299**	**1,006,451**	**259,972**

Notes:

1. Natural gas has 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.
2. Chance of development stated in the table represents the volume-weighted average for resource entities within each License.
3. Gross - 100% of contingent resources.
4. Company Gross-– the product of OER's working interest and gross quantities.
5. 3C is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. There is a 10% probability that the quantities actually recovered will equal or exceed the 3C resource estimate.
6. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.
7. Includes properties that are sub-economic at current forecast costs and prices.
8. Includes properties that were not economically evaluated due to project immaturity.
9. Numbers may not add up due to rounding.

The chance of development for contingent resources was quantified by identifying and independently expressing confidence in four critical parameters:

- Gross Risked Resource Size:
  - Assuming that all other parameters are kept constant, it is deemed that assets with larger estimates of Best contingent resources (2C) are more likely to be developed.
- Location (Terrain):
  - Assuming that all other parameters are kept constant, it is deemed that assets on land are more likely to be developed than those offshore and that chance of development will decrease with water depth.
- Proximity to existing processing and transportation infrastructure:
  - Assuming that all other parameters are kept constant, it is deemed that assets closer to existing facilities are more likely to be developed.

- Maturity of development:
    - Assuming that all other parameters are kept constant, it is deemed that assets closer to final investment decision are more likely to be developed.

The parameters were weighted to apply adjudged relative importance between them. The Gross Risked Resource Size was weighted above location, which was weighted above proximity to facilities, which in turn was weighted above development maturity. Overall chance of development for each asset was then quantified as the product of the weighted probabilities of the four parameters.

The following paragraphs discuss the future classification of OER's contingent resources as petroleum reserves:

Akepo (OML 90)

Akepo-1ST has been completed on the C1, D1 and D6 reservoirs which have been reclassified from reserves to contingent resources unfavorable project economics. Recoverable resources in levels C5, D3, D4, D5a, D5b and E1 are also booked as contingent resources.

The development option currently being pursued is a single well development, using the suspended producer Akepo-1ST and tying back to a neighboring facility (Britannia-U FPSO), for which negotiations are ongoing.

Contingent resources in Akepo are based on Conceptual Studies and classed as *Development Unclarified*, with a chance of development of 69%. Evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties. OER's working interest of capital cost required to achieve commercial production is estimated to be U.S.$ 19.7 million, for estimated start-up in 2018.

Future classification as reserves is contingent upon:

- Further technical studies and subsequent approval of an updated development plan for the field
- Improved economic conditions to make development viable, that is, a significant rise in oil price or a reduction in development costs

Ebendo (OML 56)

The contingent resources are located in the XXIVa and XXVI reservoirs. These reservoirs have been discovered by existing wells on the field but studies are still ongoing to determine commerciality of development by one dual string producer, Ebendo 10.

Contingent Resources in Ebendo are based on Conceptual Studies and classed as *Development Unclarified*, with a chance of development of 74%. Evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties. OER's working interest of costs required to achieve commercial production is estimated to be U.S.$ 9.0 million, for estimated start-up in 2017.

Future classification as reserves is contingent upon:

- Further technical studies and subsequent approval of an updated development plan for the field
- Demonstration of economic viability

Qua Ibo (OML 13)

Contingent Resources here pertain to solution gas from the developed reservoirs, C4 and D5.

Contingent Resources in Qua Ibo are based on Conceptual Studies and classed as *Development Unclarified*, with a chance of development of 59%. Evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties. The most mature concept involves gas compression with pipeline transportation and OER's working interest of capital expenditure is estimated to be U.S.$ 14.4 million, for estimated start-up in 2018.

Future classification as reserves is contingent upon:

- Further engineering studies
- Demonstration of economic viability of concepts being considered

OMLs 60, 61, 62 and 63

NAOC JV contains contingent resources with respect to oil and gas in the Alinso, Ashaka, Beniboye, Ebocha, Idu, Mbede, Nimbe South, Samabri-Biseni and Taylor Creek fields. These fields contain discovered reservoirs that are yet to be developed or redeveloped, which are excluded from the operator's long term work program. In addition, there are oil, NGL and gas contingent resources which constitute technically recoverable, non-commercialized oil, NGL and gas volumes before and after the economic limit.

Given that these resources are in close proximity to a developed property, the average chance of development for all resource entities within these blocks is quantified as 76%. Nonetheless, the necessary technical and commercial studies required to mature these opportunities are immature, hence they have been classed as *Development Unclarified.* Associated development costs have not been determined and estimated start-up is expected to be beyond 2024.

Future classification of these resources as reserves is contingent upon:

- Further appraisal and development studies on Alinso, Ashaka, Beniboye, Ebocha, Idu, Mbede, Nimbe South, Samabri-Biseni and Taylor Creek reservoirs which contain contingent resources
- Improved economic conditions to defer economic limit
- Reservoir and operational management of gas resources to avoid over production gas beyond sales commitments
- Securing commercial arrangements for uncommitted gas volumes

OML 122

Contingent resources reported for OML 122 are for the Bilabri field only, and relate to gas and oil in the C1 and C2 reservoirs. 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 U.S.$ 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.

Contingent resources in Bilabri are based on Conceptual Studies and classed as *Development on Hold*, with a chance of development of 63%. Evaluations have been suspended due to the ongoing dispute. OER's working interest of capital cost required to achieve commercial production is estimated to be U.S.$ 185.5 million, for estimated start-up in 2018.

Future classification as reserves is contingent upon:

- Resolution of a commercial dispute between the partners
- Further technical studies to demonstrate that a commercial development is possible
- Preparation and approval of a field development plan

OML 125

Contingent resources booked for OML 125 relate to (i) future (separator) gas production; (ii) development of the AN03 reservoir of Abo main field; (iii) development of the A098, A188 and the B200 reservoirs of the Abo North field. These fields contain discovered reservoirs that are yet to be developed or redeveloped, which are excluded from the operator's long term work program.

Contingent Resources for the ANO3 upper and lower reservoirs of Abo main field are based on a Development Study and classed as *Development not Viable*, with a chance of development of 81%. Associated development costs have not been determined and estimated start-up is expected to be beyond 2019.

Future classification as reserves is contingent upon:

- Further engineering studies
- Demonstration of economic viability of concepts being considered

Contingent Resources for the A098, A188 and B200 reservoirs of the Abo North field are based on a Conceptual Study and classed as *Development not Viable*, with a chance of development of 31%. No further acquisition or evaluation is currently planned. Associated development costs have not been determined and estimated start-up is expected to be beyond 2019.

Future classification as reserves is contingent upon:

- Improved economic conditions to make development viable, that is, a significant rise in oil price or a reduction in development costs
- Discovery of a nearby field for joint development.

The volume-weighted chance of development for all contingent resources projects in OML 125 is 57%.

OML 131

Contingent resources for this block are located in (i) six discovered sands (CP505, CP565, CP641, CP750, CP759 and CP808) and (ii) two sands (CP505, CP701) of the Ebitemi field.

Bolia-Chota is a unitized asset across OMLs 131 and 135; the latter being operated by Shell. There is a pre-unit agreement granting OER 51% of the unit area. A major joint development is intended involving an FPSO and multiple wells. Studies are ongoing but are still conceptual and the project is classed as *Development Unclarified*, with a chance of development of 58%. OER's share of capital cost is estimated to be over U.S.$ 4 billion, and estimated start up is 2028.

Future classification as reserves is contingent upon:

- Further appraisal or studies to prove up more volume and reduce sub-surface uncertainty,
- Further studies to achieve most economically optimal development concept,
- Improved economic conditions to make development viable, that is, a significant rise in oil price or a reduction in development costs,
- Signing a formal unitization agreement,
- Preparation and approval of a field development plan.

The volume-weighted chance of development for all contingent resources projects in OML 131 is 58%.

OML 134

There are oil and gas contingent resources in reservoirs H350, H450, H560, H625 and H630 of the Oberan South structure as well as the H340, H350, H355 and H360 reservoirs of the Mindiogboro discovery.

Development plans are somewhat immature and studies are conceptual. The project is classed as *Development not Viable*, with a chance of development of 53%. The operator has communicated tentative plans to continue exploration and appraisal in this block. OER's working interest share of capital cost is estimated at U.S.$ 175.5 million.

Future classification as reserves is contingent upon:

- Further exploration and appraisal to prove up more volume and reduce sub-surface uncertainty
- Further engineering studies to achieve most economically optimal development concept
- Improved economic conditions to make development viable, that is, a significant rise in oil price or a reduction in development costs
- Preparation and approval of a field development plan

OML 145

Four discoveries in this License hold contingent resources: Uge, Uge-North, Nza and Orso. Of these, the Uge field is the largest and most progressed for development by ExxonMobil, the operator.

A number of development scenarios are being investigated for Uge, including a standalone FPSO and tie back to existing facility. Evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties. The project is classed as *Development Unclarified*, with a chance of development of 59%. OER's share of capital cost is estimated to be circa U.S.$ 1.6 billion for estimated start up in 2025.

Future classification as reserves is contingent upon:

- Further appraisal or studies to prove up more volume and reduce sub-surface uncertainty
- Further engineering studies to achieve most economically optimal development concept
- Improved economic conditions to make development viable, that is, a significant rise in oil price or a reduction in development costs
- Preparation and approval of a field development plan

The volume-weighted chance of development for all contingent resources projects in OML 145 is 57%.

Significant Factors or Uncertainties Affecting Contingent Resources Data

The process of estimating contingent resources is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from on-going appraisal activities and ongoing studies become available and as economic conditions impacting oil and gas prices and costs change. The contingent resources estimates contained herein are based on recent prices and economic conditions. As circumstances change and additional data become available, contingent resources estimates may be revised due to technical factors and/or commercial factors.

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 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:

- Upon finalization of unitization, OER's share in the Bolia-Chota unit area (OML 131/135) may change from the current value of 51%, which is based on the pre-unit agreement.
- There is additional uncertainty in oil-in-place for Bolia-Chota. Although reports and presentations noted that Bolia-4 (in Shell operated OML135) encountered oil, there was no log data available to verify this. Consequently, during the independent evaluation an oil leg was not attributed to the well area.

- The significant proportion of gas contingent resources in OMLs 60, 61, 62 and 63 is made up of late life associated gas production which is linked to cash flows economic for the oil stream. Therefore estimates of these contingent resources fluctuate with economic conditions.
- Qua-Ibo gas booked as contingent resources are associated and will deplete by flaring with oil production until solutions are in place for transportation and commercialization.
- 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.

Item 7.2 Prospective Resources

There is no certainty that it will be commercially viable to produce any portion of the prospective resources. The prospective resources have been risked for chance of geologic success (discovery), and have been presented before and after adjustment for risk based on the estimated probability 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 uncertainty 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.

Prospective resources hereby disclosed have been rigorously evaluated using standard industry practices. All prospective resources reported herein have been subject to independent evaluation by qualified assessors, DeGolyer and MacNaughton (D&M).

Specific Definitions Pertaining To Prospective Resources

Mean Estimate **-** In accordance with petroleum industry standards, the mean estimate is the probability-weighted average (expected value), which typically has a probability in the P45 to P15 range, depending on the variance of prospective resources volume or associated quantity. Therefore, the probability of a prospect or accumulation containing the probability-weighted average volume or greater is usually between 45 and 15 percent. The mean estimate is the preferred probabilistic estimate of resources volumes.

Best (Median) Estimate **-** The best (median) is the P50 quantity. P50 means that there is a 50-percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

The Probability Of Geologic Success - The probability of geologic success (Pg) is defined as the probability of discovering reservoirs that flow hydrocarbons at a measurable rate. The Pg is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is Pg. Pg is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). Consequently, the Pg is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.

The Threshold Economic Field Size **-** The threshold economic field size (TEFS) is the minimum amount of the producible petroleum required to recover the total capital and operating expenditure used to establish the potential accumulation as having a potential present worth at 10 percent equal to zero using the mid-price scenario.

Probability of Economic Success **-** The probability of economic success (Pe) is defined as the probability that a given discovery will be economically viable. It takes into account Pg, PTEFS, TEFS, capital costs, operating expenses, the proposed development plan, the economic model (discounted cash flow analyses), and other business and economic factors. P_e is calculated as follows:

$$P_e = P_g \text{ x } P_{TEFS}$$

For prospective resources, the 'Best' (P50) and Mean estimates prior to risking are summarized in the following tables. However, only the mean estimate after risking is shown. The mean estimate is the accepted industry standard for the proper probability-weighted average of results. When applying risk to probabilistic results, the risked mean is the only acceptable (according to statistical methods) representation of a risked value. Applying risk to any single point on the continuum of outcomes, including P50 (the 'Best') is incorrect and potentially misleading, according to accepted industry standards for application of statistical risk. As such, we have provided only the risked mean, as directed by accepted statistical methodology. The risked mean estimate is the result of truncation and adjustment

for TEFS and application of P_e. As stated in COGEH Section 2.8.2, the risked mean value may be reported as the 'Best' estimate risked prospective resources.

D&M evaluated a total of 54 prospects and leads within Licenses where OER holds an interest. The aforementioned are a combination of drill ready and low maturity prospects.

The following tables sets forth the Best and Mean estimates of unrisked prospective resources:

Summary of Unrisked Oil and Gas *Best* Estimate Prospective Resources as of December 31, 2015 based on Forecast Prices and Costs

Prospective Resources Category	License	Light and Medium Oil Gross[2] (Mbbl)	Light and Medium Oil Comp Gross[3] (Mbbl)	Conventional Natural Gas Gross[2] (MMscf)	Conventional Natural Gas Comp Gross[3] (MMscf)	Oil Equivalent[1] Gross[2] (Mboe)	Oil Equivalent[1] Comp Gross[3] (Mboe)
Best Estimate	Akepo (OML 90)	8,490	3,396	3,148	1,259	9,015	3,606
Best Estimate	Ebendo (OML56)	4,669	2,101	2,576	1,159	5,098	2,294
Best Estimate	OMLs 60-63	212,195	42,439	177,335	35,467	241,751	48,350
Best Estimate	OML 125	86,853	13,028	21,540	3,231	90,443	13,567
Best Estimate	OML 131	137,295	137,295	74,149	74,149	149,653	149,653
Best Estimate	OML 134	96,413	14,462	65,873	9,881	107,392	16,109
Best Estimate	OML 145	160,028	34,406	58,800	12,642	169,828	36,513
Best Estimate	OPL 321/323	2,411,490	723,447	1,058,973	317,692	2,587,986	776,396
Best Estimate	EEZ Block 5	1,163,734	1,163,734	636,373	636,373	1,269,796	1,269,796
	Total OER	**4,281,167**	**2,134,308**	**2,098,767**	**1,091,853**	**4,630,962**	**2,316,284**

Summary of Unrisked Oil and Gas *Mean* Estimate Prospective Resources as of December 31, 2015 based on Forecast Prices and Costs

Prospective Resources Category	License	Light and Medium Oil Gross[2] (Mbbl)	Light and Medium Oil Comp Gross[3] (Mbbl)	Conventional Natural Gas Gross[2] (MMscf)	Conventional Natural Gas Comp Gross[3] (MMscf)	Oil Equivalent[1] Gross[2] (Mboe)	Oil Equivalent[1] Comp Gross[3] (Mboe)
Mean Estimate	Akepo (OML 90)	8,645	3,458	3,210	1,284	9,180	3,672
Mean Estimate	Ebendo (OML56)	4,851	2,183	2,669	1,201	5,296	2,383
Mean Estimate	OMLs 60-63	226,020	45,204	188,385	37,677	257,418	51,484
Mean Estimate	OML 125	106,440	15,966	26,207	3,931	110,808	16,621
Mean Estimate	OML 131	152,113	152,113	82,550	82,550	165,871	165,871
Mean Estimate	OML 134	101,220	15,183	69,260	10,389	112,763	16,915
Mean Estimate	OML 145	174,409	37,498	64,805	13,933	185,210	39,820
Mean Estimate	OPL 321/323	2,566,417	769,925	1,132,067	339,620	2,755,094	826,528
Mean Estimate	EEZ Block 5	1,350,844	1,350,844	742,965	742,965	1,474,672	1,474,672
	Total OER	**4,690,959**	**2,392,374**	**2,312,117**	**1,233,550**	**5,076,312**	**2,597,966**

Notes:

1. Natural gas has 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.
2. Gross - 100% of prospective resources.
3. Company Gross - the product of OER's working interest and gross quantities.
4. Prospective resources carry discovery and development risks. There is uncertainty that it will be commercially viable to produce any portion of the resources. "Unrisked" in this table refers to resources before application of discovery or development risk.
5. Properties were not economically evaluated.
6. Numbers may not add up due to rounding.

The following tables set forth the Mean estimates of risked prospective resources, for chance of geological success and chance of economic success:

Summary of Partially Risked[1] Oil and Gas *Mean* Estimate Prospective Resources as of December 31, 2015 based on Forecast Prices and Costs

Prospective Resources Category	License	Chance of Geological Success (%)[3]	Light and Medium Oil Gross[4] (Mbbl)	Light and Medium Oil Comp Gross[3] (Mbbl)	Conventional Natural Gas Gross[4] (MMscf)	Conventional Natural Gas Comp Gross[3] (MMscf)	Oil Equivalent[2] Gross[4] (Mboe)	Oil Equivalent[2] Comp Gross[3] (Mboe)
Mean Estimate	Akepo (OML 90)	35.0%	3,025	1,210	1,123	449	3,212	1,285
Mean Estimate	Ebendo (OML56)	49.0%	2,378	1,070	1,307	588	2,596	1,168
Mean Estimate	OMLs 60-63	37.9%	85,680	17,136	70,585	14,117	97,444	19,489
Mean Estimate	OML 125	42.0%	44,707	6,706	11,000	1,650	46,540	6,981
Mean Estimate	OML 131	25.0%	38,028	38,028	20,638	20,638	41,468	41,468
Mean Estimate	OML 134	31.6%	31,913	4,787	22,213	3,332	35,616	5,342
Mean Estimate	OML 145	49.2%	85,712	18,428	31,972	6,874	91,040	19,574
Mean Estimate	OPL 321/323	23.9%	612,397	183,719	269,807	80,942	657,364	197,209
Mean Estimate	EEZ Block 5	26.1%	351,953	351,953	193,574	193,574	384,215	384,215
	Total OER		**1,255,792**	**623,037**	**622,218**	**322,164**	**1,359,495**	**676,731**

Summary of Risked[6] Oil and Gas *Mean* Estimate Prospective Resources as of December 31, 2015 based on Forecast Prices and Costs

Prospective Resources Category	License	Chance of Economic Success (%)[7]	Light and Medium Oil Gross[4] (Mbbl)	Light and Medium Oil Comp Gross[3] (Mbbl)	Conventional Natural Gas Gross[4] (MMscf)	Conventional Natural Gas Comp Gross[3] (MMscf)	Oil Equivalent[2] Gross[4] (Mboe)	Oil Equivalent[2] Comp Gross[3] (Mboe)
Mean Estimate	Akepo (OML 90)	n/a	0	0	0	0	0	0
Mean Estimate	Ebendo (OML56)	n/a	0	0	0	0	0	0
Mean Estimate	OMLs 60-63	25.8%	62,600	12,520	52,395	10,479	71,333	14,267
Mean Estimate	OML 125	14.3%	26,327	3,949	6,740	1,011	27,450	4,118
Mean Estimate	OML 131	22.4%	35,763	35,763	19,421	19,421	39,000	39,000
Mean Estimate	OML 134	18.5%	16,053	2,408	11,320	1,698	17,940	2,691
Mean Estimate	OML 145	35.0%	62,242	13,382	25,047	5,385	66,416	14,280
Mean Estimate	OPL 321/323	20.0%	547,323	164,197	244,073	73,222	588,002	176,401
Mean Estimate	EEZ Block 5	21.1%	291,419	291,419	160,226	160,226	318,123	318,123
	Total OER		**1,041,727**	**523,638**	**519,222**	**271,442**	**1,128,264**	**568,878**

Notes:

1. Partially risked in this sub-section of the table refers to risking for chance of discovery only (i.e. chance of geological success). Prospective resources in this sub-section of the table have not been risked for chance of development.
2. Natural gas has 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.
3. Chance of geological success is the chance of discovering reservoirs that flow hydrocarbons at a measurable rate. It has been used to represent the chance of discovery. Values stated are volume-weighted averages for resource entities within each License.
4. Gross - 100% of prospective resources.
5. Company Gross - the product of OER's working interest and gross quantities.
6. Risked in this sub-section of the table refers to risking for chance of commerciality (i.e. chance of discovering economic resources), which combines both discovery and development risks.
7. Chance of economic success is the chance that a given discovery will be economically viable. It has been used to represent the chance of commerciality, which combines both discovery and development risks. Values stated are volume-weighted averages for resource entities within each License.
8. Prospective resources carry discovery and development risks. There is uncertainty that it will be commercially viable to produce any portion of the resources. “Unrisked” in this table refers to resources before application of discovery or development risk.
9. Properties were not economically evaluated.
10. Numbers may not add up due to rounding.

The following paragraphs discuss the maturity of OER's prospective resources in respect of timing and chance of development:

Akepo (OML 90)

There are prospective resources in Akepo in 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.

Due to project immaturity the total cost to get to commercial production has not been estimated.

The prospect is not expected to be drilled within the next five years, and is not included as part of the Akepo marginal field License. Akepo North currently has no chance of economic success as it falls below the TEFS.

Ebendo (OML 56)

There is one prospect in OML 56, Ebendo North. This prospect is a fault dependent three-way dip closure north of the Ebendo field. Elements of risk include reservoir quality, trap and seal.

Due to project immaturity the total cost to get to commercial production has not been estimated, however the prospect is expected to be drilled within the next two years.

Ebendo North currently has no chance of economic success as it falls below the TEFS.

OML 61

There are a total of eight prospects in OML 61 (Ogbogene West Up-dip, Mbede Deep, Idu Deep, Samabri North, Ndoni Creek East, Ogbogene NE, Obiafu SW Deep, and Oshi Deep). These prospects are fault dependent three-way dip closures near or within currently productive fields. Elements of risk include reservoir quality, trap and seal.

Due to project immaturity the total cost required to get to commercial production has not yet been estimated.

These prospects are expected to be drilled in a few years with a chance of economic success as follows; the Ogbogene West Up-dip with a chance of economic success of 15%, the Idu Deep with a chance of economic success of 19%, the Ndoni Creek East with a chance of economic success of 19%, the Ogbogene NE structure with a chance of economic success of 35%, the Obiafu SW Deep with a chance of economic success of 18%, and the Oshi Deep prospect with a chance of economic success of 33%. The Mbede Deep and Samabri North currently have no chance of economic success as they fall below the TEFS.

OML 62

There are a total of four prospects in OML 62 (Grangbene Deep, Nikorogba Deep, Tuomo West Deep, and Okpokuno Deep). These prospects are a combination of fault dependent three-way dip closures and faulted anticlines. Elements of risk include reservoir quality, trap and seal.

Due to project immaturity the total cost required to get to commercial production has not yet been estimated.

The Grangbene Deep prospect is expected to be drilled in 2022 with a chance of economic success of 33%; the Tuomo West Deep prospect is expected to be drilled in 2023 with a chance of economic success of 27%, while the Okpokuno Deep is expected to be drilled in 2019 with a chance of economic success of 23%. The Nikorogba Deep currently has no chance of economic success as it falls below the TEFS.

OML 63

There are a total of four prospects in OML 63 (Ogbainbiri Deep, Ekedei Deep, Nimbe South Deep, and Itabala Deep). The prospects offset current productive fields and are a combination of fault dependent three-way dip closures and faulted anticlines. Elements of risk include reservoir quality, trap and seal.

Due to project immaturity total cost required to get to commercial production has not yet been estimated.

The Ogbainbiri Deep prospect is expected to be drilled in 2019 with a chance of economic success of 28%, the Ekedei Deep prospect is expected to be drilled in 2021 with a chance of economic success of 29%, the Nimbe South Deep prospect is expected to be drilled in 2021 with a chance of economic success of 9%, while the Itabala Deep prospect is not expected to be drilled within the next 8 years with a chance of economic success of 28%.

OML 125

There are a total of six prospects in OML 125 (Abo Intermediate, Abo South East, Abo North West, Ovoro Deep, Obra Deep, and Aboribo). Many of these prospects 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.

Due to project immaturity total cost required to get to commercial production has not yet been estimated.

These prospects are expected to be drilled in a few years with a chance of economic success as follows; Abo Intermediate 32%, Abo North West 7%, Ovoro Deep 7%, Obra Deep 7% and Aboribo 12%. The Abo South East currently has no chance of economic success as it falls below the TEFS.

OML 131

There are a total of two prospects in OML 131 (Pulolulu and East Chota). These prospects target analogous reservoirs to the discovered hydrocarbon accumulations at Chota and Bolia fields. Elements of risk include reservoir presence, trap and seal.

Due to project immaturity total cost required to get to commercial production has not yet been estimated.

The Pulolulu prospect has been given a chance of economic success of 22% and the East Chota prospect has been given a chance of economic success of 23%.

OML 134

In addition to the discoveries within OML 134, there are a total of six prospects (Oberan North, Oberan South East, Oberan North A, Oberan East A, Oberan East B, and Oberan East D). Many of these prospects are highly compartmentalized individual fault blocks.

Due to project immaturity, the total cost required to get to commercial production has not yet been estimated.

These prospects are not expected to be drilled within the next five years. The Oberan North has been given a chance of economic success of 41%, the Oberan South East 7%, and the Oberan East A 2%. The Oberan North A, Oberan East B and Oberan East D have no chance of economic success as they fall below the TEFS.

OML 145

In addition to the discoveries within OML 145, there are a total of six prospects (Ogazi Lead C, Uge Deep, Nza Deep, Ichokwu, Uge Fault Block B and Torotoro).

Due to project immaturity total cost required to get to commercial production has not yet been estimated.

These prospects are not expected to be drilled within the next five years. The Ogazi Lead C has been given a chance of economic success of 12%, the Uge Fault Block B has been given a chance of economic success of 66%

and the Torotoro has been given a chance of economic success of 6%. The Uge Deep, Nza Deep and Ichokwu have no chance of economic success as they fall below the TEFS.

OPL 321/323

There are eight prospects in OPL 321/323; Elephant, which is a large up-thrown, three-way fault closure against a south-east trending normal fault and is associated with a shale diaper, identified from seismic, and has a total of seven prospective reservoirs, Gorilla, a series of stacked turbidites in a south-east to north-west oriented sub-basin, Octopus (split into Octopus A, Octopus B, Octopus C and Octopus D), a highly fault segmented shale-cored anticline, and Lobster and Whale, which are adjacent anticlines separated by a structural syncline, interpreted to contain turbidite sequences.

Due to project immaturity total cost required to get to commercial production has not yet been estimated.

These prospects are not expected to be drilled within the next five years. The Gorilla, Lobster and Whale prospects have been given a chance of economic success of 22%, the Elephant prospect has been given a chance of economic success of 20%, the Octopus A has been given a chance of economic success of 14%, the Octopus B has been given a chance of economic success of 7%, the Octopus C has been given a chance of economic success of 15%, and the Octopus D has been given a chance of economic success of 3%.

EEZ Block 5

There are a total of six prospects EEZ Block 5 (Pargo, Seriola, Atum, Espadim, Cavala, and Barracuda).

Due to project immaturity total cost required to get to commercial production has not yet been estimated.

These prospects are not expected to be drilled within the next five years. The Pargo prospect has been given a chance of economic success of 24%, the Seriola prospect has been given a chance of economic success of 23%, the Atum prospect has been given a chance of economic success of 7%, and the Barracuda prospect has been given a chance of economic success of 22%. The Espadium and Cavala have no chance of economic success as they fall below the TEFS.

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

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

CANADIAN NATIONAL INSTRUMENT 51-101
FORM 51-101F2
REPORT ON RESERVES DATA, CONTINGENT RESOURCES DATA, AND PROSPECTIVE RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR

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

1. We have evaluated the Company's reserves data, contingent resources data, and prospective resources data as at December 31, 2015. The reserves data are estimates of the proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs. The contingent resources data and prospective resources data are risked estimates of volume.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following table sets forth the estimated future net revenue (before deduction of income taxes) in thousands of United States dollars (M U.S.$) attributed to proved-plus-probable reserves only, 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, 2015, and

identifies the respective portions thereof that we have evaluated and reported on to the Company's management and Reserves Committee of the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation	Location of Reserves	Net Present Value of Future Net Revenue (before Income Taxes, Discounted at 10 Percent)			
			Audited (M U.S.$)	Evaluated (M U.S.$)	Reviewed (M U.S.$)	Total (M U.S.$)
DeGolyer and MacNaughton	Report as of December 31, 2015 on Reserves and Associated Revenue and Contingent Resources attributable to Oando Energy Resources Inc. for Certain Properties in Nigeria with a preparation date of February 22, 2016	Nigeria	Not Applicable	3,166,352	Not Applicable	3,166,352

Note: In the Evaluation only Nigerian income taxes were considered. The before income taxes values shown are before Nigerian income taxes.

6. The following table sets forth the risked volume of contingent resources and prospective resources in thousands of barrels (Mbbl) and millions of cubic feet (MMcf) included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data and the prospective resources data thereof that we have evaluated for the year ending December 31, 2015, and reported on to the Company's management and Reserves Committee of the Company's board of directors:

Classification	Independent Reserves Evaluator	Location	Effective Date of Evaluation Report	Risked Volume	
				Oil (Mbbl)	Gas (MMcf)
Prospective Resources	DeGolyer and MacNaughton	Nigeria	December 31, 2015	523,362	271,312
Contingent Resources (2C)	DeGolyer and MacNaughton	Nigeria	December 31, 2015	56,677	472,374

Note: The risked prospective resources reflect the mean estimate, which is a result of truncation and adjustment for the threshold economic field size and application of the probability of discovering and developing the prospective resources. As stated in the COGE Handbook, section 2.8.2, the risked mean values may be reported as the Best estimate risked prospective resources.

7. In our opinion, the reserves data, contingent resources data, prospective resources data, and revenue associated with the proved-plus-probable reserves 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, contingent resources data, and prospective resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our report referred to in paragraphs 5 and 6 for events and circumstances occurring after the preparation date.

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

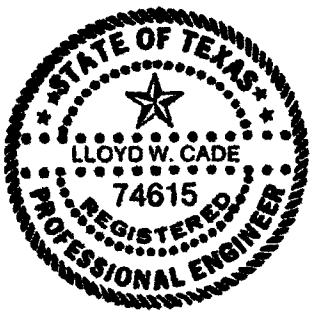
Executed as to our report referred to above:

DeGolyer and MacNaughton, Dallas, Texas USA, dated February 25, 2016.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716



Lloyd W. Cade, P.E.

Lloyd W. Cade, P.E.
Senior Vice President
DeGolyer and MacNaughton

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

Management of Oando Energy Resources Inc. (the "**Company**") is 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 which are estimates of proved, probable, and possible reserves, related future net revenue, contingent resources, and prospective resources as at December 31, 2015.

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

The Reserves 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 data, contingent resources data, and prospective resources data with management and the independent qualified reserves evaluator.

The Reserves 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 Committee, approved:

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

b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, and prospective resources data; and,

c) the content and filing of this report.

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Because the reserves data, contingent resources data, and prospective 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 29, 2016

SCHEDULE "D" – AUDIT AND RISK COMMITTEE CHARTER

CHARTER OF THE AUDIT AND RISK OMMITTEE OF OANDO ENERGY RESOURCES INC.

AMENDED AND RESTATED ON JULY 27, 2015.

1. PURPOSE

The Audit and Risk 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:

AUDIT:

(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; and

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

ENTERPRISE RISK

The Audit Committee is responsible for:

a) Setting up policies and strategies for enterprise risk management framework of the Company including risk tolerance, governance and management.

b) Defining, implementing and overseeing the Company's risk management policy and framework including reviewing the Company's overall global risk exposure including strategic risks, risks relating to compliance including environmental, corruption risks, reputational risks, liquidity and funding risks, credit risks and market risks.

c) Reviewing risks associated with growth plans of the Company, deviations from budgeted forecasts, impact of delays in implementation of the projects as approved by the Board including escalation in project costs.

d) Regulating and supporting risk management process to be in line with the Company's strategy and business goals taking into consideration changing situations, and in particular ensuring that sound policies, procedures and processes are in place for the enterprise-wide management of the Company's material risks.

e) Reviewing the Risk Register, including providing specification on control measure or mitigation plans, and the development of effective risk management systems to ensure continuous efficiency.

f) Providing recommendations after monitoring and evaluating risk management for further implementation of risk management and internal control.

g) Reporting risk management results to the Board of Directors on a periodic basis, and in situations where factors or events exist which may have significant impact of the Company, notify the Board of Directors immediately.

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 available under 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 **Financial Expert**

(a) **Attributes of the Financial Expert**. To the extent possible, the Board will appoint to the Audit Committee at least one Director who has the following attributes (the "**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 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.

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 and discuss with the Reserves and Resources Committee of the Board of Directors 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) cyber security risk and strategy;

(xiv) any other relevant reports or financial information submitted by the Company to any governmental body, or the public; and

(xv) pension plan financial statements, if any.

5.2 External Auditor

(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)

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 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.

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.

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:

(i) management;

(ii) the External Auditor; and

(iii) the internal auditor.

The External Auditor will have direct access to the Audit Committee at their own initiative.

6.3 **Regular Reporting**

The Chair of the Audit Committee will regularly report the Audit Committee's findings and recommendations to the Board.

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:

(i) 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

(ii) 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 notice of articles or articles or as directed by the Board.

8. AUDIT COMMITTEE WORKPLAN

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. 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.

Amended and Restated this 27th day of July, 2015.