INDEPENDENT OIL & GAS PLC

SUBSCRIPTION AND ADMISSION TO AIM

INDEPENDENT OIL & GAS PLC

Nominated Adviser & Broker

Charles Stanley Securities

THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about what action to take you should consult an independent financial adviser authorised pursuant to the Financial Services and Markets Act 2000 who specialises in advising upon investment in shares and other securities.

This document does not comprise a prospectus within the meaning of section 85 of FSMA and does not constitute an offer of transferable securities to the public in the United Kingdom, within the meaning of section 102B of FSMA and has not been approved or examined by and will not be filed with the Financial Conduct Authority, the UK Listing Authority or the London Stock Exchange, but comprises an AIM admission document and has been prepared in accordance with the AIM Rules. A copy of this document has been delivered to the London Stock Exchange as an admission document in respect of the Ordinary Shares, but a copy has not been filed with the Registrar of Companies in England and Wales.

Application has been made for the whole of the ordinary share capital of Independent Oil & Gas plc in issue to be admitted to trading on AIM. It is expected that Admission will become effective and that dealings on AIM in the Ordinary Shares will commence on 30 September 2013.

AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies. AIM securities are not admitted to the Official List of the UK Listing Authority. A prospective investor should be aware of the risks of investing in such companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser. Each AIM company is required by the AIM Rules for Companies to have a nominated adviser. The nominated adviser is required to make a declaration to the London Stock Exchange on Admission in the form set out in Schedule Two to the AIM Rules for Nominated Advisers. Neither the London Stock Exchange nor the UK Listing Authority have themselves examined or approved the contents of this document. The rules of AIM are less demanding than those of the Official List. It is emphasised that no application is being made for admission of the Ordinary Shares to the Official List.

The whole text of this document should be read. The attention of investors is drawn in particular to the risk factors set out in Part II of this document.

Independent Oil & Gas plc

(Registered in England & Wales with Company number 07434350)

Subscription of 8,405,800 Ordinary Shares to raise £2 million

and

Admission to trading on AIM

Nominated Adviser and Broker

Charles Stanley Securities

Share Capital on Admission

	Issued and fully paid	
	£	*Number*
Ordinary Shares of 1p each	595,318.54	59,531,854

The Company and the Directors, whose names are set out on page 4 of this document, accept responsibility for the information contained in this document including individual and collective responsibility for compliance with the AIM Rules. To the best of the knowledge and belief of the Company and the Directors (who have taken all reasonable care to ensure that such is the case) the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

Charles Stanley, which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting exclusively as Nominated Adviser and Broker for IOG and for no one else in connection with the matters described herein and will not be responsible to anyone other than IOG for providing the protections afforded to customers of Charles Stanley, or for advising them on the contents of this document or any matter referred to herein.

Copies of this document will be available to the public free of charge during normal business hours on any day (Saturdays, Sundays and public holidays excepted) at the registered office of Independent Oil & Gas plc at One America Square, Crosswall, London, EC3N 2SG for a period of one month following Admission. Copies will also be available for download from the Company's website at www.independentoilandgas.com.

This document does not constitute an offer to sell, or a solicitation of an offer to buy, Ordinary Shares in any jurisdiction in which such offer or solicitation is unlawful. In particular, this document is not for distribution in or into the United States, Canada, Australia, South Africa, the Republic of Ireland or Japan. The Ordinary Shares have not been and will not be registered under the Under States Securities Act of 1933 (as amended) nor under the securities legislation of any state of the United States or any province or territory of Canada, Australia, South Africa, the Republic of Ireland or Japan or in any country, territory or possession where to do so may contravene local securities law or regulations. Accordingly, the Ordinary Shares may not, subject to certain exemptions be offered or sold directly or indirectly in or into, or to any national, citizen or resident of the United States, Australia, South Africa, the Republic of Ireland or Japan.

No securities regulatory authority has expressed an opinion about the Ordinary Shares and it is an offence to claim otherwise. While information in this document derived from third parties is obtained from sources which the Company believes to be reliable, such information is not guaranteed as to its accuracy or completeness. An investment in the Company is speculative due to the nature of the Company's business. The ability of the Company to carry out its growth initiatives as described in this document is dependent on the Company obtaining additional capital. There is no assurance that the Company will be able to successfully raise the capital required or to complete each of the growth initiatives described.

FORWARD LOOKING STATEMENTS

Certain statements contained in this document constitute forward-looking statements. When used in this document, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Company, are intended to identify forward-looking statements. These statements are primarily contained in Parts I to IV of this document. Such statements reflect the Company's current views with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Company's actual results, performance or achievements to vary from those described in this document. Should one or more of these risks or uncertainties materialise, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in document as intended, planned, anticipated, believed, estimated or expected.

The forward looking statements in this document are based on current expectations and intentions and are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied by these statements.

Certain risks to the Company are specifically described in Part II of this document headed "Risk Factors". If one or more of these risks or uncertainties materialises, or if underlying assumptions prove to be incorrect, the Company's actual results may vary materially from those expected, estimated or projected. Given these risks and uncertainties, potential investors should not place any reliance on forward looking statements. These forward looking statements are stated as at the date of this document. Neither the Directors nor the Company undertake any obligation to update forward looking statements or risk factors other than as required by the AIM Rules or by the rules of any other securities regulatory authority whether as a result of new information, future events or otherwise.

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DIRECTORS, SECRETARY AND ADVISERS

Directors	Seyyed Mehdi Varzi (*Non-executive Chairman*) Mark Christopher Routh (*Chief Executive Officer*) Peter Jeremy Young (*Chief Financial Officer*) Marie-Louise Clayton (*Non-Executive Director*) Michael Cory Jordan (*Non-Executive Director*) *All of* 70 Clifton Street London EC2A 4HB
Registered Office	One America Square Crosswall London EC3N 2SG
Company Secretary	Ben Harber SGH Martineau Company Secretarial LLP One America Square Crosswall London EC3N 2SG
Website	www.independentoilandgas.com
Nominated Adviser & Broker	Charles Stanley Securities 131 Finsbury Pavement London EC2A 1NT
Solicitors to the Company	Field Fisher Waterhouse LLP 35 Vine Street London EC3N 2AA
Solicitors to the Nominated Adviser and Broker	Bond Dickinson LLP St. Ann's Wharf 112 Quayside Newcastle upon Tyne NE1 3DX
Reporting Accountants and Auditors to the Company	BDO LLP 55 Baker Street London W1U 7EU

Competent Persons	ERC Equipoise Limited 6th Floor Stephenson House 2 Cherry Orchard Road Croydon CR0 6BA London
	AGR TRACS International Limited Triggs Turner House 128 High Street Guildford Surrey GU1 3HH
Registrars	Computershare Investor Services PLC The Pavilions Bridgwater Road Bristol BS13 8AE

SUBSCRIPTION AND MARKET STATISTICS

Number of Ordinary Shares currently in issue	47,323,417
Number of new Ordinary Shares to be issued pursuant to the Subscription	8,405,800
Subscription Price	23.7931 pence
Gross proceeds of the Subscription	£2 million
Net proceeds of the Subscription receivable by the Company	£1.6 million
Number of Ordinary Shares in issue upon Admission	59,531,854
Subscription Shares as a percentage of the enlarged issued share capital	14.12 per cent.
Market capitalisation, upon Admission, at the Subscription Price	£14.2 million
Tradeable instrument display mnemonic	IOG
ISIN	GB00BF49WF64
SEDOL	BF49WF6

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

	2013
Admission and dealings expected to commence in the Ordinary Shares on AIM	8.00 a.m. on 30 September
CREST member accounts expected to be credited	30 September
Despatch of definitive share certificates in respect of the Ordinary Shares	by 14 October

Each of the dates in the above timetable is subject to change

DEFINITIONS

The following definitions apply throughout this document unless the context requires otherwise:

"Act"	the UK Companies Act 2006, as amended from time to time;
"Admission"	admission of the Enlarged Share Capital to trading on AIM and such admission becoming effective in accordance with the AIM Rules for Companies;
"AIM"	the market of that name operated by the London Stock Exchange;
"AGR TRACS"	AGR TRACS International Limited of Triggs Turner House, 128 High Street, Guildford, Surrey, GU1 3HH;
"AIM Rules for Companies" or **"AIM Rules"**	the London Stock Exchange's rules and guidance notes contained in its "AIM Rules for Companies" publication relating to companies whose securities are traded on AIM, as amended from time to time;
"AIM Rules for Nominated Advisers"	the London Stock Exchange's rules contained in its "AIM Rules for Nominated Advisers" publication relating to the nominated advisers of companies whose securities are traded on AIM, as amended from time to time;
"ARCO"	Atlantic Richfield Company;
"Articles"	the articles of association of the Company in force on Admission;
"ATP"	ATP Oil & Gas Corporation;
"ATP UK"	ATP Oil & Gas UK Ltd;
"Audit Committee"	the audit committee of the Board, details of which are set out in paragraph 8 of Part I of this document;
"Blocks"	the five blocks and part blocks in the UK North Sea in which the Group currently holds an interest, further details of which are set out in paragraph 2 of Part I of this document and "Block" shall mean any one of them;
"Blythe"	the gas discovery in Blocks 48/22b and 48/23a discovered by well 48/22-1 by Burmah in 1966 and appraised by wells 48/22-2 and 48/23-3 drilled in 1987 and 48/23a-4 drilled in 1990, all by ARCO;
"Blythe East"	a promote licence to the east of the Blythe Licence applied for by IOG in respect of a 100 per cent. working interest in the 27th Offshore Licensing Round which is pending award by DECC, subject to an environmental review process;
"Blythe Licence"	licence P1736 covering Blocks 48/22b and 48/23a which contains the Blythe field discovery;
"BP"	BP Oil International Limited;
"Board"	the board of directors of the Company from time to time;
"Burmah"	the Burmah Oil Company Ltd;
"Centrica"	Centrica plc;
"certificated" or **"in certificated form"**	an Ordinary Share which is not in uncertificated form (that is, not in CREST);

"CH4"	CH4 Energy Limited, a company purchased by Venture in 2006 and subsequently purchased by Centrica in 2009;
"Charles Stanley"	Charles Stanley Securities, a trading division of Charles Stanley & Co. Limited;
"Company" or **"IOG"**	Independent Oil and Gas plc, a company incorporated in England & Wales with registered number 07434350;
"Corporate Governance Code"	the UK Corporate Governance Code published by the Financial Reporting Council in September 2012 (as amended);
"CPRs" or **"Competent Person's Reports"**	the reports of ERC Equipoise and AGR TRACS on Blythe and Skipper respectively as set out in Part IV of this document;
"CREST"	the computerised settlement system (as defined in the CREST Regulations) operated by Euroclear which facilitates the transfer of title to shares in uncertificated form;
"CREST Regulations"	the Uncertificated Securities Regulations 2001 (SI 2001/3755) including any enactment or subordinate legislation which amends or supersedes those regulations and any applicable rules made under those regulations or any such enactment or subordinate legislation for the time being in force;
"DECC"	the Department of Energy and Climate Change of the UK Government;
"Directors"	the current directors of the Company whose names are set out on page 4 of this document;
"Disclosure and Transparency Rules"	the disclosure and transparency rules made by the FCA in exercise of its functions as competent authority pursuant to Part VI of FSMA;
"DTI"	the Department of Trade and Industry of the UK Government;
"Ebor"	Ebor Energy UK Ltd;
"Engen"	Engen Resources Limited;
"Enlarged Share Capital"	the 59,531,854 Ordinary Shares in issue on Admission;
"ERC Equipoise"	ERC Equipoise Limited of 6th Floor Stephenson House, 2 Cherry Orchard Road, Croydon CR0 6BA, London;
"Euroclear"	Euroclear UK & Ireland Limited, a company incorporated in England & Wales with registered number 2878738, being the operator of CREST;
"Existing Ordinary Shares"	the 47,323,417 Ordinary Shares in issue as at the date of this document;
"FCA"	the Financial Conduct Authority of the United Kingdom;
"FSMA"	the Financial Services and Markets Act 2000 of the UK (as amended), including any regulations made pursuant thereto;
"Group" or **"IOG Group"**	the Company together with its subsidiaries as at Admission;
"HMRC"	HM Revenue and Customs;
"IFRS"	International Financial Reporting Standards, as adopted by the European Union;

"IOG North Sea"	IOG North Sea Limited, a wholly-owned subsidiary of the Company;
"ISIN"	International Securities Identification Number;
"LAPS"	a 20" pipeline known as the Lancelot Area Pipeline System which evacuates gas from Perenco's Lancelot platform in Block 48/17 of the Southern North Sea and transports the gas to the Bacton Gas Terminal on the coast of Norfolk;
"Loan Notes"	the unsecured convertible loan notes issued by the Company, details of which are set out at paragraph 4.4 of Part V of this document;
"Lock-in Deeds"	the lock-in deeds dated 24 September 2013 between the Company, Charles Stanley and the Locked-in Persons, details of which are set out in paragraph 14.3 of Part V of this document;
"Locked-in Persons"	the Directors, Gordon Young, International Petroleum Exploitation A.S., John Boyle, Villa Mirador S.A., Paul Murray, Brian Oldfield, Chris Brown, RJM Energy Ltd., Campana Consulting Ltd. and Tom Haselton;
"London Stock Exchange"	London Stock Exchange plc;
"Long Term Incentive Plan"	the IOG Long Term Incentive Plan 2013, further details of which are set out in paragraph 16 of Part V of this document;
"Majors"	a term commonly used to refer to national oil companies and multi-national oil companies with a market capitalisation in excess of £10 billion;
"MOST"	MOST Oil & Gas Ltd;
"Official List"	the Official List maintained by the UK Listing Authority pursuant to Part VII of the FSMA;
"Ordinary Shares"	the ordinary shares of par value 1p each in the capital of the Company;
"Panel"	the UK Panel on Takeovers and Mergers;
"p" or **"pence"**	pence sterling;
"Perenco"	Perenco UK Limited;
"Petroleum Act"	the United Kingdom Petroleum Act of 1998, as amended from time to time;
"PRT"	petroleum revenue tax;
"QCA"	the Quoted Companies Alliance;
'Registrar"	Computershare Investor Services plc of The Pavilions, Bridgwater Road, Bristol, BS13 8AE, United Kingdom;
"Remuneration Committee"	the remuneration committee of the Board, details of which are set out in paragraph 8 of Part I of this document;
"Secretary of State"	the Secretary of State for Energy and Climate Change;
"Share Dealing Code"	the code on dealing in the Company's securities adopted by the Company that complies with the AIM Rules;
"Shareholders"	holders of Ordinary Shares, from time to time;

“Significant Shareholder”	a Shareholder holding three per cent. or more of the Ordinary Shares in issue from time to time;
“Skipper”	the heavy oil discovery in Block 9/21a discovered by well 9/21-2 drilled by Unocal in 1990;
“Skipper Licence”	Licence P1609 covering Block 9/21a which contains the Skipper field discovery;
“Skipper West Licence”	Licence P1941 covering Blocks 8/20a and 8/25a awarded to IOG in the 27th Licencing Round;
“Sterling” or **“£”**	pounds sterling, the lawful currency of the UK;
“Subscriber”	a person who has conditionally agreed to subscribe for Subscription Shares at the Subscription Price pursuant to the Subscription;
“Subscription”	the conditional subscription by Subscribers to subscribe for the Subscription Shares at the Subscription Price;
“Subscription Price”	23.7931 pence per Subscription Share;
“Subscription Shares”	8,405,800 new Ordinary Shares to be issued by the Company and subscribed for pursuant to the Subscription;
“Supplementary Charge”	the 32 per cent. extra corporation tax due to HMRC on oil company revenues calculated in the same way as for ring fence corporation tax but with no deduction for financing costs;
“Takeover Code”	the UK City Code on Takeovers and Mergers (as amended from time to time);
“Tullow”	Tullow Oil Plc;
“UK” or **“United Kingdom”**	the United Kingdom of Great Britain and Northern Ireland;
“UKCS”	the United Kingdom Continental Shelf;
“UKLA” or **“UK Listing Authority”**	the FCA, acting in its capacity as the competent authority for the purposes of Part VI of the FSMA;
“uncertificated” or **“in uncertificated form”**	recorded on the relevant register of the share or security concerned as being held in uncertificated form in CREST and title to which, by virtue of the CREST Regulations, may be transferred by means of CREST;
“United States” or **“US”**	the United States of America, its territories and possessions, any state of the United States of America and the district of Columbia and all other areas subject to its jurisdiction;
“Unocal”	Union Oil Company of California;
“US Dollar” or **“US$”**	the legal currency of the United States from time to time;
“Venture”	Venture Production plc; and
“VAT”	value added tax.

GLOSSARY OF TECHNICAL TERMS

The following table provides an explanation of certain technical terms and abbreviations used in this document. The terms and their assigned meanings may not correspond to standard industry meanings or usage of these terms.

"ºC"	degrees Centigrade;
"ºF"	degrees Fahrenheit;
"2D seismic"	geophysical data that depicts the subsurface strata in two dimensions;
"3D seismic"	geophysical data that depicts the subsurface strata in three dimensions. 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic;
"API"	a standard measure of oil density, as defined by the American Petroleum Institute;
"appraisal well"	a well drilled as part of an appraisal drilling programme which is carried out to determine the physical extent, reserves and likely production rate of a field;
"bara" or **"bar"**	Bars (pressure) absolute;
"BarG"	Bars (pressure) Gauge;
"barrels" or **"bbl"** or **"Bbl"**	a unit of volume measurement used for petroleum and its products (for a typical crude oil 7.3 barrels ≈ 1 tonne: 6.29 barrels ≈ 1 cubic metre);
"bcf" or **"Bcf"** or **"Bscf"**	billion (10^9) standard cubic feet; 1 bcf is approximately equal to 172,414 Boe or 23,618 tonnes of oil equivalent, using a factor of 5.8 Bcf per MMBbls;
"Best Estimate"	the middle value in a range of estimates considered to be the most likely. If based on a statistical distribution, can be the mean, median or mode depending on usage;
"block"	an areal subdivision of the UKCS of 10 minutes of latitude by 12 minutes of longitude measuring approximately 10 by 20 kilometres, forming part of a quadrant. Each quadrant is divided into a grid five blocks wide and six deep, and numbered 1 to 30 from NW to SE e.g. Block 14/13 is the 13th block in Quadrant 14;
"blow-out"	when well pressure exceeds the ability of the wellhead valves to control it. Oil and gas "blow wild" at the surface;
"Boe" or **"BOE"**	barrels of oil equivalent. One barrel of oil is approximately the energy equivalent of 5,800 cf of natural gas;
"boepd" or **"BOEPD"**	barrels of oil equivalent per day;
"bopd" or "**Bbls/d"**	barrels of oil per day;
"Brent Blend"	an international benchmark comprising a mix of crude oil from 15 different oil fields in the North Sea;
"CAPEX"	capital expenditure;

“Carboniferous”	a geological period and system that extends from the end of the Devonian Period, about 359 million years ago, to the beginning of the Permian Period, about 299 million years ago;
“carried interest”	an agreement between two or more working interests whereby one party (carried party) does not share in lease revenue until a certain amount of money has been recovered by the other party (carrying party). The carrying party pays costs applicable to the carried party’s interests in the property and is reimbursed out of the revenue applicable to the carried party’s interest;
“centipoise” or **“cP”**	the unit of measurement for the viscosity of a fluid;
“CGR”	condensate gas ratio, the ratio of condensate oil produced with hydrocarbon gas usually stated in barrels per million cubic feet (Bbls/MMcf);
“Chance of Success” or **“CoS”**	the estimated chance, or probability, of making an oil and gas discovery in an exploration well;
“commercial discovery”	discovery of hydrocarbons which the Company determines to be commercially viable for appraisal and development;
“condensate”	light hydrocarbon compounds that condense into liquid at surface temperatures and pressures. They are generally produced with natural gas and are a mixture of pentane and higher hydrocarbons;
“Contingent Resources”	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies;
“Cretaceous”	geological strata formed during the period 140 million to 65 million years before the present;
“CV”	calorific value;
“dip”	the inclination of a horizontal structure from the horizontal;
“D & P”	development and production;
“discovery”	an exploration well which has encountered hydrocarbons for the first time in a structure;
“Drill-or-Drop”	a decision to either commit to drilling an exploration well or further work programme or else relinquish the licence concerned;
“drilling rig”	a drilling unit that is not permanently fixed to the seabed, for example a drillship, a semi-submersible or a jack-up unit;
“E&A”	exploration and appraisal;
“E&P”	exploration and production;
“EIA”	Environmental Impact Assessment;
“exploration well”	a well drilled to find hydrocarbons in an unproved area or to extend significantly a known oil or natural gas reservoir;
“fairway”	an area that has common components that may have oilfields or prospects within it;

"fallow"	blocks where the initial licence term has expired and there has been no drilling for a period of four years and no dedicated seismic and no significant activity for a period of two years;
"farm-in"	when a company acquires an interest in a block by taking over all or part of the financial commitment for drilling an exploration well;
"farm-out"	to assign an interest in a licence to another party;
"fault" or **"faulting"**	a displacement (vertical, inclined or lateral) below the earth's surface that acts to offset rock layers relative to one another. Faulting can create traps for hydrocarbons;
"FDP"	field development plan;
"FEED"	front end engineering and design;
"field"	an area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition;
"formation"	a layer or unit of rock. A productive formation in the context of reservoir rock;
"FPSO"	floating, production, storage and offloading;
"FSU"	floating storage unit;
"ft"	foot/feet;
"G&A"	general and administrative;
"G&G"	geological and geophysical;
"geophysical"	measurement of the earth's physical properties to explore and delineate hydrocarbons by means of electrical, seismic, gravity and magnetic methods;
"GIIP"	gas initially in place;
"gross resources"	the total estimated petroleum that is potentially recoverable from a field or prospect;
"GWC"	gas water contact;
"HIPPS"	high integrity pressure protection system;
"Hot Tap"	a sub-sea engineering procedure involving cutting in to a pressurised, flowing pipeline to install a link to connect two pipeline systems;
"HPHT"	high pressure and high temperature;
"hydrocarbon"	a compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate;
"JOA"	joint operating agreement;
"Jurassic"	geological strata (or period) formed during the period from 140 million to 205 million years before the present;
"JV"	joint venture;
"km"	kilometre;

"km^2"	square kilometres;
"LAT"	Lowest Astronomical Tide;
"lead"	a conceptual exploration idea usually based on minimal data but with sufficient support from geological analogues and the like to encourage further data acquisition and/or study on the basis that hydrocarbon accumulations of unknown size may be found in the future;
"licence"	an exclusive right to search for or to develop and produce hydrocarbons within a specific area. Usually granted by the State authorities and may be time limited;
"limestone"	a sedimentary rock containing at least 50 per cent. calcium or calcium magnesium carbonates;
"m"	metres;
"m^3" or **"cm"**	cubic metres;
"Mcf" or **"mcf"**	thousand standard cubic feet;
"Mcfd" or **"mcfd"**	thousand cubic feet per day;
"mD"	milli-Darcies;
"MD"	measured depth;
"MFP"	minimum facilities platform;
"mmbbl" or **"MMBbl"**	millions (10^6) of barrels of oil;
"mmboe" or **"MMBOE"**	millions (10^6) of barrels of oil equivalent;
"MMBO"	million (10^6) barrels of oil;
"MMBOEPD"	million (10^6) barrels of oil equivalent per day;
"MMcf"	million (10^6) cubic feet;
"MMcfd"	million (10^6) cubic feet per day;
"MMcm or **MMm^3"**	million (10^6) cubic metres;
"MMscf"	million (10^6) standard cubic feet;
"MMscfd"	million (10^6) standard cubic feet per day;
"MMstb"	million (10^6) stock tank barrels;
"MODU"	mobile Offshore Drilling Unit;
"NBP"	the UK National balancing point for gas;
"NUI"	normally unmanned installation – a term referring to a small unmanned production platform for the production of hydrocarbons;
"oil"	mixture of liquid hydrocarbons of different molecular weights;
"oil equivalent"	international standard for comparing the thermal energy of different fuels;
"operator"	the company that has legal authority to drill wells and undertake production of hydrocarbons found. The operator is often part of a consortium and acts on behalf of such consortium;

“OCM”	operating committee meeting;
“OPEX”	operating expenditure;
“P&A”	plugged and abandoned;
“POSA”	production and operating services agreement;
“ppm”	parts per million;
“psia”	pounds per square inch absolute;
“P90”	in the probabilistic estimation of hydrocarbon reserves, a term referring to the quantity of recoverable hydrocarbons from a reservoir having a 90 per cent. probability of being produced. Often also referred to as Proved or 1P;
“P50”	in the probabilistic estimation of hydrocarbon reserves, a term referring to the quantity of recoverable hydrocarbons from a reservoir having a 50 per cent. probability of being produced. Often also referred to as “Proved plus Probable” or 2P;
“P10”	in the probabilistic estimation of hydrocarbon reserves, a term referring to the quantity of recoverable hydrocarbons from a reservoir having a 10 per cent. probability of being produced. Often also referred to as “Proved plus Probable plus Possible” or 3P;
“Palaeocene”	geological epoch within the Tertiary which contains sands of formations and members such as Forties, Cromarty, Balmoral, Skaden and Heimdal;
“permeability”	a measure of the ease with which a fluid flows through the connecting pore spaces of rock or cement, usually measured in milli-Darcies;
“petroleum”	a generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products;
“play”	a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects;
“platform”	an offshore structure that is permanently fixed to the seabed;
“porosity”	the percentage of void in a porous rock compared to the solid formation;
“PRMS”	petroleum resources management system;
“probable reserves”	those reserves which are not yet proven but which are estimated to have a better than 50 per cent. chance of being technically and economically producible;
“Promote Licence”	a specific type of licence awarded by DECC whereby licence holders are given two years after an award, with low rental payments and obligations, in order to attract the technical, environmental and financial capacity to complete an agreed work programme. The licence will expire after two years if the licensee has not made a firm commitment to DECC to complete the work programme;

“prospect”	a project associated with a potential accumulation of oil or natural gas that is sufficiently well defined to represent a viable drilling target;
“prospective resources”	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects;
“proven reserves”	those reserves which on the available evidence are virtually certain to be technically and economically producible (i.e. having a better than 90 per cent. chance of being produced);
“quadrant”	an areal subdivision of the UKCS of 1 degree of longitude by 1 degree of latitude – typically around 6,600km^2. On the UKCS each quadrant is further subdivided into 30 blocks;
“recovery factor”	the percentage of the hydrocarbon in place that can be produced;
“reserves”	those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions;
“reservoir”	a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. A reservoir is a critical component of a complete petroleum system;
“resources”	deposits of naturally occurring hydrocarbons which, if recoverable, include those volumes of hydrocarbons either yet to be found (prospective) or if found the development of which depends upon a number of factors (technical, legal and/or commercial) being resolved (contingent);
“Rotliegend” or **“Rotliegendes”**	a lithostratigraphic geological unit of early Permian age (beneath the Zechstein and above the Carboniferous) that is found in the subsurface of large areas in western and central Europe;
“STOOIP” or **“STOIIP”**	stock tank oil originally in place or stock tank oil initially in place;
“Sw”	water saturation;
“scf”	standard cubic feet;
“seal”	a relatively impermeable rock, commonly shale, anhydrite or salt that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system;
“seismic survey”	a method by which an image of the earth’s subsurface is created through the generation of shockwaves and analysis of their reflection from rock strata. Such surveys can be done in two or three dimensional form;
“stratigraphic”	a mode of trapping hydrocarbons which is not dependent on structural entrapment;
“TCM”	technical committee meeting;
“TD”	total depth;
“tcf”	trillion standard cubic feet;
“Tertiary”	geological strata formed during the period from 65 million to 1.8 million years before the present;

"TVDSS"	true vertical depth sub-sea;
"TVD"	true vertical depth;
"UKCS"	United Kingdom Continental Shelf;
"UOA"	unit operating agreement; and
"up-dip"	up the plane of the dip.

PART I

INFORMATION ON THE GROUP

1. Introduction, History and Strategy of IOG

1.1 *Introduction*

IOG is a UK based energy company that has been established to identify, acquire and commercialise proven oil and gas fields in the United Kingdom Continental Shelf and Irish Sea, complemented with select, targeted exploration. IOG is focused on building a significant oil and gas company which will maximise shareholder returns through the enhanced development of hydrocarbon reserves and the acquisition, trading and monetisation of licence interests.

1.2 *History*

Having been established in November 2010, in February 2011 IOG set about combining the UK assets of MOST and Ebor. By October 2011, the acquisition of the 50 per cent interests in the Blythe gas field in the Southern North Sea and a heavy oil discovery in the Skipper Licence, south east of the Shetland Isles was completed in an all share transaction, details of which are set out in paragraphs 14.4 to 14.13 of Part V of this document. In May 2013, IOG was awarded 100 per cent of the Skipper West Licence adjacent to its Skipper Licence, thus creating the first potential hub within the Group's portfolio. These three licences include proven gas reserves, contingent oil resources and nearby exploration upside respectively.

Once the acquisitions of the Blythe and the Skipper Licences had been agreed, the Board sought a qualified and experienced CEO and Mark Routh, a petroleum engineer with considerable oil and gas experience, was appointed in August 2011. The Board was further strengthened by the appointment of Mehdi Varzi, as Chairman, in June 2012.

The operator and holder of the remaining 50 per cent. of each of the Blythe Licence and the Skipper Licence is ATP UK. ATP UK is currently the subject of a formal sale process due to its parent company, ATP, filing for Chapter 11 bankruptcy protection in the U.S. in August 2012, largely as a result of the widespread impact of the Gulf of Mexico "Macondo" disaster in 2010 on the oil and gas industry in the U.S. The Directors understand that the purchase of ATP UK is currently being progressed.

During the summer of 2012, IOG made progress towards an IPO on AIM. The financial issues affecting ATP UK created uncertainty with regards to the timing of the development and appraisal spending on Blythe and Skipper and so the IPO was put on hold. The Directors resolved to continue to run IOG as a private company and over the past year IOG has evaluated several corporate transactions including mergers, acquisitions, asset purchases and reverse take-overs, none of which proceeded to an agreed transaction ultimately as a direct result of the ATP situation.

To date IOG has been primarily funded via investment from certain of the Directors and certain of the previous shareholders in MOST and Ebor, the companies which previously owned the Skipper Licence and the Blythe Licence respectively. More specifically, in the past two years, IOG has raised funds by way of an equity issue and though the subscription of loan notes. Further details are set out in paragraph 4 of Part V of this document.

The term of both the Blythe Licence and the Skipper Licence expire on 31 December 2013, having been extended from 30 September 2013 by DECC in order to allow time for the sale process of ATP UK to conclude. The Board understands that DECC has advised that further licence extensions will be subject to confirmation that there are financial resources available to ATP UK to fulfil the agreed work programmes under the licences.

Further details regarding IOG's expected future commitments in relation to the Blythe and Skipper Licences are set out below in section 2 of this Part I.

1.3 *IOG Strategy*

IOG's strategy is to target "stranded" assets and dormant discoveries, especially those near to existing and, ideally, owned infrastructure (the "Hub Strategy"). These are assets that are marginal for the Major oil companies but are potentially profitable developments which can be beneficially developed by a smaller independent company, focused on the North Sea.

The aim is to build on the existing development assets in order to achieve a diversified, balanced portfolio of near and long term developments with exploration upside that complement the existing operations. This will include the acquisition of producing fields or near-term production if the risk is positively assessed and the acquisition price results in value accretion.

The Directors believe that there is a significant opportunity for the Company to exploit given that there are over 400 undeveloped and underdeveloped assets in the UKCS and, in addition, the Majors are in long term exit mode.

IOG is following and developing the Hub Strategy model successfully developed originally in the Gulf of Mexico and subsequently and similarly successfully deployed by Venture, Dana Petroleum and CH4 in the North Sea. The Hub Strategy targets dormant discoveries and exploration prospects nearby owned infrastructure where tariffs are already agreed and ullage is available in the offtake route for the production. In the Board's view, IOG has already delivered on this strategy by the successful application for the Skipper West Licence and the anticipated award of a licence in respect of Blythe East.

The intention to become an operator is instrumental in achieving the aforementioned growth and this status will be sought in conjunction with the right asset or assets. The skills and competencies of the Board and management team reflect this intention.

Operator status gives a licensee more control over the field development plan and its execution. This also makes it easier to deliver on the Hub Strategy because as the operator of owned infrastructure, third party consents to tie in additional discoveries are easier to facilitate. Also, as the Majors continue to divest late life producing assets they often prefer to assign operatorship and redeploy their own resources and so additional opportunities arise. In the UK licensing rounds, certain licences will only be made available to pre-qualified operators.

DECC is expected to announce the next licensing round in January 2014. This is expected to create opportunities for companies such as IOG to expand at a low cost. In the event that IOG applies for, is offered and chooses to accept any new licences, there would be a financial commitment to either appraise or develop those licences. IOG would only take on such a commitment if it had the funding to do so and it would also need to demonstrate to DECC that it had the required funding. The UK North Sea Licensing regime is covered in further detail in paragraph 5 of this Part I.

Overall, the Board is confident that the Company has the management, experience and technical expertise to create and seize new opportunities for future growth.

2. The Group's Assets

2.1 *Blythe (Blocks 48/22b and 48/23a)*

The Blythe field is located in the Southern North Sea, approximately 25 km to the north west of the Hewett field and 20 km to the south of the Lancelot field. Water depth in the area is approximately 23m. The field was discovered in 1966 by well 48/22-1, drilled by Burmah. It is a generally low permeability Rotliegendes reservoir. It was subsequently appraised by wells 48/22-2, 48/23-3 and 48/23a-4 drilled by ARCO between 1987 and 1990 which tested up to 15 MMcfd. Three of the four wells drilled into the Blythe field tested gas to surface, two of them at commercial rates, thus there is no need for further field appraisal.

The most recent well, the horizontal appraisal/development well drilled in 1990, produced gas from the Rotliegend reservoir at a lower rate than anticipated. As a result, development was not progressed at that time. Recent detailed reservoir modelling studies commissioned by ATP and IOG in 2011 and completed by ERC Equipoise early in 2012 have subsequently indicated that drilling a horizontal well to a stratigraphically lower, better quality, interval than penetrated by the previous horizontal well should lead to higher gas production rates, coupled with water production. The ERC Reservoir Development Study has led to the optimum design and placing of the Blythe development well and as a result of detailed reservoir modelling, a higher initial gas production rate is predicted. This improved well design was developed as a direct result of intervention from IOG's petroleum engineer.

As a result, development planning is now underway. The ERC Reservoir Development Study also took into account the geological mapping based on seismic re-interpretation, history matching the test results from the well that flowed gas from the Blythe reservoir in 1990 and an independent third party petrophysical study focussed on the impact of residual hydrocarbons on the estimation of gas in place. These studies which have been co-funded by ATP and IOG over the last two years, have resulted in an increased estimate of ultimately recoverable reserves and at higher initial production rates than previously assumed. This data has formed the basis of the work carried out by ERC Equipoise in its preparation of its CPR (included at Section B of Part IV of this document).

Current planning foresees the installation of a normally unmanned installation (NUI) from which a single tri-lateral production well will be drilled. Approval is currently being sought from Perenco to allow a "Hot Tap" tie in to its LAPS pipeline which runs from the Lancelot field to the Bacton gas terminal where the gas will be processed, compressed and sold. The LAPS pipeline is less than 2km from the proposed location of the Blythe NUI. The initial gas production rate is expected to be 30 MMscf/d.

Certified Gas Initially in Place ("GIIP") estimates from the CPR prepared by ERC Equipoise are:

Blythe GIIP(Bcf)	*P90*	*P50*	*P10*
Gross	38.8	52.3	84.2

However, there is an estimated 70-310 Bcf GIIP in the Carboniferous beneath the Blythe field. Gas flowed to surface from the Carboniferous at 0.9 MMcfd from well 48/23-3 drilled by ARCO in 1987.

The economically recoverable gas reserves from the Blythe field are estimated by ERC Equipoise to be:

Blythe Reserves (Bcf)	*P90*	*P50*	*P10*
Gross	22.0	34.3	47.5
Net to IOG	11.1	17.2	23.7

A conservative 69 per cent. recovery factor is used for P50.

The current licence, P1736, was granted on 19 August 2010 with a start date of 1 May 2010 in the 25th licensing round and is currently owned as follows:

ATP UK	50% (operator)
IOG	50%

There is no further appraisal required. Tariff offers have been proposed by the infrastructure owner, Perenco for two export routes.

Further details are set out below regarding the Blythe Licence term and funding.

2.1.1 *Blythe Net Costs*

Development well	£12.7 million
Platform, tie-in and all associated costs	£18.2 million
Field studies & insurance	£2.6 million
Contingency	£1.6 million
TOTAL Net CAPEX	£35.1 million

A full development plan, or FDP, has not yet been submitted to DECC. The draft plan anticipates development via a single 12,000 ft well with a 2,170 ft horizontal tri-lateral section through a small NUI. First gas is projected in 2015.

The base case development timings and **gross costs** assumed in ERC Equipoise's Competent Person Report are as follows:

	Cost		*Phasing*	
Item	*(£MM)*	*2013*	*2014*	*2015*
NUI on Blythe with metering and water knockout	20.0	1.0	8.0	11.0
Pipeline & Hot Tap	16.4	0.8	6.6	9.0
PMT/MISC/FEED etc	5.2	0.8	2.4	2.1
Contingency	3.2	0.5	1.8	1.0
Drilling	25.4	0.0	5.1	20.3
TOTAL	70.2	3.1	23.8	43.4

2.1.2 *Blythe Licence Term and Funding*

The operator, ATP UK, is currently the subject of a formal sale process due to its parent company, ATP filing for Chapter 11 protection from bankruptcy in the U.S. Accordingly, no firm spending plans have been proposed by the operator. IOG understands that a preferred purchaser of ATP UK has been identified and has met with DECC. The preferred purchaser of ATP UK has confirmed its desire to continue the development of the Blythe field. Once the new operator has agreed its development plans with IOG, there will be a funding requirement for IOG. This future expenditure is contingent and, on completion of the ATP UK sale process, would require a subsequent fund raising by IOG. In the event that IOG cannot subsequently raise its share of the development funding, its continued 50 per cent. ownership of the Blythe Licence could be at risk. This is covered further below in Part II, Risk Factors.

Currently, the term of the Blythe Licence expires on 31 December 2013. DECC granted a short term extension from 30 September 2013 to allow time for the sale process of ATP UK to conclude. DECC has advised that further licence extensions will be subject to confirmation that there are financial resources available to ATP UK to fulfil the agreed work programme under the licence. In this context, DECC will be asking for a detailed business plan from the intended buyer of ATP UK which would be expected to remain as operator of the licence. IOG as co-licensee would similarly be required to confirm its plans. The agreed work programme on the Blythe Licence is to submit a field development plan or FDP.

The preparation of the Blythe FDP by the Blythe licensees will entail, amongst other things, a pipeline route and location survey, the finalisation of the commercial terms for the export of the Blythe gas with the infrastructure owner, Perenco, and the preparation and submission of an environmental impact assessment, or EIA. An FDP would then be submitted to DECC for approval which is expected to be in the first half of 2014. At this point, IOG would have to demonstrate to DECC's satisfaction its financial capacity to fund its 50 per cent. share of the development costs. When this happens, IOG will have to raise both new debt and equity funding to finance its share of the development costs. Over the past two years, the Directors have held discussions with several potential providers of debt funding for oil and gas developments and believe that a suitable debt facility will be forthcoming, on terms acceptable to the Company, to cover the majority of the capital expenditure required for the Blythe development. The Directors anticipate that it will also be necessary to undertake an equity fund raising in order to meet the balance of the development costs of the Blythe Licence.

IOG is confident that the Blythe Licence will be extended beyond 31 December 2013. Since DECC has a mandate to promote activity and field developments to boost hydrocarbon production for the UK, it will look favourably upon a licensee which has the desire to submit an FDP, an ability to raise the funds required and which has the technical competence to operate. For these reasons, the Directors expect that both ATP UK (under new ownership) and IOG with its strong team and AIM listing will be regarded as competent to deliver a field development plan, whether as co-licensees or as a sole licensee.

2.2 ***Skipper (Block 9/21a)***

The Skipper discovery is a heavy oil field within the Palaeocene Beauly sandstone formation located in UK offshore Block 9/21a (licence P1609) in the Northern North Sea in 350ft of water. Twenty five kilometres to the east are located the Gryphon and Harding oil fields. Geologically, Skipper sits on the East Shetlands Platform, 40km west of the main bounding fault of the Viking Graben. Oil generated in the Kimmeridgian shale source rock within the Viking Graben has migrated vertically and laterally into fault terraces at the edge of the graben. While some oil has been trapped in Palaeocene turbidite sandstones on these terraces (e.g. Gryphon), the remainder has continued to migrate on to the East Shetlands Platform.

Initially, Unocal drilled wells at Skipper in 1987 and 1990 when oil was discovered in the second well with approximately 15º API. This well 9/21-2 penetrated a 51’ oil column but due to technical issues at the time the well failed to flow on test. The acreage was relinquished and it was 20 years until Skipper’s true potential was exposed through 3D seismic data and remapping with superior depth conversion.

Based on samples from the 1990 well, API is estimated at 15°, however the CPR has used a density range of 12-15-18 in its evaluation. Certified Stock Tank Oil Originally in Place (“STOOIP”) estimates from the CPR prepared by AGR TRACS are:

Skipper STOOIP (MMBbls)	*Low Estimate*	*Best Estimate*	*High Estimate*
Gross	123.1	136.5	150.8

The Contingent Resources are estimated by AGR TRACS to be:

Skipper Contingent Resources (MMBbls)	*Low Estimate*	*Best Estimate*	*High Estimate*
Gross	17.9	26.2	34.9
Net to IOG	9.0	13.1	17.5

A conservative 19.2 per cent. recovery factor is used for best estimate resources.

The current licence, P1609, was awarded in on 21 May 2009 in the 25th Licensing Round with a start date of 12 February 2009 and an initial term of 4 years. The licence is currently owned:

ATP UK	50% (operator)
IOG	50%

There is a 1.5 per cent. royalty on IOG’s working interest on Skipper, payable to Engen Resources Ltd, which originally held the Skipper Licence and assisted MOST with applying for the block. All figures have been presented net of this royalty. The agreement with Engen in relation to this royalty is summarised at paragraph 14.15 of Part V of this document.

Further details are set out below regarding the Skipper Licence term and funding.

2.2.1 *Skipper Net Costs*

Appraisal well (14 day Skipper sand test)	£9.3 million
Development wells	£99.9 million
Steel jacket platform	£70.6 million
Subsea costs & FSU mooring system	£30.2 million
TOTAL Net CAPEX	£210.0 million

The above costs relate to the P50 case and have been derived from section 3.9.3 of the CPR prepared by AGR TRACS in Section A of Part IV of this document.

Drilling and testing of the well is scheduled for Q3 2014. As part of the licence commitment, the licensees must drill down to and verify the characteristics and explore the deeper Maureen and Dornoch Sands. AGR TRACS estimates a potential P50 STOOIP 46 MMBbls in these horizons. Following the EIA and geological and engineering studies, an FDP is scheduled to be submitted in Q1 2015. Subject to the results from the appraisal well, development drilling is scheduled for Q2 2016 with first oil projected in Q2 2017. This is expected to be a phased development of up to 13 wells (11 producers + 2 injectors) with offtake via FSUs.

2.2.2 *Skipper Licence Term, Funding and Crude Sales*

The operator, ATP UK, is currently the subject of a formal sale process due to its parent company, ATP, filing for Chapter 11 protection from bankruptcy in the U.S. Accordingly, no firm spending plans have been proposed by the operator. IOG understands that a preferred purchaser of ATP UK has been identified and has met with DECC. It is probable that the new owner of ATP UK will seek to drill the Skipper appraisal well and, once such plans have been agreed with IOG, there would be a funding requirement for IOG. This potential future expenditure is therefore contingent and would require a subsequent fund raising by IOG. In the event that IOG cannot subsequently raise its share of the appraisal well funding or could not farm down or sell its share, its continued 50 per cent. ownership of the Skipper Licence could be at risk. In that case, IOG would retain a 2.5 per cent. fully carried interest in Skipper. This is covered further below in Part II, Risk Factors.

Currently, the term of the Skipper Licence expires on 31 December 2013. DECC granted a short term extension from 30 September 2013 to allow time for the sale process of ATP UK to conclude. DECC has advised that further licence extensions will be subject to confirmation that there are financial resources available to ATP UK to fulfil the agreed work programme under the licence. In this context, DECC will be asking for a detailed business plan from the intended buyer of ATP UK which would be expected to remain as operator of the licence. IOG as co-licensee would similarly be required to confirm its plans. The agreed work programme on the Skipper Licence is to drill an appraisal well to the depth of 1700m or 50m below the Maureen Formation, whichever is the shallower.

To prepare for drilling the Skipper appraisal well, the licensees will prepare and apply for the necessary permits and consents. At this point IOG would have to demonstrate to DECC's satisfaction its financial capacity to fund its 50 per cent. share of the well.

IOG has entered into a long term agreement whereby BP will market the Skipper crude. BP has also committed to participate in any subsequent Skipper reserve base lending facility on the same terms as other funders. Further details of this agreement are set out in paragraph 14.14 of Part V of this document.

IOG is confident that the Skipper Licence will be extended beyond 31 December 2013. Since DECC has a mandate to promote activity and field developments to boost hydrocarbon production for the UK, it will look favourably upon a licensee which has the desire to drill appraisal wells, an ability to raise the funds required and which has the technical competence to operate. For these reasons, the Directors expect that both ATP UK (under new ownership) and IOG with its strong team and AIM listing will be regarded as competent to deliver a field development, whether as co-licensees or as a sole licensee.

2.3 ***Skipper West – Blocks 8/25a and 8/20a***

Immediately to the west of the Skipper field, IOG recognised the presence of two oil prospects which if proven would be tied back to the facilities at Skipper. These are called Skipper NW and Skipper SW. Due to their potential size and location, these prospects would not necessarily be economic without an adjacent Skipper development which would be less than 5km away. IOG applied for this acreage in the 27th Licensing Round in May 2012 and was awarded the acreage in May 2013.

IOG estimates that the mid case resources and Chance of Success may be:

Mid Case Estimates	*STOOIP*	*Resources*	*CoS*
Skipper NW	20 MMBbls	4 MMBbls	23%
Skipper SW	119 MMBbls	24 MMBbls	49%

Note:

The views of the Directors and IOG set out above could ultimately prove to be incorrect. No warranty, express or implied, is given by the presentation of these figures and no reliance on the Company's estimates cited in this document. Attention is drawn to the risk factor on hydrocarbon resource and reserve estimates set out on page 34 of this document.

This Promote Licence (P1941) was awarded on 9 May 2013 to IOG 100 per cent. as Licence Administrator in the 27th Licensing Round with a start date of 1 January 2013. The work commitments are to reprocess the seismic data and carry out an oil migration study. IOG needs to make a drill or drop decision by 1 January 2015.

There are no reserves attributable to this licence as the two prospects need further technical work to establish whether they would be viable prospects to justify the cost of an exploration well. The potential size of these prospects is such that if a discovery was made, they would only be commercially viable if a Skipper development was to proceed in the adjacent block. For this reason, IOG will not commit significant expenditure on this licence until the Skipper appraisal well confirms that a Skipper development is viable.

2.4 ***Potential Licence Additions – Blythe East – Part Blocks 48/23 & 48/24***

Immediately to the east of the Blythe field, IOG recognised the presence of two small gas prospects which if proven would be tied back to the platform at Blythe. These are called Wherry A North and Wherry A South. Due to their potential size and location, these prospects would not necessarily be economic without the adjacent Blythe development which is only 11km away.

IOG estimates that the mid case resources and Chance of Success may be:

Mid Case Estimates	*GIIP*	*Resources*	*CoS*
Wherry A North	36 BCF	25 BCF	36%
Wherry A South	22 BCF	16 BCF	36%

Note:

The views of the Directors and IOG set out above could ultimately prove to be incorrect. No warranty, express or implied, is given by the presentation of these figures and no reliance on the Company's estimates cited in this document. Attention is drawn to the risk factor on hydrocarbon resource and reserve estimates set out on page 34 of this document.

IOG applied for this acreage in the 27th Licensing Round in May 2012 and has been informed by DECC that its application received more points than any other applicant and that DECC would be minded to award the licence to IOG if the current process of checking for environmental issues leads to a decision to award the licence. There is no certainty that the licence will be awarded.

3. Reasons for Admission and Use of Proceeds

The Directors are seeking admission of the Ordinary Shares to trading on AIM in order to raise sufficient funds to enable the Group to carry out its initial development and appraisal programmes on its licences. In addition, Admission will, in the Directors' opinion, enable the Company to raise further rounds of funding in the future to fund further acquisitions, appraisal and development activities and further exploration on the Group's existing and any future permit areas.

The net proceeds of the Subscription, being approximately £1,595,000, will be used to discharge approximately £230,000 of historic liabilities relating to the aborted IPO process in the summer of 2012 referred to in paragraph 1.2 above and also to meet certain commitments through to the end of 2014, including £130,000 on the Blythe site survey and £100,000 on licences fees and ongoing asset spend, in particular payments to the operator to carry out the technical work on the licence, not including substantial capital expenditure. The balance of £1,135,000 will be used to fund expenditure on the Field Development Plan due to be progressed on Blythe and for general working capital purposes.

Further details regarding the anticipated expenditure on the Blythe Licence are set out below in paragraph 4 below.

The Directors anticipate that a further fund raising will be required to allow IOG to develop its assets and this would only be done after a new operator is in place for Blythe and Skipper and the plans and associated budgets are known. The Directors anticipate that the source of such funds will be by way of the issue of further Ordinary Shares and by a Reserve Based Lending facility. Over the past two years, the Directors of IOG have held discussions with several potential providers of debt funding for oil and gas developments and believe that a suitable debt facility will be forthcoming, on terms acceptable to the Company.

4. Recent Developments, Interim Results and Prospects

For the fourth quarter of 2013, IOG expects minimal spend on its two main licences, Blythe and Skipper. The licence extensions beyond 31 December 2013 are expected to be conditional upon the outstanding licence commitments; namely the submission of an FDP on Blythe and the drilling of an appraisal well on Skipper to the depth of 1700m or 50m below the Maureen Formation, whichever is the shallower.

On the Blythe Licence, IOG has budgeted £130,000 spend for its 50 per cent. share of the cost of a site survey. This expenditure may be committed in 2013 but is subject to the availability of a suitable vessel to carry out the survey. As part of the required preparation for FDP submission, ATP UK is expected to commission this work activity once the funding plans of its new owner are known.

Similarly, on the Skipper Licence, no firm budget has been proposed by the current operator. However, as soon as the sale of ATP UK has completed, IOG can expect to be required to fund its 50 per cent. share of the Skipper appraisal well, which is expected to be drilled in the summer of 2014.

The interim results set out in Section A of Part III of this document highlight that there was very little activity on the licences for the six months to the end of June 2013. During the period, the Directors evaluated several corporate transactions including mergers, acquisitions, asset purchases and reverse take-overs, none of which proceeded to an agreed transaction, ultimately as a direct result of the ATP situation.

For the second half of 2013, the Directors expect to be progressing with preparation for the submission of the Blythe FDP and the Skipper appraisal well. IOG also expects to be evaluating opportunities to acquire production in the North Sea whether funded through a debt facility or through an equity fund-raise or a combination of both. Corporate transactions may be evaluated and considered if they are judged to be value adding and in line with IOG's strategy.

5. An overview of the UK North Sea Licensing and Fiscal Regimes

UK North Sea Licensing Regime

Since the 1970s, the UKCS region of the North Sea has emerged as one of the most significant hydrocarbon producing areas in the world. During 2012, approximately 0.6 billion Boe or 1.54 million boepd were recovered from the UKCS, resulting in an aggregate of approximately 42 billion Boe since 1970, with an estimated 15 to 24 billion Boe remaining to be recovered.

In 2002, in order to encourage exploration activity, the then regulator, the DTI, began a consultation process on the need to undertake substantial reforms of the UK licensing system. A new type of seaward production licence was introduced which are awarded for up to four years, with the potential to extend 50 per cent. of the area for a further four years. In the event of a commercial development, the licences are generally granted for up to eighteen years. During the exploration phase a company can surrender a licence if it wishes to do so after its committed work programme has been completed.

In particular, in 2003 the DTI also introduced the concept of the Promote Licence, in order to counteract the decrease in exploration expenditure, as the Major oil companies shifted their exploration efforts away from the North Sea in favour of new exploration frontiers such as Russia, West Africa and the deep-water Gulf of Mexico, perceiving that the North Sea did not offer the prospect of sufficiently large oil discoveries to meet their materiality requirements. Promote Licences are a variant of the seaward production licences that are designed to allow small and start-up companies to obtain a production licence first, and attract the necessary operating and financial capacity later. These licences are specifically designed to attract smaller exploration companies to the UK North Sea. The rental costs for a Promote Licence are one tenth that of a traditional licence for the first two years and the barriers to entry are less stringent. Awardees of Promote Licences are given two years to assess the licensed area without the need to drill a well. It is only after these two years of comparatively low cost evaluation that the licensee is required to elect to drill or relinquish the block.

The current regulator, the DECC, was created in October 2008. The DECC also identifies undeveloped or fallow blocks. The licensees of such blocks must plan significant activity within one year or relinquish the blocks. For fallow discoveries, the licensees have two years to put forward similar plans. This policy is designed to increase the number of blocks to be made available in later rounds from a pool of relinquished blocks.

Applicable UK statutory regulations impose a number of obligations on licensees that are primarily aimed at ensuring the efficient, safe and most environmentally appropriate means by which oil and gas can be produced. In addition, on application for a production licence, the applicant is required to set out its planned work programme. That programme is agreed with the DECC before the award of the licence and the licensee is bound to undertake that programme, unless a revised or modified programme is subsequently agreed. With regard to production, there is an obligation to decommission the field's operating and transportation facilities once production has ceased. This can involve the complete or partial removal of platforms, clearance of the sea bed and the making safe of pipelines.

The licensee is responsible for the preparation and implementation of a decommissioning programme, to ensure compliance with the necessary regulatory and environmental legislation. The programme must cover, *inter alia*, such activities associated with the abandonment and decommissioning of disused wells, installations and pipelines. These programmes are developed in conjunction with the DECC and are also subject to public scrutiny and comment. With regards to a change of control event in respect of a licensee, there is no specific requirement for obtaining the Secretary of State's approval, however it can form grounds for potential revocation if DECC were to direct a possible further change of control and such instruction was not complied with by the licensee.

Applications for licences in the 27th Round were invited in May 2012 and DECC received a record 224 applications covering 418 blocks, compared to 356 block applications received in the 26th Round. This is the largest number of block applications ever received.

UK North Sea Fiscal Regime

Effective tax rates for UK oil and gas production now range from 30 per cent. (corporation tax and the Supplementary Charge) to 81 per cent. (for fields given development status before March 1993 and which are also subject to petroleum revenue tax).

There have been a number of recent changes to the tax regime aimed at promoting investment in more difficult oil and gas fields across the UKCS. In particular, a new field allowance was introduced in the 2009 Budget, which is specifically targeted at the following categories of fields:

(i) small fields of less than 45 million BOE in size;

(ii) certain types of heavy oil fields;

(iii) very high pressure high temperature fields; and

(iv) gas developments to the West of Shetland (subsequently announced in January 2010).

The introduction of this allowance signals recognition by the UK Government that the tax system has a part to play in maximising the potential economic recovery of the UK's remaining oil and gas resources.

6. Directors and senior management

IOG is led by a strong, disciplined Board and management team with extensive experience in all aspects of the Company's business. The management's experience covers both ends of the investment spectrum from private equity backed start-up companies to FTSE-250 listed companies.

Directors

Mehdi Varzi – *Non-executive Chairman (Aged 68)*

Mr. Varzi is highly experienced with considerable oil and gas knowledge. He is a Member of the international advisory panel, RECIPCO, with specific responsibility for energy developments and an advisor to Una Oil S.A., a private offshore international oil services company. He has held various high profile city jobs including Managing Director, Global Energy Research at Dresdner Kleinwort Wasserstein and vice Chairman of Gulf Keystone Petroleum plc.

Mark Routh – *Chief Executive Officer (Aged 55)*

Mr. Routh has over 30 years' experience in the oil and gas industry. He is the former Chief Executive Officer and founder of oil and gas company, CH4 Energy Limited, which was an owner and operator in the North Sea. CH4 was formed with £1 million funding from management and 3i in 2002 and sold to Venture in 2006 for £154.4 million, providing 3i a with a record 7.3 multiple return on its investment. Prior to founding CH4, Mr. Routh served for ten years with Amerada Hess, six years with BP and five years with Schlumberger in South East Asia and the North Sea. Mr. Routh is also the non-executive Chairman of Warrego Energy Ltd a company with onshore gas assets in Western Australia. Mr. Routh has an MSc in Petroleum Engineering from Imperial College, London.

Peter Young – *Chief Financial Officer (Aged 41)*

Mr. Young has over 15 years' experience in oil and gas banking and finance with a focus on the mid-cap E&P sector. He was previously on the board of Ebor Energy Inc. and Multi Operational Service Tankers Inc. He was a founder member of IOG in 2011 as Business Development Director and became CFO in February 2013. Prior to that he was Regional Head of Energy Derivative Sales at Standard Chartered Bank.

Marie-Louise Clayton – *Non-executive Director (Aged 52)*

Ms. Clayton has 30 years' experience. She is the former Chief Financial Officer of oil and gas company, Venture Production plc. Prior to joining Venture, Ms. Clayton was Group Finance Director and Chief Information Officer of the Primary Food Division of Associated British Foods plc and served at a number of major industrial companies including ExxonMobil, Alcatel, and GEC Alstom. She is currently a non-executive director of fully listed Diploma plc, AIM quoted Zotefoams plc and Geoffrey Osborne Ltd, a large private construction company. Previously Ms. Clayton was the chair of Audit at Forth Ports plc.

Mike Jordan – *Non-executive Director (Aged 42)*

Mr. Jordan is a serial entrepreneur leading the successful development and subsequent divestment of three environmental groups between 1995 and 2006. He formed Acura Investment group in 2007 and, as Chief Executive Officer, has investments in energy, property, retail and the oil and gas sector. He has been President of Ebor Energy Inc. since late 2008.

Further details of the service agreements and appointment letters of the Directors, together with their interests in the Company's share capital, are set out in Part V of this document.

Senior Management

Richard Jameson – *Operations Director (Aged 57)*

Mr. Jameson has 30 years' experience in project management and engineering, with the last ten years in production operations management, including design, engineering, construction and project implementation, commissioning and decommissioning both on and offshore in the upstream oil and gas industry with Hess, Petro Canada, Foster Wheeler and others. He holds qualifications in Business Administration (MBA), Mechanical and Production Engineering (HND), Marketing (Dip.M) and is a member of the Chartered Institute of Marketing.

Chris Brown – *Technical Director (Aged 56)*

Mr. Brown has 32 years of upstream oil and gas experience, including 10 years working overseas. He has a track record in finding oil in Egypt, Libya, Italy, Peru, Poland and the North Sea. Mr. Brown has experience in managing all types of seismic and well operations and has successfully managed a number of multi-disciplined teams including geoscience, engineering and commercial analysts. Mr. Brown has an MSc Geology from Imperial College, London.

Brian Oldfield – *Chief Geoscientist (Aged 75)*

Mr. Oldfield has 44 years' experience of the international oil industry, geology and geophysics, including early roles at Conoco & Zapata and consultancy roles at Total, Idemitsu, Statoil and Agip. Mr. Oldfield has experience in 30 geological basins in Europe, Russia, Africa, Middle and Far East with over 20 years in the UK North Sea working in all basins of the UK developing exploration plays for regional and licensed areas.

Colin Jones – *Petroleum Engineer (Aged 50)*

Mr. Jones has 27 years worldwide experience, currently with DNO International on heavy oil developments. He was with Norsk Hydro for 10 years before starting an independent consultancy. Mr. Jones was a founding director of MOST Inc and former Chairman of the Society of Petroleum Engineers, Oslo. Mr. Jones is active in mergers and acquisitions, company restructuring, asset valuations, reserves auditing, on and offshore field operations and field development studies. He has experience in many former Soviet Union countries and also from South America, North Africa, the Middle East and Europe.

John Boyle – *Drilling and Operations (Aged 62)*

Mr. Boyle has 40 years worldwide oil industry experience including drilling and operations experience with Shell in Holland, Qatar and Brunei, and as wells team leader for major North Sea projects with BP. Mr. Boyle joined Cairn Energy 2009 in a senior drilling management role as part of high profile frontier exploration programme offshore Greenland.

All of the above members of the senior management of the Group currently provide services on a consultancy basis.

7. Details of the Subscription

The Subscription will raise £2 million for the Company (before expenses). The Subscription Shares are being placed with institutional and other investors and will represent approximately 14.12 per cent. of the Enlarged Share Capital.

The Subscription, which has not been underwritten, is conditional, *inter alia*, on Admission becoming effective on or before 30 September 2013. The Subscription Shares will rank *pari passu* in all respects with the Existing Ordinary Shares, including the right to receive all dividends and other distributions declared, paid or made after the date of issue and will be placed free of any expenses and stamp duty.

Following Admission and subject to a Subscriber (and/or any of its associates) continuing to hold all of the Subscription Shares then, upon the first occurrence (but not otherwise) of the Company seeking to raise additional capital following Admission pursuant to an offer of shares (but not, for the avoidance of any doubt, any securities that are convertible or carry rights to subscribe for new Ordinary Shares) by way of:

(i) a fresh issue of Ordinary Shares which is made on a non pre-emptive basis to certain existing holders of Ordinary Shares and/or to potential new investors in the Company; or

(ii) a rights issue to existing holders of Ordinary Shares on a pre-emptive basis,

and the price per Ordinary Share at which the Offer is made (the "Offer Price") is less than approximately 28.55 pence then the Subscriber shall have the right to acquire such number of new Ordinary Shares at a subscription price equal to the nominal value of an Ordinary Share, as shall as near as possible result in the Offer Price representing 120 per cent. of the average subscription price paid by the Subscriber.

Following Admission, the Directors and their associates will between them be interested in 26,992,524 Ordinary Shares, representing approximately 45.34 per cent. of the Enlarged Share Capital. Following Admission, certain other Significant Shareholders, as referred to in paragraph 12.1 of Part V of this document, will each hold three per cent. or more of the Enlarged Share Capital.

The existing aggregate shareholdings of Shareholders of the Company prior to the Subscription will be diluted by approximately 14.12 per cent. by the issue of the Subscription Shares.

Further details of the Subscription Agreements are set out in paragraph 14.18 of Part V of this document.

8. Corporate Governance

The Directors recognise the importance of sound corporate governance commensurate with the size and nature of the Company and the interests of its Shareholders. The Corporate Governance Code does not apply to companies quoted on AIM and there is no formal alternative for AIM companies. The Quoted Companies Alliance has published a set of corporate governance guidelines for AIM companies, which include a code of best practice for AIM companies, comprising principles intended as a minimum standard, and recommendations for reporting corporate governance matters. However, the Directors intend to implement steps to comply with the Corporate Governance Code, so far as it is practicable having regard to the size and current stage of development of the Company.

Set out below is a description of the Company's proposed corporate governance practices.

The Board

The Board will meet regularly and be responsible for strategy, performance, approval of any major capital expenditure and the framework of internal controls.

The Board will be responsible for establishing and maintaining the Group's system of internal financial controls and importance is placed on maintaining a robust control environment. The key procedures which the Board intends to establish with a view to providing effective internal financial control include the following:

- the Company will institute a monthly management reporting process to enable the Board to monitor the performance of the Group;
- the Board will adopt and review a comprehensive annual budget for the Group. Monthly results will be examined against the budget and deviations will be closely monitored by the Board;

- the Board will be responsible for maintaining and identifying major business risks faced by the Group and for determining the appropriate courses of action to manage those risks; and
- full consolidated management information will be prepared on a regular basis, at least half yearly.

The Board recognises, however, that such a system of internal financial control can only provide reasonable, not absolute, assurance against material misstatement or loss. The effectiveness of the system of internal financial control operated by the Group will therefore be subject to regular review by the Board in light of the future growth and development of the Company and adjusted accordingly.

To enable the Board to discharge its duties it is intended that all of the Directors will receive timely information.

The Board includes three non-executive directors. If necessary, the non-executive directors may take independent advice. The Board has delegated specific responsibilities to the committees referred to below.

Audit Committee

The Audit Committee will initially comprise Mehdi Varzi (Chairman), Marie-Louise Clayton and Mike Jordan. The Audit Committee will have primary responsibility for monitoring the quality of internal controls and ensuring that the financial performance of the Group is properly measured and reported on. In addition, it will receive and review reports from the Company's management and auditors. The Audit Committee will meet at least twice a year and will have unrestricted access to the Company's auditors.

Remuneration Committee

The Remuneration Committee will initially comprise Mike Jordan (Chairman), Marie-Louise Clayton and Mehdi Varzi. The Remuneration Committee will, *inter alia*, determine the remuneration of the executive directors and grant share options and any other equity incentives pursuant to any share option scheme or equity incentive scheme in operation from time to time. The Remuneration Committee will meet at least twice a year.

Nomination committee

There will be no nomination committee initially. This will be reviewed as the business progresses.

The Share Dealing Code

The Company has adopted the Share Dealing Code which governs dealings by the Directors and employees (as well as certain relevant persons) in the Company's securities and which is appropriate for a company whose shares are admitted to trading on AIM (in order to, *inter alia*, ensure compliance with Rule 21 of the AIM Rules for Companies).

The Company will take all reasonable steps to ensure compliance with the terms of the Share Dealing Code by the Directors and all other relevant persons.

9. Dividend Policy

It is the intention of the Directors to achieve capital growth. In the short term, the Directors intend to retain any future profits in the Company and, accordingly, are unlikely to declare dividends in the foreseeable future. However, the Directors will consider the payments of dividends out of the distributable profits of the Company when they consider it is appropriate to do so.

10. The Takeover Code

The Takeover Code applies to offers for all listed and unlisted public companies considered by the Panel to be resident in the UK, the Channel Islands or the Isle of Man. The Panel will normally consider a company to be resident only if it is incorporated in the UK, the Channel Islands or the Isle of Man and has its place of central management in one of those jurisdictions (referred to as the "residency test"). The Company is incorporated in England and Wales and is deemed to have its place of central management in England and

Wales and the Panel would therefore consider that the Takeover Code applies to the Company. At Admission, the Company will therefore fall under the jurisdiction of the Takeover Code which will apply for the benefit of all Shareholders.

With effect from 30 September 2013 the Takeover Code will be amended and the residency test will no longer apply. However, this will not affect the application of the Takeover Code to the Company as it will have securities admitted to a multilateral trading facility in the UK.

11. Share Options

The Board believes that it is important that employees of the Group (including executive directors) are appropriately and properly motivated and rewarded, with the success of the Group dependent to a significant degree on the future performance of the executive management team. Accordingly, the Board has adopted the Long Term Incentive Plan allowing the Company to grant to employees options over Ordinary Shares. The Long Term Incentive Plan will be administered by the Remuneration Committee and the maximum aggregate awards under the Long Term Incentive Plan, together with any other employee share schemes adopted after Admission, cannot exceed ten per cent. of the issued share capital of the Company at the time of grant. Further details of the Long Term Incentive Plan are set out in paragraph 16.1 of Part V of this document.

The Board has granted, conditional on Admission, options over 4,500,000 Ordinary Shares to the Company's executive Directors pursuant to the Long Term Incentive Plan. These options have been granted in two tranches with exercise prices of 29.74p and 41.63p per Ordinary Share respectively. The options will not be exercisable for a minimum of three years from the date of grant and only vest where the price of the Ordinary Shares on AIM exceeds 47.58p and 59.48p per Ordinary Share, respectively, for 20 consecutive trading days and provided certain key performance indicators set by the Remuneration Committee at the time of grant are satisfied.

In addition, to reward the outstanding work performed by certain members of the IOG team in the development of IOG to date and in respect of Admission, the Board has granted, subject to Admission, options over a further 6,873,946 Ordinary Shares. These options have been granted pursuant to individual option agreements between the Company and the individual rather than pursuant to the Long Term Incentive Plan. Such options are exercisable at a price of 1p per Ordinary Share at any time after 1 January 2015 until 30 June 2015 and are not subject to any performance conditions.

The Directors may establish further share incentive arrangements for the benefit of the Group's employees in the future. Any options to be granted under any such share incentive arrangements will be at the discretion of the Remuneration Committee. Options may also be granted to non-executive directors of, and consultants to, the Group. These options will not be granted pursuant to the Long Term Incentive plan, but will be granted under individual option agreements between the Company and the individual concerned.

Details of the options granted to the Directors are set out in paragraph 9.2 of Part V of this document.

12. Lock-in and orderly market arrangements

The Directors, each of the members of the Company's management team listed in paragraph 6 above and several existing Shareholders have entered into the Lock-in Deed with the Company and Charles Stanley, pursuant to which they have each agreed:

- not to dispose of any of their interests in Ordinary Shares for a period of at least twelve months from the date of Admission, save in certain limited circumstances permitted by rule 7 of the AIM Rules; and
- in the case of the Directors, not to dispose of any of their interests in Ordinary Shares for a period of twelve months from the first anniversary of the date of Admission, except through Charles Stanley (or the Company's broker from time to time), so as to maintain an orderly market in the Ordinary Shares.

The aggregate interests following Admission which shall be subject to the lock-in and orderly market arrangements as described above will amount to 39,845,153 Ordinary Shares, which is equivalent to approximately 66.93 per cent. of the Enlarged Share Capital. Further details of the Lock-in Deed are set out in paragraph 14.3 of Part V of this document.

13. Settlement, dealings and CREST

CREST is a paperless settlement procedure enabling securities to be evidenced otherwise than by a certificate and transferred otherwise than by written instrument. The Articles contain provisions concerning the transfer of shares which are consistent with the transfer of shares in dematerialised form in CREST under the CREST Regulations. The Directors have applied for the Ordinary Shares to be admitted to CREST with effect from Admission and CREST has agreed to such admission. Accordingly, settlement of transactions in the Ordinary Shares following Admission may take place within the CREST system if relevant Shareholders so wish. CREST is a voluntary system and Shareholders who wish to receive and retain share certificates will be able to do so. Where Subscribers have requested to receive their Ordinary Shares in certificated form, share certificates will be despatched by first-class post within fourteen days of the date of Admission.

Application will be made to the London Stock Exchange for the Enlarged Share Capital to be admitted to trading on AIM. It is expected that Admission will become effective and that dealings will commence on 30 September 2013.

No temporary documents of title will be issued. All documents sent by or to a Subscriber, or at his/her direction, will be sent through the post at the Subscriber's risk. Pending the receipt of definitive share certificates in respect of the Subscription Shares (other than in respect of those Subscription Shares settled via CREST), transfers will be certified against the register of members of the Company.

For further information concerning CREST, Shareholders should contact their brokers or Euroclear at 33 Cannon Street, London, EC4M 5SB or by telephone on +44 (0)20 7849 0000.

14. Taxation

The attention of investors is drawn to certain information regarding UK taxation, insofar as it may be applicable to UK residents in relation to the Subscription and Admission, set out in paragraph 18 of Part V of this document. Your attention is also drawn to the risk factor on taxation set out on page 40 of this document.

All information in this document in relation to taxation is intended only as a general guide to the current tax position for UK investors as at the date of this document and is not intended to constitute personal tax advice for any person. Prospective investors are strongly advised to consult their own independent professional tax advisers regarding the tax consequences of purchasing and owning the Company's Ordinary Shares. No information is being provided as to any US taxation matters.

15. Further information and risk factors

Your attention is drawn to Parts II to V (inclusive) of this document and the definitions. In particular you are advised to carefully consider the Risk Factors contained in Part II of this Document.

PART II

RISK FACTORS

The exploration for and development of natural resources is a highly speculative activity which involves a high degree of risk. Accordingly, the Ordinary Shares should be regarded as a highly speculative investment and an investment in the Company should only be made by those with the necessary expertise to evaluate the investment fully.

The Group's business, financial condition or results of operations could be materially and adversely affected by any of the risks described below. In such cases, the market price of the Ordinary Shares may decline and investors may lose all or part of their investment. In addition to the other relevant information set out in this document, the Directors consider that the following risk factors, which are not set out in any particular order of priority, magnitude or probability, are of particular relevance to the Group's activities and to any investment in the Company. It should be noted that additional risks and uncertainties not presently known to the Directors or which they currently believe to be immaterial may also have an adverse effect on the Group's operating results, financial condition and prospects. Any one or more of these risk factors could have a materially adverse impact on the value of the Group and should be taken into consideration when assessing the Company.

There can be no certainty that the Group will be able to implement successfully the strategy set out in this document. No representation is or can be made as to the future performance of the Group and there can be no assurance that the Group will achieve its objectives.

1. Risks relating to the Group's activities and the oil and gas industry

Terms of licences

As outlined in paragraphs 2.1.2 and 2.2.2 of Part I of this document, there is a risk that the IOG Group's two material assets – Blythe and Skipper – could be at risk if a new operator is put in place that seeks to carry out significant expenditure on these assets before IOG can raise the necessary funding for its share. Until the plans of any new operator are known, these expenditures are considered contingent and IOG is not raising funds to cover this eventuality on Admission, but would seek to do so via a secondary fund raising once the operator's plans are known and agreed.

There is a risk that the terms of the Blythe Licence and the Skipper Licence are not extended beyond 31 December 2013. The Directors believe that DECC will continue to extend the licences since they have already granted three extensions on these licences during 2013. DECC has granted these extensions to allow the completion of the ATP sale process. Please see sections 2.1.2 (Blythe) and 2.2.2 (Skipper) of Part I above regarding the specific issues pertaining to each licence and why extensions are likely to be granted.

Title matters and payment obligations

Whilst the Group has diligently investigated its title to, and rights and interests in, the licences granted to or acquired by the IOG Group and its JV partners in respect of the Blocks and, to the best of its knowledge, such title, rights and interests are in good standing, this should not be construed as a guarantee of the same. The licences may be subject to undetected defects. If a defect does exist, it is possible that the Group may lose all or part of its interest in the licence to which the defect relates and its exploration and appraisal programme and prospects may accordingly be adversely affected.

While the Directors have no reason to believe that the existence and extent of any of the Group's properties are in doubt, title to oil and gas properties is subject to potential litigation by third parties claiming an interest in them. The failure to comply with all applicable laws and regulations, including failure to pay taxes, meet minimum expenditure requirements or carry out and report assessment work may invalidate title to portions of the properties where the petroleum rights are not held by the Group.

Under the licences and certain other contractual agreements to which the Group is, or may in the future become party, the Group is or may become subject to payment and other obligations. Failure to satisfy these obligations will render the licence liable to be revoked. Further, if any contractual obligations are not complied with when due, in addition to any other remedies which may be available to other parties, this could result in dilution or forfeiture of interests held by the Group.

Early stage of operations

The Group's operations are at an early stage of development and future success will depend on the Directors' ability to successfully manage and exploit the current asset portfolio and to take advantage of further opportunities which may arise. There can be no guarantee that the Group can or will be able to, or that it will be commercially advantageous for the Group to, develop the Blocks.

Further, the Group has no assets producing positive cash flow and its ultimate success will depend on the Directors' ability to implement their strategy, generate cash flow from economically viable projects and access debt and equity markets. Whilst the Directors are optimistic about the Group's prospects, there is no certainty that sustainable revenue streams and sustainable profitability will be achieved. The Group will not generate any material income until production has successfully commenced or producing assets have been acquired and in the meantime the Group will continue to expend its cash reserves and will, in due course, need to raise debt and/or additional equity capital.

The Group's projects have no recent operating history upon which to base estimates of future cash operating costs. For early stage projects, estimates of proven and probable reserves and cash operating costs are, to a large extent, based upon the interpretation of geological data and feasibility studies which derive estimates of cash operating costs based upon anticipated recoveries, expected recovery rates, comparable facility and equipment operating costs, anticipated climatic conditions and other factors. As a result, it is possible that actual cash operating costs and economic returns may differ materially from those estimated.

General exploration and production risks

There can be no guarantee that the hydrocarbons currently discovered will be developed into profitable production, or that additional hydrocarbons will be discovered in commercial quantities or developed to profitable production. The business of exploration for, and development and exploitation of, hydrocarbon deposits is speculative and involves a high degree of risk, which even a combination of careful evaluation, experience and knowledge may not eliminate. Hydrocarbon deposits assessed by the Group may not ultimately contain economically recoverable volumes of resources and even if they do, delays in the construction and commissioning of production projects or other technical difficulties may result in any projected target dates for production being delayed or further capital expenditure being required.

The operations and planned drilling activities of the Group and its JV partners may be disrupted, curtailed, delayed or cancelled by a variety of risks and hazards which are beyond the control of the Group, including unusual or unexpected geological formations, formation pressures, geotechnical and seismic factors, environmental hazards such as accidental spills or leakage of petroleum liquids, gas leaks, ruptures or discharge of toxic gases, industrial accidents, occupational and health hazards, technical failures, mechanical difficulties, equipment shortages, labour disputes, fires, power outages, compliance with governmental requirements and extended interruptions due to inclement or hazardous weather and ocean conditions, explosions, blow-outs, pipe failure and other acts of God. Any one of these risks and hazards could result in work stoppages, damage to, or destruction of, the Group's or its partners' facilities, personal injury or loss of life, severe damage to or destruction of property, environmental damage or pollution, clean-up responsibilities, regulatory investigation and penalties, business interruption, monetary losses and possible legal liability which could have a material adverse impact on the business, operations and financial performance of the Group. Although precautions to minimise risk are taken, even a combination of careful evaluation, experience and knowledge may not eliminate all of the hazards and risks. In addition, not all of these risks are insurable.

Hydrocarbon resource and reserve estimates

No assurance can be given that hydrocarbon resources and reserves reported by the Group in the future are present as estimated, will be recovered at the rates estimated or that they can be brought into profitable production. Hydrocarbon resource and reserve estimates may require revisions and/or changes (either up or down) based on actual production experience and in light of the prevailing market price of oil and gas. A decline in the market price for oil and gas could render reserves uneconomic to recover and may ultimately result in a reclassification of reserves as resources.

Unless stated otherwise, the hydrocarbon resources data contained in this document is taken from the CPRs. There are uncertainties inherent in estimating the quantity of resources and reserves and in projecting future rates of production, including factors beyond the Group's control. Estimating the amount of hydrocarbon resources and reserves is an interpretive process and, in addition, results of drilling, testing and production subsequent to the date of an estimate may result in material revisions to original estimates.

The hydrocarbon resources data contained in this document and in the CPRs are estimates only and should not be construed as representing exact quantities. The nature of reserve quantification studies means that there can be no guarantee that estimates of quantities and quality of the resources disclosed will be available for extraction. Accordingly, actual production, revenues, cash flows, royalties and development and operating expenditures may vary from these estimates. Such variances may be material. Any reserves estimates contained in this document are based on production data, prices, costs, ownership, geophysical, geological and engineering data, and other information assembled by the Group (which it may not necessarily have produced). The estimates may prove to be incorrect and potential investors should not place reliance on the forward looking statements contained in this document (including data included in the CPRs or taken from the CPRs) concerning the Group's resources and reserves or production levels.

Hydrocarbon resources and reserves estimates are expressions of judgement based on knowledge, experience and industry practice. They are therefore imprecise and depend to some extent on interpretations, which may ultimately prove to be inaccurate. Accordingly, two different independent parties may not necessarily arrive at the same conclusions. The views of the Directors as set out in this document could ultimately prove to be incorrect and investors are urged to refer to the views of AGR TRACS and ERC Equipoise when analysing the information concerning Skipper and Blythe respectively contained in this document. Estimates that were reasonable when made may change significantly when new information from additional analysis and drilling becomes available. This may result in alterations to development and production plans which may, in turn, adversely affect operations.

If the assumptions upon which the estimates of the Group's hydrocarbon resources have been based prove to be incorrect, the Group (or the operator of an asset in which the Group has an interest) may be unable to recover and produce the estimated levels or quality of hydrocarbons set out in this document and the Group's business, prospects, financial condition or results of operations could be materially and adversely affected.

Farm-out and joint venture partners

The Group has entered into agreements with ATP UK and it operates the existing assets in which the Group has an ownership interest. From time to time, the Group may enter into additional partnership and/or farm-out agreements to operate and/or fund all or a portion of the exploration and development costs associated with its existing and potential future assets. Liquidity and cash flow problems encountered by the partners and co-owners of such assets and any non-compliance by the partners and co-owners may lead to a delay in the pace of drilling or project development that may be detrimental to a project or may otherwise have adverse consequences for the Group. In addition, any farm-out partners and working interest owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farm-out partner, the Group may have to obtain alternative funding in order to complete the exploration and development of the assets subject to the farm-out agreement. In the case of a working interest owner, the Group may be required to pay the working interest owner's share of the project costs. The Group cannot assure investors that it would be able to obtain the capital necessary in order to fund either of these contingencies. It is also possible that the interests of the Group and those of its joint venture partners are not aligned resulting in project delays or additional costs or losses.

Counterparty risk

The Group will be subject to agreements with a number of counterparties in relation to the potential future sale and supply of oil and gas production volumes. Therefore, the Group will potentially be subject to the risk of delayed payment for delivered production volumes or counterparty default. Such delays or defaults could have a material adverse effect on the Group's business.

Volatility in the price of oil and gas and the general economic climate

The general economic climate and market price of, and demand for, oil and natural gas is volatile and is affected by a variety of factors which are beyond the Group's control. These could include international supply and demand, the level of consumer product demand, weather conditions, the price and availability of alternative fuels and new technologies, growth in gross domestic product, supply and demand of capital, employment trends, international economic trends, currency exchange rate fluctuations, the level of interest rates and the rate of inflation, the cost of freight, actions taken by governments and international cartels, global or regional political events and international events, as well as a range of other market forces. The aggregate effect of these factors is impossible to predict. International oil prices have fluctuated widely in recent years and may continue to fluctuate significantly in the future. Sustained downward movements in oil and gas prices could render less economic, or wholly uneconomic, some or all of the exploration and potential future oil and gas production related activities to be undertaken by the Group and adversely affect the value of the Group's exploration assets.

The marketability of any oil and gas discovered will be affected by numerous factors beyond the Group's control. These factors include market fluctuations, proximity and capacity of oil and gas pipelines and processing equipment and government regulations including regulations relating to taxation, royalties, allowable production, importing and exporting of oil and gas and environmental protection.

Availability of drilling, exploration and production equipment

The availability of drilling rigs and other equipment and third party services or technical contractors is affected by the level and location of drilling activity around the world. An increase in drilling operations outside the current North Sea focus area of the Group or in other areas may reduce the availability of equipment and services to the Group. Similarly, the Group may have difficulty sourcing the exploration and production equipment it requires in the timeframe envisaged by the Group's plans due to high global demand for such equipment. The reduced availability of equipment and services, as well as their potentially high cost, may delay the Group's ability to exploit any reserves and adversely affect the Group's operations and profitability.

Government regulations and permits

The Group's intended activities will be dependent upon the appropriate licences, concessions, leases, permits and regulatory consents which could subsequently be withdrawn or made subject to limitations. There can be no guarantee as to the terms of any such concessions or assurance that current concessions or future concessions will be renewed or, if so, on what terms when they come up for renewal. Although the Directors believe that the Group's activities are currently carried out in accordance with all applicable rules and regulations, no assurance can be given that new rules, laws and regulations will not be enacted or that existing or future rules and regulations will not be applied in a manner which could serve to limit or curtail exploration, production or development of the Group's business or have an otherwise negative impact on its activities. Amendments to existing rules, laws and regulations governing the Group's operations and activities, or increases in or more stringent enforcement, implementation or interpretation thereof, could have a material adverse impact on the Group's business, results of operations and financial condition and its industry in general in terms of additional compliance costs.

Climatic conditions

The Directors are aware that exploration and appraisal programmes may be adversely affected by climatic conditions, with harsh weather and ocean conditions likely to cause delays in the Group's exploration and appraisal activities.

Dependence on key executives and personnel

The future performance of the Group will to a significant extent be dependent on its ability to retain the services and personal connections or contacts of key executives and to attract, recruit, motivate and retain other suitably skilled, qualified and industry experienced personnel to form a high calibre management team. Such key executives are expected to play an important role in the development and growth of the Group, in particular by maintaining good business relationships with regulatory and governmental departments and essential partners, contractors and suppliers.

Attracting and retaining additional skilled personnel may also be required to ensure the development of the Group's business. The Group faces significant competition for skilled personnel in the oil and gas sector.

Although certain key executives and personnel have entered, or will subject to Admission enter, into service agreements or letters of appointment with the Group, there can be no assurance that the Group will retain their services. The loss of the services of any of the key executives or personnel may have a material adverse effect on the business, operations, relationships and/or prospects of the Group.

Labour

Certain of the Group's operations may be carried out under potentially hazardous conditions. Whilst the Group intends to operate in accordance with relevant health and safety regulations and requirements, the Group remains susceptible to the possibility that liabilities might arise as a result of accidents or other workforce-related misfortunes, some of which may be beyond the Group's control.

Further, the Group may struggle to recruit engineers and other important members of the workforce required to run a full exploration or appraisal programme. Shortages of labour, or of skilled workers, may cause delays or other stoppages during exploration and appraisal activities.

Environmental, health and safety and other regulatory standards

The projects in which the Group invests and its exploration and potential production activities are subject to various laws and regulations relating to the protection of the environment (including regular environmental impact assessments and the obtaining of appropriate permits or approvals by relevant environmental authorities) and are also required to comply with applicable health and safety and other regulatory standards. Environmental legislation in particular can, in certain jurisdictions, comprise numerous regulations which might conflict with one another and which cannot be consistently interpreted. Such regulations typically cover a wide variety of matters including, without limitation, prevention of waste, pollution and protection of the environment, labour regulations and worker safety. The Group may also be subject under such regulations to clean-up costs and liability for toxic or hazardous substances which may exist on or under any of its properties or which may be produced as a result of its operations. As a result, although all necessary environmental consents are in place in respect of the licences awarded to the Group to enable exploration for oil and gas to take place and the Group intends to operate in accordance with the highest standards of environmental practice and comply in all material respects, full compliance with applicable environmental laws and regulations may not always be ensured.

Any failure to comply with relevant environmental, health and safety and other regulatory standards may subject the Group to extensive liability, fines and/or penalties and have an adverse effect on the business and operations, financial results or financial position of the Group. Furthermore, the future introduction or enactment of new laws, guidelines and regulations could serve to limit or curtail the growth and development of the Group's business or have an otherwise negative impact on its operations. Any changes to, and increases in, current regulation or legal requirements may have a material adverse effect upon the Group in terms of additional compliance costs. The obtaining of exploration, development or production licences and permits may become more difficult and/or be the subject of delay by reason of governmental, regional or local environmental consultation, approvals or other considerations or requirements. These factors may lead to delayed or reduced exploration, development or production activity as well as to increased costs and may have a material adverse effect on the Group's business.

Decommissioning and abandonment

Upon cessation of any operations on a Block, the Group together with its JV partners or co-owners may through their licence interests assume responsibility for costs associated with abandoning infrastructure and restoring the operational sites by taking reasonable and necessary steps in accordance with generally accepted environmental practices in the international petroleum industry. Any environmental permits held by the Group may also specify commitments to the UK Government for specific rehabilitation activities on a site. At the end of any exploitation period, the relevant authority will typically confirm fulfilment, or require further work as necessary, to meet the permit conditions.

The oil and gas industry in the UK has little experience of decommissioning petroleum exploration and production facilities on the UKCS. Few such facilities on the UKCS have been removed. Consequently, it is difficult to predict the costs that the Group may be exposed to in satisfying any such future decommissioning obligations.

The Group's objectives may not be fulfilled

The ability of the Board to implement the Group's strategy could be adversely affected by changes in the economy and/or industries in which it operates. Although the Group has a clearly defined strategy and the Board is optimistic about the Group's existing assets and future plans, there can be no guarantee that its objectives or any of them will be achieved on a timely basis or at all. In particular, further projects and/or opportunities may not be available or of the quality or in the number required to satisfy the Group's requirements and therefore the anticipated development or growth of the Group may not be achieved. The Group's ability to attract new growth opportunities is also dependent on the maintenance of its reputation.

2. General business risks relating to the Group

Future funding requirements

Significant capital investment will be required to achieve commercial production from the Group's existing projects. The Group will need to raise additional capital by way of the issue of further Ordinary Shares and/or by way of debt financing, or through other means, to finance its anticipated future operations, its working capital or capital expenditure requirements or to make acquisitions and finance its growth through future stages of development.

Additional equity issues may have a dilutive effect on the then prevailing Shareholders and investors if they are unable or choose not to subscribe and the issue of additional Ordinary Shares by the Company, or the possibility of such an issue, may cause the market price of the Ordinary Shares to decline.

Furthermore, any debt financing, if available, may include conditions that would restrict the Group's freedom to operate its business, such as conditions that:

- limit the Group's ability to pay dividends or require it to seek consent for the payment of dividends;
- increase the Group's vulnerability to general adverse economic and industry conditions;
- require the Group to dedicate a portion of any cash flow arising from future operations to payments on its debt, thereby reducing the availability of its cash flow to fund capital expenditures, working capital and other general corporate purposes; and
- limit the Group's flexibility in planning for, or reacting to, changes in its business and its industries.

There can be no guarantee or assurance that such debt funding or additional equity will be forthcoming when required, or as to the terms and price on which such funds would be available if at all. If the Group is unable to obtain additional financing as needed, or on terms which are acceptable, it may not be able to fulfil its strategy, which could have a material adverse effect on the Group's business, financial position and prospects. It may also be required to reduce the scope of its operations or anticipated growth, forfeit its interest in some or all of its assets, incur financial penalties or reduce or terminate its operations.

Capital expenditure may be higher than anticipated

The estimated capital expenditure requirements for the various assets in which the Group is interested are based on expected costs and made on certain assumptions. Should those capital expenditure requirements turn out to be higher than currently expected (for example, if there are unexpected difficulties in drilling or connecting to infrastructure, abandonment or decommissioning costs, other capital expenditure or price rises), the Group may need to seek additional funds which it may not be able to secure on reasonable commercial terms or at all or it may need to divert funds from other projects to satisfy the increased capital expenditure requirements. If this happens, it may have a material adverse effect on the Group's business.

Exchange rate fluctuations

Currency fluctuations may affect the Group's operating cash flow since certain of its costs and revenues are likely to be denominated in currencies other than Pounds Sterling such as US Dollars. Fluctuations in exchange rates between currencies in which the Group operates may cause fluctuations in its financial results which are not necessarily related to its underlying operations. The Group does not currently have a foreign currency hedging policy in place. If and when appropriate, the adoption of such a policy will be considered by the Board.

The Group may be subject to risks relating to acquisitions

Part of the Group's future strategy includes potentially increasing oil and gas resources, reserves and/or production through strategic business acquisitions. Risks commonly associated with acquisitions of companies or businesses include the difficulty of integrating the operations and personnel of the acquired business, problems with minority shareholders in acquired companies, the potential disruption of the Group's own business, the possibility that indemnification agreements with the sellers may be unenforceable or insufficient to cover potential liabilities, as well as operational risks relating to the assets acquired. Furthermore, the value of any business the Group acquires or invests in may be less than the amount it pays.

The competitive environment

Oil and gas exploration, appraisal, development and production and the natural resource industry in general is intensely competitive in all of its phases. The Group competes with numerous other local and international companies focused on the UKCS, including larger competitors with access to greater financial, technical and other resources than the Group, which may give them a competitive advantage in the exploration for and commercial exploitation of attractive oil and gas assets. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests and competition could adversely affect the Group's ability to acquire suitable additional assets in the future. This may lead to increased costs in the carrying on of the Group's activities and reduced available growth opportunities. The Group's success will depend on its ability to select and acquire exploration, appraisal and development rights on suitable assets or prospects on terms that it considers acceptable and there can be no assurance that the Group will continue to be able to compete successfully with its rivals.

Insurance coverage and uninsured risks

The Group plans to insure the risks it considers appropriate for the Group's needs and circumstances. However, the Group may elect not to have insurance for certain risks, due to the high premium costs associated with insuring those risks or for various other reasons, including an assessment that the risks are remote.

No assurance can be given that the Group will be able to obtain insurance coverage at reasonable rates (or at all), or that any coverage it or the relevant operator obtains and the proceeds of any insurance will be adequate and available to cover any claims arising. The Group may become subject to liability for pollution, blow-outs or other hazards against which it has not insured or cannot insure, including those in respect of past activities for which it was not responsible. Any indemnities the Group may receive from such parties may be difficult to enforce if such sub-contractors, operators or joint venture partners lack adequate resources. In the event that insurance coverage is not available or the Group's insurance is insufficient to fully cover any losses, claims and/or liabilities incurred, or indemnities are difficult to enforce, the Group's business and operations, financial results or financial position may be disrupted and adversely affected.

The payment by the Group's insurers of any insurance claims may result in increases in the premiums payable by the Group for its insurance cover and adversely affect the Group's financial performance. In the future, some or all of the Group's insurance coverage may become unavailable or prohibitively expensive.

Taxation

This document has been prepared in accordance with current UK tax legislation, practice and concession and interpretation thereof. Any change in the Group's tax status or the tax applicable to a holding of Ordinary Shares or in taxation legislation or its interpretation, could affect the value of the investments held by the Group, affect the Group's ability to provide returns to Shareholders and/or alter the post-tax returns to Shareholders. It should be noted that the information contained in paragraph 18 of Part V of this document relating to the taxation of the Group and its investors is based upon current tax law and practice which is subject to legislative change. The taxation of an investment in the Company depends on the individual circumstances of investors, including, *inter alia*, tax laws in the jurisdiction in which that Shareholder is resident or domiciled. Potential investors should consult their professional advisers on the possible tax consequences of subscribing for, buying, holding, selling or transferring Ordinary Shares under the laws of their country of citizenship, residence or domicile.

During periods of high profitability in the oil and gas industry, there are often calls for increased or windfall taxes on oil and gas revenue. Taxes have increased or been imposed in the past and may increase or be imposed again in the future.

3. Risks associated with the Ordinary Shares

Share price volatility and liquidity

Although the Company is applying for the Enlarged Share Capital to be admitted to trading on AIM, there can be no assurance that an active or liquid trading market for the Ordinary Shares will develop or, if developed, that it will be maintained. AIM is a market designed primarily for emerging or smaller growing companies which carry a higher than normal financial risk and tend to experience lower levels of liquidity than larger companies. Accordingly, AIM may not provide the liquidity normally associated with the Official List or some other stock exchanges. The Ordinary Shares may therefore be difficult to sell compared to the shares of companies listed on the Official List and the share price may be subject to greater fluctuations than might otherwise be the case. An investment in shares traded on AIM carries a higher risk than those listed on the Official List.

The Company is principally aiming to achieve capital growth and, therefore, Ordinary Shares may not be suitable as a short-term investment. Consequently, the share price may be subject to greater fluctuation on small volumes of shares traded, and thus the Ordinary Shares may be difficult to sell at a particular price. Prospective investors should be aware that the value of an investment in the Company may go down as well as up and that the market price of the Ordinary Shares may not reflect the underlying value of the Company. There can be no guarantee that the value of an investment in the Company will increase. Investors may therefore realise less than, or lose all of, their original investment.

The share prices of publicly quoted companies can be highly volatile and shareholdings illiquid. The price at which the Ordinary Shares are quoted and the price which investors may realise for their Ordinary Shares may be influenced by a large number of factors, some of which are general or market specific, others which are sector specific and others which are specific to the Group and its operations. These factors include, without limitation, the performance of the Company and the overall stock market, large purchases or sales of Ordinary Shares by other investors, changes in legislation or regulations and changes in general economic, political or regulatory conditions and other factors which are outside of the control of the Company.

Shareholders may sell their Ordinary Shares in the future to realise their investment. Sales of substantial amounts of Ordinary Shares following Admission and/or on termination of the lock-in restrictions (the terms of which are summarised in paragraph 14.3 of Part V of this document), or the perception that such sales could occur, could materially adversely affect the market price of the Ordinary Shares available for sale compared to the demand to buy Ordinary Shares. Such sales may also make it more difficult for the Company to sell equity securities in the future at a time and price that is deemed appropriate. There can be no guarantee that the price of the Ordinary Shares will reflect their actual or potential market value or the underlying value of the Group's net assets and the price of the Ordinary Shares may decline below the Subscription Price.

Investment risk

An investment in the Company is highly speculative, involves a considerable degree of risk and is suitable only for persons or entities which have substantial financial means and who can afford to hold their ownership interests for an indefinite amount of time. While various oil and gas investment opportunities are available, potential investors should consider the risks that pertain to oil and gas development projects in general, and ventures in the UKCS in particular.

Dividends

There can be no assurance as to the level of future dividends. The declaration, payment and amount of any future dividends of the Company are subject to the discretion of the Directors, and will depend on, among other things, the Company's earnings, financial position, cash requirements and availability of profits. A dividend may never be paid and at present, there is no intention to pay a dividend. At present, the Company's dividend policy is that all funds available for distribution should be reinvested in the business of the Company.

It should be noted that the factors listed above are not intended to be exhaustive and do not necessarily comprise all of the risks to which the Group is or may be exposed or all those associated with an investment in the Company. In particular, the Company's performance is likely to be affected by changes in market and/or economic conditions, political, judicial, and administrative factors and in legal, accounting, regulatory and tax requirements in the areas in which it operates and holds its major assets. There may be additional risks and uncertainties that the Directors do not currently consider to be material or of which they are currently unaware which may also have an adverse effect upon the Group.

If any of the risks referred to in this Part II crystallise, the Group's business, financial condition, results or future operations could be materially adversely affected. In such case, the price of its Ordinary Shares could decline and investors may lose all or part of their investment.

PART III

FINANCIAL INFORMATION ON THE GROUP

Section A – Unaudited Interim Results for the Six Months ended 30 June 2013

Independent Oil and Gas plc

Interim Report
For the Six Months ended 30 June 2013

Contents

Report and unaudited financial statements
For the six months ended 30 June 2013

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Country of incorporation of parent company	United Kingdom
Legal form	Public limited company with share capital
Directors	Mehdi Varzi Marie-Louise Clayton Peter Young Mark Routh Michael Jordan
Secretary and registered office	Ben Harber One America Square Crosswall London EC3N 2SG
Company number	07434350
Auditors	BDO LLP 55 Baker Street London W1U 7EU

Business review

For the six months ended 30 June 2013

The directors present the unaudited condensed consolidated financial statements of Independent Oil and Gas plc ("the Company") and its subsidiaries ("the Group") for the six months ended 30 June 2013. All amounts are shown in Pounds Sterling, unless otherwise stated.

Business activities

During the first six months of 2013 management continued to pursue the appraisal and development of its Skipper and Blythe field interests and also completed a successful application for the Skipper West exploration licence.

Risks and uncertainties

The Group operates in the oil and gas industry, an environment subject to a range of inherent risks and uncertainties. Being at an early stage the prime risks to which the Group is subject are the access to sufficient funding to continue its operations, the status and financing of its partners, changes in cost and reserves estimates for its assets, operational delays and failures, changes in forward commodity prices and the successful development of its oil and gas reserves.

Key performance indicators

The Group's main business is the acquisition and exploitation of oil and gas acreage. Non-financial performance is tracked through the accumulation of licence interests and the successful discovery and exploitation of oil and gas reserves.

Future developments

Once sufficient new finance has been obtained the Group plans to appraise and develop its existing discoveries in conjunction with its partners, explore its new licence interests and seek new investment opportunities.

In this context the Company announced on 16 September 2013 its intention to seek admission to the Alternative Investment Market ("AIM") of the London Stock Exchange with associated new funding.

Mark Routh
CEO

23 September 2013

Independent review report

To the members of Independent Oil and Gas plc

Introduction

We have been engaged by the company to review the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2013 which comprises the consolidated statement of comprehensive income, the consolidated statement of changes in equity, the consolidated statement of financial position, the consolidated cash flow statement and the related notes.

Directors' responsibilities

The half-yearly financial report is the responsibility of and has been approved by the directors. The directors are responsible for preparing the half-yearly financial report.

As disclosed in note 1, the annual financial statements of the group are prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union. The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting", as adopted by the European Union.

Our responsibility

Our responsibility is to express to the company a conclusion on the condensed set of financial statements in the half-yearly financial report based on our review.

Our report has been prepared in accordance with the terms of our engagement to assist the company and for no other purpose. No person is entitled to rely on this report unless such a person is a person entitled to rely upon this report by virtue of and for the purpose of our terms of engagement or has been expressly authorised to do so by our prior written consent. Save as above, we do not accept responsibility for this report to any other person or for any other purpose and we hereby expressly disclaim any and all such liability

Scope of review

We conducted our review in accordance with International Standard on Review Engagements (UK and Ireland) 2410, "Review of Interim Financial Information Performed by the Independent Auditor of the Entity", issued by the Auditing Practices Board for use in the United Kingdom. A review of interim financial information consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing (UK and Ireland) and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Conclusion

Based on our review, nothing has come to our attention that causes us to believe that the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2013 is not prepared, in all material respects, in accordance with International Accounting Standard 34 as adopted by the European Union.

BDO LLP
Chartered Accountants and Registered Auditors
London
United Kingdom

23 September 2013

BDO LLP is a limited liability partnership registered in England and Wales (with registered number OC305127).

Condensed consolidated statement of comprehensive income
For the six months ended 30 June 2013

	Note	*2013* *6 months* *£*	*2012* *12 months* *£*
Other administrative expenses		70,026	391,587
Exchange loss/(gain)		77,430	(45,026)
Operating loss		147,456	346,561
Finance expense	3	86,999	99,858
Loss before tax		234,455	446,419
Taxation	4	–	–
Loss from continuing operations		234,455	446,419
Total comprehensive loss		234,455	446,419
Loss per ordinary share attributable to equity holders of parent	5	0.5p	0.9p

All amounts relate to continuing activities.

All recognised gains and losses in the current and prior periods are included in the income statement.

Condensed consolidated statement of changes in equity
For the six months ended 30 June 2013

	Share capital £	*Share premium* £	*Convertible debt option reserve* £	*Retained Profit/ (deficit)* £	*Total equity* £
Group					
At 31 December 2011	471,768	12,992,373	–	(172,633)	13,291,508
Share capital issued	1,389	86,107	–	–	87,496
Issue of convertible loan notes	–	–	122,412	–	122,412
Loss for the year	–	–	–	(446,419)	(446,419)
At 31 December 2012	473,157	13,078,480	122,412	(619,052)	13,054,997
Share capital issued	–	–	–	–	–
Issue of convertible loan notes	–	–	11,073	–	11,073
Loss for the period	–	–	–	(234,455)	(234,455)
At 30 June 2013	473,157	13,078,480	133,485	(853,507)	12,831,615

Share capital

Amounts subscribed for share capital at nominal value.

Share premium account

Amounts received by the Company on the issue of its shares in excess of the nominal value of the shares.

Convertible debt option reserve

Amount of proceeds on issue of convertible debt relating to the equity component (i.e. option to convert the debt into share capital).

Retained deficit

Cumulative net gains and losses recognised in the Statement of Comprehensive Income net of amounts recognised directly in equity.

Condensed consolidated statement of financial position
At 30 June 2013

	Note	*2013 30 June £*	*2012 31 December £*
Non-current assets			
Oil and gas costs pending determination	6	15,195,979	15,171,428
Current assets			
Other receivables	7	25,657	30,206
Cash and cash equivalents		10,549	22,703
		36,206	52,909
Total assets		15,232,185	15,224,337
Current liabilities			
Loan notes	8	(496,065)	(396,353)
Trade and other payables	8	(347,108)	(311,733)
	8	(843,173)	(708,086)
Non-current liabilities			
Trade and other payables	9	(1,557,397)	(1,461,254)
Total liabilities		(2,400,570)	(2,169,340)
Net assets		12,831,615	13,054,997
Capital and reserves			
Called up equity share capital	10	473,157	473,157
Share premium account	10	13,078,480	13,078,480
Convertible debt option reserve	8	133,485	122,412
Retained deficit		(853,507)	(619,052)
		12,831,615	13,054,997

The financial statements were approved and authorised for issue by the Board of Directors on 23 September 2013 and were signed on its behalf by:

Peter Young
Director

Condensed consolidated cash flow statement
For the six months ended 30 June 2013

	Note	*2013* *6 months*	*2012* *12 months*
Cash flows from operating activities			
Cash used in operations	11	(37,490)	(198,935)
Net cash used in operating activities		(37,490)	(198,935)
Cash flows from investing activities			
Purchase of intangible non-current assets		(17,164)	(428,648)
Cash used in investing activities		(17,164)	(428,648)
Cash flows from financing activities			
Proceeds from issue of ordinary shares		–	87,496
Proceeds from issue of loan notes		42,500	444,743
Net cash generated from financing activities		42,500	532,239
Decrease in cash and cash equivalents in the period		(12,154)	(95,344)
Cash and cash equivalents at start of period		22,703	118,047
Cash and cash equivalents at end of period		10,549	22,703

Notes forming part of the financial statements
For the six months ended 30 June 2013

1. Accounting policies

General Information

Independent Oil and Gas plc is a company domiciled in the United Kingdom. The condensed consolidated interim financial statements for the six months ended 30 June 2013 include the accounts of the Company and its wholly-owned subsidiaries IOG (North Sea) Limited (formerly IOG (Blythe) Limited) and IOG (Skipper) Limited, together referred to as the 'Group'.

Statement of significant accounting policies

These condensed consolidated financial statements have been prepared in accordance with IAS 34, "Interim Financial Reporting", as adopted by the European Union. These financial statements do not include all disclosures required in a complete set of annual financial statements and therefore should be read in conjunction with the Group's financial statements for the year ended 31 December 2012.

As no financial statements were prepared for the six month period ended 30 June 2012, comparative information provided in this report has been extracted from the 2012 financial statements and consequently 2012 comparative information in the Consolidated Statement of Financial Position and in the Consolidated Cash Flow Statement as well as the associated notes is for the full year 2012.

The accounting policies used in the preparation of the 2013 condensed consolidated financial statements for the six months to 30 June 2013 are consistent with those used in the preparation of the Group's audited financial statements for the year ended 31 December 2012 which have been filed with the Registrar of Companies. The IASB has issued a number of IFRS and IFRIC amendments or interpretations since the last annual report was published. It is not expected that any of these will have a material impact on the Group.

The annual financial statements are prepared in accordance with IFRSs as adopted by the European Union. The Independent Auditors' Report included in the statutory Annual Report for 2012 was unqualified; did not contain a statement under section 498(2) or 498(3) of the Companies Act 2006, and did not include reference to any matters to which the auditor drew attention by way of emphasis.

Going concern

The directors have been considering a number of options in order to raise additional finance to fund the Group's ongoing oil and gas appraisal and development activities. In this context the Company announced on 16 September 2013 its intention to seek admission to the Alternative Investment Market ("AIM") of the London Stock Exchange with associated new funding.

As a result, the directors consider that the Group has adequate working capital for at least the next twelve months. Accordingly, the directors continue to adopt the going concern basis in preparing the interim report and accounts.

2. Segmental information

The Group complies with IFRS 8, Operating Segments, which requires operating segments to be identified on the basis of internal reports about components of the Group that are regularly reviewed by the directors to allocate resources to the segments and to assess their performance. In the opinion of the directors, the operations of the Group comprise one class of business, being the exploration and development of oil and gas opportunities in the North Sea.

3. Finance expense

	2013 £	2012 £
Loan interest	68,284	74,022
Other Interest	18,715	25,836
	86,999	99,858

4. Taxation

(a) ***Current taxation***

There was no tax charge during the year since the Group had no income. Expenditures to date will be accumulated for offset against future tax charges. The average standard rate applicable to 2012 was 24.5 per cent. and to the first six months of 2013 was 23.5 per cent.

(b) ***Deferred taxation***

Due to the nature of the Group's exploration activities there is a long lead time in either developing or otherwise realising exploration assets. A deferred tax asset will only be created if there is reasonable certainty that profits will be earned in the foreseeable future.

5. Loss per share

The calculation of earnings per share is based on the loss attributable to ordinary shareholders divided by the weighted average number of shares in issue during the period.

	2013 £	2012 £
Loss for the period	(234,455)	(446,419)
Weighted average number of share	47,323,417	47,290,405
Loss per share basic and diluted	(0.5)p	(0.9)p

6. Non-current assets

Oil and gas costs pending determination – Group

	2013 £	2012 £
At cost		
At beginning of the period	15,171,428	14,556,759
Acquisitions	–	229,588
Additions	24,551	385,081
At end of the period	15,195,979	15,171,428
Write-downs at the beginning and end of the period	–	–
Net book value		
At 30 June/31 December	15,195,979	15,171,428
At 1 January	15,171,428	14,556,759

On 1 April 2012 long term creditors assumed under the terms of the acquisition of interest in the Blythe and Skipper fields increased by £229,588 (US$370,861) in accordance with the relevant agreement as that creditor had not been repaid by 31 March 2012.

In August 2012 ATP Oil & Gas Corporation, the US parent of the Company's operating partner for its oil & gas assets, ATP Oil & Gas (UK) Ltd, filed for protection from its creditors under Chapter 11 of the US Bankruptcy Code. Bids have been requested for ATP's assets and the directors understand that negotiations with preferred bidders have commenced with expected completion in the near future. Once a sale has been completed and a new operator appointed, the management expect the operator to propose appraisal and development plans for the fields. Pending completion of this process the Blythe and Skipper licences have been extended to 31 December 2013. Management expects the licences to be further extended by the Department of Energy and Climate Change once a new operator has been installed.

7. Other receivables

	2013	*2012*
	£	*£*
Group		
Value added tax recoverable	25,657	30,206

8. Current liabilities

	2013	*2012*
	£	*£*
Group		
Loan notes	496,065	396,353
Trade payables	160,896	186,889
Amounts due to joint venture partners	42,227	22,171
Accruals	143,985	102,673
	843,173	708,086

During the first six months of 2013 the Company raised additional finance totalling £42,500 (2012 – £444,743) through the issue of loan notes. Interest accrues on the loan notes at a rate of 7.5 per cent. per annum and totalled £17,528 for the first six months of 2013 (2012 – £19,958) bringing total interest to £37,486 at 30 June 2013. In the event of an AIM admission or Initial Public Offering of the Company, the loan notes plus accrued interest will convert into ordinary shares of the Company at a price equivalent to 80 per cent. of the offering price. Otherwise the loan notes will be redeemed on 30 September 2013. In view of the right to conversion into equity of the loan notes, a fair value of £133,485 (2012 – £122,412) has been ascribed to the equity component and is reflected in the convertible debt option reserve within capital and reserves. There has been an additional interest charge of £50,756 (2012 – £54,064) to reflect the effective interest rate of the loan notes.

9. Non-current liabilities

	2013	*2012*
	£	*£*
Group		
Trade creditors	1,557,397	1,461,254

These trade creditors were assumed by the Group in conjunction with acquisition of licence interests in 2011. Of the Group total, £1,174,123 is due no later than 31 March 2015 whilst the balance is not due until after sustained production is achieved from the Skipper field.

10. Equity share capital

Allotted, issued and fully paid	*Number*	*Share capital* £	*Share premium* £	*Total* £
At 1 January 2012				
Ordinary shares of 1 pence each	47,184,705	471,768	12,992,373	13,464,141
Equity issued	138,712	1,389	86,107	87,496
At 31 December 2012				
Ordinary shares of 1 pence each	47,323,417	473,157	13,078,480	13,551,637
Equity issued	–	–	–	–
At 30 June 2013				
Ordinary shares of 1 pence each	47,323,417	473,157	13,078,480	13,551,637

11. Cash flow statement

	2013 £	*2012* £
Loss after tax	234,455	446,419
Adjustments for:		
Capitalisation	–	12,432
Interest on loan notes	(68,284)	(74,022)
Interest on long-term payable	(18,714)	(25,836)
Foreign exchange	(77,429)	45,024
(Decrease)/increase in trade and other receivables	(4,549)	2,091
Increase in trade and other payables	(27,989)	(207,173)
Cash used in operations	37,490	198,935

12. Capital commitments

The Group has authorised and committed to capital expenditure in the current period as part of the exploration and development work programme for the licences in which it participates:

	2013 £	*2012* £
Authorised but not contracted	70,000	64,000
Contracts	132,500	132,000
	202,500	196,000

All capital commitments derive from the Group's participation in its joint venture operations and entities. Pending resolution of the financial position of the operator of both exploration licences, ATP (UK) Limited, current commitments are limited to licence fees and general work

13. Related party transactions

Key management and personnel remuneration for the period was £13,770 (2012: £20,910).

Acura Oil & Gas Limited, of which Michael Jordan is a director, acquired 37,200 shares during 2012 for £23,473 bringing its total holding to 8,862,779 shares being 18.8 per cent. of the total issued share capital with no further additions during 2013 to-date. Acura also subscribed for £30,000 of loan notes during the first six months of 2013 (2012: £Nil).

Mark Routh acquired 37,768 shares during 2012 for £23,818 bringing his total holding to 2,285,516 shares being 4.8 per cent. of the total issued share capital with no further additions during 2013 to-date. He also subscribed for £200,000 in loan notes in 2012 upon which £21,123 of interest was outstanding at 30 June 2013. Subsequent to the period end, Mark Routh subscribed for a further £40,000 of loan notes.

Peter Young received £13,770 for consultancy services during the period (2012: £20,910), of which £Nil was outstanding at 30 June 2013 (2012: £4,335), and also subscribed for 8,000 shares in 2012 for £5,048 bringing his total holding to 6,548,281 being 13.9 per cent. of the total issued share capital with no further additions during 2013 to-date. In addition his wife, Fiona Young, held 6,600,436 shares (2012: 6,600,436) being13.9 per cent. of the total issued share capital.

Marie Louise Clayton held 2,419,518 shares (2012: 2,419,518) directly plus a further 40,655 shares acquired in 2012 through Clayton Consulting Partners, of which she is a director, being 5.1 per cent. and 0.1 per cent. of the total issued share capital respectively with no further additions during 2013 to-date.

Thomas Hardy acquired 5,020 shares during 2012 bringing his total to 303,787 shares being 0.6 per cent. of the total issued share capital with no further additions during 2013 to-date.

14. Subsequent events

Since 30 June 2013 the Company has raised additional finance totalling £129,892 through the issue of additional loan notes. Interest accrues on the loan notes at a rate of 7.5 per cent. per annum. In the event of an admission to AIM or Initial Public Offering of the Company the loan notes plus accrued interest will convert into ordinary shares of the Company at a price equivalent to 80 per cent. of the offering price. Otherwise the loan notes will be redeemed on 30 September 2013.

Independent Oil and Gas plc

(formerly Silbury 395 Limited)

Report and Audited Financial Statements
Year ended 31 December 2012

Company Number 07434350

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Report and audited financial statements
For the year ended 31 December 2012

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Country of incorporation of parent company	United Kingdom
Legal form	Public limited company with share capital
Directors	Mehdi Varzi Marie-Louise Clayton Peter Young Mark Routh Michael Jordan
Secretary and registered office	Ben Harber One America Square Crosswall London EC3N 2SG
Company number	07434350
Auditors	BDO LLP 55 Baker Street London W1U 7EU

Report of the Directors

For the year ended 31 December 2012

The directors present their report and audited financial statements of Independent Oil and Gas plc ("the Company") and its subsidiaries ("the Group") for the year to 31 December 2012. All amounts are shown in Pounds Sterling, unless otherwise stated. On 18 September 2013, the Company re-registered as a public limited company and changed its name to Independent Oil and Gas plc.

Review of activities and business review

The Company was incorporated as Silbury 395 Limited on 9 November 2010 and subsequently changed its name to Independent Oil and Gas Limited on 25 March 2011.

The principal activity of the Group during the year was the acquisition and development of oil and gas production assets.

Risks and uncertainties

The Group operates in the oil and gas industry, an environment subject to a range of inherent risks and uncertainties. Being at an early stage the prime risks to which the Group is subject are the access to sufficient funding to continue its operations, the status and financing of its partners, changes in cost and reserves estimates for its assets, changes in forward commodity prices and the successful development of its oil and gas reserves.

Key performance indicators

The Group's main business is the acquisition and exploitation of oil and gas acreage. Non-financial performance is tracked through the accumulation of licence interests, and the successful discovery and exploitation of oil and gas reserves.

Future developments

Once sufficient new finance has been obtained the Group plans to appraise and develop its existing discoveries in conjunction with its partners, explore its new licence interests and seek new investment opportunities.

Results and dividend

The Group made a loss on ordinary activities of £446,419 for the year (2011: £172,633). The directors do not recommend the payment of a dividend (2011: £Nil).

Going concern

The Company's access to further funding over the past year has been complicated by the financial position of the Company's operating partner for its oil and gas assets, ATP Oil & Gas (UK) Ltd, whose US parent filed for protection from its creditors under Chapter 11 of the US Bankruptcy Code on 17 August 2012. Bids have been requested for ATP's assets and the directors understand that negotiations with preferred bidders have commenced with expected completion in the near future.

The directors have been considering a number of options in order to raise additional finance to fund the Group's ongoing oil and gas appraisal and development activities. In this context the Company announced on 16 September 2013 its intention to seek admission to the Alternative Investment Market ("AIM") of the London Stock Exchange with associated new funding.

As a result, the directors consider that the Group has adequate working capital for at least the next twelve months. Accordingly, the directors continue to adopt the going concern basis in preparing the annual report and accounts.

Directors

The directors who held office during the year were:

Mark Routh
Marie-Louise Clayton
Peter Young
Thomas Hardy (resigned 22 March 2013)
Michael Jordan (appointed 17 August 2012)
Mehdi Varzi (appointed 17 August 2012)

Related Parties

Information on related parties can be found in note 20 to the financial statements.

Subsequent Events

Information on subsequent events can be found in note 21.

Financial Instruments

Information on financial instruments can be found in note 17.

Directors' responsibilities

The directors are responsible for preparing the Report of the Directors and the financial statements in accordance with applicable law and regulations.

Company law requires the directors to prepare financial statements for each financial year. Under that legislation the directors have elected to prepare the Group and Company financial statements in accordance with International Financial Reporting Standards ("IFRSs") as adopted by the European Union. Under company law the directors must not approve the financial statements unless they are satisfied that they give a true and fair view of the state of affairs of the Group and Company and of the profit or loss of the Group and Company for that period.

In preparing these financial statements, the Directors are required to:

- select suitable accounting policies and then apply them consistently;
- make judgments and accounting estimates that are reasonable and prudent;
- state whether they have been prepared in accordance with IFRSs as adopted by the European Union, subject to any material departures disclosed and explained in the financial statements; and
- prepare the financial statements on the going concern basis unless it is inappropriate to presume that the Company will continue in business.

The directors are responsible for keeping adequate accounting records that are sufficient to show and explain the Company's transactions and disclose with reasonable accuracy at any time the financial position of the Company and enable them to ensure that the financial statements comply with the requirements of the Companies Act 2006. They are also responsible for safeguarding the assets of the Company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Directors' confirmation

Each person who is director at the time when this report is approved has confirmed that:

(a) So far as each director is aware, there is no relevant audit information of which the Company's auditors are unaware; and

(b) Each director has taken all the steps that ought to have been taken as a director, including making appropriate enquiries of fellow directors and the Company's auditors for that purpose, in order to be aware of any information needed by the Company's auditors in connection with preparing their report and to establish that the Company's auditors are aware of that information.

Auditors

BDO LLP have expressed their willingness to continue in office and a resolution to re-appoint them will be proposed at the annual general meeting.

On behalf of the Board

Peter Young
Director

20 September 2013

Independent auditor's report

To the members of Independent Oil and Gas plc

TO THE MEMBERS OF INDEPENDENT OIL AND GAS LIMITED

We have audited the financial statements of Independent Oil and Gas plc for the year to 31 December 2012 which comprise the Consolidated Statement of Comprehensive Income, Consolidated and Company Statements of Changes in Equity, Consolidated and Company Statements of Financial Position, Consolidated and Company Statements of Cash Flows and the related notes. The financial reporting framework that has been applied in their preparation is applicable law and International Financial Reporting Standards (IFRSs) as adopted by the European Union and, as regards the Parent Company financial statements, as applied in accordance with the provisions of the Companies Act 2006.

This report is made solely to the Company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the Company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Company and the Company's members as a body for our audit work, for this report, or for the opinions we have formed.

Respective responsibilities of directors and auditors

As explained more fully in the Statement of Directors' Responsibilities, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view. Our responsibility is to audit and express an opinion on the financial statements in accordance with applicable law and International Standards on Auditing (UK and Ireland). Those standards require us to comply with the Auditing Practices Board's Ethical Standards for Auditors.

Scope of the audit of the financial statements

A description of the scope of an audit of financial statements is provided on the Financial Reporting Council's website at www.frc.org.uk/auditscopeukprivate.

Opinion on financial statements

In our opinion:

- the financial statements give a true and fair view of the state of the Group's and the Parent Company's affairs as at 31 December 2012 and of the Group's loss for the year then ended;
- the Group financial statements have been properly prepared in accordance with IFRSs as adopted by the European Union;
- the Parent Company financial statements have been properly prepared in accordance with IFRSs as adopted by the European Union and as applied in accordance with the provisions of the Companies Act 2006; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

Opinion on other matters prescribed by the Companies Act 2006

In our opinion the information given in the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements.

Matters on which we are required to report by exception

We have nothing to report in respect of the following matters where the Companies Act 2006 requires us to report to you if, in our opinion:

- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements are not in agreement with the accounting records and returns; or
- certain disclosures of directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

Scott Knight *(senior statutory auditor)*
For and on behalf of BDO LLP, statutory auditor
London
United Kingdom

20 September 2013

BDO LLP is a limited liability partnership registered in England and Wales (with registered number OC305127).

Consolidated statement of comprehensive income
For the year ended 31 December 2012

	Note	*2012*	*2011*
		£	£
Other administrative expenses		391,587	140,029
Exchange (gain)/loss		(45,026)	32,604
Operating loss	3	346,561	172,633
Finance expense	5	99,858	–
Loss before tax		446,419	172,633
Taxation	6	–	–
Loss from continuing operations		446,419	172,633
Total comprehensive loss		446,419	172,633

All amounts relate to continuing activities.

All recognised gains and losses in the current and prior year are included in the income statement.

The notes on pages 68 to 83 form part of these financial statements.

Consolidated statement of changes in equity

For the year ended 31 December 2012

	Share capital £	*Share premium* £	*Convertible debt option reserve* £	*Retained Profit/(deficit)* £	*Total equity* £
Group					
At 9 November 2010	–	–	–	–	–
Share capital issued	471,768	12,992,373	–	–	13,464,141
Loss for the period	–	–	–	(172,633)	(172,633)
At 31 December 2011	471,768	12,992,373	–	(172,633)	13,291,508
Share capital issued	1,389	86,107	–	–	87,496
Issue of convertible loan notes	–	–	122,412	–	122,412
Loss for the year	–	–	–	(446,419)	(446,419)
At 31 December 2012	473,157	13,078,480	122,412	(619,052)	13,054,997
Company					
At 9 November 2010	–	–	–	–	–
Share capital issued	471,768	12,992,373	–	–	13,464,141
Profit for the period	–	–	–	834	834
At 31 December 2011	471,768	12,992,373	–	834	13,464,975
Share capital issued	1,389	86,107	–	–	87,496
Issue of convertible loan notes	–	–	122,412	–	122,412
Profit for the year	–	–		6,014	6,014
At 31 December 2012	473,157	13,078,480	122,412	6,848	13,680,897

Share capital

Amounts subscribed for share capital at nominal value.

Share premium account

Amounts received by the Company on the issue of its shares in excess of the nominal value of the shares.

Convertible debt option reserve

Amount of proceeds on issue of convertible debt relating to the equity component (i.e. option to convert the debt into share capital).

Retained profit/(deficit)

Cumulative net gains and losses recognised in the Statement of Comprehensive Income net of amounts recognised directly in equity.

The notes on pages 68 to 83 form part of these financial statements.

Consolidated statement of financial position
At 31 December 2012

Company Number: 07434350

	Note	*2012* £	*2011* £
Non-current assets			
Oil and gas costs pending determination	7	15,171,428	14,556,759
Current assets			
Other receivables	10	30,206	28,115
Cash and cash equivalents	15	22,703	118,047
		52,909	146,162
Total assets		15,224,337	14,702,921
Current liabilities			
Loan notes	11	(396,353)	–
Trade and other payables	11	(311,733)	(160,559)
	11	(708,086)	(160,559)
Non-current liabilities			
Trade and other payables	12	(1,461,254)	(1,250,854)
Total liabilities		(2,169,340)	(1,411,413)
Net assets		13,054,997	13,291,508
Capital and reserves			
Called up equity share capital	13	473,157	471,768
Share premium account	13	13,078,480	12,992,373
Convertible debt option reserve	11	122,412	–
Retained deficit		(619,052)	(172,633)
		13,054,997	13,291,508

The financial statements were approved and authorised for issue by the Board of Directors on 20 September 2013 and were signed on its behalf by:

Peter Young
Director

The notes on pages 68 to 83 form part of these financial statements.

Company statement of financial position
At 31 December 2012

Company Number: 07434350

	Note	*2012* £	*2011* £
Non-current assets			
Investments	8	12,591,943	12,591,943
Current assets			
Trade and other receivables	10	30,206	28,115
Amounts due from subsidiaries	8	1,723,761	882,807
Cash and cash equivalents	15	22,703	118,047
		1,776,670	1,028,969
Total assets		14,368,613	13,620,912
Current liabilities			
Loan Notes	11	(396,353)	–
Trade and other payables	11	(267,722)	(132,296)
	11	(664,075)	(132,296)
Trade and other payables	12	(23,641)	(23,641)
Total liabilities		(687,716)	(155,937)
Net assets		13,680,897	13,464,975
Capital and reserves			
Called up equity share capital	13	473,157	471,768
Share premium account	13	13,078,480	12,992,373
Convertible debt option reserve	11	122,412	–
Retained profit		6,848	834
		13,680,897	13,464,975

The financial statements were approved and authorised for issue by the Board of Directors on 20 September 2013 and were signed on its behalf by:

Peter Young
Director

The notes on pages 68 to 83 form part of these financial statements.

Consolidated cash flow statement
For the year ended 31 December 2012

	Note	*2012*	*2011*
Cash flows from operating activities			
Cash used in operations	14	(198,935)	(147,819)
Net cash used in operating activities		(198,935)	(147,819)
Cash flows from investing activities			
Purchase of intangible non-current assets		(428,648)	(690,849)
Net cash received with acquisitions		–	315,306
Net cash used in investing activities		(428,648)	(375,543)
Cash flows from financing activities			
Proceeds from issue of ordinary shares		87,496	641,409
Proceeds from issue of loan notes		444,743	–
Net cash generated from financing activities		532,239	641,409
(Decrease)/increase in cash and cash equivalents in the period		(95,344)	118,047
Cash and cash equivalents at start of period		118,047	–
Cash and cash equivalents at end of period	15	22,703	118,047

The notes on pages 68 to 83 form part of these financial statements.

Company cash flow statement
For the year ended 31 December 2012

	Note	*2012* £	*2011* £
Cash flows from operating activities			
Cash used in operations	14	(156,094)	(160,210)
Net cash used in operating activities		(156,094)	(160,210)
Cash flows from investing activities			
Amounts invested in subsidiaries		(471,489)	(678,458)
Net cash received with acquisitions		–	315,306
Net cash used in investing activities		(471,489)	(363,152)
Cash flows from financing activities			
Proceeds from issue of ordinary shares		87,496	641,409
Proceeds from issue of loan notes		444,743	–
Net cash generated from financing activities		532,239	641,409
(Decrease)/increase in cash and cash equivalents in the period		(95,344)	118,047
Cash and cash equivalents at start of period		118,047	–
Cash and cash equivalents at end of period	15	22,703	118,047

The notes on pages 68 to 83 form part of these financial statements.

Notes forming part of the financial statements
For the year ended 31 December 2012

1. Accounting policies

Statement of significant accounting policies

IAS 8 requires management to use its judgement in developing and applying accounting policies that result in information which is relevant to the economic decision-making needs of users; that are reliable, free from bias, prudent, complete and represent faithfully the financial position, financial performance and cash flows of the entity.

Basis of preparation

The principal accounting policies adopted in the preparation of the financial statements are set out below. The policies have been consistently applied to all the years presented, unless otherwise stated.

These financial statements have been prepared on the basis of a going concern and in line with International Financial Reporting Standards ("IFRSs") and IFRIC interpretations issued by the International Accounting Standards Board ("IASB") adopted by the European Union and in accordance with applicable United Kingdom Law.

The adoption of all of the new and revised Standards and Interpretations issued by the IASB and the International Financial Reporting Interpretations Committee (IFRIC) of the IASB that are relevant to the operations and effective for annual reporting periods beginning on or after 1 January 2010 are reflected in these financial statements.

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of policies and reported amounts of assets and liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and factors that are believed to be reasonable under the circumstances, the results of which form the basis of making judgements about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised if the revision only affects that period or in the period of revision and future periods if the revision affects both current and future periods.

Adoption of new and revised International Financial Accounting Standards

New and amended standards adopted by the Group:

The accounting policies adopted are consistent with those of the previous financial period, except for the following new and amended IFRS and IFRIC interpretations applied as of 1 January 2012.

Standard	*Effective date*	*Impact on initial application*
Amendments to IFRS 7 Disclosures – Transfer of Financial Assets	1 July 2011	Applies for periods beginning on or after the effective date. No impact upon the Group or Company.
Amendments to IAS 12 Deferred tax – recovery of underlying assets	1 January 2012	Applies for periods beginning on or after 1 January 2012. No impact upon the Group or Company.

No other IFRS issued and adopted but not yet effective are expected to have a material impact on the Group's financial statements.

Standards, amendments and interpretations, which are effective for reporting periods beginning after the date of these financial statements which have not been adopted early:

Standard	*Description*	*Effective date*
IAS 1	Financial statements presentation – Other comprehensive income	1 July 2012
IFRS 9*	Financial Instruments	1 January 2015
IFRS 10	Consolidated Financial Statements	1 January 2014
IFRS 11	Joint Arrangements	1 January 2014
IFRS 12	Disclosure of Interests in Other Entities	1 January 2014
IFRS 13	Fair Value Measurement	1 January 2013
IAS 27	Separate Financial Statements	1 January 2014
IAS 28	Investments in Associates and Joint Ventures	1 January 2014
IAS 19	Employee Benefits	1 January 2013
IFRS 7	Financial Instrument Disclosures	1 January 2013
IAS 32	Financial Instrument Presentation	1 January 2014

Items marked * had not yet been endorsed by the European Union at the date these financial statements were approved and authorised for issued by the Board.

These new and revised standards and interpretations are not expected to materially affect the Group's reporting or reported numbers.

Going concern

The directors have been considering a number of options in order to raise additional finance to fund the Group's ongoing oil and gas appraisal and development activities. In this context the Company announced on 16 September 2013 its intention to seek admission to the Alternative Investment Market ("AIM") of the London Stock exchange with associated new funding.

As a result, the directors consider that Group has adequate working capital for at least the next twelve months. Accordingly, the directors continue to adopt the going concern basis in preparing the annual report and accounts.

Basis of consolidation

Where the Company has the power, either directly or indirectly, to govern the financial and operating policies of another entity or business so as to obtain benefits from its activities, it is classified as a subsidiary. The consolidated financial statements present the results of the Company and its subsidiaries as if they formed a single entity. Inter-company transactions and balances between Group companies are therefore eliminated in full. The financial statements of subsidiaries are included in the Group's financial statements from the date that control commences until the date that control ceases.

Subsidiaries

A subsidiary is an entity over which the Company is able to exercise control. Control is achieved where the Company has the power, directly or indirectly, to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that presently are exercisable are taken into account.

Jointly controlled assets

Jointly controlled assets are arrangements in which the Group holds an interest on a long term basis which are jointly controlled by the Group and one or more venturers under a contractual arrangement. The Group's exploration, development and production activities are generally conducted jointly with other companies in this way. When these arrangements do not constitute entities in their own right, the consolidated financial statements reflect the relevant proportion of costs, revenues, assets and liabilities applicable to the Group's interests in accordance with IAS 31.

Oil and gas exploration assets and development/producing assets

The Group follows a successful efforts based accounting policy for oil and gas assets. Under successful efforts expenditure incurred on the acquisition of a licence interest is initially capitalised on a licence by licence basis. Costs are held undepleted within exploration assets until such time as the exploration phase on the licence area is complete or commercial reserves have been discovered.

Exploration expenditure incurred in the process of determining exploration targets is capitalised initially within intangible assets and subsequently allocated to drilling activities. Exploration drilling costs are initially capitalised on a well by well basis until the success or otherwise of the well has been established. The success or failure of each exploration effort is judged on a well by well basis. Drilling costs are written off on completion of a well unless the results indicate that hydrocarbon reserves exist and there is a reasonable prospect that these reserves are commercial.

Costs incurred prior to obtaining the legal rights to explore an area are expensed immediately to the Statement of Comprehensive Income as exploration costs written off.

All lease and licence acquisition costs, geological and geophysical costs and other direct costs of exploration, evaluation and development are capitalised as intangible assets or oil and gas development costs according to their nature. Intangible assets comprise costs relating to the exploration and evaluation of licences which the Directors consider to be unevaluated until reserves are appraised as commercial, at which time they are transferred to oil and gas development costs following an impairment review and depreciated accordingly.

Where results of exploration drilling indicate the presence of hydrocarbons which are ultimately considered not commercially viable, all related costs are written off to the Statement of Comprehensive Income as exploration costs written off.

All costs incurred after the technical feasibility and commercial viability of producing hydrocarbons have been demonstrated are capitalised as oil and gas development costs on a field by field basis. Subsequent expenditure is capitalised only where it either enhances the economic benefits of the development/producing asset or replaces part of the existing development/producing asset. Any costs remaining associated with the replaced asset part are expensed.

Net proceeds from any disposal of an exploration asset are initially credited against the previously capitalised costs. Any surplus proceeds are credited to the Statement of Comprehensive Income. Net proceeds from any disposal of development/producing assets are credited against the previously capitalised cost. A gain or loss on disposal of a development/producing asset is recognised in the Statement of Comprehensive Income to the extent that the net proceeds exceed or are less than the appropriate portion of the net capitalised costs of the asset.

Depletion and amortisation

The Group depletes separately, where applicable, any identifiable part of development/producing assets, such as fields, processing facilities and pipelines which is significant in relation to the total cost of a development/producing asset.

The Group depletes expenditure on oil and gas production and development on a unit of production basis, based on proved and probable reserves on a field by field basis. In certain circumstances, fields within a single development area may be combined for depletion purposes.

Impairment

Exploration assets are reviewed regularly for indications of impairment and costs are written off where circumstances indicate that the carrying value might not be recoverable. In such circumstances the exploration asset is allocated to development/producing assets within the same geographic segment and tested for impairment. Any such impairment arising is recognised in the Statement of Comprehensive Income as exploration costs written off for the period. Where there are no development or producing assets within a geographic segment, the exploration costs are charged immediately to the Statement of Comprehensive Income.

Impairment reviews on development/producing oil and gas assets are carried out on each cash generating unit identified in accordance with IAS 36. The Group's cash generating units are those assets which generate largely independent cash flows and are normally, but not always, single development areas.

At each reporting date, where there are indications of impairment, the net book value of the cash generating unit is compared with the associated expected discounted future cash flows. If the net book value is higher, then the difference is written off to the Statement of Comprehensive Income as cost of sales.

Where there has been a charge for impairment in an earlier year that charge will be reversed in a later period where there has been a change in circumstances to the extent that the discounted cash flows are higher than the net book value at the time. In reversing impairment losses, the carrying amount of the asset will be increased to the lower of its original carrying value or the carrying value that would have been determined (net of depletion) had no impairment loss been recognised in prior periods.

Investments and loans

Shares in subsidiary undertakings are shown at cost. Loans to subsidiary undertakings are stated at amortised cost.

Provisions are made for any impairment in value.

Financial instruments

(i) *Financial assets*

Loans and receivables
The Group's loans and receivables comprise trade receivables, other financial assets, and cash and cash equivalents.

These assets are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They arise principally through prepayments and recoverable VAT but may also incorporate other types of contractual monetary asset. Loans and receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment.

A provision for impairment is established when there is objective evidence that the asset will not be collectible in full according to the original terms of the instruments. The amount of the provision is the difference between the asset's carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account, and the amount of the loss is recognised in profit or loss. When loans and receivables are uncollectible, they are written off against the allowance account for loans and receivables. Subsequent recoveries of amounts previously written off are credited to profit or loss, subject to a restriction that the carrying amount of the asset at the date the impairment is reversed does not exceed what the amortised cost would have been had the impairment not been recognised.

Cash and cash equivalents
Cash includes cash on hand and demand deposits with any bank or other financial institution. Cash equivalents are short-term, highly liquid investments that are readily convertible to known amounts of cash which are subject to an insignificant risk of changes in value.

(ii) *Financial liabilities held at cost*

Trade payables and other short-term monetary liabilities are recognised at fair value and in view of the short payment periods are not amortised.

Equity

Equity instruments issued by the Company are recorded at the proceeds received, net of direct issue costs, allocated between share capital and share premium.

Share issue expenses and Share premium account

The costs of issuing new share capital are written-off against the Share premium account arising out of the proceeds of the new issue.

Taxation

Tax on the profit or loss for the period comprises current and deferred tax. Tax is recognised in the Statement of Comprehensive Income except to the extent that it relates to items recognised in other comprehensive income, in which case it is recognised in other comprehensive income.

Current tax is the expected tax payable on the taxable income for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax assets and liabilities are recognised where the carrying amount of an asset or liability in the statement of financial position differs to its tax base, except for differences arising on the initial recognition of an asset or liability in a transaction which is not a business combination and at the time of the transaction affects neither accounting or taxable profit; and investments in subsidiaries and jointly controlled entities where the Group is able to control the timing of the reversal of the difference and it is probable that the difference will not reverse in the foreseeable future.

Recognition of deferred tax assets is restricted to those instances where it is probable that taxable profit will be available against which the difference can be utilised.

The amount of the asset or liability is determined using tax rates that have been enacted or substantively enacted by the reporting date and are expected to apply when the deferred tax liabilities/(assets) are settled/(recovered). Deferred tax balances are not discounted.

Deferred tax assets and liabilities are offset when the Group has a legally enforceable right to offset current tax assets and liabilities and the deferred tax assets and liabilities relate to taxes levied by the same tax authority on either:

- the same taxable Group company; or
- different Group entities which intend either to settle current tax assets and liabilities on a net basis; or
- to realise the assets and settle the liabilities simultaneously, in each future period in which significant amounts of deferred tax assets or liabilities are expected to be settled or recovered.

Decommissioning

At the end of the producing life of a field, costs are incurred in removing and decommissioning production facilities. The Group recognises the full discounted cost of decommissioning as an asset and liability when the obligation to rectify environmental damage arises. Where material, the decommissioning asset is included within fixed assets with the cost of the related installation. The corresponding liability is included within provisions. Revisions to the estimated costs of decommissioning which alter the level of the provisions required are also reflected in adjustments to the decommissioning asset. The amortisation of the asset, calculated on a unit of production basis based on proved and probable reserves, is shown as the “decommissioning charge” in the Statement of Comprehensive Income and the unwinding of the discount on the provision is included within “finance costs”.

Foreign currencies

The functional and presentation currency of the Group and the Company is Pounds Sterling.

The Group translates foreign currency transactions into the functional currency at the rate of exchange prevailing at the transaction date. Monetary assets and liabilities denominated in foreign currency are translated into the functional currency at the rate of exchange prevailing at the reporting date. Exchange differences arising are taken to the Statement of Comprehensive Income except for those incurred on borrowings specifically allocable to development projects, which are capitalised as part of the cost of the asset.

Segmental reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision makers have been identified as the Chief Executive Officer, Chief Financial Officer and the other executive and non-executive Board members.

Key sources of estimation uncertainty

The key assumptions concerning the future, and other key sources of estimation uncertainty at the reporting date, that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year, are discussed below:

Gas and liquids reserves

The volume of proven and probable gas and liquids reserves is an estimate that affects the unit of production depreciation of producing gas and oil property, plant and equipment as well as being a significant estimate affecting decommissioning estimates and impairment calculations.

The impact of a change in estimated proven and probable reserves is dealt with prospectively by depreciating the remaining book value of producing assets over the expected future production. If proven and probable reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down (impairment) of the asset's book value.

The Group currently holds no proven and probable gas and liquids reserves.

Decommissioning costs

The estimated cost of decommissioning at the end of the producing lives of fields is reviewed periodically and is based on proven and probable reserves, price levels and technology at the reporting date. Provision is made for the estimated cost of decommissioning at the reporting date. The payment dates of total expected future decommissioning costs are uncertain and dependent on the lives of the facilities. The abandonment of the fields is expected to happen in one to thirty five years. As no field developments have commenced to-date no provision for decommissioning costs had been made at the balance sheet date.

2. Segmental information

The Group complies with IFRS 8, Operating Segments, which requires operating segments to be identified on the basis of internal reports about components of the Group that are regularly reviewed by the directors to allocate resources to the segments and to assess their performance. In the opinion of the directors, the operations of the Group comprise one class of business, being the exploration and development of oil and gas opportunities in the North Sea.

3. Operating loss

The Group operating loss is stated after charging/(crediting) the following:

	2012 £	*2011* £
Fees payable to the Company's auditor for the audit of the Company's and Group's annual financial statements	24,000	35,000
Exploration expense	97,300	–
Staff costs	23,027	123,316
Staff costs capitalised as oil and gas non-current assets	(12,432)	(51,509)
Foreign exchange (gain)/loss	(45,026)	32,604

4. Staff costs and directors' remuneration

The Group did not have any employees during this period.

All personnel were engaged under consultancy contracts.

	2012	*2011*
	£	*£*
Group		
Directors' costs	20,910	76,348
Management costs	2,117	46,968
	23,027	123,316

During the period, the average number of employees was:

	Number	*Number*
Management/operational	2	2
Directors	5	5

	£	*£*
Company		
Directors' costs	20,910	76,348
Management costs	2,117	46,968
	23,027	123,316

During the period, the average number of employees was:

	Number	*Number*
Management/operational	2	2
Directors	5	5

Key management and personnel are considered to be the Executive and Non-executive Directors. Directors held no options during 2012 (2011: Nil).

The Company paid premiums of £12,282 for Directors and Officers Liability insurance during the year (2011: £Nil).

5. Finance expense

	2012	*2011*
	£	*£*
Loan interest	74,022	–
Other Interest	25,836	–
	99,858	–

6. Taxation

(a) ***Current taxation***

There was no tax charge during the year since the Group had no income. Expenditures to date will be accumulated for offset against future tax charges.

The reasons for the difference between the actual tax charge for the year and the standard rate of corporation tax in the United Kingdom applied to profits for the year are as follows:

	2012	*2011*
	£	*£*
Loss for the year	446,419	172,633
Income tax expense (including income tax on associate and discontinued operation)	–	–
Loss before income taxes	446,419	172,633
Expected tax credit based on the standard rate of United Kingdom corporation tax at the domestic rate of 24.5% (2011: 26.5%)	109,373	45,748
Expenses not deductible for tax purposes	(32,971)	(54)
Unrecognised taxable losses carried forward	(76,402)	(45,694)
Total tax expense	–	–

Changes in tax rates and factors affecting the future tax charge

Finance Act 2012 includes provision for the main rate of corporation tax to reduce from 26 per cent. to 24 per cent. on 1 April 2012, and to 23 per cent. on 1 April 2013. It has also been announced that there will be a further 1 per cent. reduction to bring the main rate to 22 per cent. from 1 April 2014. This will reduce the Company's future tax charge accordingly. The rate of 24 per cent. was substantially enacted on the 26 March 2012 and the rate of 23 per cent. substantially enacted on 6 July 2012. Future net production revenues with be subject to ring fence corporation tax including a supplementary charge. Currently applicable rates total 62 per cent. combined.

(b) ***Deferred taxation***

Due to the nature of the Group's exploration activities there is a long lead time in either developing or otherwise realising exploration assets. A deferred tax asset will only be created if there is reasonable certainty that profits will be earned in the foreseeable future.

7. Non-current assets

Oil and gas costs pending determination – Group

	2012	*2011*
	£	*£*
At cost		
At beginning of the year	14,556,759	–
Acquisitions	229,588	13,783,465
Additions	385,081	773,294
At end of the year	15,171,428	14,556,759
Write-downs at the beginning and end of the year	–	–
Net book value		
At 31 December	15,171,428	14,556,759
At 1 January	14,556,759	–

On 27 October 2011 the Group exercised its options to acquire 50 per cent. interests in UKCS licences P1736 (Blocks 48/22b and 48/23a) from Ebor Energy UK Limited and P1609 (Block 9/21a) from MOST including equivalent interests in the Blythe and Skipper fields respectively. Consideration consisted of the issue of shares in Independent Oil and Gas Limited plus the acceptance of creditors and the transfer of cash balances as set out below.

	Licence P1736 (Blythe)	*Licence P1609 (Skipper)*	*Total*
	£	*£*	*£*
Shares issued	4,109,283	8,654,448	12,763,731
Creditors assumed	–	1,218,250	1,218,250
Associated costs	60,427	56,363	116,790
Cash received	(210,959)	(104,347)	(315,306)
Net consideration	3,958,751	9,824,714	13,783,465

On 1 April 2012 long term creditors assumed under the terms of the acquisition increased by £229,588 (US$370,861) in accordance with the relevant agreement as that creditor had not been repaid by 31 March 2012.

In August 2012 ATP Oil & Gas Corporation, the US parent of the Company's operating partner for its oil & gas assets, ATP Oil & Gas (UK) Ltd, filed for protection from its creditors under Chapter 11 of the US Bankruptcy Code. Bids have been requested for ATP's assets and the directors understand that negotiations with preferred bidders have commenced with expected completion in the near future. Once a sale has been completed and a new operator appointed, the management expect the operator to propose appraisal and development plans for the fields. Pending completion of this process the Blythe and Skipper licences have been extended to 31 December 2013. Management expects the licences to be further extended by the Department of Energy and Climate Change once a new operator has been installed.

8. Investments

	Shares in Group companies	*Loans to Group companies*	*Total*
	£	*£*	*£*
Company			
At cost			
At beginning of period	–	–	–
Additions	12,591,943	882,807	13,474,750
Written off	–	–	–
At 31 December 2011	12,591,943	882,807	13,474,750
Additions	–	840,954	840,954
At 31 December 2012	12,591,943	1,723,761	14,315,704

The Company's principal subsidiaries are as follows:

Directly held	*Country of incorporation*	*Area of operation*	*%*
IOG Skipper Limited	United Kingdom	United Kingdom	100
IOG North Sea Limited (formerly IOG Blythe Limited)	United Kingdom	United Kingdom	100

Both subsidiaries were incorporated in the United Kingdom on 13 May 2011 and are engaged in the business of oil and gas exploration in the North Sea.

9. Interests in jointly controlled assets

Licence	*Beneficial interest %*	*Operator*
United Kingdom		
Skipper oil field	50.00%	ATP
Blythe gas field	50.00%	ATP
Skipper West exploration licence	100.00%	IOG

10. Other receivables

	2012	*2011*
	£	*£*
Group and Company		
Value added tax recoverable	30,206	28,115

11. Current liabilities

	2012	*2011*
	£	*£*
Group		
Loan notes	396,353	–
Trade payables	186,889	96,050
Amounts due to joint venture partners	22,171	29,509
Accruals	102,673	35,000
	708,086	160,559
Company		
Loan notes	396,353	–
Trade payables	162,876	96,037
Amounts due to joint venture partners	22,171	29,509
Accruals	82,675	6,750
	664,075	132,296

During 2012 the Company raised additional finance totalling £444,743 through the issue of loan notes. Interest accrues on the loan notes at a rate of 7.5 per cent. per annum and totalled £19,958 at 31 December 2012. In the event of an AIM admission or Initial Public Offering of the Company, the loan notes plus accrued interest will convert into ordinary shares of the Company at a price equivalent to 80 per cent. of the offering price. Otherwise the loan notes will be redeemed on 30 September 2013 In view of the right to conversion into equity of the loan notes, a fair value of £122,412 has been ascribed to the equity component and is reflected in the convertible debt option reserve within capital and reserves. There has been an additional interest charge of £54,064 to reflect the effective interest rate of the loan notes.

12. Non-current liabilities

	2012	*2011*
	£	*£*
Group		
Trade creditors	1,461,254	1,250,854
Company		
Trade creditors	23,641	23,641

These trade creditors were assumed by the Group in conjunction with acquisition of licence interests in 2011. Of the Group total, £1,174,123 is due no later than 31 March 2015 whilst the balance is not due until after sustained production is achieved from the Skipper field. The Company’s trade creditors are not due until after sustained production is achieved from the Skipper field.

13. Equity share capital

	Number	Share capital £	Share premium £	Total £
Allotted, issued and fully paid				
At beginning of period				
– Ordinary shares of 1 pence each	–	–	–	–
Asset acquisitions	44,730,089	447,223	12,316,508	12,763,731
Equity issued	2,454,616	24,545	675,865	700,410
At 31 December 2011				
– Ordinary shares of 1 pence each	47,184,705	471,768	12,992,373	13,464,141
Equity issued	138,712	1,389	86,107	87,496
At 31 December 2012				
– Ordinary shares of 1 pence each	47,323,417	473,157	13,078,480	13,551,637

14. Cash flow statement

	Company £	Group £
2012		
(Profit)/loss after tax	(6,014)	446,419
Adjustments for:		
Capitalisation	–	12,432
Recharges	369,466	–
Interest on loan notes	(74,022)	(74,022)
Interest on long-term payable	–	(25,836)
Foreign exchange	–	45,024
Decrease in trade and other receivables	2,091	2,091
Increase in trade and other payables	(135,427)	(207,173)
Cash used in operations	156,094	198,935
2011		
(Profit)/loss after tax	(834)	172,633
Adjustments for:		
Capitalisation	–	51,509
Recharges	176,498	–
Foreign exchange	–	(32,604)
Increase in trade and other receivables	28,115	28,115
Increase in trade and other payables	(43,569)	(71,834)
Cash used in operations	160,210	147,819

15. Cash and cash equivalents

	2012 £	2011 £
Group and Company		
Cash at bank	22,703	118,047

16. Company profit for the year

The Company has taken advantage of the exemption allowed under Section 408 of the Companies Act 2006 and has not presented its own Statement of Comprehensive Income in these financial statements.

The Company profit for the year was £6,014 (2011: £834).

17. Financial instruments

Significant accounting policies

Details of the significant accounting policies in respect of financial instruments are disclosed in Note 1 of the financial statements.

Financial risk management

The Board seeks to minimise its exposure to financial risk by reviewing and agreeing policies for managing each financial risk and monitoring them on a regular basis. No formal policies have been put in place in order to hedge the Group and Company's activities to the exposure to currency risk or interest risk, however as the Group enters greater commercial production this may be considered. No derivatives or hedges were entered into during the period.

General objectives, policies and processes

The Board has overall responsibility for the determination of the Group and Company's risk management objectives and policies and, whilst retaining ultimate responsibility for them, it has delegated the authority for designing and operating processes that ensure the effective implementation of the objectives and policies to the Group's finance function. The Board receives regular reports from the Finance Director through which it reviews the effectiveness of the processes put in place and the appropriateness of the objectives and policies it sets.

The Group is exposed through its operations to the following financial risks:

- Liquidity risk;
- Credit risk;
- Cash flow interest rate risk; and
- Foreign exchange risk

The overall objective of the Board is to set policies that seek to reduce risk as far as possible without unduly affecting the Group and Company's competitiveness and flexibility. Further details regarding these policies are set out below:

Principal financial instruments

The principal financial instruments used by the Group and Company, from which financial instrument risk arises are as follows:

- Other receivables
- Cash and cash equivalents
- Trade and other payables

Liquidity risk

The Group's and Company's policy is to ensure that it will always have sufficient cash to allow it to meet its liabilities when they become due. To achieve this aim, it seeks to maintain readily available cash balances to meet expected requirements for a period of at least 60 days.

Rolling cash forecasts identifying the liquidity requirements of the Group and Company are produced frequently. These are reviewed regularly by management and the Board to ensure that sufficient financial resources are made available. All Group activities are funded through the Company.

At 31 December 2012 the Group and Company had loan notes totalling £444,743 plus interest accrued of £19,958 outstanding (2011: £Nil). Due to the expected conversion, a fair value of £122,412 has been ascribed to the equity component and is reflected in the convertible debt option reserve within capital and reserves. There has been an additional interest charge of £54,064 to reflect the effective interest rate of the loan notes.

	Contractual cash flows £	*6 months or less* £	*Greater than 6 months, less than 12 months* £	*Greater than 12 months* £	*Total undiscounted* £	*Carrying amount* £
2012 Group						
Current assets						
Trade and other receivables	–	30,206	–	–	30,206	30,206
Cash and cash equivalents	–	22,703	–	–	22,703	22,703
	–	52,909	–	–	52,909	52,909
Current financial liabilities						
Loan notes	–	396,353			396,353	396,353
Trade and other payables	–	311,733	–	–	311,733	311,733
Non-current financial liabilities						
Trade and other payables	–	–	–	1,461,254	1,461,254	1,461,254
	–	708,086	–	1,461,254	2,169,340	2,169,340
2011 Group						
Current assets						
Trade and other receivables	–	28,115	–	–	28,115	28,115
Cash and cash equivalents	–	118,047	–	–	118,047	118,047
	–	146,162	–	–	146,162	146,162
Current financial liabilities						
Trade and other payables	–	160,559	–	–	160,559	160,559
Non-current financial liabilities						
Trade and other payables	–	–	–	1,250,854	1,250,854	1,250,854
	–	160,559	–	1,250,854	1,411,413	1,411,413

Credit risk

The credit risk on liquid funds is limited because the counterparties are banks with credit ratings assigned by international credit rating agencies. The Group places funds only with selected organisations with ratings of 'A' or above as ranked by Standard & Poor's for both long and short term debt.

The Group made investments and advances into subsidiary companies during the year, recovery of which is dependent on future income generation of those subsidiaries. The Group and Company's maximum exposure to credit risk by class of individual financial instrument and the contractual maturities of financial assets, including estimated interest payments and excluding the impact of netting agreements are shown below.

None of the Group's external trade and other receivables have been impaired. Group trade and other receivables are predominantly non-interest bearing. The Group does not hold any collateral as security and the Group does not hold any significant provision in the impairment account for trade and other receivables as they mainly relate to third parties with no default history.

	Carrying value £	*Maximum exposure* £
Cash and receivables		
Cash and cash equivalents	22,703	22,703
Trade and other receivables	30,206	30,206
	52,909	52,909

Cash flow interest rate risk

The interest rate profile of the financial assets and liabilities as at 31 December is as follows (excluding short term assets and liabilities):

	Fixed interest maturing in 1 year or less	*Non-interest bearing*	*Total*
	£	*£*	*£*
Group and Company			
2012			
Cash and cash equivalents			
Pound Sterling	–	22,703	22,703
US Dollar	–	–	–
	–	22,703	22,703
Loans and borrowings			
Pounds Sterling	396,353	–	396,353
2011			
Cash and cash equivalents			
Pound Sterling	–	108,200	108,200
US Dollar	–	9,847	9,847
	–	118,047	118,047
Loans and borrowings			
Pounds Sterling	–	–	–

Interest rate sensitivity analysis

As loans and creditors are subject to only fixed interest rates, variations in commercial interest rates would have had have no impact upon the Group's and Company's result for the year ended 31 December 2012.

Foreign exchange risk

The table above shows the extent to which the Group and Company have monetary assets and liabilities in currencies other than the functional currency of the operating company involved. These exposures give rise to the net currency gains and losses recognised in profit or loss.

The Group carried limited exposure to foreign exchange risk during the period to 31 December 2012. Its costs are incurred almost entirely in pounds sterling and it has no current revenues. The Group and the Company's cash balances are maintained in Pounds sterling which is the functional and reporting currency of each Group company. Consequently no formal policies have been put in place in order to hedge the Group and Company's activities to the exposure to currency risk. It is the Group's policy to ensure that individual Group entities enter into transactions in their functional currency wherever possible. The Group considers this minimises any foreign exchange exposure.

The management regularly monitor the currency profile and obtain informal advice to ensure that the cash balances are held in currencies which minimise the impact on the results and position of the Group and the Company from foreign exchange movements.

Consequently the management do not consider that a Foreign Exchange sensitivity analysis is material to the results of the Group and the Company.

Capital

The objective of the Directors is to maximise shareholder returns and minimise risks by keeping a reasonable balance between debt and equity. To date the Group has been principally equity financed, reflecting the early stage and consequent relatively high risk of its activities. During 2012, the Group issued £444,743 in interest bearing loan notes pending the raising of further equity and/or public listing of its shares.

In managing its capital, comprising equity, as described in the Statement of Changes in Equity, and loan notes, as disclosed in Note 11, the Group and Company's primary objective is to ensure its ability to provide a sufficient return for its equity shareholders, principally though capital growth. In order to achieve and seek to maximise this return objective the Group and Company will in the future seek to maintain a gearing ratio that balances risks and returns at an acceptable level while also maintaining a sufficient funding base to enable the Group and Company to meet its working capital and strategic investment needs. In making decisions to adjust its capital structure to achieve these aims, either through new share issues, increases or reductions in debt, or altering a dividend or share buyback policies, the Group considers not only its short term position but also its medium and longer term operational and strategic objectives.

Borrowing facilities

During 2012 the Company raised £444,743 through the issue of loan notes. Interest accrues on the loan notes at a rate of 7.5 per cent. per annum and totalled £19,958 at 31 December 2012. In the event of an AIM admission or Initial Public Offering of the Company, the loan notes plus accrued interest will convert into ordinary shares of the Company at a price equivalent to 80 per cent. of the offering price. Otherwise the loan notes will be redeemed on 30 September 2013. Due to the expected conversion, a fair value of £122,412 has been ascribed to the equity component and is reflected in the convertible debt option reserve within capital and reserves. There has been an additional interest charge of £54,064 to reflect the effective interest rate of the loan notes.

Hedges

The Group did not hold any hedge instruments at the reporting date.

18. Financial commitments

The Group has authorised and committed to capital expenditure in the current period as part of the exploration and development work programme for the licences in which it participates:

	2012	*2011*
	£	*£*
Authorised but not contracted	64,000	9,250,000
Contracts	132,000	461,000
	196,000	9,711,000

All capital commitments derive from the Group's participation in its joint venture operations and entities. Pending resolution of the financial position of the operator of both exploration licences, ATP (UK) Limited, current commitments are limited to licence fees and general work.

19. Related party transactions

Key management and personnel remuneration for the period was £20,910 (2011: £76,348).

Acura Oil & Gas Limited, of which Michael Jordan is a director, acquired 37,200 shares during the year (2011 – 8,825,579) for £23,473 bringing its total holding to 8,862,779 shares being 18.8 per cent. of the total issued share capital.

Mark Routh acquired 37,768 shares during the year (2011 – 2,247,748) for £23,818 bringing his total holding to 2,285,516 shares being 4.8 per cent. of the total issued share capital. He also subscribed for £200,000 in loan notes (2011 – £nil) upon which £9,904 of interest was outstanding at 31 December 2012.

Peter Young received £20,910 for consultancy services during the year (2011 – £41,678), of which £4,335 was outstanding at year end (2011 – £nil), and also subscribed for 8,000 shares (2011 – 6,540,281) for £5,048 bringing his total holding to 6,548,281 being 13.9 per cent. of the total issued share capital. In addition his wife, Fiona Young, held 6,600,436 shares (2011 – 6,600,436) being13.9 per cent. of the total issued share capital.

Marie Louise Clayton held 2,419,518 shares (2011 – 2,419,518) directly plus a further 40,655 shares (2011 – nil) acquired for £25,639 during the year through Clayton Consulting Partners, of which she is a director, being 5.1 per cent. and 0.1 per cent. of the total issued share capital respectively.

Thomas Hardy acquired 5,020 shares during the year (2011 – 298,767) for £3,166 bringing his total to 303,787 shares being 0.6 per cent. of the total issued share capital.

20. Subsequent events

During 2013 to-date the Company has raised additional finance totalling £172,392 through the issue of loan notes. Interest accrues on the loan notes at a rate of 7.5 per cent. per annum. In the event of an admission to AIM or Initial Public Offering of the Company the loan notes plus accrued interest will convert into ordinary shares of the Company at a price equivalent to 80 per cent. of the offering price. Otherwise the loan notes will be redeemed on 30 September 2013.

The Company announced on 16 September 2013 its intention to seek admission to the Alternative Investment Market ("AIM") of the London Stock Exchange with associated new funding.

PART IV

COMPETENT PERSON'S REPORTS

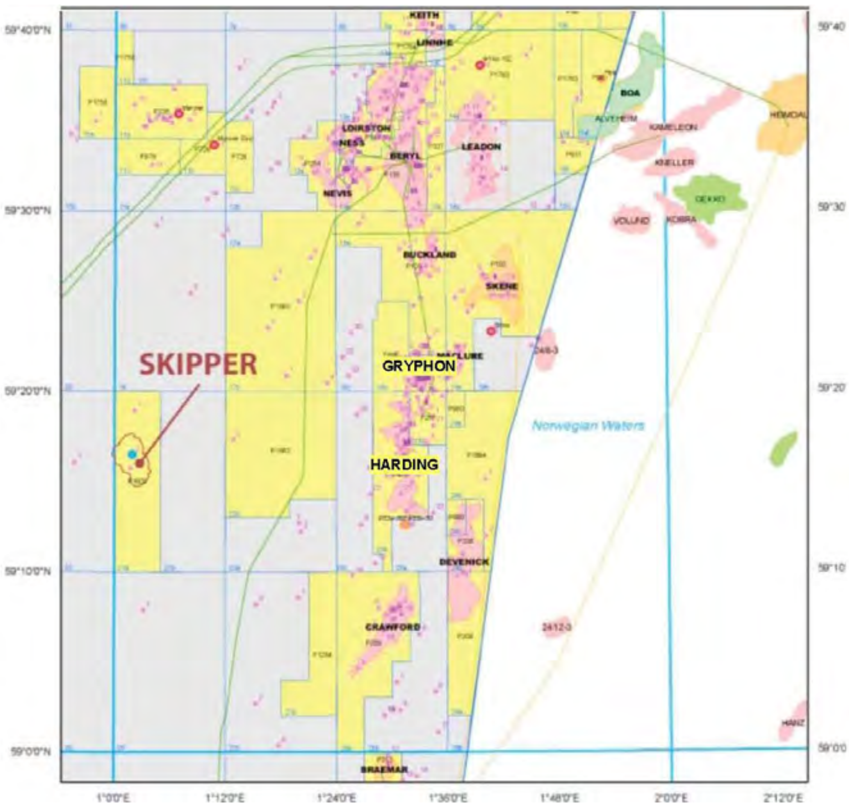
Section A – Competent Person's Report of AGR TRACS on Block 9/21a

Competent Person's Report

Skipper Oil Discovery

for

Independent Oil and Gas plc



John Severs, Peter Chandler, Anuar Ishniyazov,
Russell Parsons

Report Effective Date: 23rd September 2013

This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, these are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. AGR TRACS International Limited shall have no liability arising out of or related to the use of the report.

Status	**Final**	
Date	**23rd September 2013**	
Issued by	**John Severs**	
Approved by	**Nigel Blott**	

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Cover Letter

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September 23rd 2013

Gentlemen,

In May 2013 AGR TRACS International Limited ("AGR TRACS") was contracted by Independent Oil and Gas Limited ("IOG") to update the Competent Persons Report ("CPR") for their 50% working interest in the Skipper oil discovery issued by AGR TRACS in May 2011; the update was requested for the company's proposed application for admission ("**Admission**") to trading on the AIM market of the London Stock Exchange. This report excludes IOG's 100% interests in Blocks 8/25 and 8/20 acquired in October 2012. Licence P1609 is a production licence which bestows upon IOG North Sea Limited, a wholly owned subsidiary of IOG, a right to search, bore for, and get, petroleum within the defined licence area.

Asset	Holder	Interest	Status	License Expiry Date	License Area	Comments
Skipper UK offshore Block 9/21a (licence P1609)	IOG	50%	Exploration	30/9/2013	n/a(1)	

Summary Table of Assets

(1) Block 9/21a is bounded by the following co-ordinates:

59° 20′ 00.000″ N 1° 00′ 00.000″ E

59° 20′ 00.000″ N 1° 05′ 00.000″ E

59° 10′ 00.000″ N 1° 05′ 00.000″ E

59° 10′ 00.000″ N 1° 00′ 00.000″ E

59° 20′ 00.000″ N 1° 00′ 00.000″ E

Specified using European Datum 1950.

Skipper is a heavy oil discovery within Palaeocene Beauly sandstone formation located in UK offshore Block 9/21a (licence P1609) in the northern North Sea. It was discovered by Unocal in 1990 by well 9/21-2 which penetrated a 51' oil column. The Skipper discovery is in 350ft of water and twenty five km to the east are the Gryphon and Harding oil fields.

Skipper volumes are classed as contingent resources and relate solely to the Beauly formation. The conversion of these resources to reserves status requires further (successful) appraisal drilling and confirmation of expected flow rates as well as a development plan to confirm commerciality. An appraisal well is intended to be drilled in 2Q-3Q 2014 to test the Beauly formation and the deeper Maureen prospect.

Case (1)	Low Estimate	Best Estimate	High Estimate	Risk Factor (COCS)(3)	Operator
Gross Crude Oil	17.9	26.2	34.9	40%	ATP
Net IOG Crude Oil (2)	9.0	13.1	17.5	40%	ATP

Skipper gross and net contingent resources MMstb

(1) 1C = Low Estimate, 2C = Best Estimate, 3C = High Estimate

(2) IOG net interest is 50%. ATP Oil and Gas (UK) Ltd is operator with 50% interest

(3) "Risk Factor" or Chance of Commercial Success (COCS) for Contingent Resources means the chance, or probability, that the hydrocarbons will be commercially extracted.

DECC has granted a three month extension of the term of the Skipper licence, from 30th September to 31st December, pending a final decision on the operator ATP's present situation and a review of its business plan.

Based on cost information made available by IOG and AGR TRACS's independent technical review, Skipper shows positive NPV10 values across all resource cases and in particular in the Low Estimate resource case.

Case	Low Estimate	Best Estimate	High Estimate
Gross NPV10 (GBP millions)	14.0	274.0	492.8
Net IOG NPV10 (GBP millions)	7.0	137.0	246.4

Skipper gross and net NPV10 values

It should be noted that the Net Present Values (NPVs) do not represent the market value of these asset. The AGR TRACS evaluation represents a notional value of standalone assets under a specific set of technical, cost, price and timing assumptions and as additional technical data becomes available this may be subject to revision.

The mapping of Block 9/21a also showed three prospects in two deeper Palaeocene reservoirs (Dornoch and Maureen). Oil from the Maureen reservoir is expected to be lighter and potentially gassier than the Beauly oil. A range of prospective resources and an estimate of the geological chance of success were made for these three prospects as shown below.

Prospect	Low Estimate	Best Estimate	High Estimate	Geological chance of success
Dornoch	2.3	4.0	6.1	0.19
Maureen South	3.2	5.6	8.4	0.16
Maureen North	0.3	0.9	2.8	0.13

Gross prospective resources MMstb

Prospect	Low Estimate MMstb	Best Estimate MMstb	High Estimate MMstb	Geological chance of success
Dornoch	1.1	2.0	3.1	0.19
Maureen South	1.6	2.8	4.2	0.16
Maureen North	0.1	0.4	1.4	0.13

Net IOG prospective resources MMstb

The work was undertaken by a team of AGR TRACS professional petroleum engineers and geoscientists based on data supplied by IOG. The data comprised details of licence interests, basic exploration geological and geophysical data, interpreted data, and technical presentations. AGR TRACS has exercised due diligence on all technical information supplied by IOG.

In estimating resources we have used standard petroleum engineering techniques. These estimates are based on the joint definitions of the Society of Petroleum Engineers, the World Petroleum Congress, the American Association of Petroleum Geologists and the 2007 PRMS (Petroleum Resources Management System), and which forms the evaluation framework used in this CPR for AIM Admission.

Qualifications

AGR TRACS International Limited is a wholly owned subsidiary of AGR Group (Holdings) Limited, and is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. Except for the provision of professional services on a fee basis, AGR TRACS does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report.

The project was signed off by Nigel Blott (B.Sc.), SPE Member and General Manager of AGR TRACS, Guildford. Mr. Blott, a petroleum engineer, has over 30 years experience in the industry, from the Middle East, South-East Asia, and NW Europe. Since it was founded in 1992, TRACS, and later AGR TRACS, has conducted valuations for many energy companies and financial institutions.

Basis of Opinion

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data.

It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

The reported hydrocarbon volumes are estimates based on professional engineering judgment, and are subject to future revisions, upward or downward, as a result of future operations or as additional information becomes available.

Confirmations

In accordance with your instructions, AGR TRACS hereby confirms that:

(a) AGR TRACS consents to the CPR to be issued into the public domain by IOG.

(b) AGR TRACS accepts responsibility for the CPR and for any information sourced from the CPR. In accordance with Schedule Two to the AIM Rules (and paragraph 1.2 of Annex 1 of Appendix 3 to the Financial Conduct Authority's Prospectus Rules), AGR TRACS confirms, to the best of AGR TRACS's knowledge and belief (having taken all reasonable care to ensure that such is the case), the information contained therein is in accordance with the facts and contains no omission likely to affect the import of such information;

(c) AGR TRACS confirms that it is unaware of any material change in circumstances to those stated in the CPR

(d) Nigel Blott, General Manager of AGR TRACS, who supervised the evaluation, is professionally qualified and a member in good standing of the Society of Petroleum Engineers (SPE);

(e) AGR TRACS has the relevant and appropriate qualifications, experience and technical knowledge to professionally and independently appraise the assets in Offshore Block 9/21A, UKCS, which we have reported on;

(f) AGR TRACS considers that the scope of the CPR is appropriate and was prepared to a standard expected in accordance with the AIM Guidance Note;

(g) AGR TRACS has at least five years' relevant experience in the estimation, assessment and evaluation of the type of fluid deposit under consideration;

(h) AGR TRACS is independent of IOG and its directors, senior management and advisers, has no material interest in IOG and has acted as an independent competent person for the purposes of providing a report on the Assets;

(i) AGR TRACS is not a sole practitioner.

Yours faithfully,

Nigel Blott

General Manager

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1. Summary

AGR TRACS was contracted by Independent Oil and Gas Limited (IOG) to produce a Competent Persons Report for the Skipper discovery in which IOG has a 50% working interest.

The evaluation consisted of an assessment of the range of in-place hydrocarbon volumes which included a review of the seismic interpretation and the resultant depth maps provided by the operator ATP Oil and Gas (UK) Ltd, and additional interpretations and depth conversions undertaken by AGR TRACS to obtain a range of gross rock volumes. Petrophysical analysis was checked and average reservoir properties calculated. Reservoir engineering studies were undertaken to produce production profiles and ranges of recovery factors. Using the results of the analysis, probabilistic estimates of recoverable hydrocarbons were made and an economic analysis undertaken. In addition, prospective oil resources were calculated for two deeper Palaeocene reservoirs at Skipper.

1.1. Skipper

Skipper is a heavy oil discovery within Palaeocene Beauly sandstone formation located in UK offshore Block 9/21a (licence P1609). It was discovered by Unocal in 1990 by the well 9/21-2 which penetrated a 51' oil column. The well failed to flow on test.

The main uncertainty at Skipper is the viscosity of the oil. Correlations were made on the basis of a recovered dead oil sample to give a range of viscosity at reservoir conditions. Assumptions were made on relative permeability which were checked against nearby analogue fields. Using the above data, a fractional flow approach was used to generate a range of oil production profiles and recovery factors based on horizontal production and water injection wells. The recovery factors were combined in a Monte Carlo analysis for the STOIIP estimation to give the estimated range of ultimate recoverable oil. This was then constrained by an economic cut-off to give the range of contingent oil resources below:

Case (1)	Low Estimate	Best Estimate	High Estimate
Gross Crude Oil	17.9	26.2	34.9
Net IOG Crude Oil (2)	9.0	13.1	17.5

Table 1-1: Skipper contingent oil resources – gross and net IOG MMstb

(1) 1C = Low Estimate, 2C = Best Estimate, 3C = High Estimate

(2) IOG net interest is 50%. ATP Oil and Gas (UK) Ltd is operator with 50% interest

A notional field development concept has been used for early stage assessment of commerciality, entailing the drilling of horizontal producing wells and water injection wells with processing modules hosted on a new build steel jacket platform. For the Low Estimate Case, the project returns a positive NPV10 value (based on $90/bbl Brent with a 10% discount applied for crude oil quality differences), and this could be further built on in the event of successful testing of the deeper Paleocene Dornoch and Maureen prospects.

Case	Low Estimate	Best Estimate	High Estimate
Gross NPV10 (GBP millions)	14.0	274.0	492.8
Gross NPV0 (GBP millions)	179.2	517.0	788.2
Net IOG NPV10 (GBP millions)	7.0	137.0	246.4
Net IOG NPV0 (GBP millions)	89.6	258.5	394.1

Table 1-2: Skipper contingent resources – gross and net IOG NPV10 & NPV0

The mapping showed three prospects in two deeper Palaeocene reservoirs (Dornoch and Maureen). A range of prospective resources and an estimate of the geological chance of success were made for these three prospects as shown below.

Prospect	Low Estimate	Best Estimate	High Estimate	Geological chance of success
Dornoch	2.3	4.0	6.1	0.19
Maureen South	3.2	5.6	8.4	0.16
Maureen North	0.3	0.9	2.8	0.13

Table 1-3: Gross prospective resources MMstb

Prospect	Low Estimate	Best Estimate	High Estimate	Geological chance of success
Dornoch	1.1	2.0	3.1	0.19
Maureen South	1.6	2.8	4.2	0.16
Maureen North	0.1	0.4	1.4	0.13

Table 1-4: Net IOG prospective resources MMstb

2. Introduction

The Skipper licence was awarded to ATP Oil and Gas (UK) Ltd (operator) and MOST in the 25th UK round in February 2009 with MOST interest acquired by IOG Skipper Ltd on 8th December 2011. The obligatory work programme is to drill one well to 1700m, or 50m below the Maureen Formation, whichever is the shallower. DECC has granted a three month extension of the term of the Skipper licence, from 30th September to 31st December, pending a final decision on the operator ATP's present situation and a review of its business plan.

The Skipper evaluation consisted of the following:

1. Review of all reports and technical data provided
2. Review of well results including
    a. Petrophysical analysis of reservoirs including calculation of reservoir and pay averages
    b. Geochemical data from 9/21-2 well
3. Seismic review
    a. Check of well/seismic ties
    b. Check of general quality of seismic data and interpretation
    c. Review of the seismic interpretation
    d. Assessment of the depth conversion uncertainty
    e. Undertake additional interpretations to obtain the possible range of GRVs
    f. Calculate the possible range of STOIIP.
4. Reservoir engineering review
    a. Check of well fluid data
    b. Estimation of a range of viscosity
    c. Estimated RF and production profiles
5. Economics analysis for the proposed development scenario of the discovery
6. Report results
    a. Produce a CPR report meeting the required standards for AIM

3. Block 9/21a, Skipper

3.1. Overview

The Skipper discovery is located in Block 9/21a in the Northern North Sea in 350ft of water (Figure 3-1). Twenty five km to the east are located the Gryphon and Harding oil fields (Figure 3-2). Geologically Skipper sits on the East Shetlands Platform, 40km west of the main bounding fault of the Viking Graben (Figure 3-3). Oil generated in Kimmeridgian shale source rock within the Viking Graben has migrated vertically and laterally into fault terraces at the edge of the graben. While some oil has been trapped in Palaeocene turbidite sandstones on these terraces (e.g. Gryphon), the remainder has continued to migrate on to the East Shetlands Platform.

Skipper was discovered by Unocal in 1990 by the well 9/21-2. This well penetrated 51' of oil bearing sands in the Palaeocene Beauly Formation. However, due to biodegradation, the oil is heavy and viscous and the well failed to flow on test and it was plugged and abandoned with oil shows.

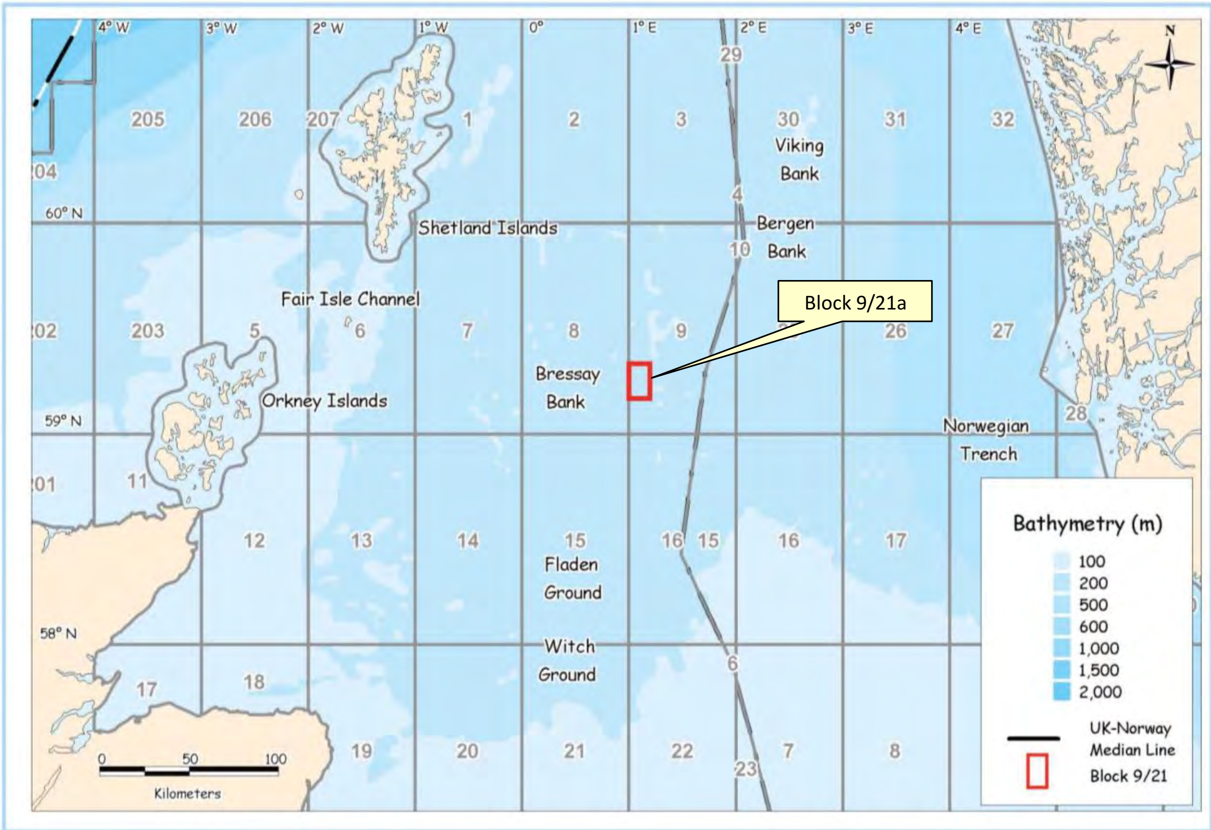


Figure 3-1: Location of block 9/21a

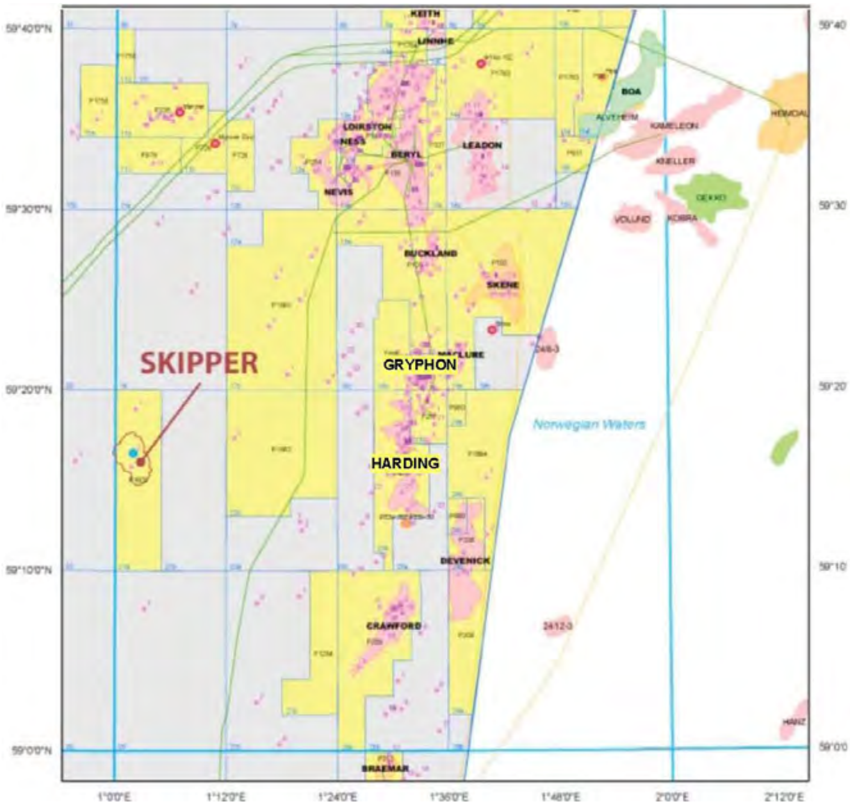


Figure 3-2: Skipper and nearby oil fields

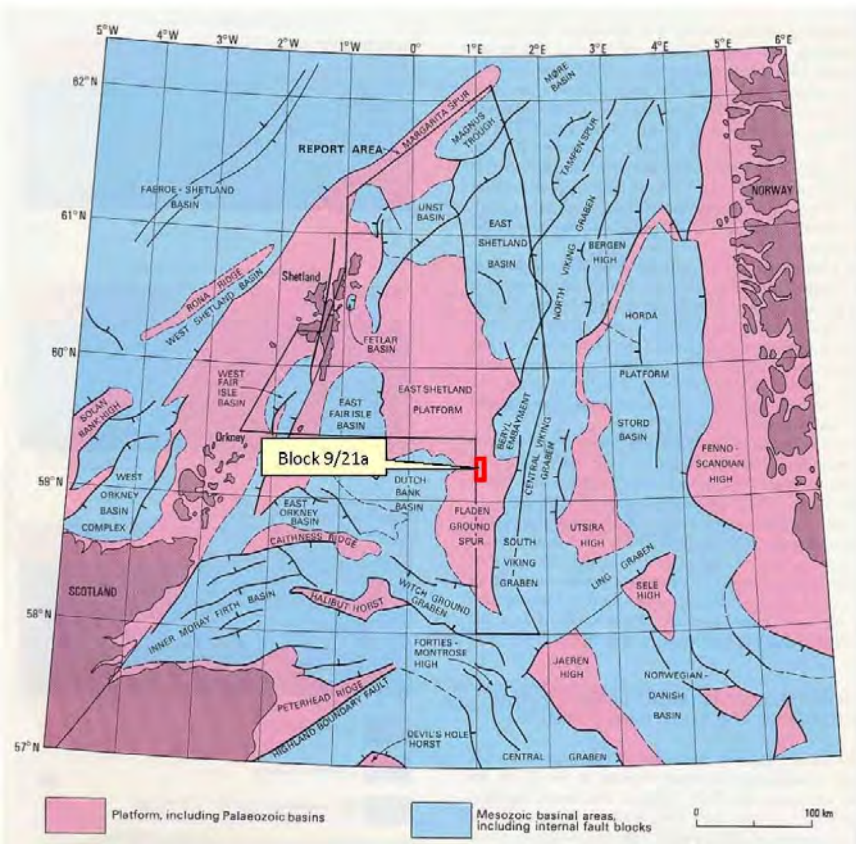


Figure 3-3: North Sea basin architecture

3.2. Database

The primary data source for the Skipper discovery is a SMT Kingdom project that was produced by the operator ATP. It contains a 3D seismic survey in time reprocessed by Fugro in 2009. Although this survey only covers the northern half of the block it is sufficient to delineate Skipper (Figure 3-4). The seismic data shows that the Beauly sandstone produces a moderate quality reflector that is suitable for a basic structural interpretation and mapping. The reservoir appears too thin and the seismic data of insufficient quality to produce attributes to enable further delineation of the field. The Kingdom project contained the interpretation undertaken by ATP. This included all horizons, and time and depth grids.

Two wells are located in the block 9/21a, 9/21-1 and 9/21-2. Full log suites suitable for reliable log analysis were available for both these wells. Petrophysical analysis has been undertaken by PGL for Ingen and their report and log outputs provided. Formation tops were contained in the Kingdom project. A check-shot survey was only available for 9/21-2.

The main reports provided for the evaluation were as follows:

- 25th Round application document for UKCS block 9/21. May 2008
- Completion report 9/21-2. Unocal May 1991
- Competent Person's Report conducted for Engen Resources Limited. April 2006
- 9/21-2 well test analysis. Ingen March 2005
- Geochemical analysis of oil shows in sidewall cores and of tested oils in the 9/21-2 well. Robertson Group. January 1991
- Geochemical evaluation of oil samples from the 9/21-2 well. Fugro Robertson, February 2006

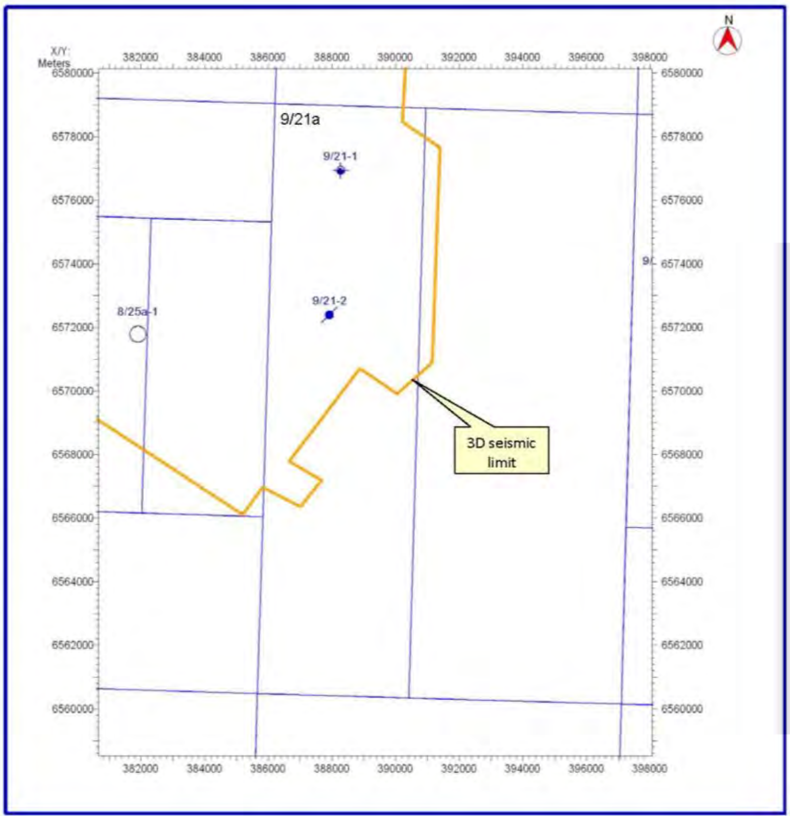


Figure 3-4: 9/21a database map

3.3. Beauly reservoir

The Beauly reservoir unit forms part of the Moray group of Palaeocene sands. The Palaeocene in general is high in volume of sand with limited coal and volcanics, inter-dispersed with shale sections that form reservoir seals.

The Beauly reservoir contains a series of coarsening up sequences of sands with minor interbedded clays, indicative of delta margin facies. The top reservoir seal is a claystone unit that grades towards siltstone with decreasing depth and is indicative of the delta margin facies.

The Beauly reservoir consists of a single coarsening up sequence clearly defined by the gamma ray in 9/21-1 & 9/21-2 (Figure 3-5).

3.3.1. Petrophysical analysis

Interpreted logs were provided from the petrophysical analysis undertaken by PGL for ATP. To test the uncertainty of these results, an independent analysis was undertaken. This was based on well logs alone as no core data were available to calculate electrical and mechanical properties. Both wells were analysed simultaneously using the same petrophysical parameters.

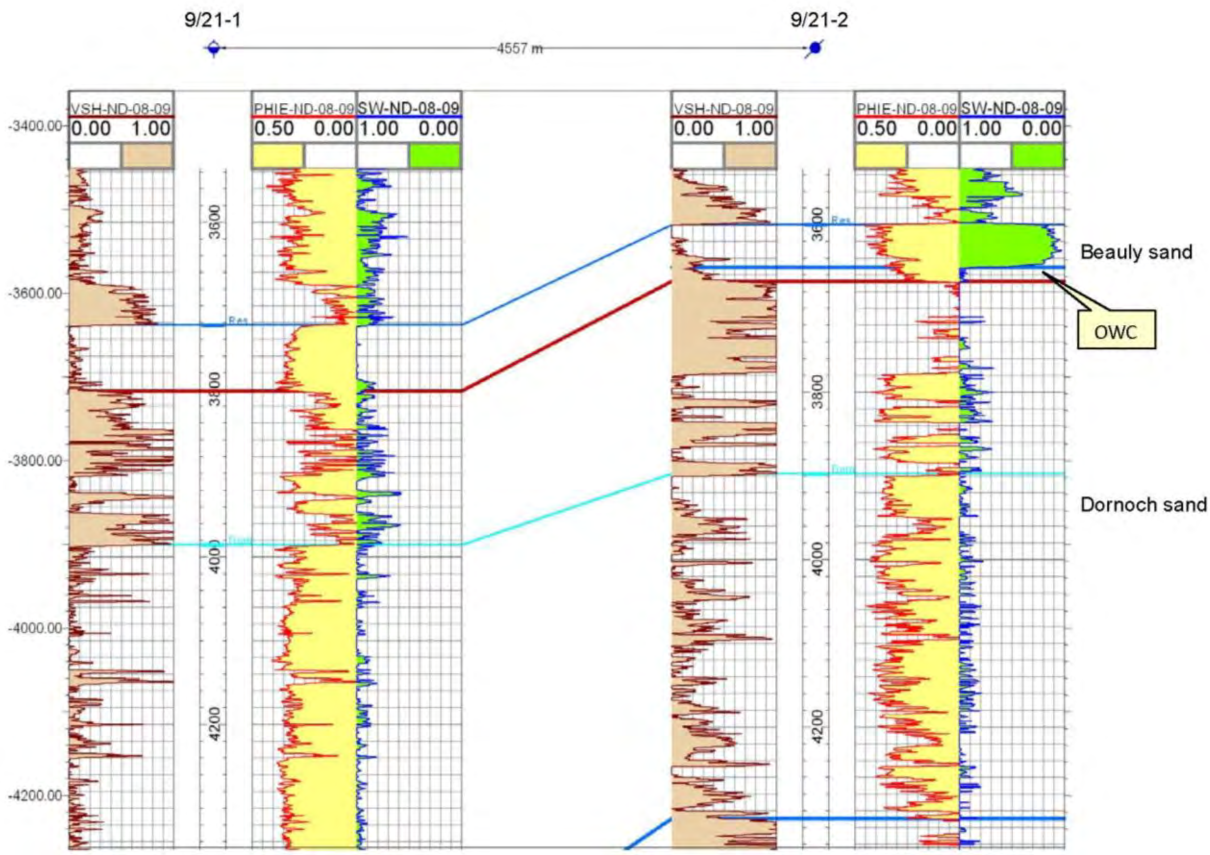


Figure 3-5: Interpreted logs produced by PGL

Hole conditions within the Beauly formation vary significantly, as shown by the caliper log. The water wet 9/21-1 well is in gauge and all logs are in excellent condition. The oil bearing section of 9/21-2 is significantly washed out, which impacts the traditional porosity curves of sonic, density and neutron. All curves in both wells are on depth with respect to the GR logs.

Volume of shale was calculated from a combination of the gamma ray and separation between the neutron and density logs. The resultant volume of clay (VCLav) log is the mean average of both methods.Net to gross for both wells is high, reflecting the overall good quality reservoir

To calculate porosity from either the density or sonic log, the matrix and fluid densities or velocities are required. In the absence of core data, the textbook values of quartz; 2.66 g/cc and 55.5 us/ft have been applied. For fluid density, a simple mix of brine and hydrocarbon density was generated based on a provisional Sw log.

Porosities show a slight decrease in values between the oil and water legs, and several factors could be responsible for this. Firstly, the washed out section in the oil leg causes a density and sonic error. Secondly, it is often seen in Palaeocene reservoirs that secondary mineralisation in the water leg reduces porosity, while the presence of oil preserves porosity. The washouts in the oil leg compared to the in-gauge hole of the water legs may indicate that secondary mineralisation has occurred increasing the strength of the sands within the water leg. Of the two possibilities and in the absence of core data it is difficult to distinguish which is most likely.

Water saturations are generated using Archie, the electrical properties of ‘a’ and ‘n’ are taken as standard 1 and 2 respectively, the values of ‘m’ and Rw are derived from Pickett analysis (Figure 3-6). Formation temperature is derived from a generic North Sea gradient. Water saturation in 9/21-2 is low in the net pay section, averaging 13.7%, which is not unusual given the reservoir quality.

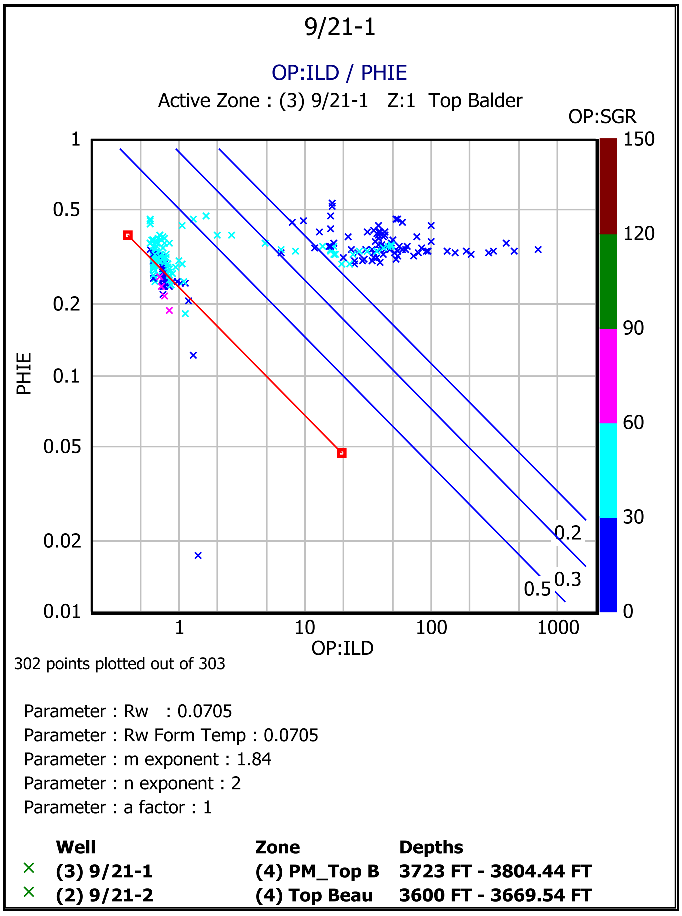


Figure 3-6: Beauly reservoir Pickett plot

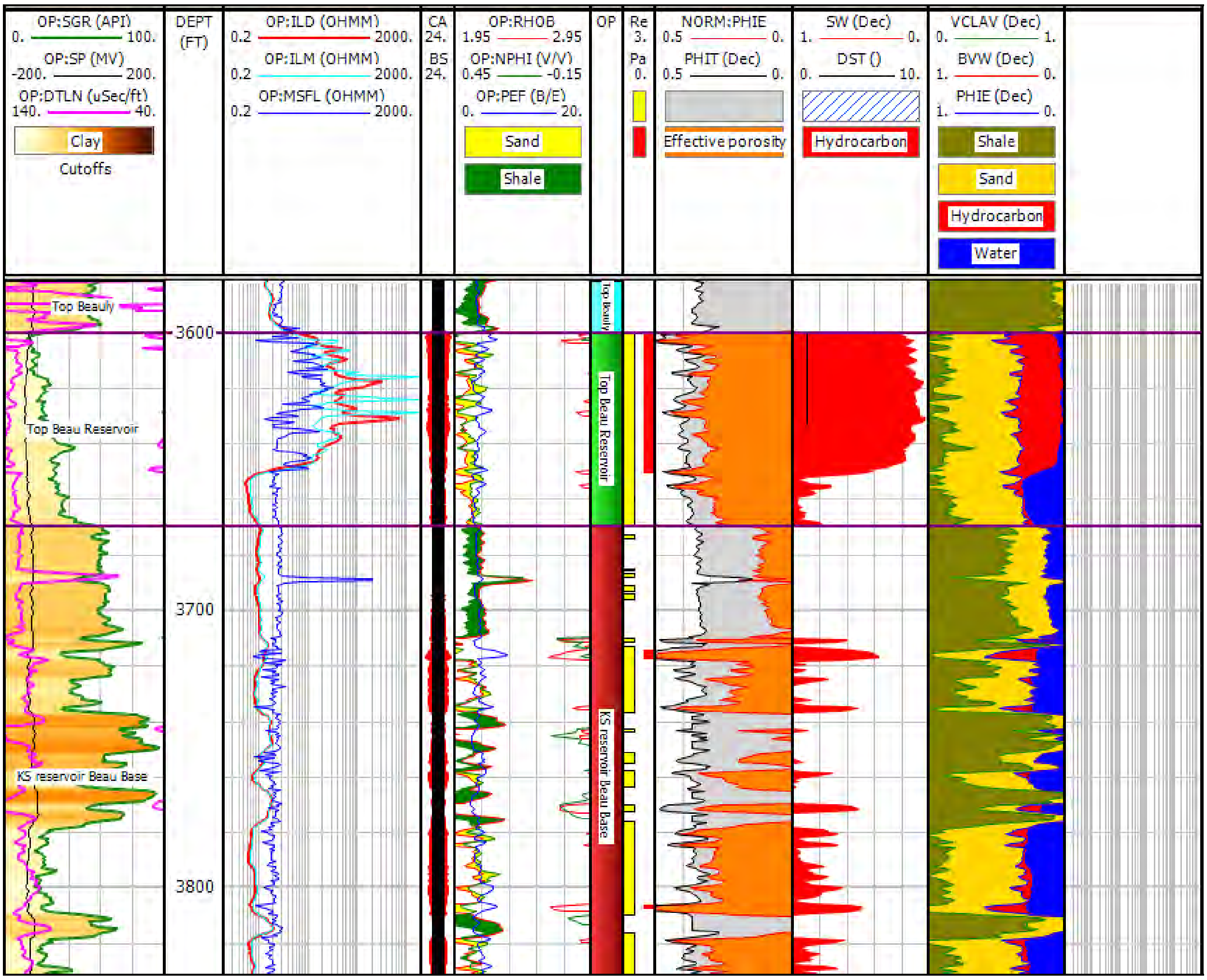


Figure 3-7: 9/21-2 CPI for Beauly sandstone

The results of the AGR TRACS and PGL petrophysical analysis are similar. The main difference arises from the incorporation of the GR log in the calculation of volume of clay. This was used because of the washout in the oil zone in 9/21-2 affecting the neutron and density logs. Overall the PGL logs were accepted as reasonable and were used to calculate the reservoir and pay averages shown below.

Well	Beauly sand ATP				
	Gross	Net	NGR	PHIE	Sw
9-21-1	79.1	76.0	0.960	0.315	0.979
9-21-2	67.9	65.5	0.965	0.337	0.341
Sums/Average	147.0	141.5	**0.963**	**0.325**	0.684

Table 3-1: Beauly reservoir averages

Well	Beauly sand ATP				
	Gross	Net	NGR	PHIE	Sw
9-21-1	79.1	0	0		
9-21-2	67.9	50.0	0.736	0.359	0.145
Sums/Average	147.0	50.0	0.340	0.359	**0.145**

Table 3-2: Beauly pay averages

Logs and cut-off

Reservoir

- Porosity: PHIE-ND-08-09<0.1
- Clay volume: VSH-ND-08-09>0.5

Pay

- Porosity: PHIE-ND-08-09<0.1
- Clay volume: VSH-ND-08-09>0.5
- Water saturation: SW-ND-08-09>0.7

3.4. Seismic interpretation

The assessment of the seismic interpretation provided by ATP consisted of the following:

- Check to ensure the correct seismic well ties had been made.
- Review of pick uncertainty across the field
- Review of time maps
- Review of depth conversion
- Review of the field extents

The primary purpose of the geophysical assessment was to understand the range of STOIIP discovered at Skipper. However, in addition, AGR TRACS was requested to look at the exploration potential of the underlying Dornoch and Maureen Palaeocene reservoirs. As a result the following horizons produced by ATP were reviewed.

Horizon	Horizon name	Time grid	Comment
Upper Tertiary maximum flooding surface	UTMFS Both Auto 2	UTMFS4	Used for depth conversion
Top Beauly sand	Near Top Skipper Both post better synthetics Auto 1	Near Top Skipper PBS	Main reservoir pick. Picked at the top of a reflection peak.
Top Dornoch	Top Dornoch 4 Auto 3	Top Dornoch 8	Weak peak used for Dornoch reservoir prospects
Top Maureen	Near Top Maureen Auto 1	Near Top Maureen 2	Moderate peak used for Dornoch reservoir prospect

Table 3-3: ATP seismic picks

Synthetic seismograms were examined to check the accuracy of the pick on the seismic data. The synthetic seismogram for 9/21-2 (Figure 3-8) showed a good correlation between the seismic reflectors and the synthetic trace which provided confidence that the correct events have been recognised. For the Beauly sand the upper part of a seismic peak has been picked. Although this event has been picked with reasonable accuracy over the 3D data set, there is a degree of subjectivity as the pick is not at the maximum amplitude of the peak. No faults have been interpreted at Skipper although there are indications that minor faults could be present at the margins of the field.

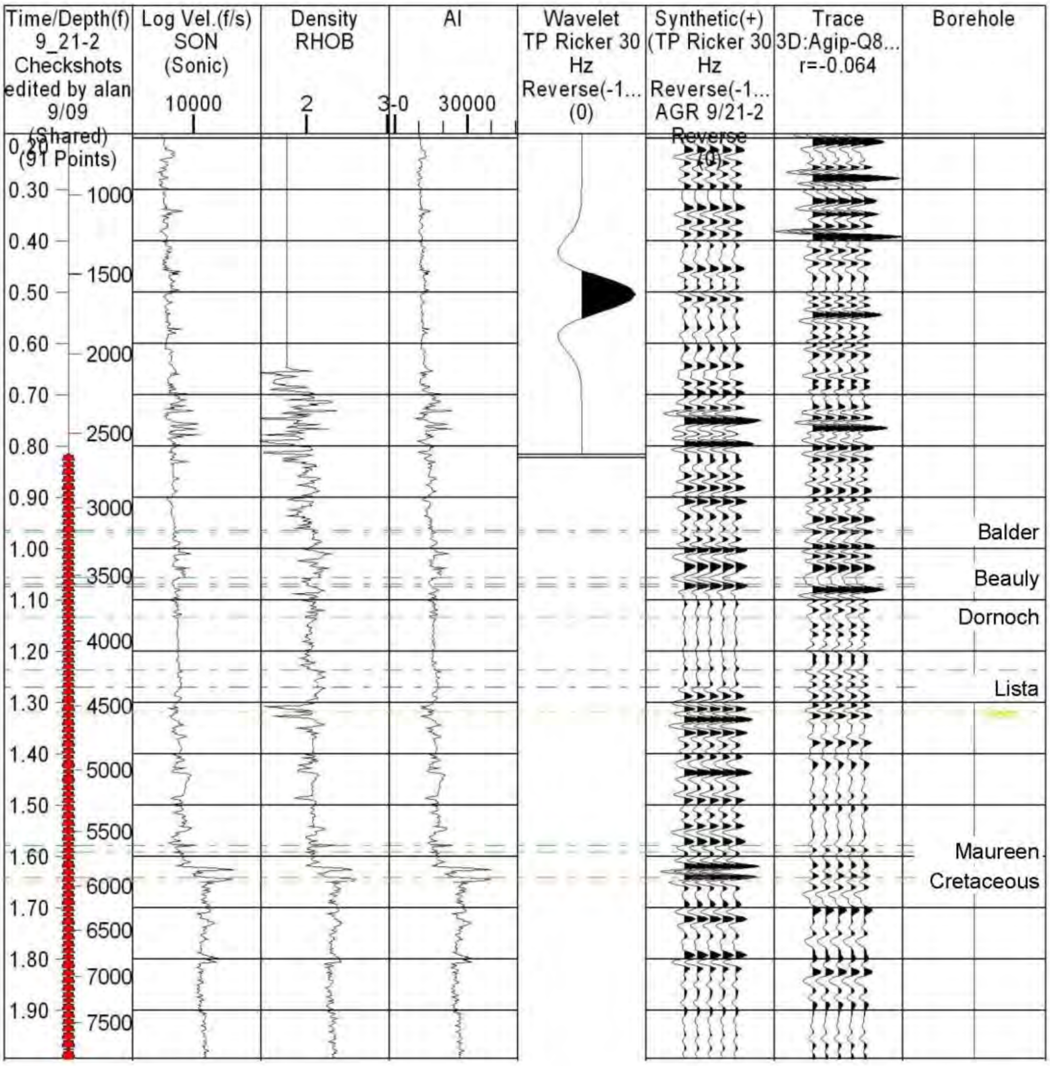


Figure 3-8: Synthetic seismogram 9/21-2

The time map produced by ATP shows a simple rollover closure with approximately 45 metres of relief that encompasses an area of 9.5 km^2. In time the structure appears to spill to the south (Figure 3-9).

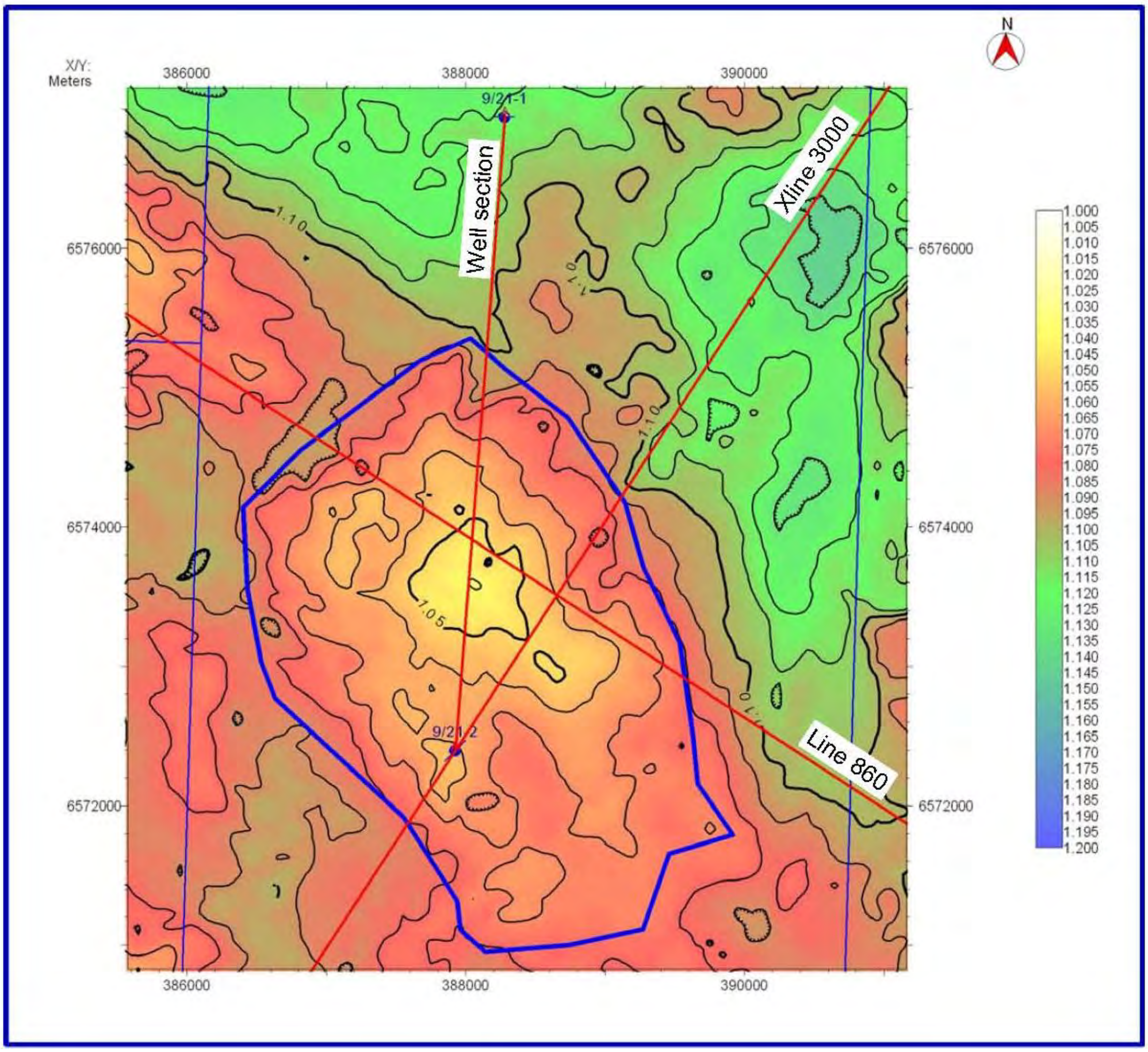


Figure 3-9: Beauly time structure (ATP)

The top Dornoch does not produce a good quality reflector and the synthetic seismogram indicates that a peak, approximately 10ms above the top of the sand, has been used (Figure 3-10). This event, although weak, appears to have been picked consistently across the area.

According to the synthetic seismogram the top Maureen does not produce a strong seismic reflector. As a result, a moderate quality peak 15ms above the Maureen has been interpreted. This event shows some complexity which in some areas could provide alternate interpretation.

Although the interpretation of the top Beauly reservoir is considered reasonable, because of the degree of subjectivity in the ATP pick, it was decided to produce two alternate interpretations to investigate the range in trap size. The picks used were the point of maximum amplitude on the peak immediately below the ATP pick and the trough within the Beauly immediately overlying the reservoir. These events were picked and mapped over the area of the Skipper discovery.

As the AGR TRACS horizons were of fair to good quality, they were auto filled. In addition, a dip map was produced for the AGR TRACS Beauly peak horizon (Figure 3-11). This highlighted areas of maximum gradient and was used to indicate the presence of faults.

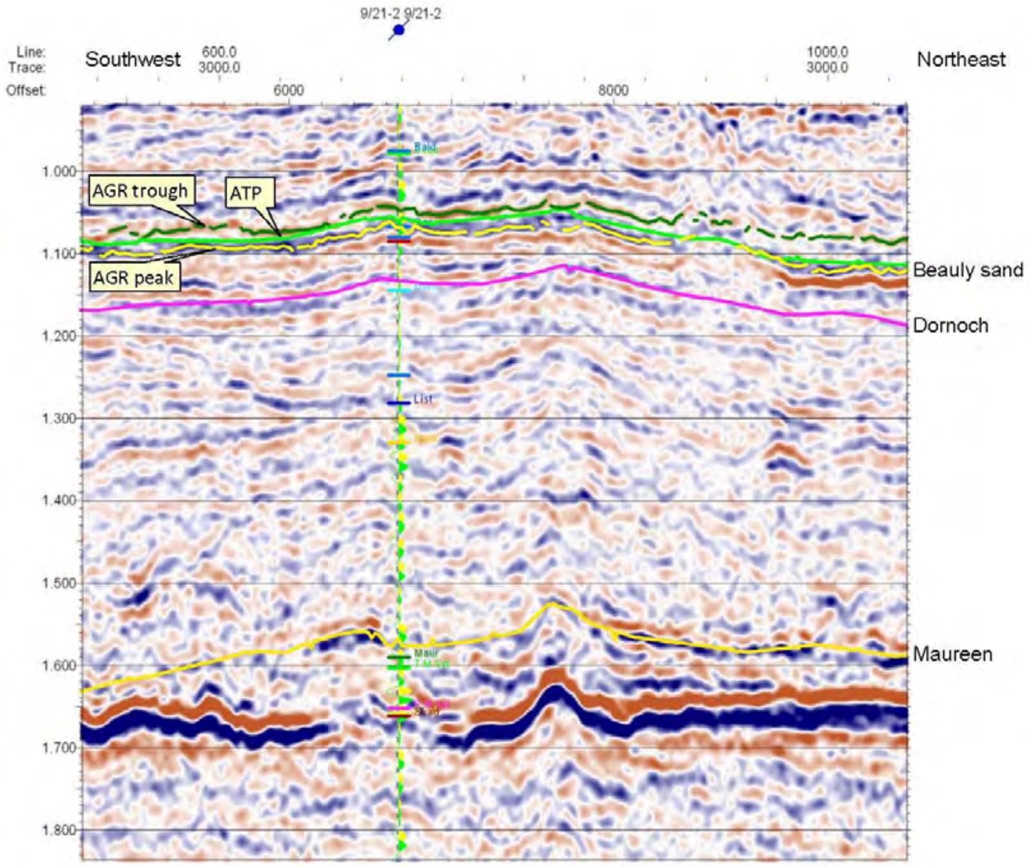


Figure 3-10: Cross line 3000 through 9/21-2

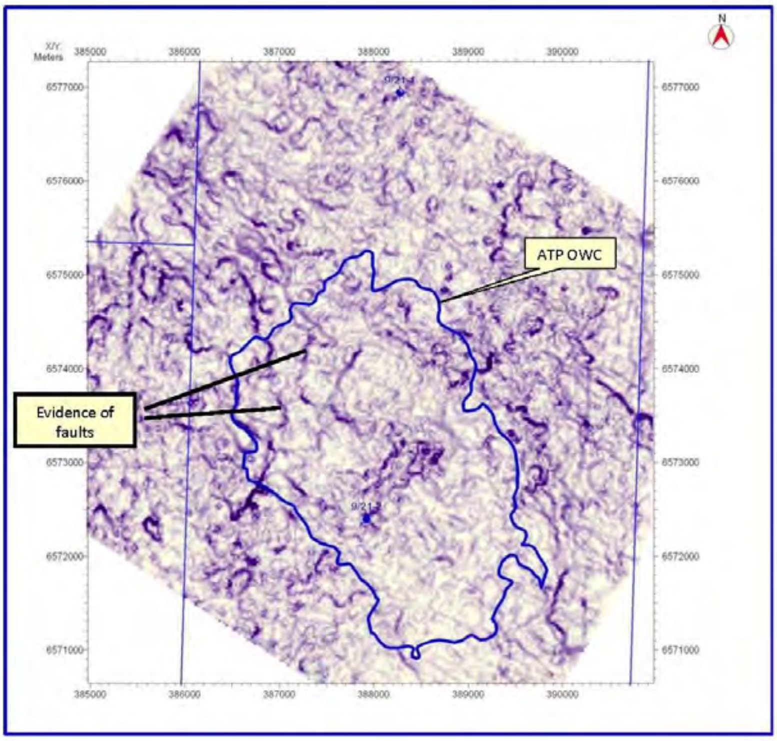


Figure 3-11: AGR TRACS Beauly sand dip map

3.5. Depth conversion

ATP used a 2 layer velocity model to convert their Beauly sand time horizon to depth (Figure 3-12). This was based on the analysis of 3 wells (9/21-1, 9/21-2 & 9/20-1). The layers and velocity functions are given on the following table:

Layer	Velocity function
Surface to Upper Tertiary maximum flooding surface	Velocity ft/s=1412*TWTs+4986.5
Upper Tertiary maximum flooding surface to top Beauly reservoir	Velocity ft/s=-8086.4*TWTs+10393

Table 3-4: ATP velocity model

The negative velocity gradient for the lower layer is surprising but may be due to the increased thickness being related to an increase in sand content, as sand has a lower velocity than shale. As part of the evaluation other depth conversions were examined however, the ATP model produced the lowest residual errors and was thus considered robust. Therefore this velocity model was used to depth convert the alternative AGR TRACS interpretations (Figure 3-13 & Figure 3-14). Residual differences grids were produced to ensure the maps correctly tied the wells.

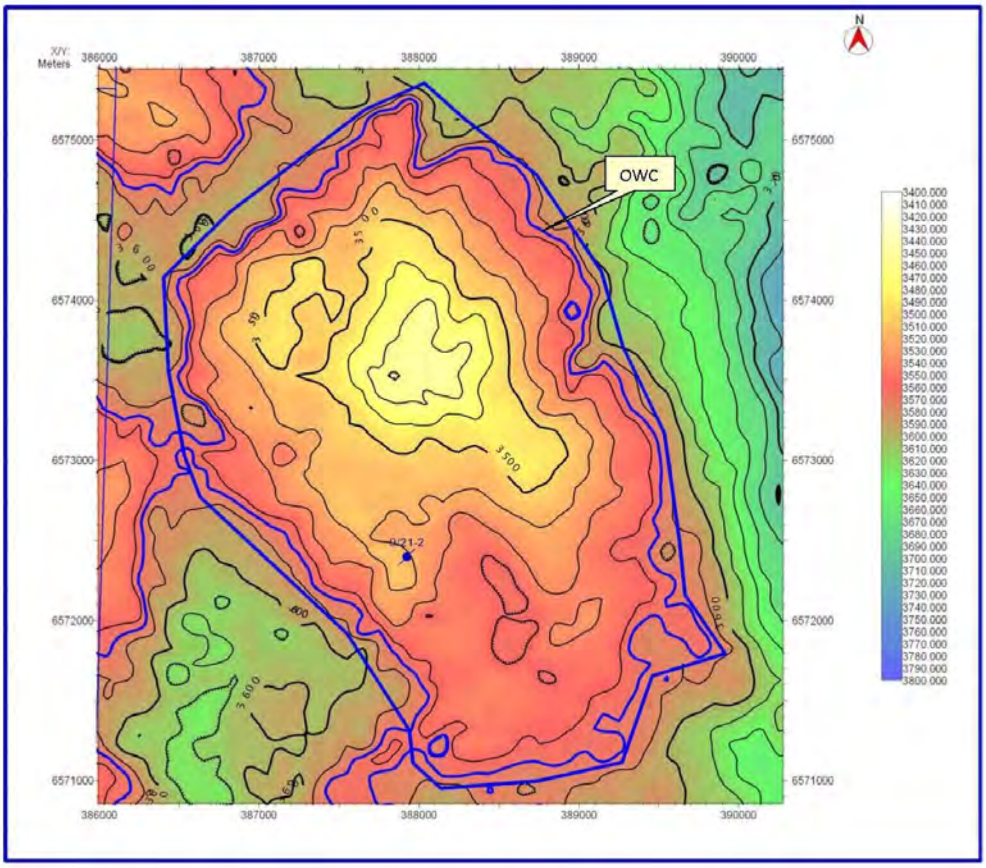


Figure 3-12: ATP top Beauly sandstone depth map

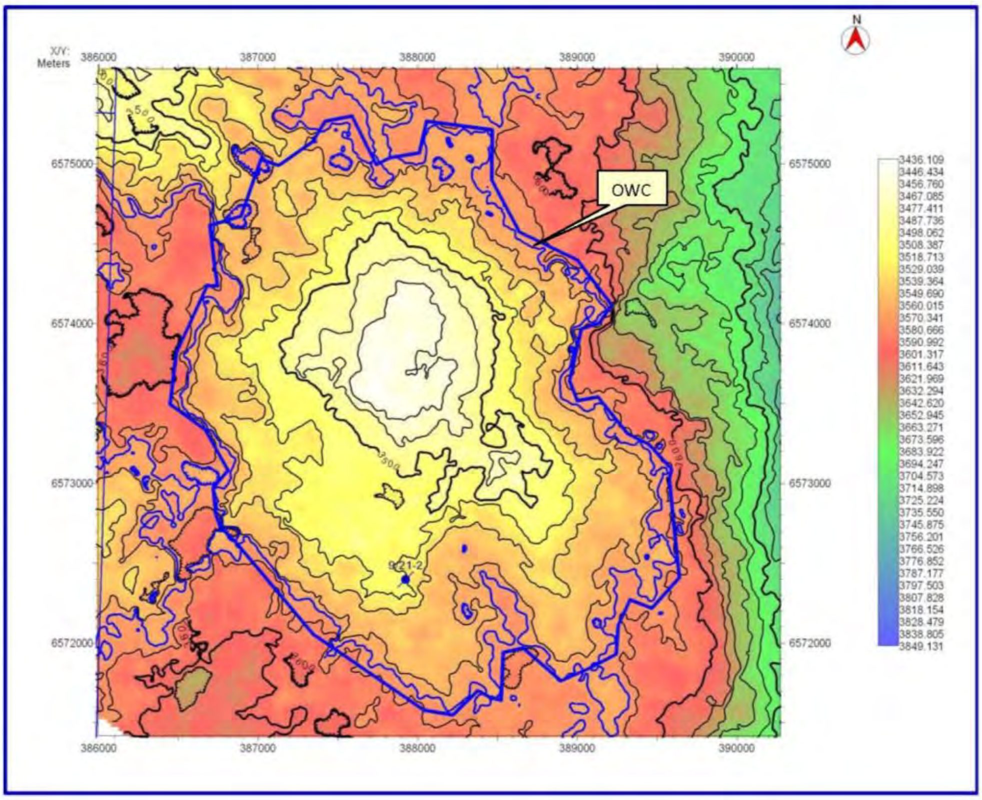


Figure 3-13: AGR TRACS top Beauly sandstone depth map (peak horizon)

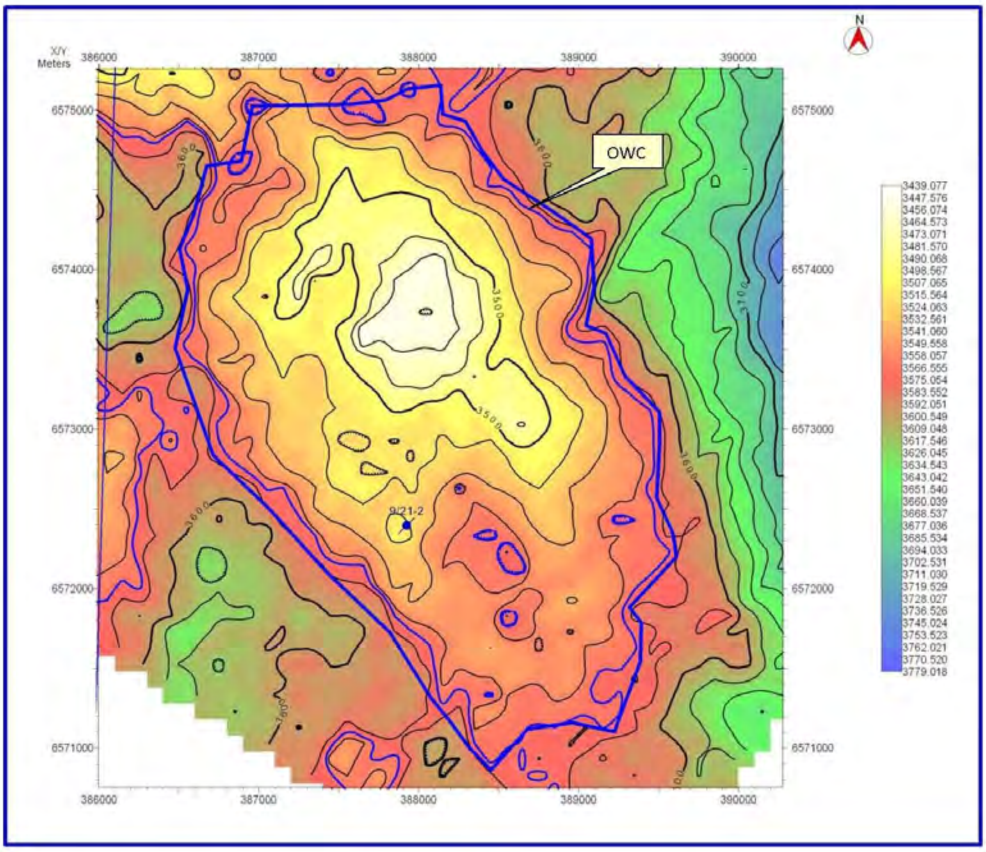


Figure 3-14: AGR TRACS top Beauly sandstone depth map (trough horizon)

A review of the alternate depth maps showed a similar structure. None of the maps quite close to the OWC. The ATP closes to within 5' of the OWC at the spill point to the west. The AGR TRACS maps both spill to the north, the peak event 20' above the OWC and the trough 30' above the OWC. On this basis the ATP map fits best with the geological model. However, the ATP interpretation is inconsistent at the spill point in the northwest so the closure is rather forced. Overall it is considered that the northwest spill point is most likely and the lack of closure to the spill point on the AGR TRACS maps is due to small errors in the velocity model or an increase in shale at the top of the reservoir in this direction.

3.6. STOIIP Estimation

STOIIP for Skipper was estimated probabilistically. Gross rock volume (GRV) was based on an OWC of -3569' TVDSS. As the reservoir thickness (70') is less than the maximum vertical relief of the closure (129'), a base reservoir surface was created using the well isochores. GRVs were calculated from the three alternate depth maps incorporating a base reservoir surface. The mean GRV assumption for the probabilistic analysis was based on the average GRV calculated from the three maps with a normal distribution and a standard deviation. These values are given in the table below:

Map	ATP Near Top Skipper Depth 4 Tied	AGR TRACS Skipper peak v2 depth tied	AGR TRACS Skipper trough v2 depth tied	Average	Standard Deviation
GRV m^3*10^6	91.27	83.92	85.71	86.97	3.83

Table 3-5: Skipper GRV calculations

Reservoir parameters were deduced from the interpreted petrophysical logs provided by ATP. Reservoir averages were obtained using both 9/21-1 and 9/21-2 with the water saturation taken from the pay zone in 9/21-2. The input assumptions for the reservoir properties are given in the table below.

NGR			PHIE		Sw			FVF		
min	base	max	mean	standard deviation	min	base	max	min	base	max
0.926	0.963	1.000	0.325	0.016	0.105	0.145	0.185	1.032	1.060	1.123

Table 3-6: Beauly reservoir parameters

These inputs were used in a Monte Carlo analysis to produce the following STOIIP forecast for the Beauly reservoir at Skipper:

Reservoir	Mean MMstb	P90 MMstb	P50 MMstb	P10 MMstb
Beauly	136.8	123.1	136.5	150.8

Table 3-7: Skipper STOIIP

3.7. Exploration potential

In addition to the oil discovered in the Beauly reservoir at Skipper, two deeper Palaeocene reservoirs have been proposed as prospective. The upper is the Dornoch sand which immediately underlies the Beauly sands. It is over 400' thick with very good porosity and high net to gross (Figure 3-5). It was wet in 9/21-2 but forms the reservoir in the Bressay and Bentley fields 80km to the north both of which are proceeding to development.

The second reservoir prospect is the basal Palaeocene sand(s) of the Maureen Formation. Again these sands were wet in both 9/21-1 and 9/21-2. Both these reservoirs have been interpreted by ATP and a review of the picks showed them to be reasonable although the Dornoch seismic event was weak and the Maureen rather complex.

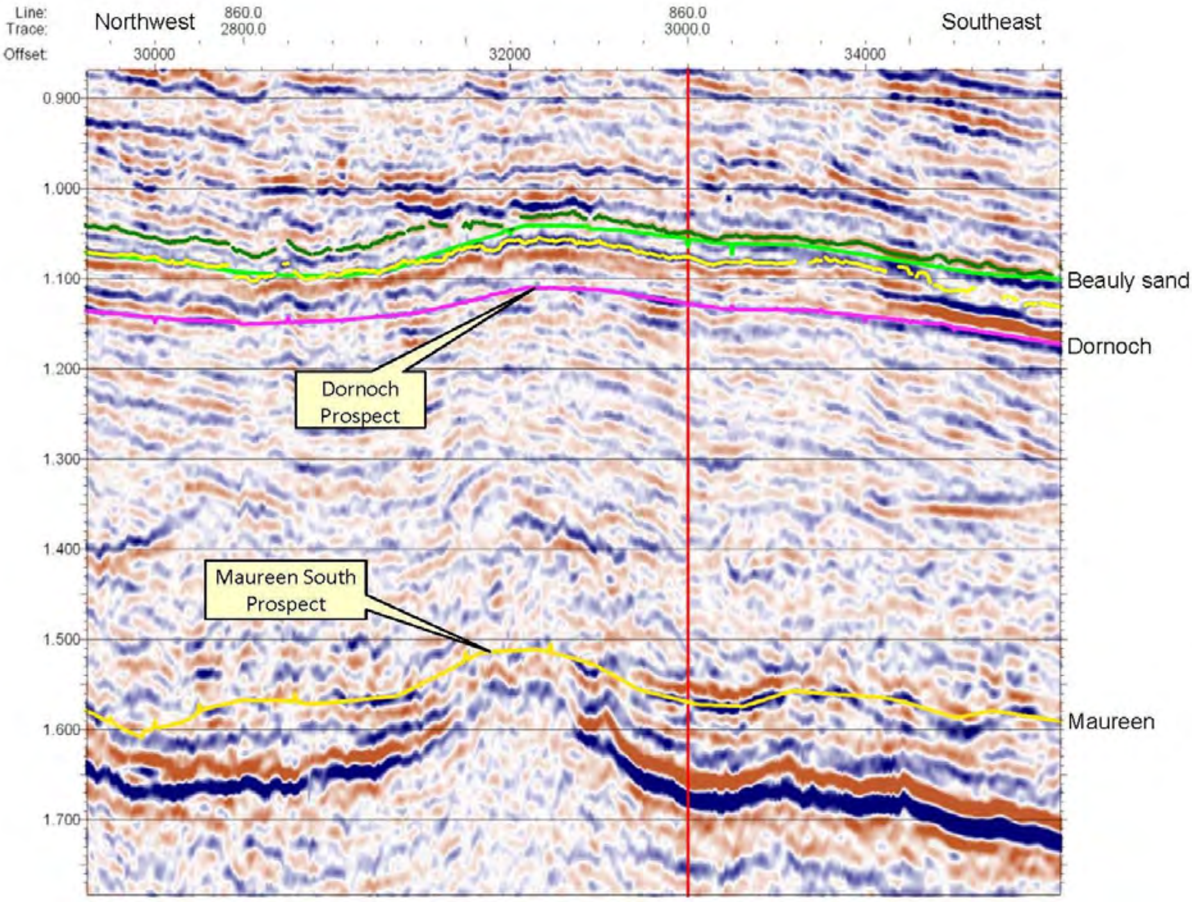


Figure 3-15: Seismic line 860 showing rollover in Dornoch and Maureen sands

Volumes for both the Dornoch and Maureen reservoirs were calculated probabilistically and a geological chance of success (COS) estimated for each. This was based on the four element scheme given below:

- **Source** – Included the probability that source rocks are present and have generated and expelled hydrocarbon that could migrate into the prospect.
- **Seal** – Assessed the probability that effective top and cross fault seals are present.
- **Reservoir** – Assessed the probability that the proposed reservoir is present and is effective.
- **Trap** – Assessed the probability that the trap is present as mapped and is representative of the structure of the proposed reservoir.

3.7.1. Dornoch Prospect

Mapping of the Dornoch shows a four-way dip closure which includes 9/21-2 within the maximum extent. Therefore the Dornoch has been partially tested by the well and the remaining potential is restricted to the area up-dip from the well.

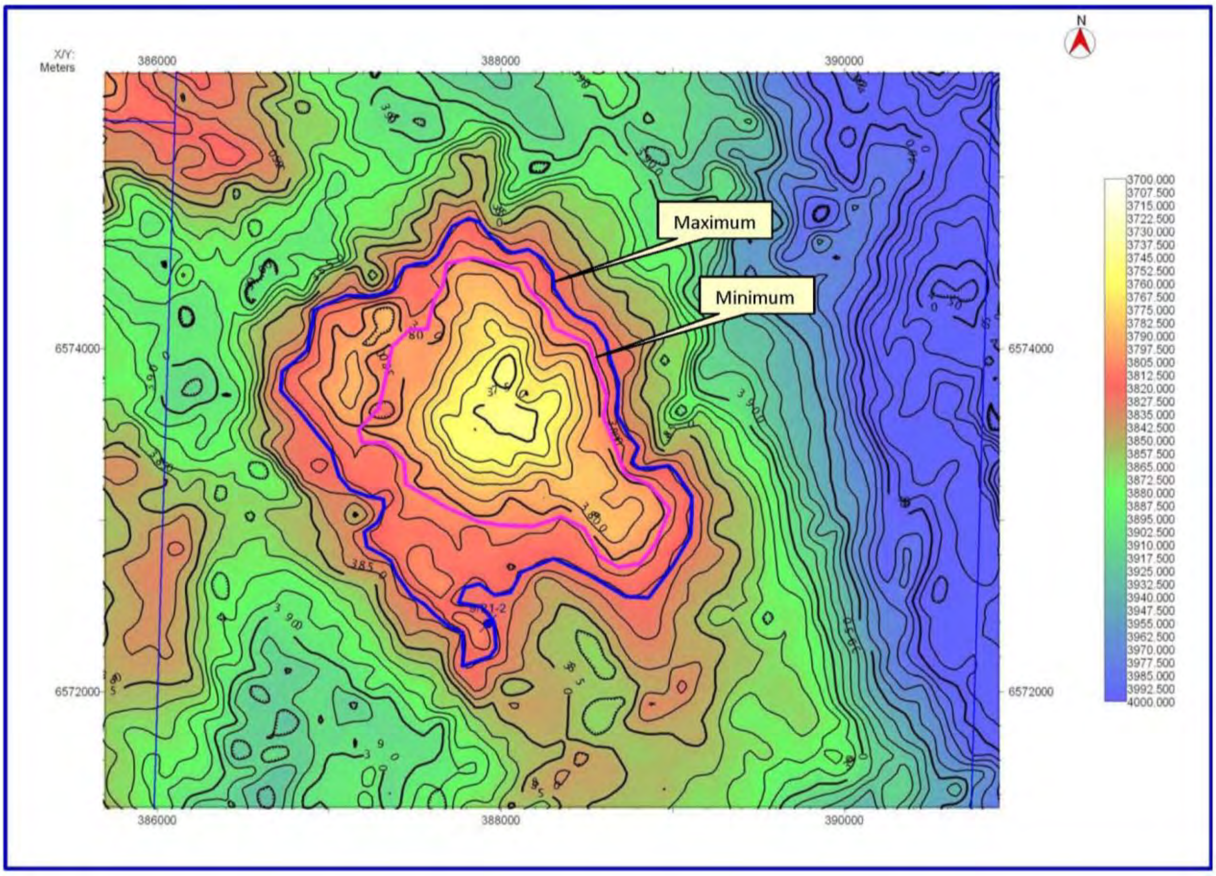


Figure 3-16: Top Dornoch depth map

To estimate a range of GRV, minimum and maximum polygons were used with a range of possible OWCs. As the reservoir is substantially thicker than the vertical relief, a base reservoir surface was not required. A triangular GRV assumption was used with the input parameter given in the table below:

Crest ft	OWC ft			Area km^2		GRV m^3*10^6		
	Shallow	Mid	Deep	min	max	P90	P50	P10
-3745	-3800	-3810	-3816	1.73	3.30	9.07	15.20	19.97

Table 3-8: Dornoch GRV assumption

Reservoir parameters were taken from the ATP petrophysical analysis with a water saturation estimated from the relationship with porosity seen in the Beauly. These inputs together with the output range of STOIIP are given in the tables below:

NGR			PHIE		Sw			FVF		
P90	P50	P10	Mean	Standard Deviation	Min	Base	Max	Min	Base	Max
0.866	0.878	0.888	0.305	0.031	0101	0.171	0.241	1.032	1.060	1.123

Table 3-9: Dornoch reservoir parameters

Reservoir	Mean MMstb	P90 MMstb	P50 MMstb	P10 MMstb
Dornoch	19.4	11.6	19.5	26.8

Table 3-10: Dornoch STOIIP

The Dornoch is assessed to have a moderate chance of success. The main risk is charging the reservoir with oil as the closure has already been partially tested by 9/21-2. The results and comments on the assessment of chance of success are given in the table below:

Parameter	COS	Comments
Source/charge	0.3	Closure tested by 9/21-2. Good evidence that oil has not migrated into the closure
Seal	0.8	100' argillaceous section overlies reservoir. Some minor faulting present
Reservoir	1.0	Thick porous reservoir proven adjacent to prospect
Trap	0.8	Seismic horizon quality poor although events mirrors overlying Beauly
Overall	0.19	

Table 3-11: Dornoch geological chance of success

3.7.2. Maureen Prospects

ATP mapping of the Maureen Formation shows that two closures are present (north and south). Neither closure was tested by the wells although 9/21-1 was close to testing the northern closure.

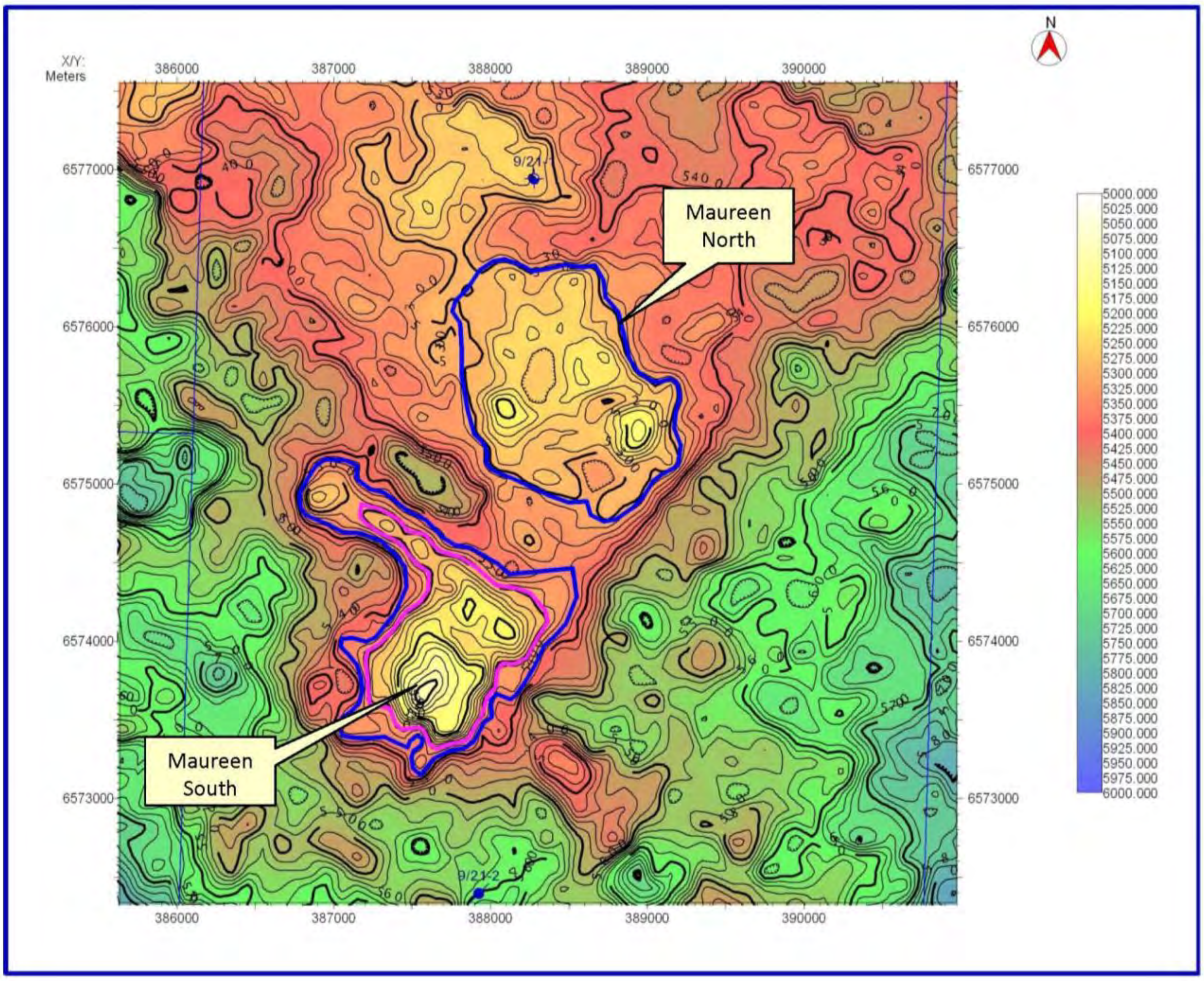


Figure 3-17: Maureen depth map

To estimate a range of GRV, minimum and maximum polygons were used for the southern closure with a range of possible OWCs. As the reservoir was of similar thickness to the vertical relief, a base reservoir surface was not required. A triangular GRV assumption was used for the south closure while a lognormal distribution was assumed for the northern. These inputs are given in the table below:

Closure	OWC ft			Area km^2		GRV m^3*10^6		
	Shallow	Mid	Deep	Min	Max	P90	P50/ Mean	P10
South	-5300	-5340	-5360	0.89	1.51	16.21	27.65	36.19
North		-5280	-5300		1.65		6.74	14.39

Table 3-12: Maureen GRV assumption

The Maureen reservoirs were approximately 240' thick in both 9/21-1 and 9/21-2 (Figure 3-18). They have good porosity but are more variable in character than the Dornoch. Reservoir parameters were taken from the ATP petrophysical analysis with a water saturation estimated from the relationship with porosity seen in the Beauly. These inputs together with the output range of STOIIP are given in the tables below:

NGR			PHIE		Sw			FVF		
P90	P50	P10	Mean	Standard Deviation	Min	Base	Max	Min	Base	Max
0.744	0.829	0.914	0.254	0.017	0.137	0.237	0.337	1.078	1.159	1.355

Table 3-13: Maureen reservoir parameters

Closure	Mean MMstb	P90 MMstb	P50 MMstb	P10 MMstb
Maureen South	22.8	13.3	22.9	31.9
Maureen North	5.1	1.1	3.6	11.1

Table 3-14: Maureen STOIIP

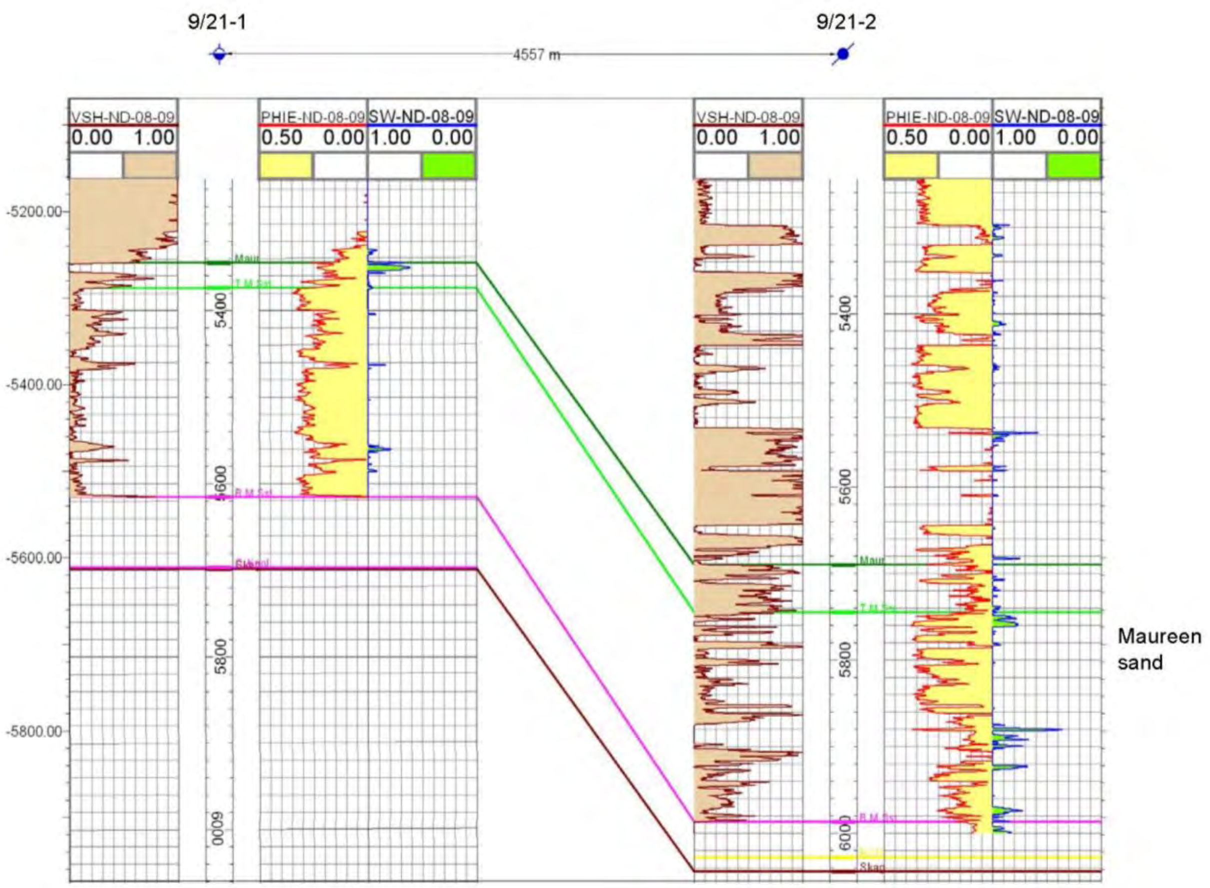


Figure 3-18: Maureen Formation well section

The Maureen prospects are assessed to have a moderate chance of success. The main risk is assessed as oil charge. The evidence is that the hydrocarbons have already migrated to shallower stratigraphic levels, as seen at Gryphon, prior to lateral migration on to the East Shetlands Platform. The results and comments on the assessment of chance of success are given in the tables below:

Parameter	POS	Comments
Source/charge	0.4	Small closure tested by 9/21-1. No evidence that oil has not migrated into the closure although closure mapped down migration fairway
Seal	0.7	100' argillaceous section overlies reservoir. Evidence of faults that could breach the seal.
Reservoir	0.8	Isochron of Maureen thickens within trap suggesting sands are well developed.
Trap	0.7	Seismic horizon quality poor.
Overall	0.16	

Table 3-15: Maureen South geological chance of success

Parameter	POS	Comments
Source/charge	0.3	Small closure tested by 9/21-1. No evidence that oil has not migrated through closure which is adjacent to the well
Seal	0.8	100' argillaceous section overlies reservoir. Only minor faulting present
Reservoir	0.7	Maureen isochron thinner than at 9/21-1
Trap	0.8	Moderate quality seismic reflection.
Overall	0.13	

Table 3-16: Maureen North geological chance of success

3.8. Reservoir Engineering

3.8.1. Fluid Properties

Four degassed and biodegraded oil samples were obtained during various phases of the well test in well 9/21-2 in 1990. These samples were analysed by Robertson group plc in 1991 and again by Fugro Robertson Limited in 2006. In addition, in 1991 hydrocarbon extracts of two sidewall samples and one water-based drilling fluid sample were analysed.

Geochemical analysis reports of oil samples from the well 9/21-2 were reviewed. The main conclusions made by Fugro/Robertson were:

- All four samples were biodegraded, the level of biodegradation was 8 to 9 on a scale of 1 to 10.
- Oil gravity on the basis of column chromatography is about 14° API at 25°C and dead oil viscosity is about 800cSt (750cP) at 40°C.
- Even a small amount of a non-degraded oil component in the oils would significantly reduce the estimated oil viscosity.

- Light hydrocarbon components may have been lost during sampling and sample storage.
- The oil was generated from the Kimmeridge Clay Formation and was biodegraded during or before final emplacement. Uneven recharge of the fresh oil was diagnosed from the analysis and comparison of the sampled fluids.

The oil properties of the Skipper prospect are a major uncertainty in planning the field development. No pressurised and representative fluid sample for the Skipper field is available and oil properties are highly uncertain. The Skipper oil density is believed to be around 15 °API, with medium to high viscosity at reservoir conditions, depending on the reservoir temperature and the dissolved gas content (GOR). High oil viscosity might require a different development approach compared with conventional oils, requiring higher well density and different processing considerations. A representative fluid sample is critical to determine the best development scenario, and good estimates of recoverable volumes, well count, facilities size, etc.

A dead oil viscosity of 750 cP was estimated from the depressurised sample by Robertsons. This can be taken as representing a pessimistic scenario. Oil viscosity at saturation pressure at reservoir conditions was calculated with range of correlations, for low, mid and high cases (see Figure 3-19). These correlations require inputs of GOR and dead oil viscosity. Correlations of dead oil viscosity in turn, depend on oil gravity and reservoir temperature. The following assumptions were made to derive viscosity for production forecasting, (see Table 3-17).

i) The maximum possible GOR for the pressure and depth of the Skipper reservoir was determined using the Standing correlation. This would be the GOR if the oil in reservoir were at saturation pressure. This value of GOR was used for high case. For the mid case 50% of the high case GOR was used. For the low case 25% of the high case GOR was used;

ii) A density range of 12-15-18° API was assumed;

iii) 750 cP viscosity was used for the dead oil as an input for low case while 500cP and 250 cP were used for the mid and low cases;

iv) Viscosity at saturation pressure was estimated with several correlations for low, mid and high case assumptions (Figure 3-19). Averages for high, low and mid cases used for generating production forecast, Table 3-17.

	Low	Mid	High	Comments
μ_{oD}, cP	750	500	250	dead oil viscosity
Rs, scf/stb	68	135	270	solution GOR
°API	12	15	18	oil density
μ_{obp}, cP	370	160	50	viscosity at Psat

Table 3-17: Oil viscosity assumptions for Skipper Beauly formation

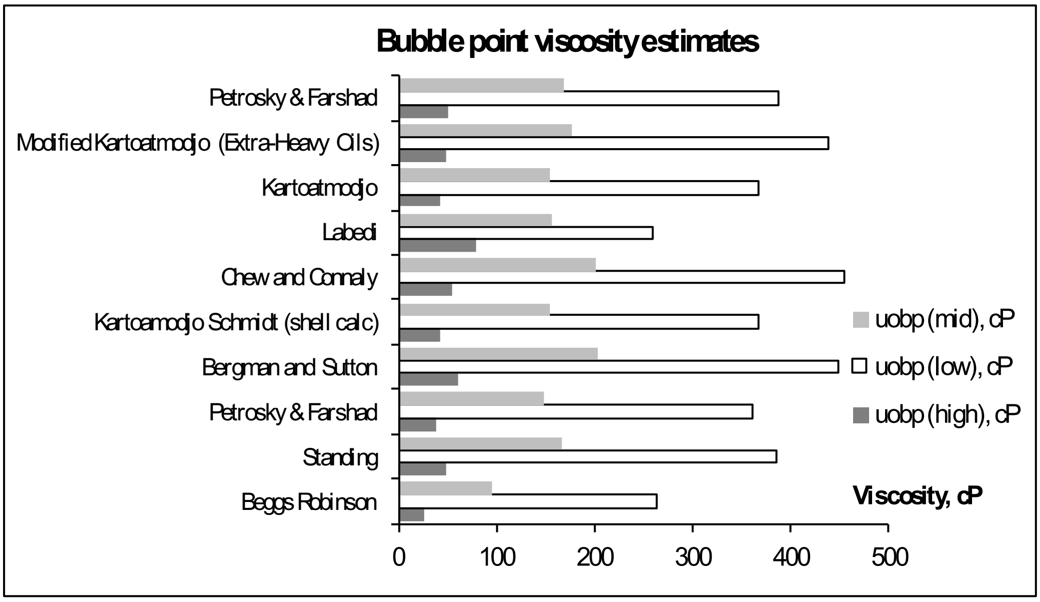


Figure 3-19: Skipper oil viscosity with correlations

Formation Volume Factors (FVF) were calculated using the Standing correlation for Skipper Beauly, Dornoch and Maureen Formations. Assumptions used for the Beauly and Dornoch FVF range are given in the Table 3-18 and for Maureen in Table 3-19. The Maureen prospect is nearly 2000 ft deeper, and has higher pressure and temperature. Oil from the Maureen reservoir is expected to be lighter and potentially gassier than the Beauly oil.

	P90	P50	P10
Temp, degF	89	89	89
Oil gravity, API	12	15	18
Gas gravity, SG	0.7	0.8	0.9
Initial GOR, scf/stb	68	135	270
FVF (Bo), rb/stb	1.032	1.060	1.123

Table 3-18: Beauly and Dornoch Formation Volume Factor range

	P90	P50	P10
Temp, degF	104	104	104
Oil gravity, API	15	22	29
Gas gravity, SG	0.7	0.8	0.9
Initial GOR, scf/stb	172	344	688
FVF (Bo), rb/stb	1.078	1.159	1.355

Table 3-19: Maureen Formation Volume Factor range

3.8.2. Recovery Efficiency

To estimate the recovery efficiency range for the Skipper prospect, fractional flow curves were constructed and cross checked against the performance of analogous fields.

The Captain field is the producing field with the most viscous oil in the North Sea. In-situ oil viscosity of Captain is about 88cP with 19 °API oil (SPE 54623). The field started production in 1997 with cumulative production to date (Np) of 257 MMstb (DECC, to April-2013). This gives a recovery factor to date of over 25% if 1,000 MMstb STOIIP is assumed. The estimated ultimate oil recovery (EUR) for this field is 350 to 375 MMstb depending on watercut development at a late stage of the field life, infill drilling, well shut-offs etc. (Figure 3-20). This would give a recovery efficiency of 35-37.5%.

The Bentley field is located in block 9/3b and is under development by Xcite Energy Resources Limited. Bentley crude is 10-12 °API, with live oil viscosity of 627cP and the base case development plan is with cold production. In the Xcite 'Reserves assessment Report Update' (July 2011) the stated base case STOIIP is 488 MMstb, and recovery is 27.8 MMstb and 87.2 MMstb for the first and second stages of development respectively. This gives an ultimate recovery efficiency of 23.6%. A small well spacing was assumed for this field with multilateral wells. The well count information is not published.

The relative permeability of the Bressay (1000cP) and Mariner (65cP) fields were provided by ATP (Table 3-20 and Figure 3-21). These fields are also under development. Using end points relative permeabilities, the maximum recovery factor with waterflood was calculated as 26% and 50% for Bressay and Mariner, respectively. If a 70% volumetric sweep efficiency is assumed, then recovery would reduce down to 18% and 35% for Bressay and Mariner respectively.

Fractional flow curves (watercut vs. recovery factor) were constructed for the low, mid and high cases of the Beauly reservoir in Skipper (Figure 3-22). This approach is based on Buckley-Leverett displacement theory and assumes diffuse fluid flow. To account for the expected water tonguing/under-running, a volumetric sweep efficiency of 70% was assumed. Recovery factors for the Beauly reservoir were calculated at 11-21-36% for the low-mid-high cases, with a cut-off at 95% watercut.

The same range of recovery factors was used for the Dornoch reservoir. For the Maureen reservoir, which is expected to have lighter oil, higher recovery factors envisaged. 15-25-40% recovery factors were assumed to be representative.

Ranges of recovery factors for Beauly, Dornoch and Maureen reservoirs were input for probabilistic analysis into a Monte Carlo model. The resulting estimates of technically recoverable volumes of oil are given in the Table 3-21. It should be noted that the Maureen North accumulation is unlikely to be developed in the low or mid cases.

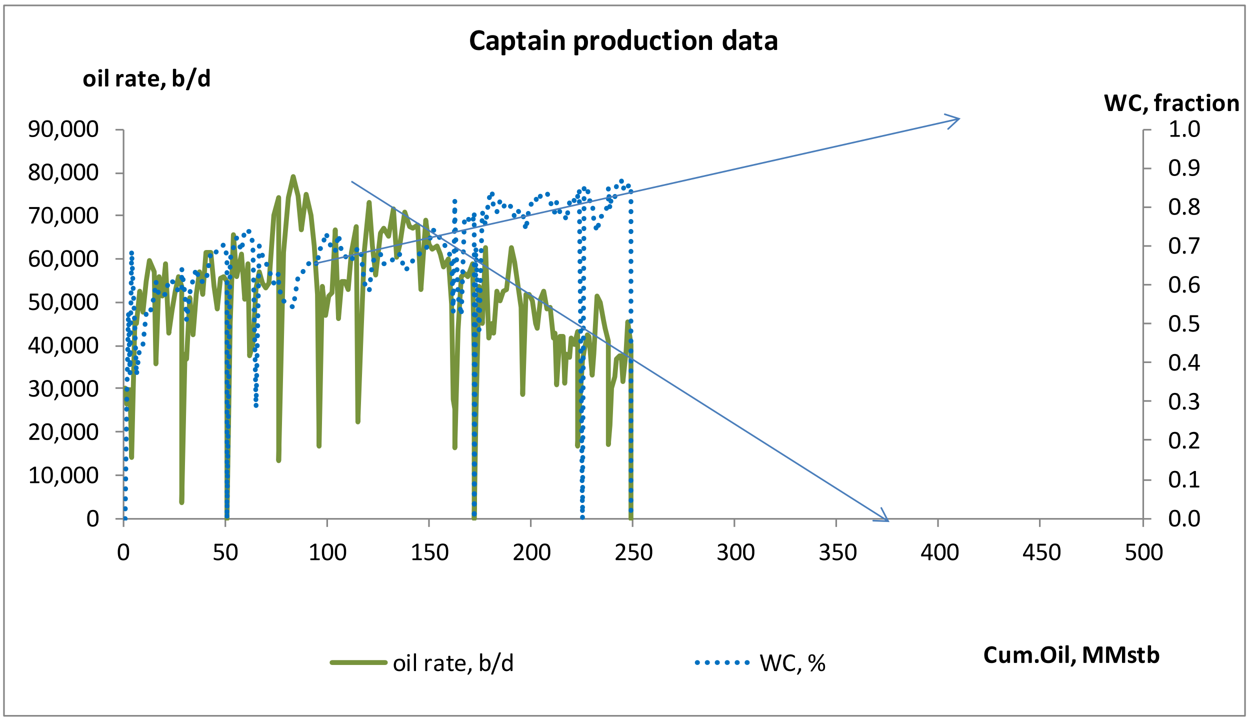


Figure 3-20: Captain field decline curve analysis

	Bressay	Mariner	Comments
Sor, fraction	0.49	0.30	Residual oil saturation
Swc, fraction	0.33	0.41	Connate water saturation
Max RF, fraction	0.26	0.50	Max RF with waterflood
RF, 70% sweep	0.18	0.35	RF with 70% sweep efficiency

Table 3-20: Sor, Swc and RF estimates for Bressay and Mariner

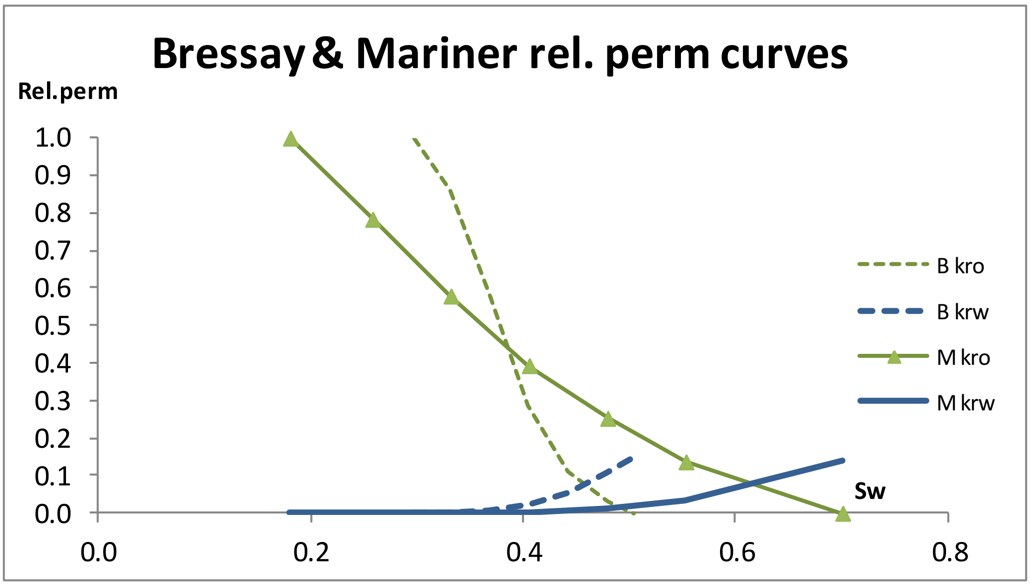


Figure 3-21: Bressay and Mariner relative permeability curves

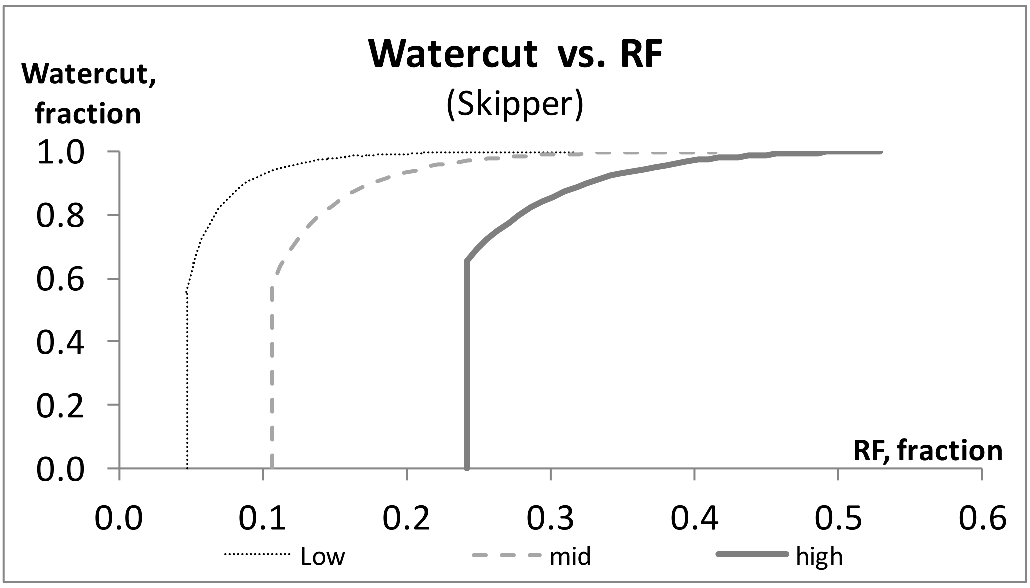


Figure 3-22: Skipper fractional flow curve with 70% volumetric sweep efficiency applied

Prospect	Mean	P90	P50	P10
Beauly, MMstb	29.2	21.4	28.5	38.0
Dornoch, MMstb	4.1	2.3	4.0	6.1
Maureen South, MMstb	5.8	3.2	5.6	8.4
Maureen North, MMstb	1.3	0.3	0.9	2.8

Table 3-21: Technically recoverable resources Beauly, Dornoch and Maureen

3.8.3. Production Profiles

Production profiles for the notional development of the Beauly reservoir were generated for low, mid and high cases. Wells were assumed to be located in the crest of the structure in the region of the field largely without basal water and water injection wells located on the NE and SW flanks just outside the OWC contour (Figure 3-23 and Figure 3-24).

- Wells were assumed to be able to produce with constant liquid rate with watercut development defined by fractional flow curves.
- Achievable initial flow rates estimated with Joshi correlation for the 4000 ft long horizontal wells. Well Productivity Indices (PI's) were estimated to range from 5 to more than a 100 b/d/psi. Due to high oil viscosities and the potentially unconsolidated nature of the reservoir, the rates for the wells were constrained.
- It is estimated that 14, 11 and 7 horizontal production wells will be required for the low, mid and high cases respectively, in order to drain the reservoir. In each case 4 vertical or 2 horizontal water injectors were assumed.
- Production profiles for the low, mid, and high cases before economic cut-off are given in Appendix 1 and are presented in Figure 3-25.

Water is expected to be tonguing towards producers in the Skipper field due to the high oil viscosity, and hence high mobility ratio. Vertical permeability also plays an important role here and will affect coning of the water and the speed of water breakthrough to the producers. Coring of the appraisal well is recommended, along with obtaining a representative fluid sample for oil quality assessment. These activities are now included along with plans for a drill stem test in the appraisal well planned for 2Q-3Q 2014 which will also test the Maureen formation. This data is essential to reduce sub-surface uncertainties and clarify potential issues for Skipper field development.

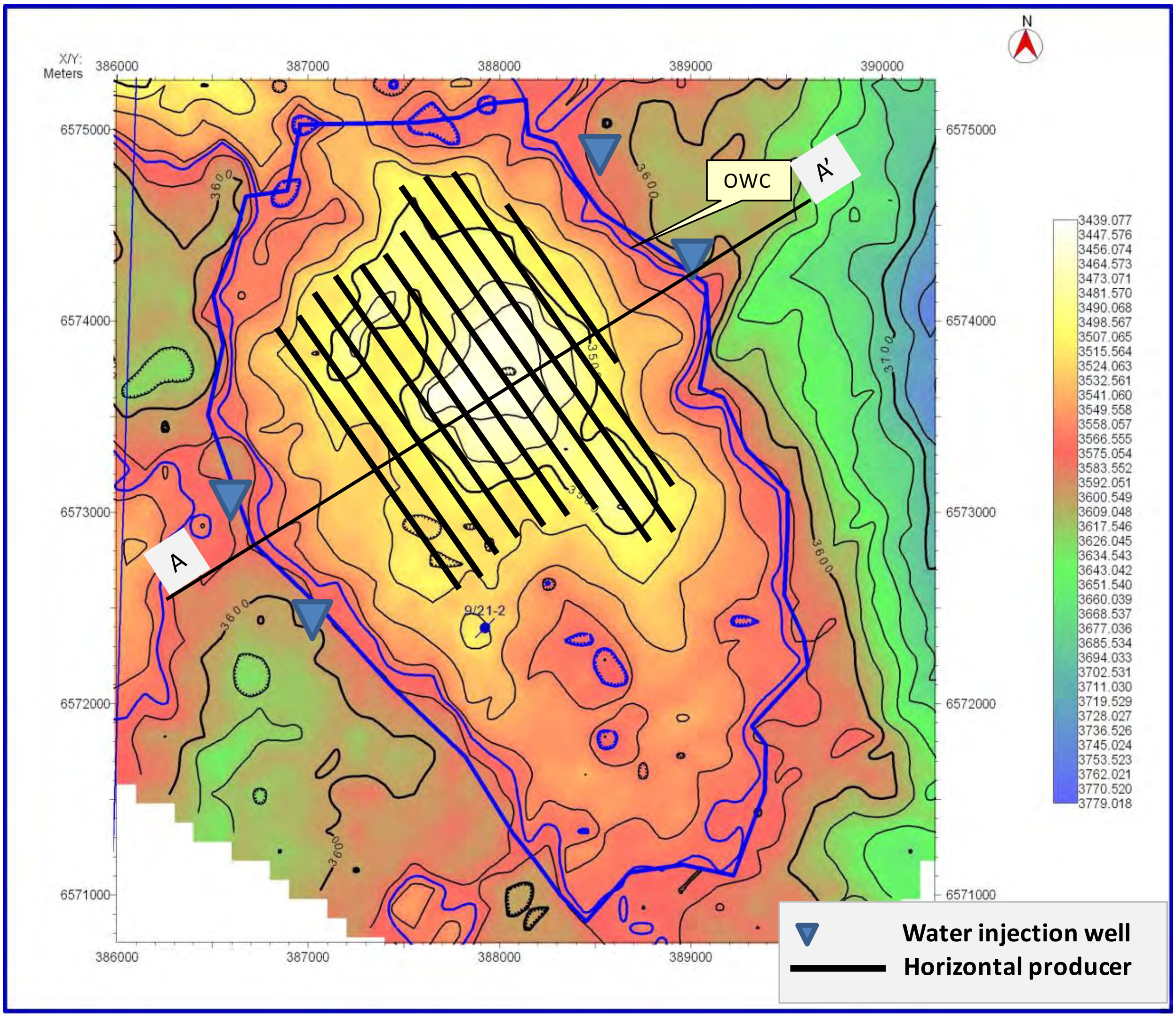


Figure 3-23: Skipper field notional well locations

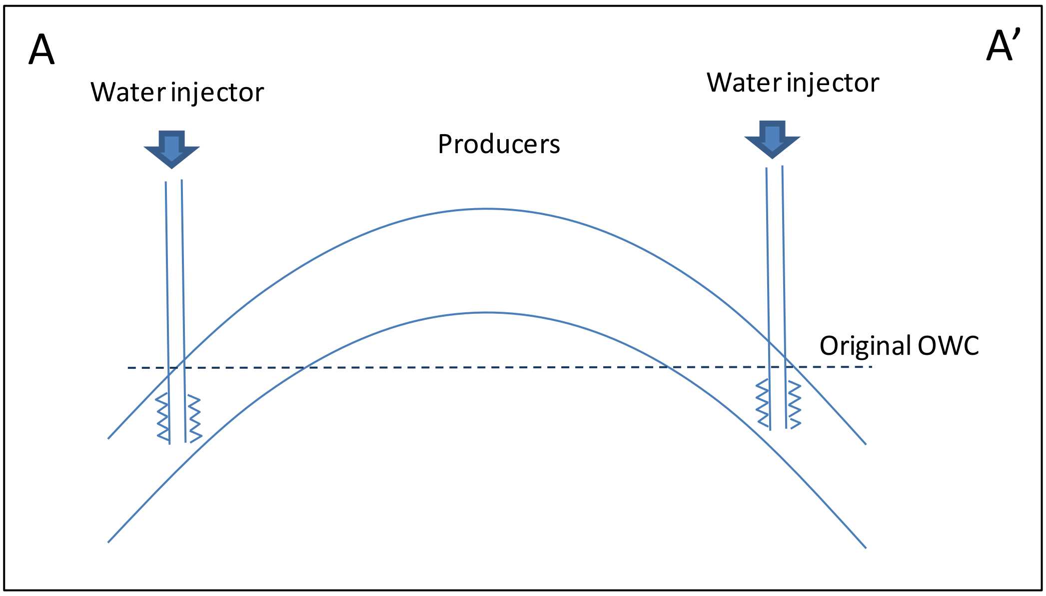


Figure 3-24: Schematic of the Beauly reservoir notional development plan

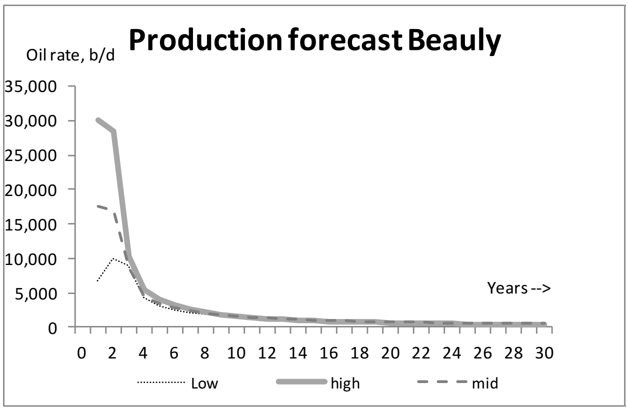


Figure 3-25: Notional production profiles for the Beauly reservoir.

3.9. Economic Evaluation

3.9.1. Assumptions Register

Reference Case Price:	Brent $90/bbl
Skipper discount vs Brent:	10%
Discount rate:	10%
Escalation:	2%/year
Exchange rate:	$1.57/1.0 GBP
Development CAPEX:	Jacket/process modules GBP 141.1 million Sub-sea GBP 60.3 million
Well Cost:	Horizontal producers: first well GBP 18.01 million, subsequent producers GBP 14.41 million each; water injection wells (2), GBP 13.09 million each
OPEX:	All-in cost GBP 17.44 million/year plus GBP 0.3/bbl variable cost
Tax rate:	30% CIT, 32% Supplementary Income Tax
Ultra heavy oil allowance:	GBP 800 million * 32%, maximum 1/5th of allowance per year
Decommissioning cost:	GBP 36 million gross
Economic limit test:	Applied
RFES:	6%/year
CAPEX Contingency:	15% Jacket, Topsides and Subsea; 5 days waiting on weather for each well

3.9.2. Development Concept

A notional field development concept has been used for early stage assessment of commerciality, entailing the drilling of horizontal producing wells and water injection wells with processing modules hosted on a new build steel jacket platform. In this evaluation two horizontal water injection wells are assumed in place of an alternative four vertical injectors. The option of field development utilizing multilateral producers has not been included but it is recognized that this may be evaluated as an option in the future. For reasons of oil viscosity and density, producing wells are assumed to use ESPs.

An appraisal well is planned to be drilled in 2Q-3Q 2014 and information from the coring, sampling and flow testing will provide essential technical data to support field development planning.

The process modules included in the current development concept would include water and sand treatment facilities to allow for re-injection of produced water. Based on expected crude oil quality, available associated gas for utilities could be limited and this may need to be supplemented by diesel shipped out to the facility or by laying a spur line from an existing gas pipeline, although successful development of the Maureen South prospect with its higher GOR could substantially mitigate fuel import requirements.

Produced oil would be stored in an FSO with capacity for circa 300,000 barrels storage (approx. 10 days forward cover at peak production, P10 case), and be equipped with coil-heated tanks to maintain mobility; export would be via shuttle tanker. Diluent in the form of light crudes/condensates may be be required to ensure viscosity is compatible with terminal and refinery operations, and this could be delivered by shuttle tanker to the FSO. Potential requirements will be defined as part of the field development planning including any production contribution from the Maureen prospects. OPEX estimates provided by IOG of GBP 17.4 million/year (2011 prices, escalated by 2%/year to 2013) have been used in the assessment of project economics with an GBP 0.3/bbl variable costs added although it should be noted that at this stage estimates are subject to considerable uncertainty.

An alternative development concept utilizing a leased FPSO has been ruled out as high all in daily operating costs would lead to premature field abandonment and low commercially recoverable volumes.

3.9.3. Costs

CAPEX estimates for the platform and processing modules are at an early stage of definition and fuller evaluation will follow once appraisal drilling and well testing is completed. Well costs for horizontal producers are estimated at GBP 18.1 million for the first well and GBP 13.2 million for subsequent wells. Estimates include 5 days waiting on weather per well and are based on a multiwell daily rig rate of GBP 242,000/day (USD 380,000/day); injectors are costed at GBP 13.1 million each and subsea works at GBP 60.3 million. An all-in OPEX cost including FSO operations of GBP 17.44 million plus GBP 0.3/bbl variable costs has been used (2011 price basis, escalated at 2%/year thereafter).

Case (1)	Producers	Water Injectors	Well Costs GBP Millions	Jacket and Process Modules	Subsea, FSO Mooring System
Low Estimate (1C)	14	2	245.6	141.1	60.3
Best Estimate (2C)	11	2	199.7	141.1	60.3
High Estimate (3C)	7	2	138.6	141.1	60.3

Table 3-22: Gross Skipper field development costs (GBP million), base year cost 2013

(1) Excluding contingency of GBP 30.2 million. Waiting on weather included in well cost estimates (GBP 1.2 MM per well).

3.9.4. Results

All cases show positive NPV10 values; under current assumptions, the Low Estimate case remains positive at values down to USD 80/barrel (USD 72.0/bbl after quality discount). Conversely, a Brent price of USD 110/bbl (2012 average USD 111.44/bbl) results in Low Estimate NPV10 of GBP 113.5 million (gross), and GBP 365.5 million undiscounted.

Case	1C/Low Est.	2C/Mid Est.	3C/High Est
Gross NPV10 (GBP millions)	14.0	274.0	492.8
Gross NPV0 (GBP millions)	179.2	517.0	788.2
Net IOG NPV10 (GBP millions)	7.0	137.0	246.4
Net IOG NPV0 (GBP millions)	89.6	258.5	394.1

Table 3-23: Skipper field NPV10/NPV0 gross/net values (GBP million)

It is also worth observing that in the Low Estimate case, the Ultra Heavy Oil allowance shelters Skipper from any Supplementary Income Tax liability it would otherwise incur and reduces High Estimate liability by approximately 60%.

Co-developments with prospects such as Maureen and Dornach as well as prospects identified in IOG operated Blocks 8/25 and 8/20 could provide incremental oil flows to further support Skipper commerciality in the later years of field life, particularly if crude oil API gravity in these prospects is higher.

3.9.5. Reserves/Resources

The Skipper resources are classified as "Contingent Resources (Development Unclarified)", and are considered to have a 40% Chance Of Commercial Success ("COCS") depending on confirmation of the longer term status of the operator ATP, and extension of the current license. The asset would be expected to move to "Contingent Resources (Development Pending) once this situation is resolved.

Under the assumed development scenario and resource base, Table 3-24 shows the gross contingent resources after applying an economic limit test. For reference, technically recoverable resources are also shown together with the percentage commercially recoverable.

Case	Gross Low Estimate	Gross Best Estimate	Gross High Estimate
Contingent Resources, MMbls	17.92	26.17	34.90
Technically Recoverable Resources	21.4	28.5	38.0
Commercially Recoverable Volume %	84%	92%	92%

Table 3-24: Skipper field gross contingent resources as % of technically recoverable volume

4. Conclusions

Skipper is a heavy oil discovery within Palaeocene Beauly sandstone formation located in UK offshore Block 9/21a (licence P1609) in the northern North Sea. It was discovered by Unocal in 1990 by well 9/21-2 which penetrated a 51' oil column. The Skipper discovery is in 350ft of water and twenty five km to the east are the Gryphon and Harding oil fields.

Skipper volumes are classed as contingent resources and relate solely to the Beauly formation. The conversion of these resources to reserves status requires further (successful) appraisal drilling and confirmation of expected flow rates as well as a development plan to confirm commerciality. An appraisal well is intended to be drilled in 2Q-3Q 2014 to test the Beauly formation and the deeper Maureen prospect.

Case (1)	Low Estimate	Best Estimate	High Estimate
Gross Crude Oil	17.9	26.2	34.9
Net IOG Crude Oil (2)	9.0	13.1	17.5

Skipper gross and net contingent resources MMstb

(1) 1C = Low Estimate, 2C = Best Estimate, 3C = High Estimate

(2) IOG net interest is 50%. ATP Oil and Gas (UK) Ltd is operator with 50% interest

DECC has granted a three month extension of the term of the Skipper licence, from 30th September to 31st December, pending a final decision on the operator ATP's present situation and a review of its business plan.

Based on cost information made available by IOG and AGR TRACS's independent technical review, Skipper shows positive NPV10 values across all resource cases and in particular in the Low Estimate resource case.

Case	Low Estimate	Best Estimate	High Estimate
Gross NPV10 (GBP millions)	14.0	274.0	492.8
Net IOG NPV10 (GBP millions)	7.0	137.0	246.4

Skipper gross and net NPV10 values

It should be noted that the Net Present Values (NPVs) do not represent the market value of these asset. The AGR TRACS evaluation represents a notional value of standalone assets under a specific set of technical, cost, price and timing assumptions and as additional technical data becomes available this may be subject to revision.

The mapping of Block 9/21a also showed three prospects in two deeper Palaeocene reservoirs (Dornoch and Maureen). Oil from the Maureen reservoir is expected to be lighter and potentially gassier than the Beauly oil. A range of prospective resources and an estimate of the geological chance of success were made for these three prospects as shown below.

Prospect	Low Estimate	Best Estimate	High Estimate	Geological chance of success
Dornoch	2.3	4.0	6.1	0.19
Maureen South	3.2	5.6	8.4	0.16
Maureen North	0.3	0.9	2.8	0.13

Gross prospective resources MMstb

Prospect	Low Estimate MMstb	Best Estimate MMstb	High Estimate MMstb	Geological chance of success
Dornoch	1.1	2.0	3.1	0.19
Maureen South	1.6	2.8	4.2	0.16
Maureen North	0.1	0.4	1.4	0.13

Net IOG prospective resources MMstb

5. Appendix 1: Skipper (Beauly) production forecasts

Years	Av.Oil rate, stb/d	Av.Water rate, stb/d	Cum oil, MMstb	Cum water, MMstb
1	6,679	0	2.4	0
2	10,000	3,960	6.1	1
3	8,991	9,786	9.4	5
4	4,249	15,751	10.9	11
5	3,043	16,957	12.0	17
6	2,455	17,545	12.9	23
7	2,079	17,921	13.7	30
8	1,813	18,187	14.4	37
9	1,613	18,387	14.9	43
10	1,456	18,544	15.5	50
11	1,330	18,670	16.0	57
12	1,225	18,775	16.4	64
13	1,137	18,863	16.8	71
14	1,062	18,938	17.2	78
15	997	19,003	17.6	84
16	939	19,061	17.9	91
17	889	19,111	18.2	98
18	843	19,157	18.6	105
19	803	19,197	18.8	112
20	767	19,233	19.1	119
21	733	19,267	19.4	126
22	703	19,297	19.7	134
23	675	19,325	19.9	141
24	650	19,350	20.1	148
25	626	19,374	20.4	155
26	604	19,396	20.6	162
27	584	19,416	20.8	169
28	565	19,435	21.0	176
29	547	19,453	21.2	183
30	530	19,470	21.400	190

Table 5-1: Beauly reservoir production forecast low case

Years	Av.Oil rate, stb/d	Av.Water rate, stb/d	Cum oil, MMstb	Cum water, MMstb
1	17,446	3,251	6.4	1
2	16,877	13,123	12.5	6
3	8,615	21,385	15.7	14
4	4,424	25,576	17.3	23
5	3,369	26,631	18.5	33
6	2,747	27,253	19.5	43
7	2,329	27,671	20.4	53
8	2,026	27,974	21.1	63
9	1,793	28,207	21.8	73
10	1,609	28,391	22.4	84
11	1,460	28,540	22.9	94
12	1,336	28,664	23.4	105
13	1,231	28,769	23.8	115
14	1,142	28,858	24.3	126
15	1,064	28,936	24.7	136
16	996	29,004	25.0	147
17	936	29,064	25.4	158
18	882	29,118	25.7	168
19	834	29,166	26.0	179
20	791	29,209	26.3	189
21	752	29,248	26.5	200
22	716	29,284	26.8	211
23	684	29,316	27.1	222
24	654	29,346	27.3	232
25	626	29,374	27.5	243
26	601	29,399	27.7	254
27	577	29,423	28.0	264
28	555	29,445	28.2	275
29	535	29,465	28.4	286
30	516	29,484	28.542	297

Table 5-2: Beauly reservoir production forecast mid case

Years	Av.Oil rate, stb/d	Av.Water rate, stb/d	Cum oil, MMstb	Cum water, MMstb
1	30,000	0	11.0	0
2	28,513	9,531	21.4	3
3	10,263	34,737	25.1	16
4	5,522	39,478	27.1	31
5	4,024	40,976	28.6	46
6	3,147	41,853	29.8	61
7	2,570	42,430	30.7	76
8	2,160	42,840	31.5	92
9	1,854	43,146	32.2	108
10	1,617	43,383	32.8	124
11	1,429	43,571	33.3	139
12	1,276	43,724	33.8	155
13	1,149	43,851	34.2	172
14	1,042	43,958	34.6	188
15	951	44,049	34.9	204
16	873	44,127	35.2	220
17	805	44,195	35.5	236
18	746	44,254	35.8	252
19	693	44,307	36.0	268
20	647	44,353	36.3	284
21	605	44,395	36.5	301
22	567	44,433	36.7	317
23	534	44,466	36.9	333
24	503	44,497	37.1	349
25	475	44,525	37.3	366
26	450	44,550	37.4	382
27	427	44,573	37.6	398
28	405	44,595	37.7	414
29	386	44,614	37.9	431
30	368	44,632	38.000	447

Table 5-3: Beauly reservoir production forecast high case

6. Appendix 2: Glossary

In this Report, the following words have the meanings as set out below:

$	US Dollars
%	percent
°C	Degrees Celsius
2D	Two Dimensional
3D	Three Dimensional
API	American Petroleum Institute
AVO	Amplitude Variation with Offset
Av Phi	Average Porosity (from log evaluation)
Av Sw	Average water Saturation (from log evaluation)
bbls	Barrels
bfpd	Barrels of fluid per day
bopd	barrels oil per day
bpd	barrels per day
bwpd	barrels of water per day
Cali	Caliper
Capex	capital expenditure
cm^3	cubic centimetre
m^3	cubic metre
CPI	Computer Processed Interpretation (of logs)
Den	Density log
D res	Deep resistivity log (deep investigation)
DST	Drill Stem Test
DT	Sonic log
Ft, '	feet
FTHP	Flowing Tubing Head Pressure
FWL	Free Water Level
G & G	Geological and Geophysical
GOR	Gas to Oil Ratio
GR	Gamma Ray log
GRV	Gross Rock Volume
IRR	Internal Rate of Return (from MOD cashflows)
K	Permeability
km	Kilometre
km^2	Square kilometres

m	metre
Mbopd	thousand barrels of oil per day
MD	Measured Depth
mD	milli Darcies
MM	million
MMbbls	million barrels of oil
MMstb	million stock-tank barrels of oil
N/G	Net to Gross
Neu	Neutron log
NPV	Net Present Value
OBC	Ocean Bottom Cable
ODT	Oil Down To
OPEX	operating expenditure
OUT	Oil Up To
OWC	Oil Water Contact
P & A	Plugged and Abandoned
p.a.	per annum
P10	10% probability of being exceeded
P50	50% probability of being exceeded
P90	90% probability of being exceeded
POS	Possibility Of Success
ppm wt	Parts per million by weight
PRMS	Petroleum Resource Management System
psi	pounds per square inch
psia	pounds per square inch absolute
PV	Present Value
PVT	Pressure Volume Temperature
RF	Recovery Factor
RFT	Repeat Formation Tester
RROR	Real Rate of Return (from RT cashflows)
RT	Real Terms
SG	Specific Gravity
SMT Kingdom	a PC-based interpretation workstation
SPE	Society of Petroleum Engineers
sq km	square kilometres
S res	Short resistivity log (shallow investigation)
ss	subsea

STOIIP	Stock Tank Oil Initially In Place
Sw	water Saturation
Swavg	average water Saturation
Sxo	water Saturation in invaded zone
TD	Total Depth
tvd	true vertical depth
tvdss	true vertical depth subsea
tvt	true vertical thickness
TWT	Two-Way Time
WI	Working Interest

7. Appendix 3: Petroleum Resources Classification

Summary of 2007 SPE Petroleum Resources Classification

The following paragraphs are quoted from the 2007 SPE PRMS Guidance Notes and summarise the key resources categories, while Figure 7-1 shows the recommended resources classification framework.

Class/Sub-class	Definition
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.
On Production	The development project is currently producing and selling petroleum to market.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

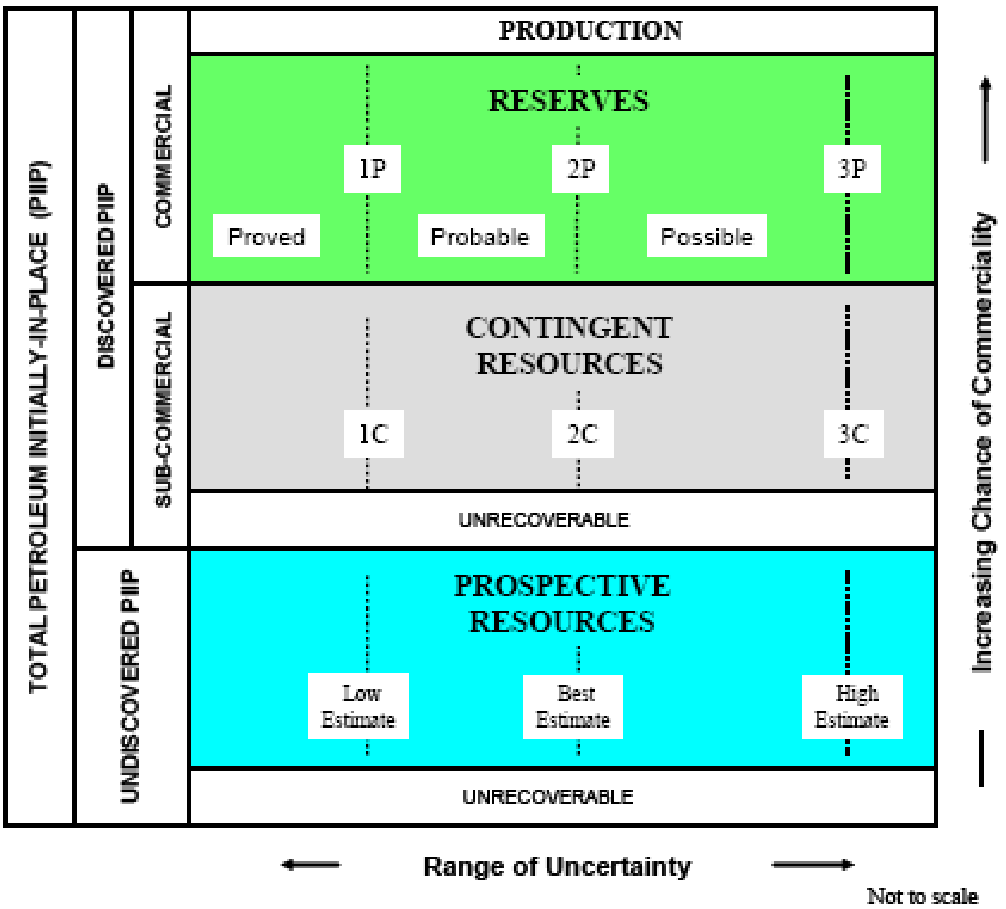


Figure 7-1: 2007 SPE PRMS Petroleum Resources Classification Framework

8. Appendix 3: Reserves and Resources Summary Tables

The tables below have been compiled in a manner consistent with that prescribed by the London Stock Exchange June 2009.

Oil & Gas – Reserves

There are no Reserves attributable to Skipper.

Oil & Liquids: MMstb Gas: Bscf	Gross			Net Attributable to IOG			Operator
DISCOVERY	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	
UK: Offshore Block 9/21a (licence P1609)							
Skipper	0	0	0	0	0	0	ATP

Source: TRACS review August 2013

Note: "Operator" is the name of the company that operates the asset.

"Gross" are 100% of the reserves attributable to the licence whilst "Net Attributable" are those attributable to the AIM company. Reserves calculated using US$90/bbl and applying a 10% crude oil quality discount.

"MMstb" – million barrels

Oil & Gas – Contingent Resources

Oil Contingent Resources per asset : MMstb	Gross			Net Attributable to IOG			Risk Factor	Operator[(1)]
DISCOVERY	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**COCS (%)**	
UK: Offshore Block 9/21a (licence P1609)								
Skipper	17.9	26.2	34.9	9.0	13.1	17.5	50%	ATP
Unrisked Totals for Oil, MMstb	**17.9**	**26.2**	**34.9**	**9.0**	**13.1**	**17.5**		

Source: TRACS review August 2013

(1) IOG net interest is 50%. ATP Oil and Gas (UK) Ltd is operator with 50% interest

Notes: "Risk Factor" or Chance of Commercial Success for Contingent Resources means the chance, or probability, that the hydrocarbons will be commercially extracted.

"Operator" is the name of the company that operates the asset.

"Gross" are 100% of the resources attributable to the licence whilst "Net Attributable" are those attributable to the AIM company.

"MMstb" – million barrels

Oil & Gas – Prospective Resources

Oil Prospective Resources per asset : MMstb	Gross			Net Attributable to IOG			Risk Factor	Operator
PROSPECT	**Low Estimate**	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	**POS (%)**	
UK: Offshore Block 9/21a (licence P1609)								
Dornoch	2.3	4.0	6.1	1.1	2.0	3.1	0.19	ATP
Maureen South	3.2	5.6	8.4	1.6	2.8	4.2	0.16	ATP
Maureen North	0.3	0.9	2.8	0.1	0.4	1.4	0.13	ATP
Unrisked Totals for Oil #	**5.8**	**10.5**	**17.3**	**2.8**	**5.2**	**8.7**		

Source: TRACS review August 2013

Notes: "Risk Factor" for Prospective Resources means the chance, or probability, of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resources maturing into a Contingent Resource. Where a prospect could contain either oil or gas the hydrocarbon type with the higher probability of being discovered has been listed in the table.

"Operator" is the name of the company that operates the asset.

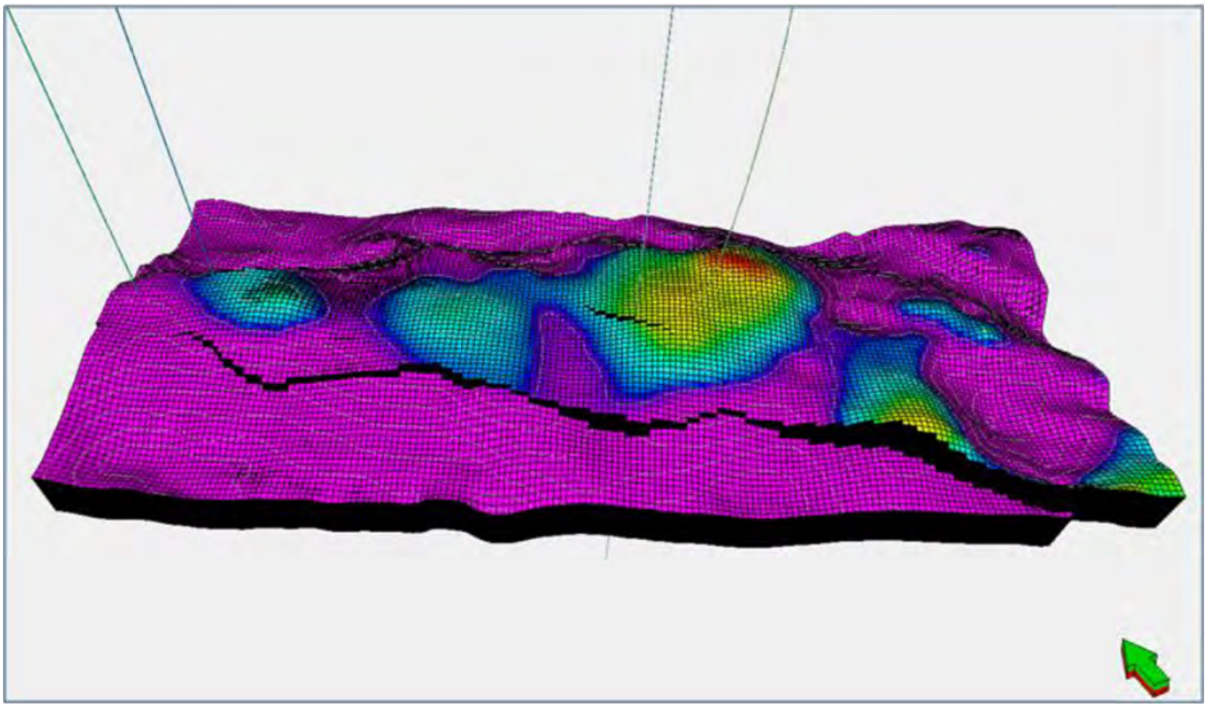
"Gross" are 100% of the resources attributable to the licence whilst "Net Attributable" are those attributable to the AIM company.

"MMstb" – million barrels

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition

Section B – Competent Report of ERC Equipoise on Blocks 48/22b and 48/23a

Competent Person's Report: The Blythe Gas Field, UK North Sea



PREPARED FOR: Independent Oil and Gas plc

BY: ERC Equipoise Limited

Month: September 2013

Year: 2013

ERC equipoise

Approved by: S McDonald

Date released to client: 23 September 2013

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23 September 2013

Dear Sirs

Introduction

ERC Equipoise Limited ("ERCE") has been engaged by Independent Oil and Gas plc (IOG) to complete a Competent Person's Report (the CPR) on IOG's 50 per cent. working interest in Blocks 48/22b and 48/23a in licence P1736 containing the Blythe gas field, located offshore in the United Kingdom North Sea.

ERCE understands that IOG is seeking admission of its entire issued share capital to trading on AIM (Admission), a market operated by London Stock Exchange plc, and that this CPR and the results herein will be included in the admission document to be prepared in connection with Admission (the "Admission Document"). This CPR has been prepared in accordance with the AIM Rules for Companies and the Note for Mining and Oil & Gas Companies dated June 2009, as issued by London Stock Exchange plc (together, the AIM Rules).

Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation and engineering and economics assessment. Except for the provision of professional services on a time-based fee basis, ERCE has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets. ERCE considers that the scope of the CPR is appropriate and includes and discloses all information required to be included therein and was prepared to a standard expected in accordance with the AIM Rules.

The work has been supervised by Mr Simon McDonald, Engineering Director of ERCE, a post-graduate in Petroleum Engineering, a Chartered Petroleum Engineer and a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. He has 36 years’ relevant experience in the evaluation of oil and gas fields and acreage, preparation of development plans and assessment of reserves. Other key personnel involved in this work hold at least a Masters degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

Method and information provided

We have carried out this review using data and information made available by IOG and the operator of the licences, ATP Oil and Gas (UK) Limited (ATP).

No site visit was undertaken during this evaluation. ERCE has relied upon information provided by IOG and ATP for the content and completeness of all data provided.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. We have estimated the degree of this uncertainty and have used statistical methods to calculate the range of petroleum initially in place and recoverable resources. Our methodology adheres to the guidelines outlined in the PRMS.

ERCE has evaluated the development schemes presented by the operator and conducted an audit of the capital and operating costs. Based on the development scheme, production profiles have been generated which have then been used in an economic model constructed by ERCE, and based upon the current fiscal terms associated with the licence. Our economic analysis looks at the developments on a stand-alone basis and does not take into account any outstanding debt, nor future indirect corporate costs. In the estimation of future cash flows, ERCE has estimated economic parameters, including oil and gas price, based on recent and current market trends. These are uncertain, and there is no guarantee that actual economic parameters will match our assumed values.

The nomenclature used in this report is presented in Appendix 2.

Independence of ERCE

Other than for the purposes of completing the CPR, neither ERCE nor any of its directors, employees or associates has any commercial interest either direct, indirect or contingent in IOG or any associated companies nor in any of the assets reviewed in this report. Neither ERCE nor any of its directors, employees or associates will receive any interest in IOG or any associated companies as a result of undertaking the CPR. ERCE will be paid normal professional rates for completing the CPR for IOG. Payment of fees is in no way contingent upon conclusions contained in the CPR.

Consent and Confirmations

ERCE confirms that it has given and not withdrawn its consent to the inclusion in Part IV of the Admission Document of its CPR and to the inclusion in Part I of the Admission Document of statements made by ERCE and to references to its name, in the form and context in which they appear, and has not withdrawn such consent.

ERCE has reviewed the information contained in the Admission Document which relates to information contained in the CPR and hereby confirms to IOG and Charles Stanley that the information presented is not misleading and it is accurate, balanced and complete and not inconsistent with the CPR.

ERCE confirms that there has been no material change in circumstances to those stated in the CPR.

In compliance with Schedule Two of the AIM Rules, we hereby confirm that ERCE is responsible for this letter and the contents of the CPR and we declare that we have taken all reasonable care to ensure that the information contained in this letter and the CPR is in accordance with the facts and that there is no omission likely to affect its import.

Yours faithfully,

Simon McDonald
Engineering Director
ERC Equipoise Limited

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1. Project Summary

1.1. Work Done

In response to your request, we have carried out a technical and economic review of the Blythe gas field located offshore United Kingdom North Sea (UKCS) in licence P1736. The discovery is located in Blocks 48/22b and 48/23a in the Southern North Sea which Independent Oil and Gas (IOG) holds a 50% working interest. The operator is ATP Oil and Gas (UK) Ltd (ATP), which holds a 50% working interest.

We have estimated the reserves in this field as at 01 October 2013 using data and information available up to 23 September 2013, and prepared economic analyses and a valuation of IOG's interests.

We have carried out this work using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1. The full text can be downloaded from: www.spe.org/spe-app/spe/industry/reserves/prms.htm

1.2. Licence Interests

Information on IOG's interest in the licence containing the Blythe field is summarised in Table 1.1.

Field	Licence Block	Operator	IOG Interest (%)	Status	Licence Expiry Date	Area (km^2)	Outstanding Commitment in this licence phase
Blythe	48/22b 48/23a	ATP	50.00	Just. for Devt	P1736 30/12/2013	28	Submission of FDP by December 2013

Table 1.1: Summary of the Blythe licence interest

In the above table, "Just for Devt" means justified for development.

The Blythe licence is a production licence which bestows upon IOG North Sea Limited a right to search, bore for, and get petroleum within the defined licence area. At this point in time, the 50% co-owner and operator of the Blythe licence, ATP, is for sale and IOG advises that it has been informed by Deloitte LLP (which is running the sale process) that a preferred bidder has been identified and has been introduced to DECC. When the sale of ATP has been completed, DECC will consider the new owner on the grounds of technical competence and financial capacity to meet future decommissioning obligations. IOG advises that it has been informed by DECC that the proposed new owner is likely to pass these conditions. Once the new owner of ATP is agreed and operatorship has been reaffirmed, then DECC has indicated that it will grant a licence extension commensurate with a development plan for the Blythe field based on the work already prepared by ATP and IOG. This will not occur until the sale of ATP has completed.

DECC has granted a further short term licence extension to 31 December 2013 to allow the deal to close with a view to being able to grant the longer extension required to deliver the Blythe field development plan.

1.3. Field Description and Reserves

The Blythe field is located in the Southern North Sea, some 25 km to the north west of the Hewett field and 20 km to the south of the Lancelot field. Water depth in the area is some 23 metres. Four wells have been drilled in the Blythe gas field in the Southern North Sea. The most recent well, a horizontal appraisal/development well drilled in 1990, produced gas from the Rotliegend reservoir at a lower rate than anticipated. As a result development was not progressed at that time.

Recent detailed reservoir modelling studies have subsequently indicated that drilling a horizontal well to a stratigraphically lower, better quality, interval than penetrated by the previous horizontal well should lead to higher gas production rates, coupled with water production. As a result, development planning is now underway.

Current planning foresees the installation of a normally unmanned installation (NUI) from which a single tri-lateral production well will be drilled. It is anticipated that the gas will be transported to shore via a short pipeline spur which will be tied in via a “Hot Tap” to the Lancelot to Bacton pipeline, where it will be processed, compressed and sold. The initial gas production rate is expected to be 30 MMscf/d. The operator, ATP has made initial commercial proposals to the Lancelot field and pipeline owner.

Based on assurances we have received from IOG, we assume that ATP will continue as operator following completion of the current company sale process and a field development plan will be submitted and approved by DECC in the first quarter of 2014. Our base case analysis assumes that first gas will occur in September 2015. At the request of IOG, we include a timing sensitivity case in our economic evaluation with first gas commencing at the end of the first quarter 2015.

Our estimates of the gross gas and condensate reserves for the Blythe field are presented in Table 1.2, together with the attributable reserves based on IOG’s 50.00 % interest.

	Gas Reserves (bcf)			Condensate Reserves (MMbbl)		
	1P	2P	3P	1P	2P	3P
Gross Reserves	22.3	34.3	47.5	0.23	0.36	0.50
Reserves Attributable to IOG	11.1	17.2	23.7	0.12	0.18	0.25

Table 1.2: Summary of gas and condensate reserves

1.4. Valuation

We have prepared cash flow forecasts and calculated net present values discounted at 10 per cent per annum (NPV10) in pounds sterling effective as at 1 October 2013 for IOG's interest in the Blythe field. We have assumed a spot gas price of 60 pence per therm in real terms, and investigated the sensitivity of the NPVs to low and high gas price assumptions of 55 pence and 65 pence per therm. For modelling of the value of the condensate production we have used a long term Brent oil price of $100/stb in real terms and also assessed low and high Brent oil price assumptions of $90/stb and $110/stb.

Table 1.3 presents our base case estimates of the post tax NPV10 in £ millions at the low, base and high price assumptions for IOG's 50% interest in the Blythe field.

Price Forecast	1P	2P	3P
Low	3.9	23.6	34.6
Base	7.2	28.0	39.9
High	10.4	32.5	44.5

Table 1.3: Base Case NPV10 for IOG's 50% interest in the field

Table 1.4 presents our timing sensitivity case (first gas the end of the first quarter 2015) estimates of the post tax NPV10 in £ millions at the low, base and high price assumptions for IOG's 50% interest in the Blythe field.

Price Forecast	1P	2P	3P
Low	4.1	25.9	37.3
Base	7.4	29.6	41.7
High	10.7	33.3	46.0

Table 1.4: NPV10 for IOG's 50% interest in the field with early start date

2. Exploration & Licence History

Blythe is a gas discovery situated in Blocks 48/22b and 48/23a of the Southern North Sea and is located 25 kilometres to the NW of the Hewett field (Figure 2.1). The accumulation was discovered in the Rotliegend formation in 1966 by Well 48/22-1, one of the first gas finds in the North Sea, which tested across the gas water contact (GWC) and flowed 0.9 MMscf/d gas and 137 bbl/d water. An appraisal well, Well 48/22-2 drilled in 1968, encountered the top of the reservoir just below the GWC and recovered only water on test. In 1987 ARCO drilled Well 48/23-3, which encountered a 141 ft gas column, and tested gas at a rate of 15.2 MMscf/d. Subsequently ARCO elected to develop the field with a single horizontal well, Well 48/23a-4, drilled in 1990. This well tested gas at rates between 15 and 11.6 MMscf/d with individual flow periods declining and the development plan was abandoned.

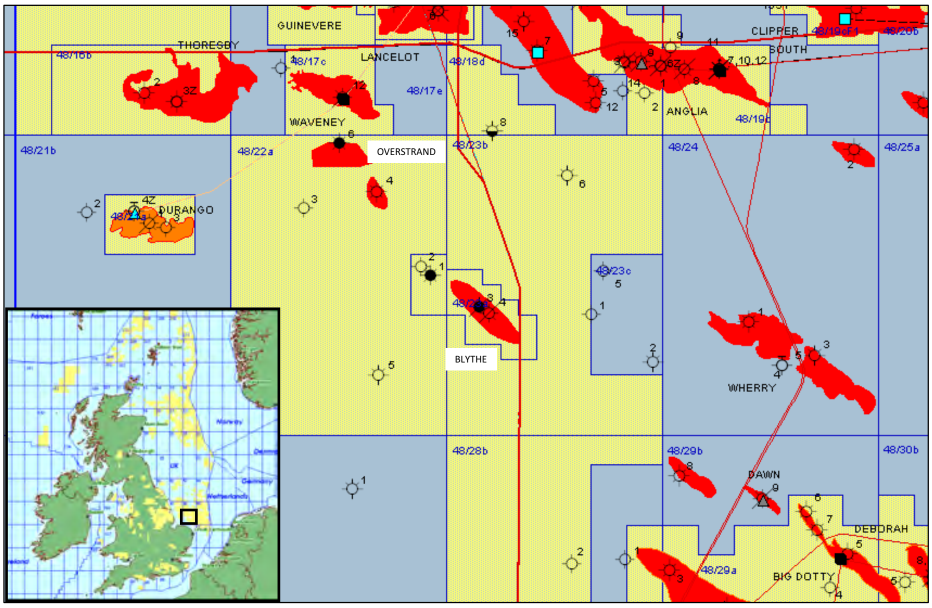

Figure 2.1: Location of the Blythe field

The licence was acquired by ATP during the 25th Licensing Round. ATP is Operator of the licence and has a 50.00 % working interest with the remaining 50.00% being held by IOG. The Operator has recently completed an integrated reservoir and development study of the Blythe discovery, including a detailed investigation into the disappointing performance of the original horizontal development well. Following completion of this study, the operator is now preparing a development plan comprising the drilling of a multi-lateral well.

3. Reservoir Evaluation and Gas in Place

Our review was undertaken using primary geotechnical data supplied by the Operator, ATP. These comprised 3D seismic data, including structural interpretation in time and depth, open hole logs and petrophysical analyses of the reservoir section, core data and detailed geological descriptions of the Rotliegend reservoir.

The database available for reservoir description within the Blythe field comprises four wells adjacent to or within the hydrocarbon bearing area. Two wells have been drilled at the NW end of the structure, one below the GWC, with a further vertical appraisal well in the core of the field and most recently a 1500 ft horizontal well also in the centre of the field. This well database has been complemented by several regional wells, all of which are located some distance from the field.

We have begun our analysis by reviewing the reservoir description reports, and the seismic mapping of the structures. This work has been used to cross-check the static model used to provide the input to the reservoir simulation of the field (Section 4). The methodology used in developing the static model is described below. We have then used the static model to compute GIIP for the field.

3.1. Geological and Geophysical Review

The Blythe gas field is located in the Lower Permian Rotliegend basin of the Southern North Sea in Blocks 48/22b and 48/23a to the west of the Dowsing Fault Zone and the Sole Pit Trough. The reservoir interval, Leman Sandstone Formation, comprises a typical sequence of aeolian and less significant fluvial facies with reworked Weissliegend sandstone at the top. The Leman Sandstone Formation is overlain by the distinctive Kupferschiefer Shale, which creates the seal to the gas-bearing reservoir.

The field is covered by a 3D Pre-SDM seismic dataset processed in 2004. The structure is shallow relief with four-way dip closure; there are a number of SE-NW trending faults either side and across the structure. There is a SW-NE trending graben in the overburden at the southern end of the structure which introduces uncertainty into the depth conversion.

The Top Rotliegend event is problematic and represents a significant source of structural uncertainty. An additional source of uncertainty is in the depth conversion, owing to the shallow relief of the structure and issues relating to the overburden graben to the south. The range of structural uncertainty has been addressed by generating three depth maps representing low, mid and high cases.

The Rotliegend at Blythe is dominated by the deposition of a thick sequence of cross-bedded, highly laminated dune sands with subsidiary interdune and fluvial intervals.

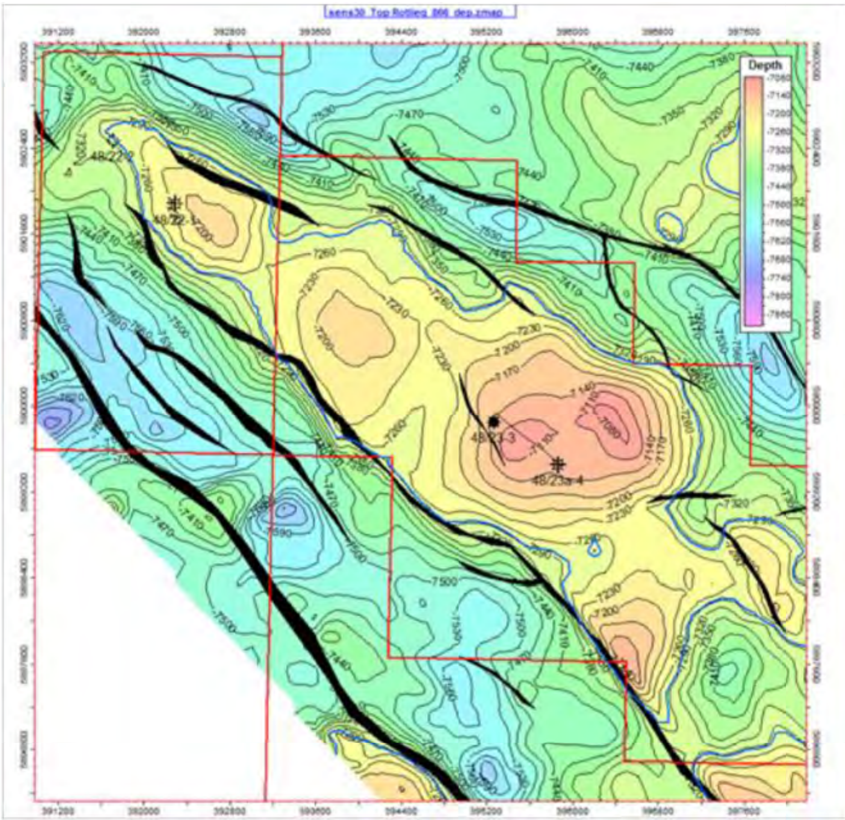

Figure 3.1: Top Rotliegend depth structure map, Blythe field

Lying to the west of the Dowsing Fault Zone and occurring at shallower depths, the Blythe field does not exhibit significant diagenetic overprinting such as illite crystallisation and therefore much of the reservoir characteristics are controlled by the original depositional textures.

The uppermost interval of the Rotliegend at Blythe, as well as much of the Southern Permian Basin, is marked by the distinct homogenous Weissliegend, which represents a late widespread flooding event that has truncated and redeposited the underlying aeolian sands. The underlying topography of the dune sands has led to significant variations in the thickness of the Weissliegend across the region. At Blythe itself the Weissliegend varies in thickness between 8 ft to 51 ft. The reservoir quality of the Weissliegend is similarly variable.

Porosity varies between 7% and 21% (Figure 3.2). Core permeability data acquired in Well 48/23-3 shows a general increase in permeability with depth in the aeolian facies, with the A4 and A5 layers having the best properties in this well (Figure 3.3). Residual oil/bitumen has been identified in the Blythe reservoir (Well 48/23-3; below 7195 ft ss down to the GWC) which, together with the laminated nature of the sands in potentially areally-limited dunesets, has probably contributed to the poor performance of the horizontal well.

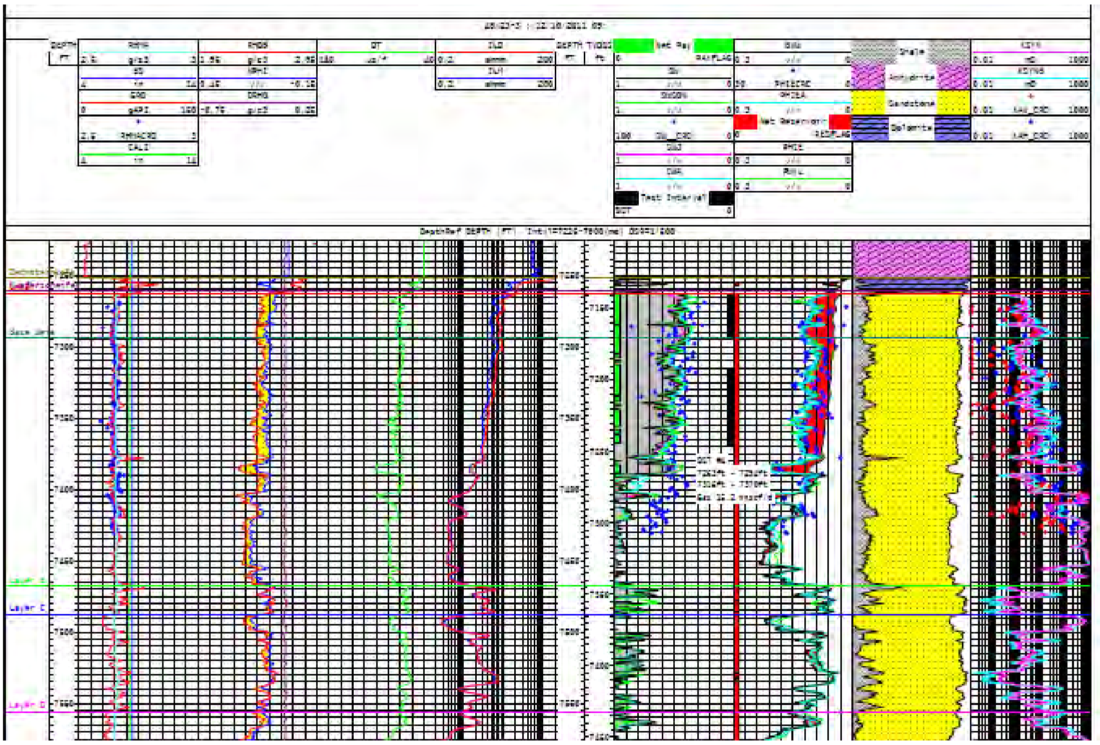

Figure 3.2: Blythe Well 48/23-3 CPI

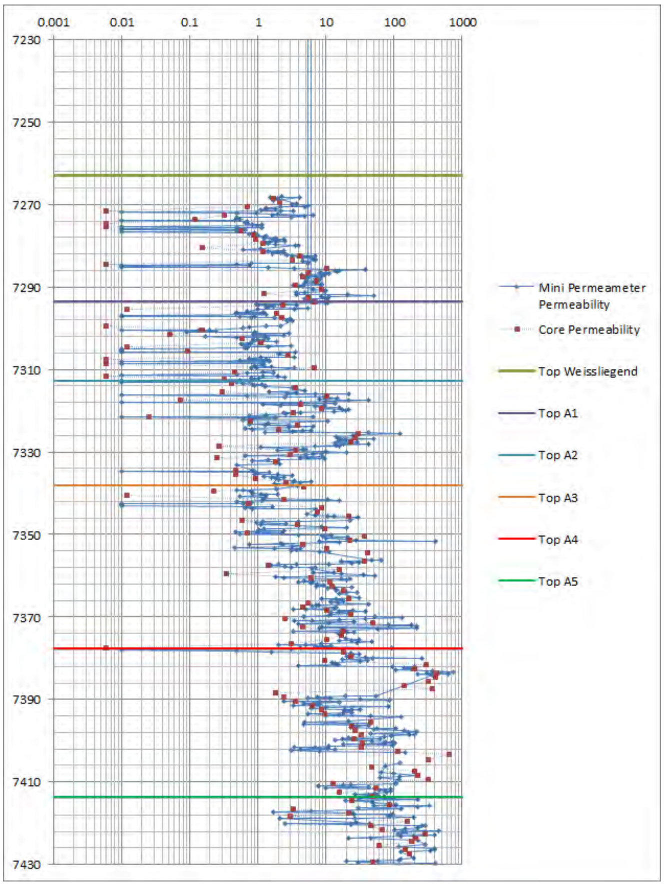

Figure 3.3 Well 48/23-3 core and minipermeameter permeability profiles vs depth

3.2. Calculation of Gas Initially in Place

The gas-bearing interval of the field has been subdivided into six layers based upon the core descriptions, permeability data and log data. However, due to the aeolian sand nature of much of the reservoir detailed correlation is difficult and open to some uncertainty. This is particularly the case in horizontal Well 48/23a-4. These six layers have formed the basis of the reservoir characterisation undertaken in this study.

The uppermost layer, Weissliegend, is difficult to pick from logs, but easily distinguishable in the core of Wells 48/22-2 and 48/23-3. No core data are available in Well 48/23a-4 and it is difficult to correlate and identify the Weissliegend in the well.

As with the Weissliegend, the isochores of the A1-A5 layers vary considerably across the field.

The main input to the Petrel volumetric model was a Top Rotliegend depth map (ft ss) provided by ATP. The Top Rotliegend structure map was selected as a P50 volumetric case from a series of stochastic depth-conversions of ATP's interpretation of Pre-STM data, which we have reviewed. Additional maps representing P90 and P10 volumetric cases were generated from the depth conversion sensitivities. Structural depth maps for the deeper layers were constructed using isochores generated from the true-vertical thicknesses observed in the wells on structure.

Average porosities calculated in the wells are quite variable across the Blythe field with average values generally being notably higher in the northwest of the structure and decreasing towards the south-east and crest. Model porosity was populated within each reservoir zone using a stochastic distribution method controlled by trend maps derived from the observed well data. Net to gross ratio was considered to be unity due to the nature of the reservoir. Water saturation was calculated from permeability and height above contact using relationships provided by the operator and cross-checked against the well data.

The gas water contact of 7283 ft ss was encountered in Well 48/23-3.

GIIP estimates for Blythe have been derived from the P90, P50 and P10 models and are summarised in Table 3.1.

Case	GIIP (Bcf)
P90	38.8
P50	52.3
P10	84.2

Table 3.1: Blythe GIIP range

4. Reservoir Development

4.1. Reservoir Performance and Production Analysis

The engineering analysis of the Blythe field has consisted of a re-interpretation of the well test data followed by estimation of the recoverable hydrocarbons using reservoir simulation modelling.

The Blythe field structure is an elongate anticline containing a wet gas with a low condensate to gas ratio of around 10 bbl/MMscf.

Tests have been carried out in all four wells. There are little data available from the tests in the first two wells, acquired in 1967 and 1968, other than the composite log records. All of the test results suggest a relatively low permeability system but the main anomaly is the comparative performance of Well 48/23a-4 where the long horizontal well performed poorly compared to the relatively short, vertical section in Well 48/23-3.

Well 48/22-1 reportedly flowed at around 0.9 MMscf/d with 137 bbl/d water at a drawdown of around 2525 psi. The perforated interval, from 7296 - 7391 ft md included the very thin Weissliegend section at the top of the well but the layers perforated were predominantly the A1, A2 and A3.

48/22-2 was drilled below the GWC and produced only water. The test was performed open hole over the interval 7357 – 7425 ft rkb. The flow rate was poor and no reservoir fluids flowed to surface although on reversing the string contents at the end of the test 56 bbl of formation water were measured.

Well 48/23-3 was drilled as a vertical appraisal well with production testing conducted on the Carboniferous, Rotliegend and Zechstein intervals. The Rotliegend reservoir was perforated over the interval 7263 – 7294 ft rkb and 7317 – 7370 ft rkb with TCP guns inside 7" liner. The well flowed at ca. 15 MMscf/d with a FTHP of 858 psig, i.e. ca. 1000 psi bottom hole drawdown. The drawdown periods were characterised by declining rates and pressures, and the analysis is additionally complicated by a leaking downhole tester valve. Well test analysis has indicated an average reservoir permeability ca. 4 md based on a kh of 312 md ft which is reasonably in line with the core permeability-thickness, kh of 724 md ft (Figure 4.1 and Figure 4.2). The estimated skin factor based on pressure transient analysis is negligible. To obtain an acceptable match the analysis also required three, sealing boundaries to be included close to the well (all three within 130 ft).

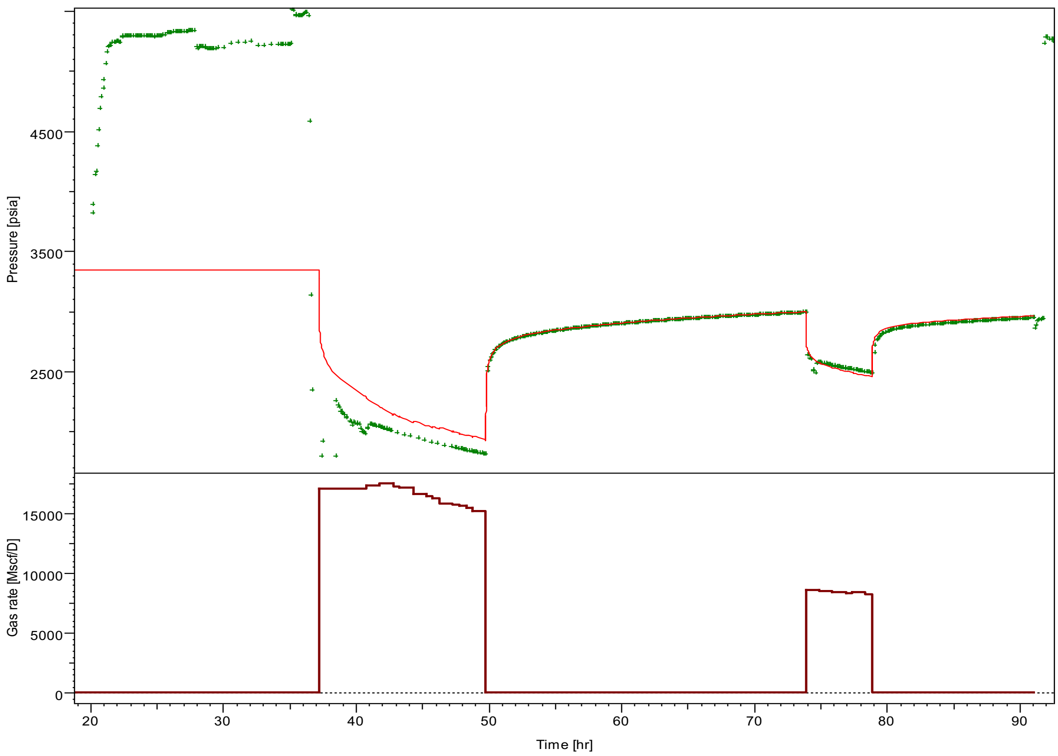

Figure 4.1: 48/23-3 well test Cartesian match

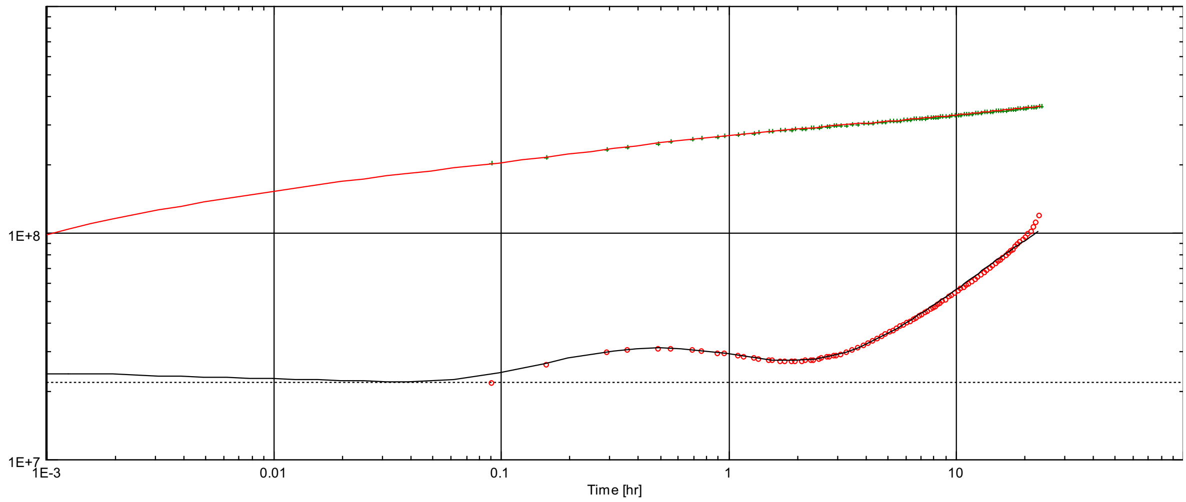

Figure 4.2: 48/23-3 well test log log plot (buildup 1)

Well 48/23a-4 was drilled to determine whether horizontal drilling was an effective method for improving productivity in the area. The 1534 ft horizontal section through the Rotliegend was drilled and completed with a 5" perforated liner. The toe of the well passed very close to the location of Well 48/23-3. During clean out the open hole section was displaced to NaCl brine from OBM prior to testing. The production test results for Well 48/23a-4 were disappointing (particularly when compared to the 'twin' Well 48/23-3) with a maximum production rate of ca. 15 MMscf/d @ ca. 2000 psi drawdown. No fully stabilised production rate was achieved during the test with a general decline in rate and pressures for each flow period. We have interpreted the well test with a kh of 55 md ft (Figure 4.3 and Figure 4.4).

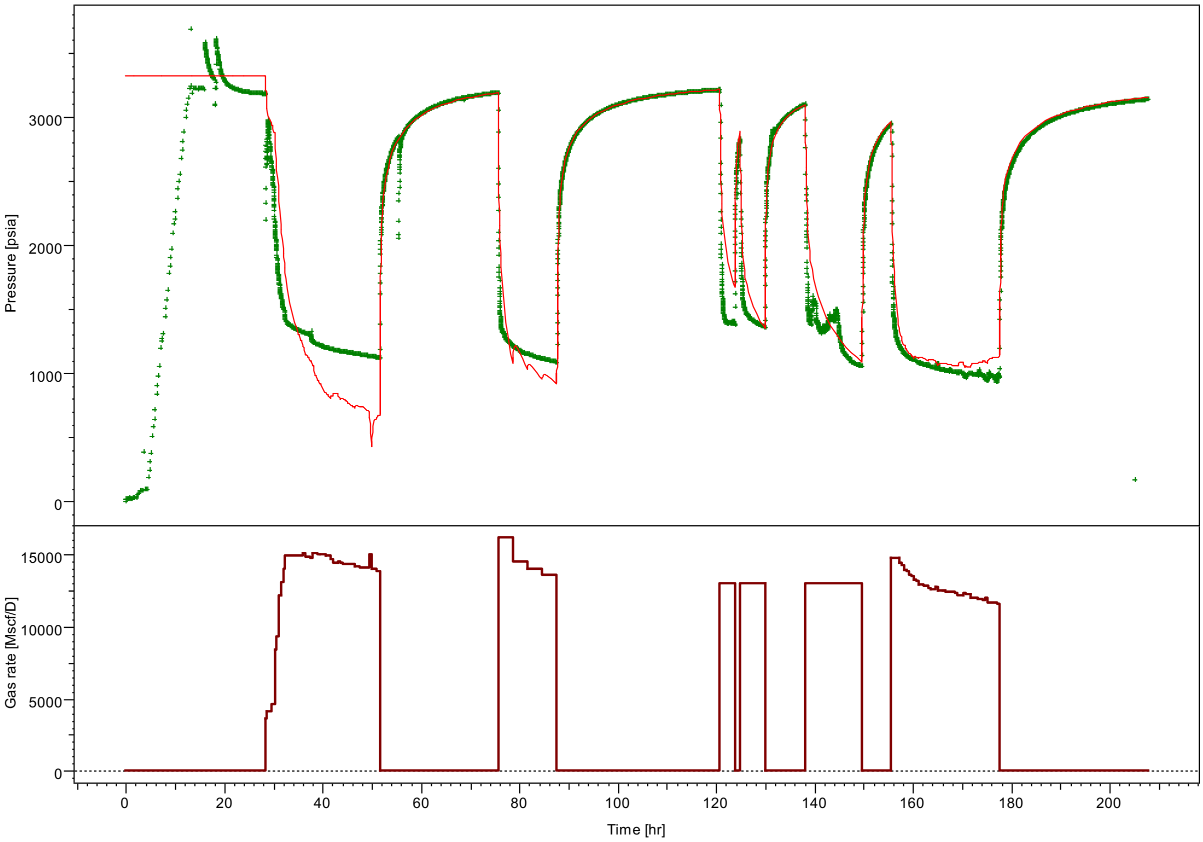

Figure 4.3 Well 48/23a-4 test match – cartesian plot

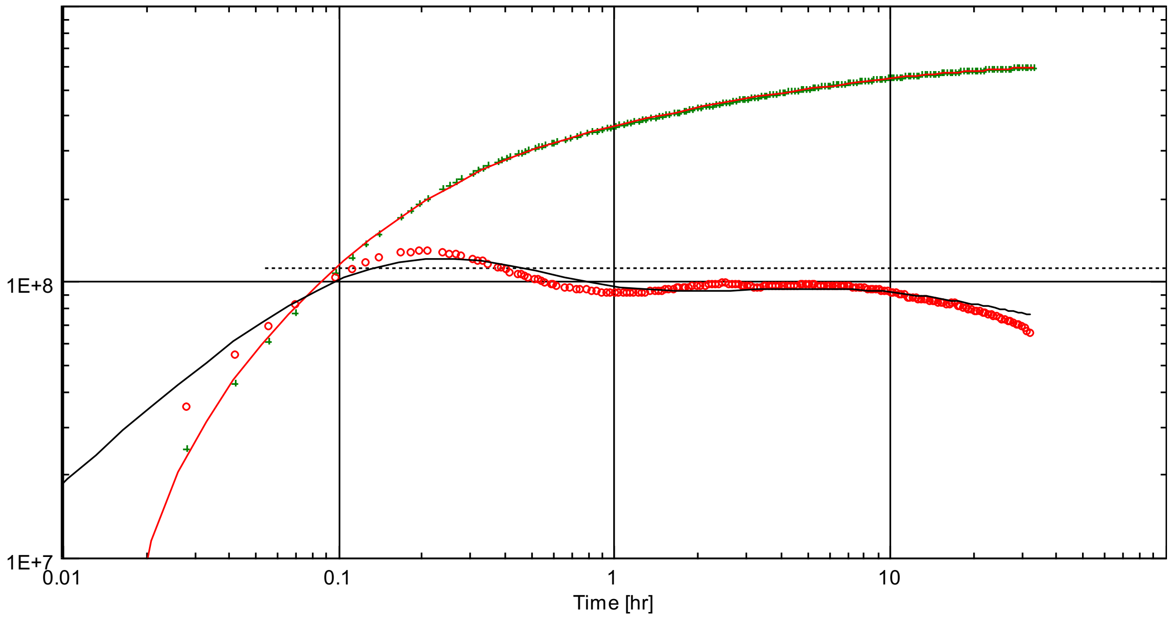

Figure 4.4 Well 48/23a-4 test match (build up 2) – log log plot

We have attempted to match the test analyses within the dynamic reservoir simulator and have found it to be impossible to match the tests of Wells 48/23-3 and 48/23a-4 using a consistent set of reservoir parameters. In order to generate our resources estimates the reservoir parameters (specifically the layer permeabilities) which have best matched Well 48/23a-4 have been used to predict the full field reservoir performance as this well has tested the largest volume of reservoir rock (due to its long, horizontal section) and was tested for the longest duration (7.5 days compared to 2.3 days for Well 48/23-3). The reservoir parameters derived from the Well 48/23a-4 match also lead to the more conservative forecasts.

Three deterministic full field reservoir simulation models have been created based on the static models used to generate the P90, P50 and P10 GIIP estimates and production forecasts. These models have then been adjusted using the reservoir parameters determined from the well test matched model.

4.2. Development Plan and Predicted Production Performance

The operator's development plan for the Blythe field consists of drilling a trilateral production well targeting the A4 reservoir in the anticlinal area mapped to the North East of the current well control. The planned well will intersect the Weissliegend, A1, A2, A3 and, most importantly, the A4 reservoir horizons. Two additional, 1000 ft long side laterals are planned to encounter the Weissliegend to maximise reservoir coverage. In order to allow the accurate placement of this well into the better quality, A4 layer of the Rotliegend the Operator plans to drill a pilot hole to confirm the Top Rotliegend pick and finalise the profile of the production boreholes. The current development well plan and P50 resource estimates are based on encountering the crest of the A4 reservoir mapped from the Operator's P50, Pre-STM generated Top Rotliegend map (Figure 4.5).

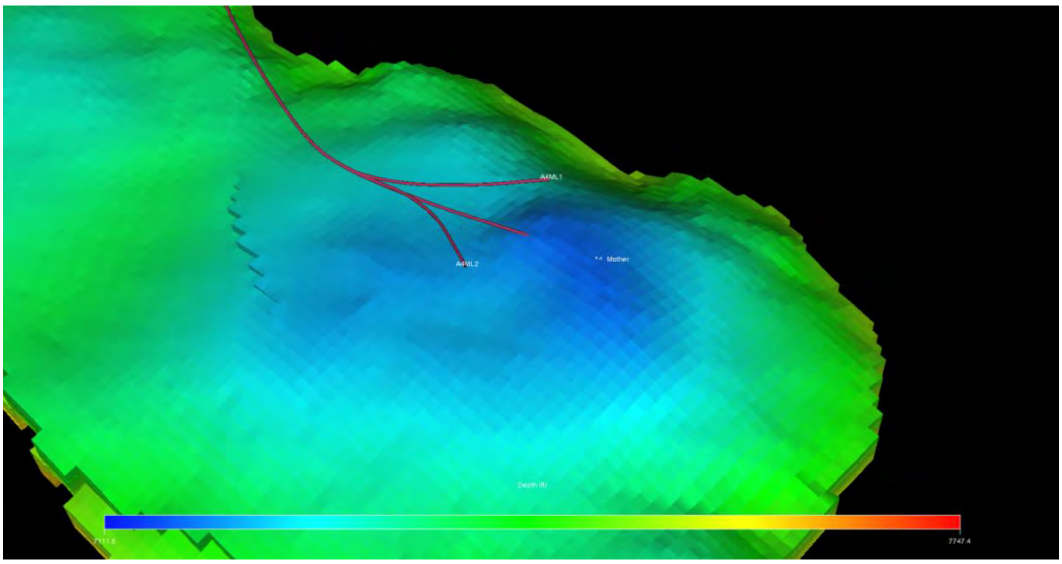

Figure 4.5: Planned development well displayed against top A4 reservoir horizon, P50 Model

The initial plan is to drill the main bore horizontally in the A4 layer 100 ft above the GWC. However, when this trajectory was inserted into the P90 and P10 GIIP models, in the case of the P90 model the A4 layer was not penetrated and in the case of the P10 model the crest is further to the south east such that the trajectory stays in the A3 layer.

In mitigation of this outcome the landing point of the horizontal section has been adjusted downwards to be 50 ft above the GWC. The effect of this is to ensure the well encounters the crest of the A4 layer in the P90 map and the flank of the A4 in the P10 map. Whilst these cases produce more water than the base case they both maintain the deliverability from the expected higher A4 quality reservoir and so can reach and maintain the desired 30 MMscf/day initial rate. The ability to adjust the positioning of the horizontal well is vital and, therefore, a pilot hole is considered essential for the success of the project.

4.3. Reserves

The ultimate recovery predicted by the simulation models for the three GIIP cases, together with the respective recovery factor (e.g. 1P recovery / 1P GIIP) are presented in Table 4.1.

	1P	2P	3P
Total Gas Recovery (bcf)	23.6	36.1	50.0
Total Condensate Recovery (MMbbl)	0.24	0.36	0.50
Gas Recovery Factor (%)	61	69	59

Table 4.1: Technical ultimate recovery and recovery factor

Life of field sales production profiles derived from the low, mid and high GIIP three models are presented in Table 4.2 after deduction of 5 % losses for fuel and flare. All three forecasts assume production through a 2 km pipeline to the Hot Tap at the Lancelot to Bacton pipeline. First gas is assumed in September 2015.

Table 4.3 presents forecasts assuming first gas production occurs at the end of the first quarter 2015.

Year	Sales Gas Rate (MMscf/d)			Condensate Rate (bbl/d)		
	1P	2P	3P	1P	2P	3P
2015*	7.4	8.4	8.4	78	89	89
2016	13.5	28.5	28.5	143	300	300
2017	8.0	24.2	28.5	85	255	300
2018	6.0	13.4	25.5	63	141	269
2019	4.8	7.8	13.5	51	82	142
2020	3.9	4.7	6.2	41	50	65
2021	3.3	3.2	3.8	34	33	40
2022	2.8	2.5	2.9	29	26	30
2023	2.3	1.3	2.4	25	13	25
2024	2.0	0.0	2.0	21	0	21
2025	1.8	0.0	1.7	18	0	18
2026	1.5	0.0	1.5	16	0	16
2027	1.2	0.0	1.3	13	0	14
2028	1.0	0.0	1.1	10	0	12
2029	0.8	0.0	1.0	8	0	11
2030	0.6	0.0	0.9	7	0	10
2031	0.0	0.0	0.8	0	0	8
Total (bcf/MMbbl)	22.3	34.3	47.5	0.23	0.36	0.50

*) 2015 rate is annualised and assumes September 2015 production start
Sales gas after deduction of fuel gas of 5% from the gross gas production MMscf/d

Table 4.2: Base case forecasts of sales gas and condensate production

Year	Sales Gas Rate (MMscf/d)			Condensate Rate (bbl/d)		
	1P	2P	3P	1P	2P	3P
2015*	15.0	21.5	21.5	158	226	226
2016	10.0	28.2	28.5	105	297	300
2017	6.9	18.5	28.4	73	195	299
2018	5.4	10.4	20.2	57	109	213
2019	4.4	6.1	9.2	46	65	96
2020	3.6	3.9	4.8	38	41	50
2021	3.0	2.8	3.3	32	29	35
2022	2.6	2.2	2.6	27	23	28
2023	2.2	0.0	2.2	23	0	23
2024	1.9	0.0	1.9	20	0	20
2025	1.6	0.0	1.6	17	0	17
2026	1.4	0.0	1.4	15	0	15
2027	1.1	0.0	1.2	12	0	13
2028	0.9	0.0	1.1	9	0	11
2029	0.7	0.0	1.0	7	0	10
2030	0.0	0.0	0.9	0	0	9
2031	0.0	0.0	0.7	0	0	8
2032	0.0	0.0	0.0	0	0	0
Total (bcf/MMbbl)	22.1	34.2	47.6	0.23	0.36	0.50

*) 2015 rate is annualised and assumes end first quarter 2015 production start
Sales gas after deduction of fuel gas of 5% from the gross gas production MMscf/d

Table 4.3: Forecasts of sales gas and condensate production (end first quarter 2015 start)

5. Economic Forecasts

5.1. Input Parameters

The basic input parameters are outlined below.

5.1.1. Discount Rate and Method

A 10 per cent nominal discount rate and discounting to the mid-year point has been applied to all future net cash flows with effect from 1 October 2012.

5.1.2. UK Tax Considerations

The NPV calculations are based on the current fiscal terms for UK. The UK fiscal terms comprise of UK ring fence Corporation Tax of 30% of profits plus Supplementary Charge of 32% at oil price trigger of $75/bbl ($12.5/Mcf) else 20% of profits. Capital allowances are available at 100% write down. Tax relief for decommissioning expenditure is limited to 30% Corporation Tax and 20% rate for Supplementary Charge. The Blythe field is exempt from Petroleum Revenue Tax (PRT) and Royalty and will qualify for Small Field Allowance introduced in the Finance Bill 2010. A revision was made to the Small Field Allowance in the 2012 Budget where the maximum allowance was increased from £75 million to £150 million.

5.1.3. Assumed Gas and Oil Price

We have assumed a Base Case gas price of 60 pence per therm in 2013, escalated thereafter at 2.0% per annum inflation. High and Low gas price sensitivities have also been evaluated. The High price sensitivity assumes 65 pence per therm in 2013 and the Low price sensitivity assumes 55 pence per therm in 2013, both escalated thereafter at 2.0% per annum inflation. For condensate revenue modelling, we have assumed a Base Case Brent oil price forecast of $100 per stb in 2013, escalated thereafter at 2.0% per annum inflation, with a range of +/- $10 per stb around the Base Case.

Table 5.1 to Table 5.3 present the gas price cases and Table 5.4 to Table 5.6 the oil price cases.

Spot Gas Price (Nominal 60 p/therm) – Base Case					
2013	**2014**	**2015**	**2016**	**2017**	**2018+**
60.0	61.2	62.4	63.7	64.9	+2.0%

Table 5.1 Spot gas price, Base Case

Spot Gas Price (Nominal 65 p/ therm) – High Sensitivity					
2013	**2014**	**2015**	**2016**	**2017**	**2018+**
65.0	66.3	67.6	69.0	70.4	+2.0%

Table 5.2 Spot gas price, High Case sensitivity

Spot Gas Price (Nominal 55 p/ therm) – Low Sensitivity					
2013	**2014**	**2015**	**2016**	**2017**	**2018+**
55.0	56.1	57.2	58.4	59.5	+2.0%

Table 5.3: Spot gas price, Low Case Sensitivity

Brent Oil Price (Nominal $US per stb) – Base Case					
2013	**2014**	**2015**	**2016**	**2017**	**2018+**
100.0	102.0	104.0	106.1	108.2	+2.5%

Table 5.4: Brent oil price, Base Case

Brent Oil Price (Nominal $US per stb) – High Sensitivity					
2013	**2014**	**2015**	**2016**	**2017**	**2018+**
110.0	112.2	114.4	116.7	119.1	+2.0%

Table 5.5: Brent oil price, High Case sensitivity

Brent Oil Price (Nominal $US per stb) – Low Sensitivity					
2013	**2014**	**2015**	**2016**	**2017**	**2018+**
90.0	91.8	93.6	95..5	97.4	+2.0%

Table 5.6 Brent oil price Low Case sensitivity

5.1.4. Inflation and Cost Escalation

An annual inflation rate of 2.0 per cent per annum has been applied. Capital and operating costs have been determined in 2012 real terms and inflated at the 2.0 per cent inflation rate.

5.1.5. Currency

A flat annual exchange rate of $1.55/£ has been applied.

5.2. Economic Input

In our base case evaluation, production start-up is assumed to occur in September 2015. The production forecasts are presented in Table 4.2.

At the request of IOG we also provide a timing sensitivity evaluation where production start-up is assumed to occur at the end of the first quarter 2015. The production forecasts for this case are presented in Table 4.3. A gas calorific value of 1100 BTU/scf has been assumed.

Development planning of Blythe is still at an early stage. We have based our assessment of capital expenditure on the information provided by ATP. It is assumed that the facilities will comprise of a NUI with metering and water knockout and compression, from which a single tri-lateral production well will be drilled. A "Hot Tap" into the LAPS pipeline is assumed as the offtake solution for Blythe gas production. We note that there is no certainty in this gas offtake route as the Operator of the pipeline is currently reviewing this solution. In the event that gas offtake through a Hot Tap connection to the LAPS pipeline is not possible, then we anticipate an alternative evacuation solution will be determined, such as the production of the gas across the Lancelot platform or other field already in production.

Table 5.7 below shows the expected capital costs for the Blythe development in our base case scenario (first gas in September 2015).

Item	Cost (£MM)	Phasing		
		2013	2014	2015
NUI on Blythe with metering and water knockout	20.0	1.0	8.0	11.0
Pipeline & Hot Tap	16.4	0.8	6.6	9.0
PMT/MISC/FEED etc	5.2	0.8	2.4	2.1
Contingency	3.2	0.5	1.8	1.0
Drilling	25.4	0.0	5.1	20.3
Total	70.2	3.1	23.8	43.4

Table 5.7 Blythe capital expenditure – September 2015 start-up

The annual facility operating costs are estimated at £1.5 million. The gas transportation and processing charge is estimated to be £0.71 per Mscf. Decommissioning costs of £8.0 million have been assumed.

5.3. Results

Reserves are based on cumulative production to the economic limit based on the proposed development plan described above. The NPV calculations are based on the current UK fiscal terms and are shown in pounds Sterling after tax.

The Net Present Values presented in this report simply represent discounted future cashflow values. Though Net Present Values form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be constructed as ERCE's opinion of fair

Table 5.8 presents our estimates of the post tax NPV10 in £ millions at the low, base and high price assumptions for IOG's 50.00 % interest in the Blythe field in our base case (first gas in September 2015).

Price Forecast	1P	2P	3P
Low	3.9	23.6	34.6
Base	7.2	28.0	39.9
High	10.4	32.5	44.5

Table 5.8: NPV10 for IOG's 50% interest in the Blythe field – September 2015 start-up

Table 5.9 presents our estimates of the post tax NPV10 in £ millions at the low, base and high price assumptions for IOG's 50.00 % interest in the Blythe field in our timing sensitivity case (first gas in the first quarter 2015).

Price Forecast	1P	2P	3P
Low	4.1	25.9	37.3
Base	7.4	29.6	41.7
High	10.7	33.3	46.0

Table 5.9: NPV10 for IOG's 50% interest in the Blythe field – End first quarter 2015 start-up

6. Appendix 1: SPE PRMS Guidelines

SPE/WPC/AAPG/SPEE Petroleum Reserves and Resources Classification System and Definitions

The Petroleum Resources Management System

Preamble

Petroleum Resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum Resources managements system provides a consistent approach to estimating petroleum quantities, evaluating development projects and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum Resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum Resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing Reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of Resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE-PRMS consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum Resources. It is expected that the SPE-PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, hereinafter referred to as the SPE-PRMS, can be viewed at

www.spe.org/specma/binary/files6859916Petroleum_Resources_Management_System_2007.pdf .

Overview and Summary of Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project’s economic feasibility, its productive life, and its related cash flows.

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term “Resources” as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth’s crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional” or “unconventional.”

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE Resources classification system. The system defines the major recoverable Resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

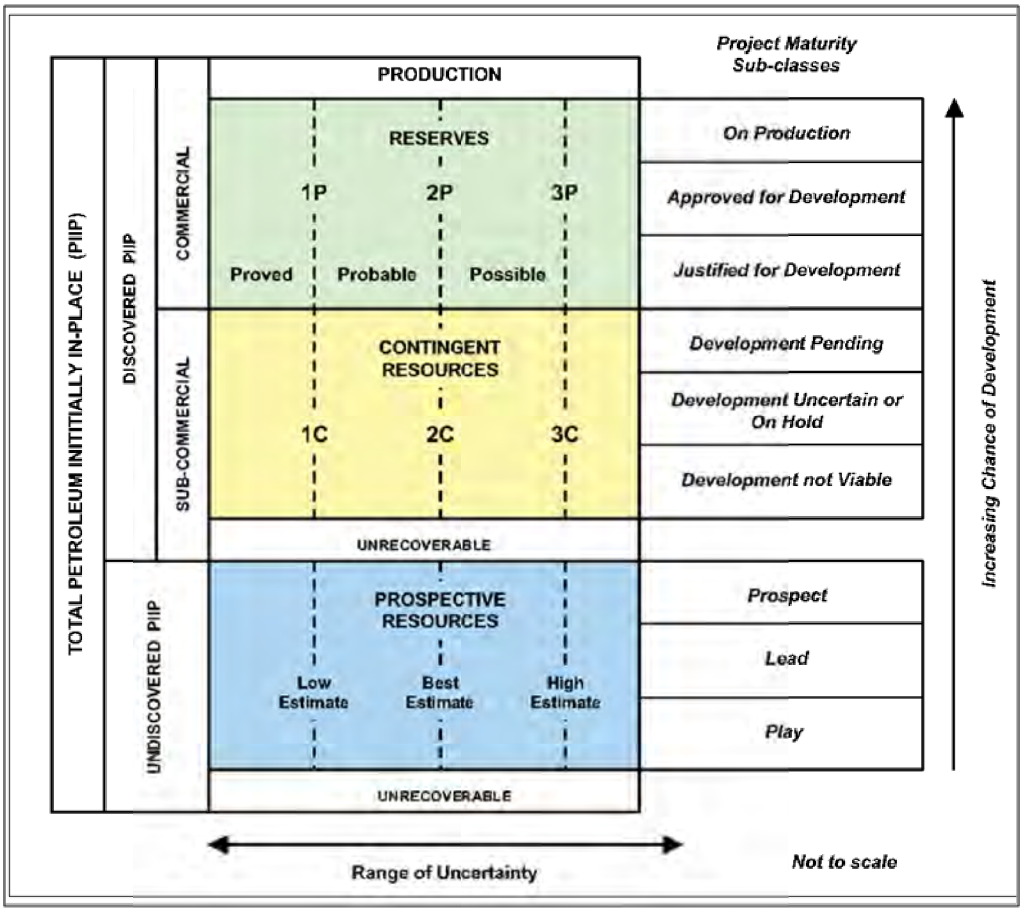

Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

The “Range of Uncertainty” reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the “Chance of Development”, that is, the chance that the project that will be developed and reach commercial producing status.

The following definitions apply to the major subdivisions within the Resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE

Total Petroleum Initially in Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations.

It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total Resources”).

DISCOVERED PETROLEUM INITIALLY-IN-PLACE

Discovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION

Production is the cumulative quantity of petroleum that has been recovered at a given date.

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

the area delineated by drilling and defined by fluid contacts, if any, and

adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved Reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.

Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.

In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.

Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.

In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE

Undiscovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

• There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

• There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

• There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete Resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project.

7. Appendix 2: Nomenclature

Nomenclature

“bbl”	means barrels
“bcf”	means thousands of millions of standard cubic feet
“Bo”	means oil shrinkage factor or formation volume factor, in rb/stb
“BTU”	means British thermal unit
“CGR”	means condensate gas ratio
“CPI”	means Computer Processed Information log
“CPR”	means competent persons report
“DECC”	means Department of Energy and Climate Change
“3D”	means three dimensional
“Eg”	means gas expansion factor
“°F”	means degrees Fahrenheit
“FDP”	means field development plan
“ft”	means feet
“ft ss”	means feet subsea
“GIIP”	means gas initially in place
“GRV”	means gross rock volume
“GWC”	means gas water contact
“kh”	means permeability thickness or horizontal permeability
“kv”	means vertical permeability
“km”	means kilometres
“M” “MM”	means thousands and millions respectively
“md" or “mD”	means millidarcy
“md”	means measured depth
“MDT” or “RFT”	means modular formation dynamic tester or repeat formation tester
"m ss"	means metres subsea
“N/G”	means net to gross ratio
“NUI”	means normally unmanned installation
“OBM”	means oil based mud
“Por” or “Phi”	means porosity
“Proved”	means Proved, as defined in Appendix 1
“Probable”	means Probable, as defined in Appendix 1
“Possible”	means Possible, as defined in Appendix 1
"1P" or “P90”	means Proved
"2P" or “P50”	means Proved + Probable

"3P" or "P10"	means Proved + Probable +Possible
"Pre-SDM"	means pre-stack depth migrated
"PRT"	means petroleum revenue tax
"psig"	means pounds per square inch gauge
"Rf"	means recovery factor
"scf"	means standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
"scf/d"	means standard cubic feet per day
"So"	means oil saturation
"stb"	means a standard barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
"stb/d"	means standard barrels per day
"ss" or "TVDSS"	means true vertical depth sub-sea
"Sw"	means water saturation

PART V

ADDITIONAL INFORMATION

1. Responsibility statement

The Directors, whose names and functions are set out on page 4 of this document, and the Company accept responsibility, individually and collectively, in accordance with the AIM Rules, for the information contained in this document. To the best of the knowledge of the Directors and the Company (who have taken all reasonable care to ensure that such is the case) the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. Incorporation and registration

2.1 The Company, whose registered office is at One America Square, Crosswall. London EC3N 2SG, was incorporated in England and Wales and registered under the Act on 9 November 2010 as a private limited company with registration number 07434350 and with the name Silbury 395 Limited. On 30 March 2011 the Company changed its name to Independent Oil & Gas Limited. On 18 September 2013, the Company re-registered as a public limited company under the Act and changed its name to Independent Oil & Gas plc. The telephone number of the Company's principal place of business is +44 (0)20 3051 9632. The address of the Company's corporate website on which the information required by Rule 26 of the AIM Rules can be found is www.independentoilandgas.com.

2.2 The principal activity of the Company is to act as a holding company. It acts as the holding company of the Group, whose principal activities are described more fully in Part I of this document and summarised at paragraph 3 below. Save for the entry of ATP Corporation into Chapter 11 bankruptcy protection in the US as mentioned in Part I of this document, there are no exceptional factors which have influenced the Company's activities.

2.3 The Company has no administrative, management or supervisory bodies other than the Board, the Remuneration Committee and Audit Committee.

2.4 The Company is governed by its Articles and the principal legislation under which the Company operates is the Act (where applicable) and the regulations made thereunder.

2.5 The Company's auditors are BDO LLP, 55 Baker Street, London W1U 7EU, which is a member firm of the Institute of Chartered Accountants in England and Wales.

2.6 The accounting reference date of the Company is 31 December.

2.7 The International Security Identification Number or "ISIN" for the Ordinary Shares is GB00BF49WF64.

2.8 Save as disclosed in paragraph 3 below, there are no undertakings in which the Company holds a proportion of the capital that are likely to have a significant effect on the assessment of its own assets and liabilities, financial position or profits.

2.9 The liability of the Shareholders is limited.

2.10 The Company is domiciled in the United Kingdom.

3. Group organisation

3.1 The Company is the Group's holding company and has the following subsidiary undertakings, all of which are directly held by the Company, as set out below:

Name	*Country of incorporation or residence*	*Proportion of ownership interest (%)*	*Proportion of voting power (%)*	*Activity*
IOG North Sea Limited	England & Wales	100	100	Oil & Gas Exploration
IOG Skipper Limited	England & Wales	100	100	Dormant

3.2 IOG North Sea, whose registered office is at One America Square, Crosswall. London EC3N 2SG, was incorporated and registered under the Act on 13 May 2011 as a private limited company with registration number 07632999 and with the name IOG Blythe Limited. On 21 May 2012 the company changed its name to IOG North Sea Limited.

4. Share capital of the Company

4.1 The history of the Company's share capital from incorporation to Admission is as follows:

(a) On incorporation, the formation agent was issued with 1 ordinary share of £1.00, nil paid (which was transferred to Peter Young on 4 May 2011 and fully paid-up).

(b) On 27 October 2011:

the Company sub-divided the 1 issued ordinary share into 100 Ordinary Shares;

a total aggregate of 44,638,090 Ordinary Shares were allotted to shareholders of Multi Operational Service Tankers Limited Inc and Ebor Energy UK Ltd; and

298,767 Ordinary Shares were allotted to Thomas Hardy and 2,247,748 Ordinary Shares were allotted to Mark Routh.

(c) On 21 May 2012, a total aggregate of 138,712 Ordinary Shares were allotted to certain shareholders of the Company as part of a rights issue.

(d) The Board has allotted, conditional on Admission, a further 309,200 Ordinary Shares to investors pursuant to the rights issue referred to in the preceding paragraph.

(e) A further 3,493,437 Ordinary Shares are to be issued upon Admission pursuant to the conversion of the Loan Notes. Please see paragraph 4.4 below for further details.

(f) A further 8,405,800 Ordinary Shares are to be issued upon Admission pursuant to the Subscription.

4.2 The number of Ordinary Shares in issue and fully paid at the beginning and end of each period covered by the historical financial information in Part III of this document and as at 24 September 2013 (being the latest practical date prior to the publication of this document) was as follows:

	Ordinary Shares in issue at beginning of period	*Ordinary Shares in issue at end of period*
Period to 31 December 2011	1[1]	47,184,705
Year to 31 December 2012	47,184,705	47,323,417
Period to 24 September 2013	47,323,417	47,323,417

Note:

1, This is an ordinary share of nominal value £1.00 prior to the subdivision carried out on 27 October 2011 and therefore equivalent to 100 Ordinary Shares.

4.3 The issued fully paid up share capital of the Company as at the date of this document and as it is expected to be immediately following Admission, is as follows:

Ordinary Shares	*Aggregate nominal value*	*Number of Ordinary Shares*
As at the date of this document	£473,234.17	47,323,417
Immediately following Admission	£595,318.54	59,531,854

4.4 ***Convertible Loan Notes***

The unsecured, interest-bearing convertible loan notes (the "**Loan Notes**") were constituted by the Company pursuant to a loan note instrument dated 3 December 2012 and amended pursuant to a Supplemental Deed dated 16 July 2013 (the "**Loan Note Instrument**"). The aggregate principal amount of the Loan Notes constituted by the Loan Note Instrument is £750,000. As at the date of this document £617,135 principal amount of Loan Notes have been issued. The Loan Notes are unsecured and accrue interest at a rate of 7.5 per cent. per annum until the actual date of repayment (or conversion). All principal and accrued but unpaid interest on the Loan Notes shall automatically convert into fully paid Ordinary Shares on Admission, at a conversion price of £0.1903448 per share, resulting in the issue of 3,493,437 new Ordinary Shares. Further details of the terms of the Loan Note Instrument are set out in paragraph 14.16 of this Part V.

4.5 On 2 September 2013, the Shareholders passed resolutions on the following terms:

(a) generally and unconditionally to authorise the Directors, until the conclusion of the Company's annual general meeting to be held in 2014, to allot shares in the Company or grant rights to subscribe for or convert any security into shares in the Company in accordance with section 551 of the Act up to an aggregate nominal amount of £500,000 comprising:

(i) up to an aggregate nominal amount of £84,058.00 in connection with the Subscription;

(ii) up to an aggregate nominal amount of £69,235.36 in connection with the grant of options to subscribe for Ordinary Shares to directors, consultants and employees of the Group by way of bonuses or other awards made to such persons in connection with Admission and completion of the Subscription;

(iii) up to an aggregate nominal amount of £13,600.00 in connection with the allotment of Ordinary Shares following Admission to certain directors, consultants and employees of the Group, in satisfaction of one half of the basic salary and fee entitlements that may become due to such persons following Admission;

(iv) up to an aggregate nominal amount of £45,000.00 in connection with the grant of options to directors and consultants of the Company under the Long Term Incentive Plan;

(v) up to an aggregate nominal amount of £2,939.11 in connection with the allotment of additional Ordinary Shares at par to which certain existing shareholders of the Company who subscribed for Ordinary Shares pursuant to the rights issue referred to in paragraph 4.1(c) above; and

(iv) otherwise than pursuant to sub-paragraphs (i) to (v), up to an aggregate nominal amount equal to one third of the aggregate nominal amount of the Company's entire issued ordinary share capital immediately following Admission, and

(b) to authorise the Directors, until the conclusion of the Company's annual general meeting to be held in 2014, pursuant to Section 570 of the Act to allot equity securities (as defined in Section 560 of the Act) for cash pursuant to the authority conferred by the resolution contained in sub-paragraph (a) above as if Section 561(1) of the Act did not apply provided that the power is limited to the allotment of equity securities:

(i) up to an aggregate nominal amount of £84,058.00 in connection with the Subscription;

(ii) up to an aggregate nominal amount of £69,235.36 in connection with the grant of options to subscribe for Ordinary Shares to directors, consultants and employees of the Group by way of bonuses or other awards made to such persons in connection with Admission and completion of the Subscription;

(iii) up to an aggregate nominal amount of £13,600.00 in connection with the allotment of Ordinary Shares following Admission to certain directors, consultants and employees of the Group, in satisfaction of one half of the basic salary entitlements that may become due to such persons following Admission;

(iv) up to an aggregate nominal amount of £45,000.00 in connection with the grant of options to directors and consultants under the Long Term Incentive Plan;

(v) up to an aggregate nominal amount of £2,939.11 in connection with the allotment of additional Ordinary Shares at par to which certain existing shareholders of the Company who subscribed for Ordinary Shares pursuant to the rights issue referred to in paragraph 4.1(c) above; and

(iv) otherwise than pursuant to sub-paragraphs (i) to (v), up to an aggregate nominal amount equal to 10 per cent. of the aggregate nominal amount of the Company's entire issued ordinary share capital immediately following Admission.

4.6 The provisions of Section 561 of the Act (which confer on shareholders rights of pre-emption in respect of the allotment of equity securities which are paid up in cash) apply to the unissued share capital of the Company except to the extent disapplied by the resolution referred to in sub-paragraph 4.5(b) above.

4.7 Save as disclosed in this paragraph 4 and paragraphs 14.16, 14.18, 14.19 and 16 of this Part V:

(a) no share or loan capital in the Company or the Group is under option or is the subject of an agreement, conditional or unconditional, to be put under option and there is no current intention to issue any Ordinary Shares; and

(b) no share or loan capital of the Company or of the Group has been issued for cash or other consideration within the period since incorporation of the Company and the date of this document and no such issue is proposed.

4.8 The Ordinary Shares have been created under the Act.

4.9 The Articles permit the Company to issue shares in uncertificated form.

4.10 No shares of the Company are currently in issue with a fixed date on which entitlement to a dividend arises and there are no arrangements in force whereby future dividends are waived or agreed to be waived.

4.11 The Company does not have in issue any securities not representing share capital.

5. Summary of the Articles of Association

5.1 Copies of the Articles are available on written request to the Company Secretary of the Company.

5.2 The Articles include provisions to the following effect:

Objects

The Articles contain no restriction on the objects of the Company.

Share Capital

The share capital of the Company consists of Ordinary Shares.

Meetings of Members

Subject to the requirement to convene and hold annual general meetings in accordance with the requirements of the Act, the Board may call general meetings whenever and at such times and places as it shall determine and, on the requisition of members pursuant to the provisions of the Act, shall forthwith proceed to convene a general meeting in accordance with the requirements of the Act.

An annual general meeting shall be called by at least 21 clear days' notice. All other general meetings that are not annual general meetings shall be called by at least 14 clear days' notice (or such other minimum period as is applicable pursuant to the Act).

Subject to the provisions of the Articles and to any restrictions imposed on any shares, the notice shall be given to all the members, to each of the directors and the auditors for the time being of the Company. The notice shall specify the time and place of the meeting and, in the case of special business, the general nature of such business. The accidental omission to give notice of a meeting, or to send any other document or information with a notice where required by the Articles, to any person entitled to receive the same, or the non-receipt of a notice of meeting or any other document or information by any such person, shall not invalidate the proceedings of that meeting. The directors may from time to time make such arrangements for the purpose of controlling the level of attendance as they shall in their absolute discretion consider appropriate.

The appointment of a proxy shall be executed by or on behalf of the appointer. Delivery of a proxy shall not preclude a member from attending and voting in person at the meeting or poll concerned. A member may appoint more than one proxy to attend on the same occasion, provided that each proxy is appointed to exercise the rights attaching to different shares held by that member. A corporation or corporation sole which is a member of the Company may authorise such person or persons as it thinks fit to act as its representative at any meeting of the Company or at any separate meeting of the holders of any class of shares.

Voting Rights

At any general meeting, on a show of hands every member who is present in person shall have one vote and on a poll every member present in person shall have one vote for every share of which he is the holder.

On a vote on a resolution on a show of hands at a meeting, every proxy present who has been duly appointed by one or more members entitled to vote on the resolution has one vote.

On a vote on a resolution on a show of hands at a meeting, a proxy has one vote for and one vote against the resolution if: (i) the proxy has been duly appointed by more than one member entitled to vote on the resolution, and (ii) the proxy has been instructed by one or more of those members to vote for the resolution and by one or more other of those members to vote against it.

Alteration of Capital

The Company may from time to time by ordinary resolution:

(a) consolidate and divide all or any of its shares into shares of larger amount; and

(b) sub-divide all or any of its shares into shares of smaller amount and attach varying rights to the shares resulting from such sub-division.

The Company may by special resolution reduce its share capital, any capital redemption reserve or redenomination reserve and any share premium account subject to the provisions of the Act.

Variation of Rights

All or any of the rights attached to any class of shares for the time being issued may (unless otherwise provided by the terms of issue of the shares of that class) be varied or abrogated, whether or not the Company is being wound up, either with the consent in writing of the holders of three-quarters in nominal value of the issued shares of that class or with the sanction of a special resolution passed at a separate general meeting of the holders of the shares of that class (but not otherwise).

Purchase of Own Shares

If undertaking a purchase of its own shares, the Company may (subject to and in accordance with the provisions of the Act and without prejudice to any relevant special rights attached to any class of shares) purchase shares of any class at any price (whether at par or above or below par), and so that any shares to be so purchased may be selected in any manner whatsoever. Every contract for the purchase of, or under which the Company may become entitled or obliged to purchase, shares in the Company shall be authorised by such resolution of the Company as may be required by the Act and by a special resolution passed at a separate general meeting of the holders of each class of shares (if any) which, at the date on which the contract is authorised by the Company in general meeting, entitle them, either immediately or at any time later on, to convert all or any of the shares of that class held by them into equity share capital of the Company.

Transfer of Shares

Subject to any restriction contained in the Articles or on any legend on any share certificate, any member may transfer all or any of his shares. Save where any rules or regulations made under the Act permit otherwise, the instrument of transfer of a share shall be in any usual form or in any other form which the Board may approve and shall be executed by or on behalf of the transferor and (in the case of a share which is not fully paid) by the transferee. The Board may in its absolute discretion decline to register any transfer of shares which are not fully paid or on which the Company has a lien. If the Board refuses to register the transfer, it shall as soon as practicable, and in any event within two months after the date on which the instrument of transfer was lodged with the Company, send to the transferee notice of the refusal along with the reasons for such refusal.

Dividends and other distributions

The Company may by ordinary resolution declare dividends in accordance with the respective rights of the members, but no dividend shall exceed the amount recommended by the Board. The Board may pay interim dividends if it appears that they are justified by the profits of the Company available for distribution.

Except as otherwise provided by the rights attached to shares, all dividends shall be declared and paid according to the amounts paid up on the shares on which the dividend is paid; but no amount paid on a share in advance of the date on which a call is payable shall be treated as paid on the share. All dividends shall be apportioned and paid proportionately to the amounts paid up on the shares during any portion or portions of the period in respect of which the dividend is paid; but, if any share is issued on terms providing that it shall rank for dividend as from a particular date, that share shall rank for dividend accordingly.

Any dividend unclaimed after a period of twelve years from the date when it became due for payment shall, if the Board so resolves, be forfeited and cease to remain owing by the Company.

The Board may, if authorised by an ordinary resolution of the shareholders of the Company, offer members the right to elect to receive shares credited as fully paid in whole or in part, instead of cash, in respect of the dividend specified by the ordinary resolution.

In a winding up, the liquidator may, with the sanction of a special resolution and subject to the Insolvency Act 1986, divide among the members *in specie* the whole or any part of the assets of the Company and/or vest the whole or any part of the assets in trustees upon such trusts for the benefit of the members as the liquidator determines.

Restrictions on Shares

If the Board is satisfied that a member or any person appearing to be interested in shares in the Company has been duly served with a notice under Section 793 of the Act and is in default in supplying to the Company the information thereby required within a prescribed period after the service of such notice the Board may serve on such member or on any such person a notice ("a direction notice") in respect of the shares in relation to which the default occurred ("default shares") directing that a member shall not be entitled to vote at any general meeting or class meeting of the Company. Where default shares represent at least 0.25 per cent. of the class of shares concerned (less any shares of that class held in treasury) the direction notice may in addition direct that (except in liquidation) no payment shall be made on any sums due from the Company on the default shares, whether in respect of capital or dividend or otherwise, and the Company shall not meet any liability to pay interest on any such payment when it is finally paid to the member and no transfer of any of the shares held by the member shall be registered unless it is a transfer of shares to an offeror by way or in pursuance of acceptance of a takeover offer (as defined in Section 974 of the Act); or the Board is satisfied that the transfer is made pursuant to a sale of the whole of the beneficial ownership of the shares the subject of the transfer to a party unconnected with the member and with other persons appearing to be interested in such shares; or the transfer results from a sale made through a recognised investment exchange as defined in the Financial Services and Markets Act 2000 or any other stock exchange outside the United Kingdom on which the Company's shares are normally traded. The prescribed period referred to above means 28 days from the date of service of the notice under Section 793 unless the default shares represent at least 0.25 per cent. of the class of shares concerned in which case it is 14 days from that date.

Directors

At every annual general meeting of the Company as near as possible (but greater than) one third of the directors for the time being shall retire by rotation and be eligible for re-election.

The directors to retire will be those who have been longest in office or, in the case of those who became or who are re-elected directors on the same day, shall, unless they otherwise agree, be determined by lot.

Save as otherwise provided in the Articles or as permitted by way of a specific authorisation by the Board pursuant to the Articles, a Director shall not vote at a meeting of the Board or a committee of the Board on any resolution of the Board concerning a matter in which he has an interest which together with any interest of any person connected with him is to his knowledge a material interest (other than by virtue of his interests in shares or debentures or other securities of or otherwise in or through the Company) unless his interest arises only because the case falls within one or more of the following paragraphs:

(a) the resolution relates to the giving of any guarantee, security, or indemnity in respect of money lent, or obligations incurred by him or by any other person at the request of or for the benefit of, the Company or any of its subsidiaries; and/or

(b) the resolution relates to the giving of any guarantee, security, or indemnity in respect of a debt or obligation of the Company or any of its subsidiaries for which the Director has assumed responsibility in whole or part and whether alone or jointly with others under a guarantee or indemnity or by giving of security; and/or

(c) his interest arises by virtue of his being, or intending to become, a participant in the underwriting or sub-underwriting of an offer of any shares, debentures, or other securities by the Company or any of its subsidiaries for subscription, purchase or exchange; and/or

(d) his interest arises in relation to the subscription or purchase by him of shares, debentures or other securities of the Company pursuant to an offer or invitation to members or debenture holders of the Company, or any class of them; and/or

(e) any proposal concerning any other company in which he and any persons connected with him do not to his knowledge hold an interest in shares representing one per cent. or more of either any class of the equity share capital, or the voting rights, in such company; and/or

(f) the resolution relates to an arrangement for the benefit of employees of the Company or of any of its subsidiaries and does not provide in respect of the Director any privilege or benefit not awarded to the employees to whom such arrangement relates; and/or

(g) any proposal concerning any insurance which the Company is empowered to purchase or maintain for the benefit of any Directors of the Company or for the benefit of persons who include Directors of the Company provided that for the purposes of this paragraph insurance shall mean only insurance against liability incurred by a Director in respect of any such act or omission by him or any other insurance which the Company is empowered to purchase or maintain for or for the benefit of any groups of persons consisting of or including Directors of the Company.

The ordinary remuneration of the Directors who do not hold executive office for their services (excluding amounts payable under any other provision of these Articles) shall not exceed in aggregate £200,000 per annum or such higher amount as the Company may from time to time by ordinary resolution determine. Subject thereto, each such Director shall be paid a fee (which shall be deemed to accrue from day to day) at such rate as may from time to time be determined by the Board. Any Director who does not hold executive office and who serves on any committee of the Directors, by the request of the Board goes or resides abroad for any purpose of the Company or otherwise performs special services which in the opinion of the Directors are outside the scope of the ordinary duties of a Director, may be paid such extra remuneration by way of salary, commission or otherwise as the Board may determine. The Directors may be paid all travelling, hotel, and other expenses properly incurred by them in connection with their attendance at meetings of the Board or committees of the Board or general meetings or separate meetings of the holders of any class of shares or of debentures of the Company or otherwise in connection with the discharge of their duties.

Unless otherwise determined by ordinary resolution, the number of Directors (other than alternate Directors) shall be not less than two nor more than ten in number. A director shall not be required to hold any shares of the Company by way of qualification.

Borrowing Powers

The Board may exercise all the powers of the Company to borrow money, to guarantee, to indemnify, to mortgage or charge its undertaking, property, assets (present and future) and uncalled capital and, subject to the provisions of the Act, to issue debentures and other securities whether outright or as collateral security for any debt, liability or obligation of the Company or of any third party.

6. Mandatory bids, squeeze-out and sell-out rules relating to the Ordinary Shares

Mandatory bid

6.1 The City Code applies to the Company. Under the City Code, if an acquisition of Ordinary Shares were to increase the aggregate holding of the acquiror and its concert parties to shares carrying 30 per cent. or more of the voting rights in the Company, the acquiror and, depending on the circumstances, its concert parties, would be required (except with the consent of the Panel on Takeovers and Mergers) to make a cash offer for the outstanding shares in the Company at a price not less than the highest price paid for the Ordinary Shares by the acquiror or its concert parties during the previous 12 months. This requirement would also be triggered by any acquisition of shares by a person holding (together with its concert parties) shares carrying between 30 and 50 per cent. of the voting rights in the Company if the effect of such acquisition were to increase the percentage of shares carrying voting rights in which that person is interested.

Squeeze-out

6.2 Under the Act, if an offeror were to acquire 90 per cent. of the Ordinary Shares pursuant to a takeover offer within four months of making its offer, it could then compulsorily acquire the remaining 10 per cent.. It would do so by sending a notice to outstanding Shareholders telling them that it will compulsorily acquire their shares and then, six weeks later, it would execute a transfer of the outstanding shares in its favour and pay the consideration to the Company, which would hold the consideration on trust for outstanding Shareholders. The consideration offered to the Shareholders whose shares are compulsorily acquired under the Act must, in general, be the same as the consideration that was available under the takeover offer.

Sell-out

6.3 The Act also gives minority Shareholders in the Company a right to be bought out in certain circumstances by an offeror who has made a takeover offer. If a takeover offer related to all the Ordinary Shares and at any time before the end of the period within which the offer could be accepted the offeror held or had agreed to acquire not less than 90 per cent. of the Ordinary Shares, any holder of shares to which the offer relates who has not accepted the offer can by a written communication to the offeror require it to acquire those shares. The offeror would be required to give any Shareholder notice of his right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of minority Shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period. If a Shareholder exercises its rights, the offeror is bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

7. Directors of the Company

7.1 Details of the Directors, their business addresses and their functions in the Company are set out on page 4 of this document under the heading "Directors, Secretary and Advisers". Each of the Directors can be contacted at the principal place of business of the Company at 70 Clifton Street, London, EC2A 4HB.

7.2 In addition to being directors of the Company, the Directors hold or have held directorships of the companies and/or are or were partners of the partnership specified opposite their respective names below within the five years prior to the date of this document:

Name	*Current Directorships/Partnerships*	*Previous Directorships/Partnerships*
Mehdi Varzi	Varzi Energy Limited Unaoil SA Recipco Limited IOG North Sea Limited IOG Skipper Limited 13/14 Gloucester Square Freehold Limited	Gulf Keystone Petrolum Ltd
Mark Routh	Warrego Energy Limited IOG North Sea Limited IOG Skipper Limited	
Marie-Louise Clayton	IOG North Sea Limited IOG Skipper Limited Worplesdon Court Resdients Company Limited GCHO Holdings Limited Geoffrey Osborne Limited Zotefoams plc	Carbon Control Software Ltd EBOR Energy UK Limited Forth Ports Limited

Name	*Current Directorships/Partnerships*	*Previous Directorships/Partnerships*
Peter Young	IOG North Sea Limited IOG Skipper Limited	Multi Operational Service Tankers Inc. EBOR Energy UK Limited MOST Oil & Gas Limited Ebor Energy Inc.
Michael Jordan	Acura Oil & Gas Limited Acura Investments Limited Acura Homes Limited Acura Homes SL Acura Investments SL IOG North Sea Limited IOG Skipper Limited Ebor Energy Inc.	Acura Europe Limited MOST Oil & Gas Limited EBOR Energy UK Limited Multi Operational Service Tankers Inc. Credential Environmental Limited

7.3 As at the date of this document, no Director has:

(a) any unspent convictions in relation to indictable offences;

(b) been declared bankrupt or been subject to any individual voluntary arrangement;

(c) been a director of any company which has been placed in receivership, compulsory liquidation, creditors' voluntary liquidation, administration, company voluntary arrangement or any composition or arrangement with its creditors generally or any class of its creditors whilst he was a director of that company or within 12 months after he ceased to be a director of that company;

(d) been a partner in any partnership which has been placed in compulsory liquidation, administration or partnership voluntary arrangement whilst he was a partner of that partnership or within 12 months after he ceased to be a partner in that partnership;

(e) been the owner of any asset or been a partner in any partnership which had an asset placed in receivership whilst he was a partner of that partnership or within the 12 months after he ceased to be a partner of that partnership; or

(f) been subject to any public criticisms by any statutory or regulatory authorities (including recognised professional bodies) or been disqualified by a court from acting as a director of a company or from acting in the management or conduct of the affairs of any company.

7.4 Save as disclosed in this document, no Director is or has been interested in any transaction which is or was unusual in its nature or conditions or significant to the business of the Group and which was effected by the Group and remains in any respect outstanding or unperformed.

7.5 Mr. Jordan's previous surname was Spencer.

8. Directors' service agreements and letters of appointment

The following agreements have been entered into between the Directors and the Company:

8.1 **Mehdi Varzi,** *Non-Executive Chairman*

Mr. Varzi's services as Non-Executive Chairman to the Company are procured by a letter of appointment dated 24 September 2013. Mr. Varzi's appointment pursuant to the letter of appointment is conditional on Admission and will be deemed to have commenced on 1 September 2013. Mr. Varzi's time commitment is anticipated to be 30 days per annum (not including any meetings of committees to which he will be appointed) and his appointment is terminable in accordance with the Articles and at any time on either party giving three months' prior written notice.

The annual fee receivable under this arrangement is £50,000 per annum. The fees payable are subject to annual review by the Board.

8.2 **Mark Routh,** *Chief Executive Officer*

Mr. Routh entered into a service agreement dated 24 September 2013 with the Company pursuant to which he is employed as Chief Executive Officer with effect from 1 September 2013 and an annual salary of £198,000 per annum. The agreement, which is conditional upon Admission, is terminable with immediate effect by the Company for cause and by either party on six months' written notice, such notice not to take effect prior to the first anniversary of the date of the agreement, and in accordance with the Articles. Mr. Routh will be entitled to take 25 days' holiday per annum in addition to usual UK bank holidays. Mr. Routh may be entitled to be paid bonuses of such amounts (if any) at such times and subject to such conditions as the Remuneration Committee may in its absolute discretion decide. Mr. Routh may be eligible to be granted share options pursuant to and in accordance with such Company share option plan(s) or share incentive scheme(s) as may be in force from time to time. Mr. Routh will be subject to certain restrictive covenants during and after the term of the agreement.

Pursuant to a letter dated 24 September 2013, Mr. Routh has agreed that until the earlier of: (a) the date on which the Company completes a fundraising pursuant to which gross funds of not less than £10 million are received by the Company; and (b) 31 December 2014, the Company may defer the payment of 50 per cent. of Mr. Routh's basic salary pursuant to his service agreement. The Company may, subject to certain conditions, settle the payment of such deferred salary at the end of each six month period by granting Mr. Routh an option over Ordinary Shares exercisable at the nominal value of such shares. The number of shares subject to the option is calculated by dividing the aggregate amount of the deferred fees by the volume weighted average trading price of the Ordinary Shares on AIM for the preceding six month period.

8.3 **Peter Young,** *Chief Financial Officer*

Mr. Young entered into a service agreement dated 24 September 2013 with the Company pursuant to which he is employed as Chief Financial Officer with effect from 1 September 2013 and an annual salary of £150,000 per annum. The agreement, which is conditional upon Admission, is terminable with immediate effect by the Company for cause and by either party on six months' written notice with such notice not to take effect prior to the first anniversary of the date of the agreement, and in accordance with the Articles. Mr. Young will be entitled to take 25 days' holiday per annum in addition to usual UK bank holidays. Mr. Young may be entitled to be paid bonuses of such amounts (if any) at such times and subject to such conditions as the Remuneration Committee may in its absolute discretion decide. Mr. Young may be eligible to be granted share options pursuant to and in accordance with such Company share option plan(s) or share incentive scheme(s) as may be in force from time to time. Mr. Young will be subject to certain restrictive covenants during and after the term of the agreement.

Pursuant to a letter dated 24 September 2013, Mr. Young has agreed that until the earlier of: (a) the date on which the Company completes a fundraising pursuant to which gross funds of not less than £10 million are received by the Company; and (b) 31 December 2014, the Company may defer the payment of 50 per cent. of Mr. Young's basic salary pursuant to his service agreement. The Company may, subject to certain conditions, settle the payment of such deferred salary at the end of each six month period by granting Mr. Young an option over Ordinary Shares exercisable at the nominal value of such shares. The number of shares subject to the option is calculated by dividing the aggregate amount of the deferred fees by the volume weighted average trading price of the Ordinary Shares on AIM for the preceding six month period.

8.4 **Marie-Louise Clayton,** *Non-Executive Director*

Ms. Clayton's services as services as Non-Executive Director to the Company are procured by a letter of appointment dated 24 September 2013. Ms. Clayton's time commitment is anticipated to be

30 days per annum (not including any meetings of committees to which she will be appointed) and her appointment is terminable in accordance with the Articles and at any time on either party giving three months' prior written notice.

The annual fee receivable under this arrangement is £30,000 per annum. The fees payable are subject to annual review by the Board.

Pursuant to a letter dated 24 September 2013, Ms. Clayton has agreed that until the earlier of: (a) the date on which the Company completes a fundraising pursuant to which gross funds of not less than £10 million are received by the Company; and (b) 31 December 2014, the Company may defer the payment of 50 per cent. of Ms. Clayton's fee pursuant to her letter of appointment. The Company may, subject to certain conditions, settle the payment of such deferred fees at the end of each six month period by granting Ms. Clayton an option over Ordinary Shares exercisable at the nominal value of such shares. The number of shares subject to the option is calculated by dividing the aggregate amount of the deferred fees by the volume weighted average trading price of the Ordinary Shares on AIM for the preceding six month period.

8.5 ***Mike Jordan,*** *Non-executive Director*

Mr. Jordan's services as Non-Executive Director to the Company are procured by a letter of appointment dated 24 September 2013. Mr. Jordan's time commitment is anticipated to be 30 days per annum (not including any meetings of committees to which he will be appointed) and his appointment is terminable in accordance with the Articles and at any time on either party giving three months' prior written notice.

The annual fee receivable under this arrangement is £30,000 per annum. The fees payable are subject to annual review by the Board.

Pursuant to a letter dated 24 September 2013, Mr. Jordan has agreed that until the earlier of: (a) the date on which the Company completes a fundraising pursuant to which gross funds of not less than £10 million are received by the Company; and (b) 31 December 2014, the Company may defer the payment of 50 per cent. of Mr. Jordan's fee pursuant to his letter of appointment. The Company may, subject to certain conditions, settle the payment of such deferred fee at the end of each six month period by granting Mr. Jordan an option over Ordinary Shares exercisable at the nominal value of such shares. The number of shares subject to the option is calculated by dividing the aggregate amount of the deferred fees by the volume weighted average trading price of the Ordinary Shares on AIM for the preceding six month period.

8.6 The aggregate remuneration paid or payable by any company in the Group (including benefits in kind) to the Directors during the year ended 31 December 2012 was £20,910. The aggregate estimated remuneration paid or payable to the Directors by any company in the Group for the current financial year under the arrangements in force is expected to amount to £166,437.

8.7 Each of the Directors has been awarded a bonus to reward outstanding work performed in connection with Admission. Each of Mark Routh, Peter Young, Marie-Louise Clayton and Mike Jordan have been granted with options to subscribe for Ordinary Shares, details of which are set out in paragraph 11 of Part I and paragraph 9.2 of Part V of this document. Mehdi Varzi has been awarded a cash bonus of £62,500, conditional on Admission. Mr. Varzi has agreed to defer payment of the bonus until such time as the Company completes a fundraising of a minimum amount of £10 million. If the Company has not completed such a fundraising by 31 December 2014 he will be granted an option over Ordinary Shares on the same terms as the options granted pursuant to the other Directors in respect of their bonus options referred to above. The number of Ordinary Shares subject to the option will be calculated by dividing the amount of the bonus by the volume weighted average trading price of the Ordinary Shares on AIM from the date of Admission until 31 December 2014.

8.8 There are no existing or proposed service agreements, consultancy agreements or letters of appointment between any of the Directors and any company in the Group which provide benefits upon termination of employment or otherwise.

9. Directors' shareholdings and other interests

9.1 The interests (within the meaning of Sections 820 – 825 (inclusive) of the Act) of the Directors and (so far as is known to the Directors having made appropriate enquiries) persons connected with them (which expression shall be construed in accordance with the AIM Rules) (all of which are beneficial except as shown below) in the Existing Share Capital, as at 24 September 2013, being the last practicable date prior to the publication of this document, and as expected to be immediately following Admission, are as follows:

Name	*Number of Existing Ordinary Shares*	*Percentage of Existing Share Capital*	*Number of Ordinary Shares immediately following Admission*	*Percentage of Enlarged Share Capital*
Mehdi Varzi	Nil	Nil	Nil	Nil
Mark Routh	2,285,516	4.83%	4,121,189	6.92%
Marie-Louise Clayton[1]	2,460,173	5.20%	2,550,773	4.28%
Peter Young	13,148,717	27.78%	13,544,820	22.75%
Mike Jordan[2]	6,610,458	13.97%	6,775,742	11.38%

Notes:

1. 40,655 Ordinary Shares are held by Clayton Consulting Partners Limited, a company in which Marie-Louise Clayton is a majority shareholder and a director.
2. All of these Ordinary Shares are held by Acura Oil & Gas Limited, a company in which Mike Jordan is the majority shareholder and director.

9.2 On Admission, the Directors and (so far as the Directors are aware, having made all reasonable enquiries) persons connected with them (within the meaning of section 252 of the Act) will have the following options over Ordinary Shares:

Name	*Date of grant*	*Type of Option*	*Number of Ordinary Shares under option*	*Exercise price (pence)*	*Final exercise date*
Mehdi Varzi	–	–	–	–	–
Mark Routh	23 September 2013	AIM Bonus Option	2,933,946	1p	30 June 2015
	23 September 2013	LTIP	1,500,000	29.74p	23 September 2023
	23 September 2013	LTIP	1,500,000	41.63p	23 September 2023
Marie-Louise Clayton[1]	23 September 2013	AIM Bonus Option	570,000	1p	30 June 2015
Peter Young	23 September 2013	AIM Bonus Option	1,700,000	1p	30 June 2015
	23 September 2013	LTIP	750,000	29.74p	23 September 2023
	23 September 2013	LTIP	750,000	41.63p	23 September 2023
Mike Jordan[2]	23 September 2013	AIM Bonus Option	290,000	1p	30 June 2015

Notes:

1. This option has been granted to Clayton Consulting Partners Limited, a company in which Marie-Louise Clayton is a majority shareholder and a director.
2. This option has been granted to Acura Oil & Gas Limited, a company in which Mike Jordan is the majority shareholder and director.

9.3 Save as disclosed in this document, none of the Directors has any interest, whether beneficial or non-beneficial, in the issued share capital or loan capital of any member of the Group and nor do (so far as is known to the Directors having made appropriate enquiries) persons connected with them (which expression shall be construed in accordance with the AIM Rules).

9.4 There are no potential conflicts of interest between any duties to the Company of the Directors and their private interests and duties to third parties.

9.5 Save as dislcosed in paragraph 9.6 below, there are no outstanding loans granted by any member of the Group to any of the Directors and there are no guarantees provided by any member of the Group for the benefit of any of the Directors.

9.6 As at the of Admission, the following directors loans remain outstanding and payable by IOG North Sea:

Name of Director	*Outstanding Amount payable to Director*
Peter Young	US$19,501.80
Mike Jordan	US$20,728.03

Such loans shall not accrue any interest nor shall they become due for repayment by IOG North Sea until the date six months after the commencement of continuous oil production from the Skipper asset.

9.7 No Director nor any member of his immediate family nor any person connected with him has a related financial product (as defined in the AIM Rules) referenced to the Ordinary Shares being admitted.

9.8 Details of any restrictions agreed by the Directors with regard to the disposal of their holdings in the Company's securities are set out in paragraph 14.3 of this Part V.

10. Employees

10.1 As at the date of this document, other than the Directors, the Group has no employees. The Group has had no employees for the period covered by the historical financial information contained in this document.

10.2 Details of the Company's share incentive arrangements are set out at paragraph 16 of this Part V.

11. Related Party Transactions

Save for the transactions described in the agreements referred to in paragraphs 14.4 to 14.9 of this Part V, during the period of two years immediately preceding the date of this document, no company in the Group has entered into any related party transactions.

12. Significant Shareholdings

12.1 As at 24 September 2013, the last practicable date prior to the publication of this document, save as set out below, the Company is not aware of any persons who directly or indirectly have an interest of three per cent. or more of the Existing Share Capital or voting rights:

Name of Shareholder	*Number of Ordinary Shares*	*Percentage of Existing Share Capital*
Peter Young	13,148,717	27.78%
Acura Oil And Gas Ltd[2]	6,610,458	13.97%
Gordon Young	3,600,077	7.61%
Tom Haselton	2,889,112	6.11%
Marie-Louise Clayton[1]	2,460,173	5.20%
Mark Routh	2,285,516	4.83%
International Petroleum Exploitation A.S.	1,754,622	3.71%
John Boyle	1,750,180	3.70%
Villa Mirador S.A.	1,565,686	3.13%

Notes:

1. 40,655 Ordinary Shares are held by Clayton Consulting Partners Limited, a company in which Marie-Louise Clayton is a majority shareholder and a director.

2. Mike Jordan is the majority shareholder and director of Acura Oil & Gas Limited.

12.2 Following Admission, the following persons will (so far as is known to the Directors, having made appropriate enquiries) directly or indirectly have an interest of three per cent. or more of the Enlarged Share Capital or voting rights:

Name of Shareholder	*Number of Ordinary Shares*	*Percentage of Enlarged Share Capital*
Peter Young	13,544,820	22.75%
Acura Oil And Gas Ltd	6,775,742	11.38%
Mark Routh	4,121,189	6.92%
Gordon Young	3,600,077	6.05%
Tom Haselton	2,889,122	4.85%
Marie-Louise Clayton	2,550,773	4.28%

12.3 Save as disclosed in paragraphs 12.1 and 12.2 of this Part V, the Directors are not aware of any person who either at the date of this document or immediately following Admission, exercises or could exercise, directly or indirectly, jointly or severally, control over the Company.

12.4 As at 24 September 2013, the latest practicable date prior to the publication of this document, the Company is not aware of any arrangements the operation of which may at a subsequent date result in a change in control of the Company.

12.5 The voting rights of the significant Shareholders listed above do not differ from the voting rights of the other Shareholders in the Company.

13. Principal Investments

Other than as disclosed in this document, the Company does not have, nor are there in progress or under consideration by the Company, any significant investments.

14. Material contracts of the Group

The following material contracts (not being contracts entered into in the ordinary course of business) have been entered into by members of the Group within the two years immediately preceding the date of this document or are other material subsisting contracts which relate to the assets and liabilities of the Group:

14.1 ***Nominated adviser and broker agreement with Charles Stanley***

Pursuant to a nominated adviser and broker agreement (the "**Nominated Adviser Agreement**") between the Company and Charles Stanley dated 24 September 2013, the Company has appointed Charles Stanley to act as nominated adviser and broker to the Company for the purposes of the AIM Rules, with effect from Admission, such appointment to continue until terminated by either the Company or Charles Stanley giving not less than three months' prior written notice, such notice not to take effect prior to Admission (or if certain circumstances in relation to the Company or Charles Stanley exist unremedied for specified periods, forthwith by Charles Stanley or the Company as set out in the Nominated Adviser Agreement). The Company has agreed to pay Charles Stanley an annual retainer fee at the rate of £30,000 (plus VAT and expenses) quarterly in advance. When the Company completes an equity fundraising of at least £10 million, the annual retainer under the Nominated Adviser Agreement will increase to £50,000. The Nominated Adviser Agreement contains certain undertakings by the Company in respect of, *inter alia*, compliance with applicable laws and regulations.

14.2 ***Introduction Agreement***

An introduction agreement dated 25 September 2013 between the Company, the Directors and Charles Stanley was entered into pursuant to which Charles Stanley has agreed to act as the Company's nominated adviser in connection with Admission. The Introduction Agreement is conditional, *inter alia*, on Admission becoming effective on or before 14 October 2013. The Company has agreed to pay to Charles Stanley, conditional on Admission, a corporate finance fee of £125,000, plus commission of 5 per cent. of the aggregate value at the Subscription Price of all Subscription Shares subscribed for by Subscribers introduced by Charles Stanley and 1.5 per cent. of such aggregate value of Subscription Shares subscribed for by other Subscribers.

Under the terms of the Introduction Agreement, the Company and the Directors have given certain customary warranties to Charles Stanley and the Company has given certain customary indemnities and undertakings to Charles Stanley in connection with Admission and other matters relating to the Company and its affairs.

Charles Stanley may terminate the Introduction Agreement in certain specified circumstances prior to Admission, principally if any of the warranties has ceased to be true and accurate in all material respects or shall have become misleading in any respect or in the event of circumstances existing which make it impracticable or inadvisable to proceed with Admission.

14.3 ***Lock-In Deeds***

Lock-In Deeds dated 24 September 2013 have been entered into by the Company, Charles Stanley and each of the Locked-In Persons pursuant to which each of the Locked-In Persons has agreed not to dispose of any of its interests in the Ordinary Shares until the first anniversary of Admission, save in certain limited circumstances permitted by Rule 7 of the AIM Rules. The Directors have further undertaken for the following 12 months to only dispose of their respective Ordinary Shares through Charles Stanley in such manner as Charles Stanley may reasonably require so as to ensure an orderly market.

14.4 ***MOST Oil Acquisition Agreement***

Pursuant to an asset purchase agreement between MOST Oil and Gas UK Limited, the Company and IOG Skipper Limited dated 27 October 2011 (the "**MOST Oil Acquisition Agreement**"), MOST agreed to sell and the Company agreed to purchase, as a going concern and with full title guarantee, all of the business and assets (including the liabilities) of MOST relating to the exploitation and development of its 50 per cent. interest in Licence P1609 Block 9/21a for a total consideration of £8,654,476.96. The consideration was satisfied by the grant by the Company to MOST of the MOST Oil Option Agreement, further details of which are set out in paragraph 14.5 below.

Under the terms of the MOST Oil Acquisition Agreement, MOST gave certain customary warranties to the Company and IOG Skipper Limited in connection with ownership and title to the business and assets relating to its 50 per cent. interest in Licence P1609 Block 9/21a.

The 50 per cent. interest in Licence P1609 Block 9/21a was formally assigned from MOST to IOG North Sea pursuant to the terms of deeds of assignment summarised at paragraph 14.6 below.

It was agreed that the Company would assume responsibility for and perform all liabilities and obligations relating to exploitation and development of Licence P1609 Block 9/21a, including the obligation to repay the principal sum of US$1,484,800 to Weatherford Technical Services Limited due under a loan note agreement dated 12 January 2009. Further details of this arrangement are set out at paragraph 14.17 below.

14.5 ***MOST Oil Option Agreement***

Pursuant to an option agreement between the Company and MOST dated 7 October 2011 (the "**MOST Oil Option Agreement**") and in satisfaction of the consideration due to MOST under the MOST Oil Acquisition Agreement, the Company granted an option to MOST to acquire 30,329,203 Ordinary Shares (the "**MOST Oil Option Shares**"), such shares to be allotted free from all encumbrances. The MOST Oil Option was subsequently assigned by MOST and exercised by the shareholders of Multi Operational Service Tankers Limited Inc on 27 October 2011.

14.6 ***Deed of Interest Assignment and Novation of Joint Operating Agreement relating to Licence P1609 Block 9/21a***

Pursuant to a deed of interest assignment and novation of joint operating agreement between IOG North Sea, ATP UK and MOST dated 17 August 2012 ("**Skipper Licence Deed of Assignment and Novation**"), MOST assigned and transferred a 50 per cent. undivided legal and beneficial interest under the Skipper Licence (Licence P1609, Block 9/21a) to IOG North Sea.

In addition, MOST shall cease to be a party to the Skipper JOA (as defined in and summarised in paragraph 14.7 below) and IOG North Sea shall instead take its place and accordingly become entitled to all the rights and benefits and subject to all of the obligations and liabilities under the Skipper JOA in respect of the interest so transferred.

14.7 ***Joint Operating Agreement relating to Licence P1609 Block 9/21a***

IOG North Sea is a party to a joint operating agreement with ATP UK dated 11 May 2010 ("**Skipper JOA**") in respect of the Skipper Licence; being Licence P1609, Block 9/21a. The Skipper JOA was novated by MOST in favour of IOG North Sea pursuant to the Skipper Licence Deed of Assignment and Novation (as summarised in paragraph 14.6 above). The Skipper JOA is deemed to have commenced on 12 February 2009 and continues for so long as the Skipper Licence remains in force and all joint property has been disposed of, all decommissioning completed and a final settlement has been made between the participants in the Skipper Licence.

The Skipper JOA regulates operations under the Skipper Licence and defines the participants' respective rights, interests, duties and obligations in connection with the Licence and petroleum produced under it. The Skipper JOA records the percentage interests held by the participants in the Skipper Licence as being IOG North Sea 50 per cent. and ATP UK 50 per cent.

ATP UK is designated and agrees to act as operator of the Skipper Licence and may only resign on 180 days' prior written notice. Where a participant fails to pay its full share of any costs and other liabilities for which it is responsible then that participant's rights under the Skipper JOA are suspended and if the default continues for more than 60 days then its interest may be forfeited to the non-defaulting participants.

No transfer shall be made by any party which results in the transferor or the transferee holding a participating interest in the Skipper Licence of less than ten per cent. To provide for the overall supervision and direction of joint operations, an operating committee is to be established composed of representatives of each party holding a participating interest. All decisions and approvals and other actions of the operating committee on all proposals coming before it shall be decided by the affirmative vote of two or more parties (which are not affiliates) then having collectively at least sixty five per cent. of the participating interests.

14.8 ***Parent Company Guarantee relating to Licence P1609 Block 9/21a***

Pursuant to a parent company guarantee between the Company and ATP UK dated 17 August 2012, the Company unconditionally and irrevocably undertakes and guarantees as primary obligor to ATP UK the proper, diligent and timely performance and observance by IOG North Sea of each and all obligations of IOG North Sea arising up to and including the time of completion of the working obligations under Licence P1609 Block 9/21a (the Skipper Licence) and the discharge of all liabilities of IOG North Sea under the Skipper JOA.

14.9 ***Ebor Acquisition Agreement***

Pursuant to an asset purchase agreement between Ebor Energy UK Limited, the Company and IOG North Sea dated 27 October 2011 (the "**Ebor Acquisition Agreement**"), Ebor agreed to sell and the Company agreed to purchase, as a going concern and with full title guarantee, those business and assets of Ebor relating to the exploitation and development of its 50 per cent. interest in Licence P1736 Blocks 48/22b and 48/23a for a total consideration of £4,109,297.04. The consideration was satisfied by the grant by the Company to Ebor of the Ebor Option Agreement, further details of which are set out in (and which is defined in) at paragraph 14.10 below.

Under the terms of the Ebor Acquisition Agreement, Ebor gave certain customary warranties to the Company and IOG North Sea in connection with ownership and title to the business and assets relating to its 50 per cent. interest in Licence P1736 Blocks 48/22b and 48/23a.

The 50 per cent. interest in Licence P1736 Blocks 48/22b and 48/23a was formally assigned from Ebor to IOG North Sea Limited pursuant to the terms of the deeds of assignment summarised at paragraph 14.11 below.

14.10 ***Ebor Option Agreement***

Pursuant to an option agreement between the Company and Ebor dated 27 October 2011 (the "**Ebor Option Agreement**") and in satisfaction of the consideration due to Ebor under the Ebor Acquisition Agreement, the Company granted an option to Ebor to acquire 14,400,883 Ordinary Shares (the "**Ebor Option Shares**"), such shares to be allotted free from all encumbrances. The Ebor Option was subsequently assigned by Ebor and exercised by the shareholders of Ebor Energy Limited Inc, on 27 October 2011.

14.11 ***Deeds of Interest Assignment and Novation of Joint Operating Agreement relating to Licence P1736 Blocks 48/22b and 48/23a***

Pursuant to a deed of interest assignement and novation of joint operating agreement dated 17 August 2012 between IOG North Sea, ATP UK and Ebor ("**Blythe Deed of Interest Assignment and Novation**"), Ebor assigned and transferred a 50 per cent. undivided legal and beneficial interest under the the Blythe Licence (Licence P1736, Blocks 48/22b and 48/23a) to IOG North Sea.

In addition, Ebor shall cease to be a party to the Blythe JOA (as summarised in paragraph 14.12 below) and IOG North Sea shall instead take its place and accordingly become entitled to all the rights and benefits and subject to all of the obligations and liabilities under the Blythe JOA in respect of the interest so transferred.

14.12 ***Joint Operating Agreement relating to Licence P1736 Blocks 48/22b and 48/23a***

IOG North Sea is a party to a joint operating agreement with ATP UK dated 11 May 2010 ("**Blythe JOA**") in respect of the Blythe Licence; being Licence P1736, Blocks 48/22b and 48/23a. The Blythe JOA was novated by Ebor in favour of IOG North Sea pursuant to the Blythe Deed of Assignment and Novation (as summarised in paragraph 14.11 above). The Blythe JOA is deemed to have commenced on 1 May 2010 and continues for so long as the Blythe Licence remains in force and all joint property has been disposed of, all decommissioning completed and a final settlement has been made between the participants in the Blythe Licence.

The Blythe JOA regulates operations under the Blythe Licence and defines the participants' respective rights, interests, duties and obligations in connection with the Licence and petroleum produced under it. The Blythe JOA records the per centage interests held by the participants in the Blythe Licence as being IOG North Sea 50 per cent. and ATP UK 50 per cent.

ATP UK is designated and agrees to act as operator of the Blythe Licence and may only resign on 180 days' prior written notice. Where a participant fails to pay its full share of any costs and other liabilities for which it is responsible then that participant's rights under the Blythe JOA are suspended and if the default continues for more than 60 days then its interest may be forfeited to the non-defaulting participants.

No transfer shall be made by any party which results in the transferor or the transferee holding a participating interest in the Blythe Licence of less than ten per cent. To provide for the overall supervision and direction of joint operations, an operating committee is to be established composed of representatives of each party holding a participating interest. All decisions and approvals and other actions of the operating committee on all proposals coming before it shall be decided by the affirmative vote of two or more parties (which are not affiliates) then having collectively at least sixty five per cent. of the participating interests.

14.13 ***Parent Company Guarantee relating to Licence P1736 Blocks 48/22b and 48/23a***

Pursuant to a parent company guarantee between the Company and ATP UK dated 17 August 2012, the Company unconditionally and irrevocably undertakes and guarantees as primary obligor to ATP UK the proper, diligent and timely performance and observance by IOG North Sea of each and all obligations of IOG North Sea arising up to and including the time of completion of the working obligations under Licence P1736, Blocks 48/22b and 48/23a (the Blythe Licence) and the discharge of all liabilities of IOG North Sea under the Blythe JOA.

14.14 ***BP Agreement***

Pursuant to an agreement dated 8 June 2012 for the supply and purchase and marketing of crude oil from the Skipper Oil Field between IOG North Sea and BP Oil International Limited (the "**BP Agreement**"): (1) (subject to the satisfaction of various conditions to BP's satisfaction, including the conditions precedent to the syndicated senior facility) BP agrees to provide a loan to IOG North Sea to assist with the development of the Skipper Oil Field, by participating as a syndicate member in a syndicated debt facility; (2) BP agrees to purchase all of IOG North Sea's entitlement to oil produced from the Skipper Oil Field, FOB from the Skipper FPSO; (3) BP agrees to market and on-sell the oil; and (4) IOG North Sea also commits to (i) (with certain exceptions) sell all of its (and its associated companies') oil from future fields to BP on similar terms, (ii) invite BP to quote for the offtake and marketing of 100 per cent. of IOG North Sea's entitlement to gas from the Blythe Gas Field and (iii) invite BP to quote for all of IOG North Sea's commodity price risk management requirements for both oil and gas.

The price to be paid by BP to IOG North Sea for each cargo of crude oil from the Skipper Oil Field is determined by reference to a formula, being: the "Dated Brent Average" (being the average of quotations for Dated Brent obtained from Platts during the relevant pricing period selected by BP) plus the "On-Sale Differential" (being the differential to Dated Brent specified in the on-sale contract) less the "Marketing Fee" (which has two elements, the first based upon the number of barrels and the second a profit share element for BP). The fixed element is adjusted for barrels sold to BP from other equity participants in the Skipper Oil Field and also from future fields.

IOG North Sea is committing to holding a 50 per cent. interest in the Skipper Oil Field and, subject to some exceptions, IOG North Sea must pay to BP a compensation amount if IOG North Sea's entitlement to oil produced from the Skipper Oil Field falls below 50 per cent. of all the oil.

The BP Agreement has a term until November 2026. There are certain grounds for early termination, including insolvency events relating to either party. IOG North Sea may terminate if BP fail to pay or to take delivery in accordance with the BP Agreement. Grounds for BP to terminate the BP Agreement early include the following: (1) Non-compliance of the Skipper FPSO with BP HSSE policies; (2) Skipper Oil Field not reaching first commercial oil production within 5 years from the date of the BP Agreement; (3) Change of control of IOG North Sea where the new owners are not cleared by BP's KYC and account opening procedures; (4) If IOG North Sea's entitlement to Skipper Oil is to less than 50 per cent. of production from the Skipper Oil Field.

14.15 ***Engen Carried Interest Agreement***

Pursuant to a carried interest agreement between IOG North Sea and Engen Resources Limited dated 1 January 2013, IOG has agreed to pay of a fee to Engen, based on the performance of the Skipper Licence oil field and calculated by reference to the proceeds of sale of all production (including the entitlement of any co-venturer) from the Skipper Licence (P1609). The fee is payable in consideration for certain technical services provided by Engen to ATP UK and MOST in connection with the application for the Skipper Licence. IOG North Sea has agreed to assume the obligations of MOST as successor to MOST's interest in the Skipper Licence.

Payments are due from commencement of production until final abandonment of production from Skipper Licence, Block 9/21a, by variable monthly instalments such that over the life of the field a total performance fee is paid equal to 1.5 per cent. of the total net value of produced hydrocarbons, after allowing for historic costs (adjusted by a factor of 125 per cent.), future adjusted capital costs, operating costs and decommissioning costs.

14.16 ***Loan Note Instrument***

A loan note instrument dated 3 December 2012 and amended pursuant to a Supplemental Deed dated 16 July 2013 was entered into by the Company constituting up to to £750,000 unsecured interest bearing convertible loan notes. The Company issued £617,135 nominal of such notes to certain investors since that date. All principal and accrued but unpaid interest on the loan notes shall automatically convert into fully paid Ordinary Shares on Admission, at a conversion price of £0.1903448 per Ordinary Share. The Company will pay simple interest on the principal amount of the loan notes outstanding at the rate 7.5 per cent. per annum which shall accrue daily. If Admission does not occur by 30 September 2013, the loan notes will be redeemed on 30 September 2013.

14.17 ***Weatherford Loan Agreement***

Pursuant to a loan agreement between Weatherford Technical Services Limited ("**Weatherford**"), Multi Operational Service Tankers Limited Inc ("**MOST Inc**") and the Company dated 17 November 2011 and amended on 29 May 2013, it was agreed between the parties that the Company would assume reponsibility for the obligation to repay to Weatherford the sum of US$1,484,800 due from MOST inc under an existing loan note issued by MOST Inc in favour Weatherford.

Under the terms of the Weatherford Loan Agreement, Weatherford agreed to fully and irrevocably release MOST Inc from any and all obligations and liabilities under the existing note and granted to the Company an unsecured dollar facility for the sum of US$1,484,800, such sum having deemed to have been drawn by the Company on 17 November 2011. Subject to certain provisions detailed below, interest is payable on all oustanding amounts of the loan at the rate of 3 per cent. per annum compounded monthly. The Company was entitled to repay the principal amount of the loan in full at any time up to 31 March 2012 without penalty; however, in the event that the loan was not repaid in full by such date, the principal amount of the loan was to be increased to $1,855,661 with effect from 1 April 2012 and interest shall accrue on the increased amount from that date. The Company is entitled to repay the loan (in whole or in part) at any time, without penalty. Upon the occurrence of an event of default (which includes an insolvency related event) all outstanding amounts under the loan shall become due and repayable immediately upon written demand of Weatherford.

In connection with the Weatherford Loan Agreement, each of IOG Skipper and IOG North Sea have entered into a deed of guarantee dated 17 November 2011 pursuant to which they have agreed, by way of continuing security, to guarantee the performance of the Company of all past, present and future payment obligations, debts and liabilities owing or incurred by the Company, under the Weatherford Loan Agreement (the "**Guaranteed Obilgations**"). Each of the guarantees is an on demand guarantee and indemnity pursuant to which each of IOG Skipper and IOG North Sea shall remain liable for the Guaranteed Obligations as if it were a principal debtor, and indemnify Weatherford on demand all costs and expenses incurred in connection with the preservation and enforcement of the guarantees or any discharge or release thereunder.

14.18 ***Subscription Agreements***

Pursuant to various subscription agreements entered into by the Company and each of the Subscribers on the same terms between 7 August and 24 September 2013 (the "**Subscription Agreements**"), the Subscribers have agreed to subscribe for 8,405,800 Subscription Shares, in aggregate, at the Subscription Price of 23.7931 pence per share.

Each Subscriber has agreed to subscribe for Subscription Shares pursuant to their respective Subscription Letter conditional upon, *inter alia*: (a) Admission taking place on or prior to 30 September 2013; (b) a minimum of 6,304,350 Subscription Shares being issued pursuant to the Subscription at the Subscription Price; (c) the fully diluted Ordinary Share capital at the time of Admission being not more than 58,000,000 (excluding the Subscription Shares and any options or warrants granted to advisers in connection with any options or warrants to be granted to the

Company's advisers in connection with Admission and any incentive options to be granted to the Company's directors, employees and consultants contemporaneous with Admission at an exercise price of not less than the Subscription Price); (d) the passing of a special resolution of the Company's shareholders to disapply certain existing pre-emption rights; (e) the Group not having acquired or disposed (or agreed to acquire or dispose) of any material assets, other than in the ordinary and proper course of its business or having assumed or incurred a material liability, obligation or expense (actual or contingent) except in the ordinary and proper course of business; (f) neither the Blythe Licence nor the Skipper Licence having been terminated, revoked or relinquished prior to Admission; and (g) neither ATP UK having been disposed of by ATP nor ATP UK having disposed of all or substantially all of its assets in either case, prior to Admission.

The number of Subscription Shares to be issued pursuant to the Subscription Agreements shall be subject to adjustment in certain circumstances. The number of Subscription Shares shall be adjusted such that upon the first occurrence of a fundraising conducted by the Company following Admission, by way of the issue of new Ordinary Shares (whether or not on a non pre-emptive basis) at an issue price ("**First Fundraising Price**") which is less than approximately 28.55 pence per Ordinary Share then the Subscribers shall be entitled to subscribe at par for such number of additional new Ordinary Shares as shall result in the First Fundraising Price representing 120 per cent. of average Subscription Price per Ordinary Share paid by the Subscribers.

14.19 ***Warrant Deed***

The Company and Charles Stanley have entered into a warrant deed dated 24 September 2013 pursuant to which the Company has granted, conditional on Admission, a warrant to Charles Stanley to subscribe for up to 630,000 Ordinary Shares. The warrant may be exercised at any time by Charles Stanley until the second anniversary of the date of Admission and at a price per share equal to the Subscription Price.

15. Litigation

No member of the Group is or has been engaged in any governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) which have had or may have a significant effect on the Group's financial position or profitability during the twelve months preceding the date of this document and so far as the Directors are aware, there are no such proceedings pending or threatened by or against any member of the Group.

16. Share Incentive Arrangements

The Company has the following arrangements in place for involving the directors, employees and consultants in the Company's share capital.

16.1 ***Long Term Incentive Plan***

The Company adopted the Long Term Incentive Plan (the "Plan") on 23 September 2013, which will be administered by the Remuneration Committee. The Company has granted options to acquire Ordinary Shares ("Options") under the Plan to each of Mark Routh and Peter Young, details of which are set out in paragraph 9.2 of this Part V.

A summary of the main provisions of the Plan is set out below.

(a) *Types of award*

The exercise of Options can be satisfied by the issue or transfer of Ordinary Shares.

Options are personal to the option holder and may not be transferred, assigned or used as security in any way.

(b) *Eligibility*

The Company may grant Options to employees of the Group, as determined by the Remuneration Committee in its absolute discretion.

(c) *Timing*

The Company may grant Options at any time, unless for the purposes of the AIM Rules the Company is in a close period or is otherwise prohibited from granting Options.

No Option may be granted following the tenth anniversary of the date the Plan was adopted.

(d) *Limit on grant of Options*

The maximum number of Ordinary Shares which may be placed under Option after Admission shall not, when aggregated with any other options or awards granted after Admission under any other employee share plan adopted by the Company, exceed ten per cent. of the Ordinary Shares then in issue in any ten year period.

(e) *Exercise price*

The exercise price of an Option must be equal to the market value of a Share on the date of grant, or such higher price determined by the Remuneration Committee. Market value will be based on a closing quoted price for an Ordinary Share on the dealing day immediately before the date of grant.

(f) *Vesting conditions*

No Option may be exercised until the expiry of a specified service period, which shall be three years from the relevant date of grant, or such longer period as the Remuneration Committee shall determine.

In addition, the Remuneration Committee may grant an option subject to performance or other vesting conditions tested during a specified performance period, as determined on or before the grant of that Option.

Once an option vests, it will be capable of exercise at any time, subject to the restrictions summarised in paragraph (g) below. To the extent a performance condition is determined not to be met, the Option (or part thereof) shall lapse.

The intention is for the initial grant of Options to have performance conditions related to an increase in Share price during a three year period commencing on the date of grant together with key performance indicators relating to health and safety policy. Further details are set out in paragraph 11 of Part I of this document.

(g) *Regulatory and tax issues on exercise*

Once vested, an Option may not be exercised unless such exercise and subsequent issue or transfer of Ordinary Shares is lawful in all applicable jurisdictions and complies with the AIM Rules, the Company's own share dealing code and all other relevant rules and regulations.

In addition, an Option may not be exercised unless or until the Option holder has entered into arrangements acceptable to the Remuneration Committee to satisfy any liability incurred by the relevant company in the Group to PAYE income tax and national insurance contributions (or their equivalent in any applicable jurisdiction), which may include the sale of Ordinary Shares on behalf of the option holder.

At the discretion of the Remuneration Committee, Option holders may be obliged to meet the cost of any employer's national insurance contributions in connection with the exercise of Options. However, the current intention is for the Company to meet the cost of any employer's national insurance contributions.

(h) *Leavers*

If an Option holder ceases to be an employee of any company in the Group at any time as a result of dismissal in circumstances constituting gross misconduct, fraud or dishonesty, or is declared bankrupt, all Options (whether vested or unvested) will lapse immediately on termination of employment.

If an Option holder ceases to be an employee of any company in the Group during the initial three year service period, as a result of certain specified reasons, including death, injury, ill health or disability, retirement, redundancy or any other reason at the discretion of the Board, then Options may be exercised on termination of employment provided that the number of Options that may be exercised shall be reduced to reflect the reduced service period, and the extent to which any performance condition has been or is likely to be met.

(i) *Corporate events*

All Options shall automatically vest in full in connection with the following corporate events, provided the applicable performance conditions are met at that time:

(i) a third party obtains control of the Company by way of a general offer or a compromise or arrangement which is sanctioned by the Court under section 899 of the Act (this excludes an internal reorganisation);

(ii) any person becomes entitled to acquire Ordinary Shares pursuant to the compulsory squeeze out provisions of the Act; or

(iii) the Company passes a resolution for a voluntary winding up.

In the event of a change of control of the Company, an Option holder may be permitted to exchange his Options for options over shares in the acquiring company.

(j) *Variations of share capital*

If there is a variation of the Company's share capital, the Remuneration Committee may vary the exercise price and the number of Ordinary Shares under option as it considers appropriate.

(k) *Amendments and termination*

The Remuneration Committee may amend certain terms of the Plan except that no amendment may be made which materially adversely affects Option holders without the approval of option holders holding at least 75 per cent. of the Ordinary Shares subject to the Options affected.

Certain provisions of the Plan require shareholder approval before they can be amended.

The Remuneration Committee can suspend or terminate the Plan at any time but any such termination will not affect the subsisting rights of option holders.

(l) *Awards not pensionable*

No Options or benefits under the Plan are pensionable.

16.2 ***Grant of bonus options conditional on Admission***

The Company has granted, conditional on Admission, Options to the Directors other than Mehdi Varzi and to certain contractors to the Company to reward outstanding work performed by them in the development of IOG and in respect of Admission (the "AIM Bonus Options"). These AIM Bonus Options have been granted pursuant to option agreements between the Company and each individual, all on substantially the same terms.

The AIM Bonus Options are exercisable on or after 1 January 2015 and lapse on 30 June 2015 unless the Company is in a close period (as defined in the AIM Rules) on that date, in which case the lapse date is extended to after the end of the close period.

The AIM Bonus Options also lapse if Admission does not take place for any reason within six months of the date of grant, or if the option holder ceases to be an employee, director or contractor (as the case may be) for any reason and at any time prior to Admission.

Provisions relating to tax, corporate events, and variations of capital are included in each option agreement, broadly on the terms summarised above in respect of the Plan.

As at the date of this document, AIM Bonus Options have been granted over 6,873,946 Ordinary Shares. The AIM Bonus Options granted to the Directors are set out in paragraph 9.2 of this Part V.

17. Working Capital

The Directors are of the opinion, having made due and careful enquiry that the working capital available to the Group will be sufficient for its present requirements, that is, for at least twelve months from the date of Admission.

18. United Kingdom Taxation

The following summary, which is intended as a general guide only, outlines certain aspects of current UK tax legislation, and what is understood to be the current practice of HMRC in the United Kingdom regarding the ownership and disposal of ordinary shares.

The Company is at the date of this document resident for tax purposes in the United Kingdom and the following is based on that status.

This summary is not a complete and exhaustive analysis of all the potential UK tax consequences for holders of Ordinary Shares of the Company. It addresses certain limited aspects of the UK taxation position of UK resident and domiciled Shareholders who are absolute beneficial owners of their Ordinary Shares and who hold their Ordinary Shares as an investment. This summary does not address the position of certain classes of Shareholders who (together with associates) have a 25 per cent. or greater interest in the Company, or, such as dealers in securities, market makers, brokers, intermediaries, collective investment schemes, pension funds or UK insurance companies or whose shares are held under a personal equity plan or an individual savings account or are "employment related securities" as defined in Section 421B of the Income Tax (Earnings and Pensions) Act 2003. Any person who is in any doubt as to his tax position or who is subject to taxation in a jurisdiction other than the UK should consult his professional advisers immediately as to the taxation consequences of their purchase, ownership and disposition of Ordinary Shares. This summary is based on current United Kingdom tax legislation. Shareholders should be aware that future legislative, administrative and judicial changes could affect the taxation consequences described below.

18.1 *The Company*

The profits of the Company will be subject to UK corporation tax. Income arising from overseas investments may be subject to overseas taxes, subject to relief which may be available under any relevant double taxation agreement with the UK or UK domestic law.

18.2 *The Shareholders*

18.2.1 *Withholding tax*

Under current UK taxation legislation, no tax will be withheld at source from dividend payments by the Company.

18.2.2 *Taxation of dividends*

(a) United Kingdom resident shareholders

Individuals

UK resident individual Shareholders who receive a dividend from the Company will generally be entitled to a tax credit, which can be set off against the individual's income tax liability on the dividend payment. The rate of tax credit on dividends paid by the company will be 10 per cent. of the total of the dividend payment and the tax credit (the "gross dividend"), or one-ninth of the dividend payment. UK resident individual Shareholders will generally be taxable on the gross dividend, which will be regarded as the top slice of the Shareholder's income. UK resident individual Shareholders who are not liable to income tax in respect of the gross dividend will generally not be entitled to reclaim any part of the tax credit. In the case of a UK resident individual Shareholder who is not liable to income tax at the higher rates (taking account of the gross dividend he or she receives), the tax credit will satisfy in full such Shareholder's liability to income tax. To the extent that a UK resident individual Shareholder's income (including the gross dividend) is subject to 40 per cent. income tax, such Shareholders will be subject to income tax on the gross dividend at the distribution income upper rate of 32.5 per cent. but will be able to set the tax credit against this liability. This results in an effective tax rate of 25 per cent. on the net dividend. To the extent that a UK resident individual Shareholder's income (including the gross dividend) is subject to 45 per cent. income tax, such Shareholders will be subject to income tax on the gross dividend at the distribution income upper rate of 37.5 per cent. on the gross dividend and an effective tax rate of approximately 31 per cent. of the net dividend.

Companies

A corporate Shareholder resident in the UK (for tax purposes) should generally not be subject to corporation tax or income tax on dividend payments received from the Company. Corporate Shareholders will not, however, be able to claim repayment of tax credits attaching to the dividend payment.

(b) Non-residents

In general, the right of non-UK resident Shareholders to reclaim tax credits attaching to dividend payments by the Company will depend upon the existence and the terms of an applicable double tax treaty between their jurisdiction of residence and the UK. In most cases, the amount of tax credit that can be claimed by non-UK resident Shareholders from HMRC will be nil. They may also be liable to tax on the dividend income under the tax law of their jurisdiction of residence. Non-UK resident Shareholders should consult their own tax advisers in respect of their liabilities on dividend payments, whether they are entitled to claim any part of the tax credit and, if so, the procedure for doing so.

18.3 ***Capital Gains Tax***

A disposal of Ordinary Shares by a Shareholder who is resident for tax purposes in the UK, will in general be subject to UK taxation on capital gains on a disposal of Ordinary Shares.

A Shareholder who is not resident in the UK for tax purposes, but who carries on a trade, profession or vocation in the UK through a permanent establishment (where the Shareholder is a company) or through a branch or agency (where the Shareholder is not a company) and has used, held or acquired the Ordinary Shares for the purposes of such trade, profession or vocation or such permanent establishment, branch or agency (as appropriate) will be subject to UK tax on capital gains on the disposal of Ordinary Shares.

In addition, any holders of Ordinary Shares who are individuals and who dispose of shares while they are temporarily non-resident may be treated as disposing of them in the tax year in which they again become resident in the UK.

For UK individuals and trustees, capital gains are chargeable at a flat rate of 18 per cent. subject to certain reliefs and exemptions. For UK corporates, indexation may apply to reduce any such gain (though indexation is no longer available to individuals and trustees).

18.4 ***Stamp duty and Stamp Duty Reserve Tax ("SDRT")***

No UK stamp duty will be payable on the issue by the Company of Ordinary Shares. Transfers of Ordinary Shares for value will generally give rise to a liability to pay UK *ad valorem* stamp duty, or stamp duty reserve tax, at the rate in each case of 50 pence per £100 of the amount or value of the consideration (rounded up in the case of stamp duty to the nearest £5).

18.5 ***Inheritance and gift taxes***

Ordinary Shares beneficially owned by an individual Shareholder will be subject to UK inheritance tax on the death of the Shareholder (even if the Shareholder is not domiciled or deemed domiciled in the UK), although the availability of exemptions and reliefs may mean that in some circumstances there is no actual tax liability. A lifetime transfer of assets to another individual or trust may also be subject to UK inheritance tax based on the loss of value to the donor, although again exemptions and reliefs may be relevant. Particular rules apply to gifts where the donor reserves or retains some benefit. Special rules also apply to close companies and to trustees of settlements who hold shares, which could bring them within the charge to UK inheritance tax.

Shareholders should consult an appropriate professional adviser if they intend to make a gift of any kind or intend to hold any Ordinary Shares through trust arrangements. They should also seek professional advice in a situation where there is a potential for a double charge to UK inheritance tax and an equivalent tax in another country.

The comments set out above are intended only as a general guide to the current tax position in the UK at the date of this document. The rates and basis of taxation can change and will be dependent on a Shareholder's personal circumstances.

Neither the Company nor its advisers warrant in any way the tax position outlined above which, in any event, is subject to changes in the relevant legislation and its interpretation and application.

19. Premises

19.1 No member of the Group owns any premises.

19.2 The Company's principal place of business is at 70 Clifton Street, London, EC2A 4HB.

20. Consents and other information

20.1 Charles Stanley has given and not withdrawn its written consent to the issue of this document with the inclusion in it of references to its name in the form and context in which they appear.

20.2 BDO LLP, have given and not withdrawn their written consent to the inclusion in this document of their reports contained in Part III of this document in the form and context in which they appear.

20.3 AGR TRACS has given and not withdrawn its written consent to the inclusion in Part IV of this document of its report, the references thereto and to its name in the form and context in which they appear.

20.4 ERC Equipoise has given and not withdrawn its written consent to the inclusion in Part IV of this document of its report, the references thereto and to its name in the form and context in which they appear.

20.5 Save as disclosed in this document, the Directors are not aware of any exceptional factors which have influenced the Group's activities. There has been no public takeover bid for the whole or any part of the share capital of the Company or any member of the Group prior to the date of this document. There are no mandatory takeover bids and/or squeeze and sell-out rules in relation to the Ordinary Shares.

20.6 There has been no significant change in the financial or trading position of the Group since 30 June 2013, the date to which the last published financial information set out in Part III of this document was prepared. In the period since that date and the date of this document, there have been no significant recent trends in production, sales and inventory and the costs and selling prices of the Group.

20.7 There are no patents or other intellectual property rights, licences or particular contracts which are of fundamental importance to the Group's business or profitability.

20.8 Except as disclosed in this document, there have been no significant authorised or contracted capital commitments of the Group at the date of publication of this document.

20.9 The total costs and expenses payable by the Company in connection with the Admission (including professional fees, commissions, the costs of printing and registrars fees) are estimated to amount to approximately £405,000 excluding VAT.

20.10 Save as disclosed in this document, the Company is not aware of any material environmental issues or risks affecting the utilisation of the Group's tangible fixed assets or its operations.

20.11 Except as stated in this paragraph and for the advisers named on pages 4 and 5 of this document and trade suppliers, no person has received, directly or indirectly, from the Company within the twelve months preceding the date of this document or has entered into any contractual arrangements to receive, directly or indirectly, from the Company on or after Admission, fees totalling £10,000 or more or securities in the Company with a value of £10,000 or more or any other benefit with a value of £10,000 or more at the date of Admission. By way of an agreement dated 9 September 2013, the Company has agreed to pay Purico Co Limited a fee of £10,000 in consideration for that company introducing a Subscriber to the Company.

20.12 Where information contained in this document has been sourced from a third party, the Company confirms that such information has been accurately reproduced and, so far as the Company is aware and is able to ascertain from the information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

20.13 Ordinary Shares are issued and allotted in registered form under the laws of England and Wales and their currency is pounds sterling. No admission to listing or trading of the Ordinary Shares is being sought on any stock exchange other than AIM.

20.14 It is expected that CREST accounts will be credited as applicable on the date of Admission. The ISIN of the Ordinary Shares is GB00BF49WF64. Share certificates (where applicable) will be despatched by first class post within 14 days of the date of Admission.

20.15 There are no arrangements in existence under which future dividends are to be waived or agreed to be waived.

20.16 Pursuant to Chapter 5 of the United Kingdom Listing Authority Disclosure and Transparency Rules (Disclosure and Transparency Rules) a person must notify the Company of the percentage of its voting rights he holds as shareholder or through his direct or indirect holding of certain financial instruments (or a combination of such holdings) if the percentage of those voting rights (a) reaches, exceeds or falls below 3 per cent., 4 per cent., 5 per cent., 6 per cent., 7 per cent., 8 per cent., 9 per cent., 10 per cent. and each 1 per cent. threshold thereafter up to 100 per cent. as a result of an acquisition or disposal of shares or such financial instruments; or (b) reaches, exceeds or falls below an applicable threshold in (a) as a result of events changing the breakdown of voting rights and on the basis of information disclosed by the Company in accordance with the Disclosure and Transparency Rules. Certain voting rights held by investment managers, unit trusts, OEICS and market makers can be disregarded except at the thresholds of 5 per cent. and 10 per cent. and above.

20.17 The Directors intend to comply with Rule 21 of the AIM Rules for Companies relating to Directors' and applicable employees' dealings in Ordinary Shares and to this end, the Company has adopted an appropriate Share Dealing Code.

21. Copies of this document

Copies of this document will be available to the public free of charge at the offices of Field Fisher Waterhouse LLP, 35 Vine Street, London EC3N 2PX during normal business hours on any weekday (other than Saturdays, Sundays and public holidays), for a period of at least one month from the date of Admission. This document will also be available for download from the Company's website at www.independentoilandgas.com.