THIS DOCUMENT AND THE ACCOMPANYING FORM OF PROXY ARE IMPORTANT AND REQUIRE YOUR IMMEDIATE ATTENTION. If you are in any doubt as to the action you should take, you are recommended to seek your own independent financial advice from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser authorised under FSMA if you are resident in the United Kingdom or, if not, from another appropriately authorised independent financial adviser.

If you have sold or otherwise transferred all of your Ordinary Shares, please forward this document, but not the accompanying personalised Form of Proxy, as soon as possible to the purchaser or transferee, or to the bank, stockbroker or other agent through whom the sale or transfer was effected, for transmission to the purchaser or transferee. If you have sold or otherwise transferred only part of your holding of Ordinary Shares, you should retain these documents and consult the bank, stockbroker or other agent through whom the sale was effected.

The distribution of this document and/or the accompanying Form of Proxy into jurisdictions other than the United Kingdom may be restricted by local law and therefore persons into whose possession this document and/or the Form of Proxy come should inform themselves about, and observe, any such restrictions. Any failure to comply with any such restrictions may constitute a violation of the securities laws of such jurisdictions.

You should read the whole of this document and all documents incorporated into it by reference in their entirety. Your attention is drawn to the letter from the Chairman which is set out in Part I of this document and which contains a recommendation from the Board that you vote in favour of the Resolution to be proposed at the General Meeting referred to below. Part II of this document entitled "Risk Factors" includes a discussion of certain risk factors which should be taken into account when considering the matters referred to in this document.

PremierOil

Premier Oil plc

(Registered in Scotland with registered number SC234781)

Proposed acquisition of the EPUK Group

Circular to Shareholders and Notice of General Meeting

A Notice of General Meeting of Premier, to be held at 157-197 Buckingham Palace Road, London, SW1W 9SP at 10.00 am on Monday 25 April 2016, is set out at the end of this document. Whether or not you intend to attend the General Meeting in person, you are asked to complete and return the enclosed Form of Proxy in accordance with the instructions printed on it as soon as possible and, in any event, so as to be received by Premier's Registrar, Capita Asset Services at PXS, 34 Beckenham Road, Beckenham, Kent BR3 4TU, by not later than 10.00 am on Thursday 21 April 2016 (or, in the case of an adjournment, not later than 48 hours before the time fixed for the holding of the adjourned meeting). Alternatively, you may appoint a proxy electronically via the internet. Instructions on how to do this can be found on the Form of Proxy. If you hold Ordinary Shares in CREST, you may appoint a proxy electronically by completing and transmitting a CREST Proxy Instruction to the Registrar, CREST participant ID number RA10, by visiting www.premier-oil-shares.com. You will be asked to enter the Investor Code shown on your proxy card and agree to certain terms and conditions. CREST Proxy Instructions must be sent as soon as possible and, in any event, so as to be received by no later than 10.00 am on Thursday 21 April 2016 (or, in the case of an adjournment, not later than 48 hours before the time fixed for the holding of the adjourned meeting). The return of the completed Form of Proxy or CREST Proxy Instruction will not prevent you from attending the General Meeting and voting in person (in substitution for your proxy vote) if you wish to do so and are so entitled.

This document is a circular relating to the Acquisition, which has been prepared in accordance with the Listing Rules and approved by the FCA.

RBC Europe Limited (trading as RBC Capital Markets) ("**RBC**"), which is authorised by the PRA and regulated in the United Kingdom by the PRA and the FCA, is acting solely for Premier and for no-one else in connection with the Acquisition and will not be responsible to any person other than Premier for providing the protections afforded to clients of RBC nor for providing advice in relation to the matters described in this document. Apart from the responsibilities and liabilities, if any, which may be imposed upon RBC by FSMA or the regulatory regime established thereunder, RBC does not accept any responsibility whatsoever or make any representation or warranty, express or implied, concerning the contents of this document, including its accuracy, completeness or verification, or concerning any other statement made or purported to be made by it, or on its behalf, in connection with Premier, and/or the Acquisition, and nothing in this document is, or shall be relied upon as, a promise or representation in this respect, whether as to the past or future. RBC accordingly disclaims, to the fullest extent permitted by law, all and any responsibility and liability whether arising in tort, contract or otherwise (save as referred to herein) which it might otherwise have in respect of this document or any such statement.

PRESENTATION OF INFORMATION

FORWARD-LOOKING STATEMENTS

Certain statements contained in this document constitute "forward-looking statements". In some cases, these forward-looking statements can be identified by the use of forward-looking terminology, including the terms "believes", "estimates", "plans", "prepares", "anticipates", "expects", "intends", "may", "will" or "should" or, in each case, their negative or other variations or comparable terminology. Shareholders should specifically consider the factors identified in this document, which could cause actual results to differ, before making any decision whether to vote in favour of the Resolution. Such forward-looking statements involve known and unknown risks, uncertainties and other factors, which may cause the actual results, performance or achievements of the Premier Group, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such forward-looking statements are based on numerous assumptions regarding the Premier Group's present and future business strategies and the environment in which the Premier Group will operate in the future. Such risks, uncertainties and other factors are set out more fully in the section entitled "Risk Factors" in Part II of this document. These forward-looking statements speak only as at the date of this document. Premier expressly disclaims any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements contained in this document to reflect any change in Premier's expectations with regard thereto or any change in events, conditions or circumstances on which any such statement is based, except as required by the FCA, the London Stock Exchange, applicable laws, the Listing Rules and the Disclosure and Transparency Rules.

PRESENTATION OF CURRENCIES

Unless otherwise indicated, all references to "£", "pounds" or "pounds sterling" are to the lawful currency of the United Kingdom and all references to "$", "US$", "US dollars" or "United States dollars" are to the lawful currency of the United States.

PRESENTATION OF RESERVES AND RESOURCES

Unless otherwise stated, statements in this document relating to the EPUK Group's reserves and resources have been prepared using the classification system set out in the Petroleum Resources Management System ("**PRMS**") published in 2007 and jointly sponsored by the Society of Petroleum Engineers ("**SPE**"), the American Association of Petroleum Geologists ("**AAPG**"), the World Petroleum Council ("**WPC**") and the Society of Petroleum Evaluation Engineers ("**SPEE**").

All references to "reserves" are to proved and probable ("**2P**") and all references to "contingent resources" are to discovered hydrocarbons that are potentially recoverable ("**2C**") but not yet considered mature enough for commercial development due to technological or business hurdles (e.g. all required internal and external approvals are not yet in place).

The accuracy of reserves estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. This document should be accepted with the understanding that reserves, resources and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material. Unless otherwise stated, all information about the EPUK Group's oil and gas reserves and resources, forward-looking production estimates and other geological information has been extracted without material adjustment from the Competent Persons' Reports in Part IV of this document.

ROUNDING

Percentages in tables have been rounded and accordingly may not add up to 100%. Certain financial data have also been rounded. As a result of this rounding, the totals of data presented in this document may vary slightly from the actual arithmetic totals of such data.

DEFINITIONS

Certain terms used in this document, including capitalised terms and certain technical terms, are defined and explained in the "Definitions" section, in Part IX of this document.

CONTENTS

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Date of this document	7 April 2016
Latest time for receipt of Forms of Proxy or CREST Proxy Instructions for the General Meeting	10.00 am on Thursday 21 April 2016
General Meeting	10.00 am on Monday 25 April 2016
Expected date of completion of the Acquisition	April 2016

Notes:

All references in this document are to London times unless otherwise stated.

Future dates are indicative only and are subject to change by the Company, in which event, details of the new times and dates will be notified to the FCA and, where appropriate, to Shareholders.

DIRECTORS, SECRETARY, REGISTERED OFFICE AND ADVISERS

Directors	Mike Welton (*Non-Executive Chairman*) Tony Durrant (*Chief Executive Officer*) Richard Rose (*Finance Director*) Robin Allan (*Director, North Sea and Exploration*) Neil Hawkings (*Director, South East Asia and Falkland Islands*) David Bamford (*Non-Executive Director*) Anne Marie Cannon (*Non-Executive Director*) Joe Darby (*Senior Independent Non-Executive Director*) Jane Hinkley (*Non-Executive Director*) David Lindsell (*Non-Executive Director*) Michel Romieu (*Non-Executive Director*)
Company Secretary	Rachel Rickard
Registered office	4th Floor Saltire Court 20 Castle Terrace Edinburgh EH1 2EN
Sponsor	RBC Europe Limited Riverbank House 2 Swan Lane London EC4R 3BF
Solicitors to the Company (as to English Law)	Slaughter and May One Bunhill Row London EC1Y 8YY
Solicitors to the Sponsor (as to English Law)	White & Case LLP 5 Old Broad Street London EC2N 1DW
Auditors and reporting accountants	Deloitte LLP 2 New Street Square London EC4A 3BZ
Reporting accountants	PricewaterhouseCoopers LLP 1 Embankment Place London WC2N 6RH
Competent Person(s)	DeGolyer and MacNaughton 5001 Spring Valley Road Suite 800 East Dallas Texas 75244 United States RISC (UK) Limited Rex House 4-12 Regent Street London SW1Y 4PE
Registrar	Capita Asset Services The Registry 34 Beckenham Road Beckenham Kent BR3 4TU

PART I—LETTER FROM THE CHAIRMAN OF PREMIER

PremierOil

(Incorporated in Scotland with registered number SC234781)

Directors	*Registered Office:*
Mike Welton (*Chairman*)	4th Floor
Tony Durrant (*Chief Executive Officer*)	Saltire Court
Richard Rose (*Finance Director*)	20 Castle Terrace
Robin Allan (*Director, North Sea and Exploration*)	Edinburgh EH1 2EN
Neil Hawkings (*Director, South East Asia and Falkland Islands*)	
David Bamford (*Non-Executive Director*)	
Anne Marie Cannon (*Non-Executive Director*)	
Joe Darby (*Senior Independent Non-Executive Director*)	
Jane Hinkley (*Non-Executive Director*)	
David Lindsell (*Non-Executive Director*)	
Michel Romieu (*Non-Executive Director*)	

7 April 2016

Dear Shareholder,

PROPOSED ACQUISITION OF EPUK GROUP

1. Introduction

On 13 January 2016, Premier announced that it had entered into a conditional agreement for the acquisition of the EPUK Group from E.ON Beteiligungen GmbH for a net consideration of $120 million plus a completion adjustment. On 1 February 2016, Premier announced that the amount of the completion adjustment had been agreed at $15 million and that the aggregate cash payment payable by Premier was therefore $135 million. The EPUK Group holds all of E.ON's UK upstream oil and gas assets which are located in the Central North Sea, West of Shetlands and the Southern Gas Basin.

Subject to the satisfaction of certain conditions, it is currently expected that the completion of the Acquisition will occur by the end of April 2016. The terms and conditions of the Acquisition are contained in the Acquisition Agreements, which are summarised in Part III of this document.

The Acquisition, because of its size in relation to the Premier Group, is a Class 1 transaction under the Listing Rules and is therefore conditional on, among other things, the approval of Shareholders.

The Acquisition is also conditional, among other things, upon the approval of the Premier Group's lending banks and US private placement noteholders and upon confirmation from the Secretary of State that the Acquisition will not result in the revocation of the EPUK Group's petroleum exploration and/or production licences or require any further change of control of the EPUK Group. The lending banks and US private placement noteholders have now provided the consents and waivers required in connection with the Acquisition and the Acquisition has also received the necessary confirmation from the Secretary of State.

A General Meeting is to be held at 10.00 am on Monday 25 April 2016 to seek approval from the Shareholders and a notice convening the General Meeting, at which the Resolution will be proposed, is set out at the end of this document.

The purpose of this document is to provide Shareholders with the background to and reasons for the Acquisition, to explain why the Directors consider it to be in the best interests of Premier and Shareholders as a whole and to recommend that Shareholders vote in favour of the Resolution.

2. Background to and reasons for the Acquisition

Premier is a full cycle exploration and production company whose focus is to invest in high quality production and development opportunities whilst maintaining exposure to upside value through selective exploration. Premier actively manages its portfolio and, when market conditions allow, looks to add high quality assets through selective acquisitions that fit within its core areas of operation and where its position is commercially advantaged.

The Directors believe that the Acquisition is an excellent opportunity to enhance the Premier Group's position in one of its core areas, the UK North Sea, and will continue its historic track record of adding long term value through acquisitions in low oil price environments.

The Directors believe that the key benefits of the Acquisition are:

- Addition of a quality asset base to the Premier Group's existing UK North Sea business;
- Potential to generate operating and cost synergies across the Premier Group's combined UK North Sea business;
- A compelling acquisition valuation that is immediately value enhancing; and
- Provision of significant financial benefits to the Premier Group within strict acquisition criteria.

Addition of a high quality asset base to the Premier Group's existing UK North Sea business

The Acquisition is a continuation of the Premier Group's strategy to focus its portfolio on its core regions, further strengthening the Premier Group's position in the UK North Sea with its associated tax synergies. The Acquisition will add approximately 75 mmboe of net reserves and an estimated 15 kboepd of net production on a full year basis to the Premier Group's UK operations, increasing the size of the UK reserves and production from 149 mmboe and approximately 17 kboepd respectively. The Acquisition also adds contingent and prospective resources which offer potential for future growth.

The Directors believe that the Acquisition will add high quality assets to the Premier Group, increasing the Premier Group's presence in the Central North Sea and establishing a presence in the Southern Gas Basin with a combination of producing and pre-development assets, and exploration acreage. Acquiring the Assets will provide the Premier Group with, amongst other things, a stake in the Elgin-Franklin asset, one of the UK's most prolific producing assets, and will enlarge the Premier Group's long-term UK portfolio with the Tolmount area development, one of the largest discoveries in the North Sea in recent years. In addition, the Acquisition will add UK gas revenues to the existing portfolio, which is helpful because the UK gas price has been historically less volatile than oil prices, rebalancing the Premier Group's commodity exposure.

Potential for significant operating and cost synergies

By combining the two UK North Sea business units, the Directors believe the Acquisition will complement the Premier Group's key strengths and will provide the potential to generate operating and cost synergies, which is highly attractive, especially in the current lower oil price environment. Following the Acquisition, the Premier Group will consolidate its interest in the Huntington field and assume the operatorship. This will allow the Premier Group the opportunity to optimise production from the field, to reduce operating costs and ultimately extract value from the asset. In addition to Huntington, the Directors believe that there will be further opportunities for operating efficiencies through augmenting the Premier Group's existing operating team and the sharing of best practices. Further savings in both operating costs and Premier Group overheads will be achieved through the removal of duplicated and overlapping activities.

Compelling acquisition valuation

The Acquisition values the Assets at approximately $1.6/boe based on 2P reserves estimated by the Competent Persons, as summarised in the table of reserves set out on page 7 and as set out in full in Part IV of this document. The Directors believe there are limited opportunities available of this scale and quality in the UK at such a compelling valuation, with Elgin-Franklin being one of the most prolific producing assets in the UK exploration and production sector. The Acquisition has a highly attractive purchase price of $120 million, compared to the net asset value of 2P reserves and the SNS infrastructure (as estimated by the Competent Persons in Part IV of this document) of approximately $494 million (pre-tax), as summarised in the table below:

	Pre-tax NPV, $mm
Central North Sea reserves (D&M CPR)	467
Southern North Sea reserves and infrastructure (RISC CPR)	27
TOTAL Asset Value	494

The Acquisition will allow Premier to create value for Shareholders through accelerating the utilisation of some of the Premier Group's existing UK tax loss position of approximately $3.5 billion.

Financial benefits to the Premier Group

The Acquisition will add both short term and long term financial benefits to the Premier Group, whilst meeting the strict financial criteria for acquisitions set by the Board to ensure that the Premier Group's financial position is appropriate. The Acquisition will add significant production and associated cash flow in 2016 and 2017, even at current oil and gas prices, aided by the valuable hedging portfolio that will be acquired with the Assets. In 2016, 33% of the estimated liquids production is hedged at $97/bbl and 32% of estimated gas production at 63p/therm. In 2017, 21% of estimated gas production is hedged at 57p/therm. At 31 December 2015, the fair values on these commodity swaps were assets of £29.7 million for the oil and £29.0 million for the gas. In the long term, the Acquisition, if Completion occurs, will continue to generate valuable production for the Premier Group with the most significant producing asset, Elgin-Franklin, having an expected remaining production life of approximately 20 years.

Based on current operator estimates, the abandonment liabilities in respect of the Assets amount to approximately $435 million. A significant proportion of these abandonment liabilities relate to long-dated assets such as Elgin-Franklin which will not be abandoned until after 2030. In respect of the other abandonment liabilities, the Premier Group has entered into an arrangement to share the abandonment cost exposure with E.ON on both the Ravenspurn North and Johnston fields with E.ON paying up to £63 million of the cost depending on final abandonment expenses incurred. Based on the Premier Group's expectation for the life of field of the Assets and after taking account of E.ON's contribution, the near-term (pre 2020) abandonment liabilities are approximately $260 million (pre-tax). In addition, the Acquisition includes approximately £250 million of historic tax paid that will be available to the Premier Group to offset against future decommissioning expenditure. The Directors believe that these arrangements significantly help to offset the abandonment liabilities in respect of the Assets.

The Acquisition meets the strict financial criteria set by the Board: the consideration payable will be financed from existing cash resources and has an expected payback period of around two years. If completed, the Acquisition is expected to be materially accretive to the Company's main financial leverage covenants in its debt arrangements. However, as is set out in more detail elsewhere in this document, the completion of the Acquisition is unlikely, in itself, to fully mitigate the anticipated shortfall under the financial leverage covenant in respect of the testing periods ending on 30 June 2016 and 31 December 2016 and under the interest cover covenant in respect of the testing period ending on 31 December 2016. Your attention is drawn to the qualified working capital statement set out in Part VII of this document.

For the reasons set out above, the Directors believe that the Acquisition will bring significant financial benefits to the Premier Group in both the short and longer term.

3. Information on the Assets

The Assets to be acquired by the Premier Group include production assets, pre-development assets and infrastructure in the Central North Sea and Southern North Sea, plus exploration acreage in both these areas and also in the West of Shetlands.

The production Assets comprise:

- a 5.2% interest in the unitised Elgin-Franklin area (including the Elgin, Franklin and West Franklin gas condensate fields), along with an 18.57% interest in the Glenelg[1] gas condensate field;
- a 25% operated interest in the Huntington oil field, which rises to 38.5% post the default of Noreco Oil (UK) Limited and Iona Energy Inc. in respect of their equity in the field;

1 The only producing well of the Glenelg field is currently shut-in and waiting on a workover to reinstate production

- a 47% operated interest in the Babbage gas field;
- operated interests in the Johnston (50.1%), Rita[2] (74%) and Hunter (79%) gas fields;
- interests in the Scoter (12%) and Merganser (7.9%) gas condensate fields; and
- interests in the Orca (23.4685%), Caister[3] (40%) and Ravenspurn North (28.745%) gas fields,

together with associated property interests including pipelines, processing, and storage and office facilities.

The pre-development Assets comprise:

- a 50% operated interest in the Tolmount gas discovery; and
- interests in the Arran (5.12%) and Austen (25%) discoveries.

Other Assets comprise:

- interests in a further 16 exploration licences in the UK (3 West of Shetland, 7 Central North Sea, 6 Southern North Sea), 13 of which are operated; plus a further 1 in the process of being awarded;
- a 20% interest in the CMS infrastructure;
- a 30% interest in the ETS pipeline; and
- a 42.7% interest in the Minke field, which ceased production in 2011.

The Acquisition offers the Premier Group:

- estimated net working interest production of approximately 15 kboepd on an annualised basis;
- approximately 75 mmboe of net working interest 2P reserves; and
- contingent and prospective resources both within the field licences and additional licences which offer potential for future growth.

Set out in the table below are the EPUK Group's reserves as at 1 January 2015, the effective date of the transaction. The figures have been extracted without material adjustment from the Competent Persons' Reports and are presented in accordance with PRMS. The Competent Persons have used consistent assumptions in their base case assessment of reserves and valuations. However, due to the nature of the assets being evaluated, different sensitivities have been provided. The details of the sensitivities provided and the related reserves and values are set out in the Competent Persons' Reports which are set out in full in Part IV of this document.

	Proven and probable 2P reserves
	(mmboe)
Central North Sea (D&M CPR)	39
Southern North Sea (RISC CPR)	36
TOTAL	**75**

The Competent Persons' have also included an estimate of the EPUK Group's reserves and resources as at 31 December 2015 of 70 mmboe.

The Elgin-Franklin area, which is operated by TOTAL, is a mid-life asset with very low operating costs of less than $8/boe in 2016. The gas condensate fields are currently producing approximately 110 kboepd and are expected to maintain high production rates for the next three years as new wells are drilled on the fields. It is a long-term asset which is expected to keep producing for approximately another twenty years.

The Huntington oil field is a Central North Sea asset familiar to the Premier Group, as it has held the largest equity stake since the OilExco Acquisition in 2009. It currently produces approximately 13 kboepd with reserves of approximately 10mmboe as at 1 January 2015. As a result of the Acquisition, the Premier Group will assume operatorship which will put it in a much stronger position to optimise future value from the field by reducing operating costs and enhancing future production.

The Babbage field, where the Premier Group will assume operatorship, is a dry gas field which currently produces from 5 wells with infill production well and near-field exploration opportunities. This field, along

[2] Rita's production was shut-in from late 2015. Investigations are underway as to cause and possible remedy to the well failure

[3] Production on Caister ceased in late 2015, with no further planned development activity

with the other assets in the Southern North Sea, offers diversification of the Premier Group's UK portfolio through incremental gas production. Further gas production will also be added from the interests to be acquired in the Scoter and Merganser gas condensate fields in the Central North Sea, in addition to the Elgin-Franklin area production.

The Tolmount discovery is one of the largest discoveries in the Southern Gas Basin in recent years with estimated gross resources of 145 Bcf–830 Bcf. It represents significant future value as development options are matured with a project sanction decision expected to be made in the near future. Gross peak production is estimated at 100–200 mmscfd. RISC (UK) Ltd has classified the Tolmount volumes as reserves rather than contingent resources as an economic development has been found and the field is progressing towards development. In addition to the current base development, there is significant growth potential in the surrounding area and through access to third party business.

Development studies are underway at the Arran and Austen discoveries and there are further discovered resources in the portfolio along with strategic exploration licences with the potential to extend the life of existing producing assets.

4. Principal terms and conditions of the Acquisition

The Purchaser and Premier have entered into the Sale and Purchase Agreement with the Seller and E.ON in relation to the EPUK Group. The parties have also entered into the Additional Restructuring Indemnity Deed.

The consideration payable by the Purchaser for the EPUK Group is calculated using a locked box mechanism, based on the balance sheet of the EPUK Group as at 31 December 2014. The consideration constitutes a base purchase price of $120 million (as at 1 January 2015), plus a completion adjustment of $15 million, giving a total consideration of $135 million. Additional adjustments to the consideration are described in Part III of this document.

The Purchaser has paid a deposit of $1.3 million to the Seller, which the Seller is entitled to keep for its own benefit if the Sale and Purchase Agreement is terminated in certain circumstances.

The Acquisition is subject to the satisfaction (or waiver, where applicable) of certain conditions, which include the approval of the Resolution by Shareholders at the General Meeting, the EPUK Group paying dividends or distributions to the Seller prior to Completion in an amount equal to £145,188,608.20, the Premier Group's lending banks and US private placement noteholders providing required consents and waivers in respect of the Acquisition, and obtaining confirmation from the Secretary of State that the Acquisition will not result in the revocation of the EPUK Group's petroleum exploration and/or production licences or require any further change of control of the EPUK Group. As at the date of this document two of these conditions have already been satisfied, as the Premier Group's lending banks and US private placement noteholders have now provided the consents and waivers required in connection with the Acquisition and the Acquisition has also received the necessary confirmation from the Secretary of State. The Acquisition is also subject to the Purchaser's compliance with its obligations in respect of Completion (which includes delivery of certain guarantees and letters of credit).

Under the Acquisition Agreements, the Seller and the Purchaser have each given customary representations, warranties, covenants and indemnities to the other, including undertakings regarding achieving satisfaction of the conditions as well as regarding the conduct of the business of the EPUK Group pending Completion. The Seller and the Purchaser have also agreed arrangements for the provision of security by the Purchaser for decommissioning liabilities and for the sharing of certain decommissioning costs.

Further details of the Acquisition Agreements are set out in Part III of this document.

5. Financing of the Acquisition

The consideration for the Acquisition will be satisfied through the Premier Group's existing cash balances and is not conditional on the Premier Group obtaining new funds to finance the Acquisition.

6. Financial effects of the Acquisition

For the year ended 31 December 2015, the EPUK Group generated a loss after tax of £115.4 million, EBITDAX of £96.4 million, and had gross assets of £537.4 million. The financial information is extracted without material adjustment from Part V of this document which also sets out further information on EPUK.

Given the cash generative nature of the Assets, the Acquisition is expected to be immediately earnings enhancing for Premier and allows the Premier Group to accelerate the utilisation of its existing UK tax loss position.

As at 31 December 2015, the EPUK Group had net assets of £143.4 million. Transaction costs are anticipated to be approximately £3.3 million and will be expensed in Premier's income statement in the year ending 31 December 2016. An unaudited pro forma statement of net assets illustrating the effect of the Acquisition on the Premier Group's net assets as at 31 December 2015, as if it had been undertaken at that date, is set out in Part VI of this document. This information is unaudited and has been prepared for illustrative purposes only. It shows that the impact of the Acquisition would have led to a pro forma decrease in net assets of $4.9 million as at 31 December 2015.

Shareholders should read the whole of this document and not just rely on the summarised financial information contained in this letter.

7. Current trading and prospects

Premier

Premier issued its Full Year Results Statement on 25 February 2016. The performance of Premier was described in the Chief Executive Officer's statement as follows:

> *"Despite the significant reduction in oil and gas prices, reflected in our results today, 2015 was a year in which we exceeded production guidance, added to reserves, achieved notable exploration success and reached agreement on a value-adding acquisition. We also reduced operating costs by over 25 per cent, significantly cut back on current and future development spend and disposed of negative cash flow assets.*
>
> *Our forward plan includes further actions to reduce debt, positioning ourselves for a prolonged period of lower oil prices, whilst continuing to take actions to build longer-term value for a recovering commodity environment."*

There has been no material change in the Board's assessment of the matters described above since 25 February 2016.

EPUK

Production from the Assets since the beginning of 2016 has averaged 17.2 kboepd ahead of the operator's budget and 15% ahead of 2015 production of 15.0 kboepd, with all three main producing assets contributing to the outperformance. Production from Elgin-Franklin has been particularly strong at 5.3 kboepd (net), 14% ahead of 2015, largely due to the performance of the West Franklin development wells, the latest of which was brought on stream in August 2015. Ongoing development drilling will continue at Elgin-Franklin, with seven new wells expected on line in the next 3 years at a cost to Premier of approximately £50 million. Production is expected to remain at current levels through to 2019. The other main producing assets, Huntington and the Babbage area, are both ahead of E.ON's budget and are performing in line with 2015 production levels at 5.2 kboepd (net) and 3.4 kboepd (net) respectively, despite an anticipated decline.

8. Working capital

Your attention is drawn to the qualified working capital statement set out in Part VII of this document.

9. Risk Factors

Shareholders should consider fully and carefully the risk factors associated with the Acquisition and the operations of the Enlarged Group. Your attention is drawn to the risk factors set out in Part II of this document.

10. General meeting

In accordance with the Listing Rules, the Acquisition is conditional upon, among other things, the approval of Shareholders at the General Meeting. Set out at the end of this document is a Notice convening the General Meeting. The General Meeting will be held at 157-197 Buckingham Palace Road, London, SW1W 9SP at 10.00 am on Monday 25 April 2016. The Resolution for Shareholders to approve the Acquisition will be proposed as an ordinary resolution requiring a simple majority of votes in favour to be passed. The Acquisition will not proceed if the Resolution is not passed.

The Board considers it to be in the best interests of Premier and its Shareholders for completion of the Acquisition to occur as soon as possible. For this reason, the General Meeting is to be convened in accordance with the applicable statutory notice period rather than the 14 working days under the UK Corporate Governance Code.

11. Action to be taken

You will find enclosed with this document the Form of Proxy for use at the General Meeting or at any adjournment thereof. You are requested to complete and sign the Form of Proxy in accordance with the instructions printed on it and return it as soon as possible to, but in any event so as to be received no later than 10.00 am on Thursday 21 April 2016 by the Registrar, Capita Asset Services at PXS, 34 Beckenham Road, Beckenham, Kent BR3 4TU or electronically via the internet. Instructions on how to do this can be found on the Form of Proxy. You may also deliver the Form of Proxy by hand to Capita Asset Services, The Registry, 34 Beckenham Road, Beckenham, Kent BR3 4TU during usual business hours. CREST members may also choose to use the CREST electronic proxy appointment service in accordance with the procedures set out in the notice convening the General Meeting at the end of this document. The lodging of the Form of Proxy (or the electronic appointment of a proxy) will not preclude you from attending and voting at the General Meeting in person if you so wish.

12. Further information

You should read the whole of this document in respect of the Acquisition and the information incorporated by reference into it and not just rely on the summarised information contained in Part I of this document. In particular, your attention is drawn to the risk factors set out in Part II of this document, the information set out in Part III of this document, and the information incorporated by reference into this document as listed in Part VIII.

13. Recommendation

The Board considers the Acquisition to be in the best interests of Premier and its Shareholders as a whole. Accordingly, the Board recommends that Shareholders vote in favour of the Resolution, as the Directors intend to do in respect of their own beneficial holdings which, as at 6 April 2016 (being the latest practicable date prior to publication of this document), amount to 2,400,671 Ordinary Shares in aggregate, representing approximately 0.47% of Premier's existing issued share capital.

Yours faithfully,

Mike Welton
Chairman

PART II—RISK FACTORS

Shareholders should be aware that a shareholding in Premier involves a degree of risk. In addition to the other information contained in, or incorporated by reference into this document, the following risk factors should be considered carefully in evaluating whether to vote in favour of the Resolution.

The risk factors in this document set out the necessary disclosure in accordance with the Listing Rules, and do not seek to cover all of the material risks which generally affect the Premier Group.

The risks and uncertainties described below represent those known to the Board as at the date of this document which the Board consider to be material risks relating to the Acquisition, in addition to material risks relating to the Enlarged Group which result from or are impacted by the Acquisition. However, these risks and uncertainties are not the only ones facing the Premier Group, the EPUK Group or, following Completion, the Enlarged Group. Additional risks and uncertainties that do not currently exist or that are not currently known to the Board, or that the Board currently consider to be immaterial, could also have a material adverse effect on the business, results of operations, financial condition or prospects of the Premier Group, the EPUK Group or, following Completion, the Enlarged Group.

If any or a combination of the events described below actually occurs, the business, results of operations, financial conditions or prospects of the Premier Group, the EPUK Group or, following Completion, the Enlarged Group could be materially and adversely impacted. In such case, the market price of Premier shares could decline and investors may lose all or part of their investment.

Shareholders should read this document as a whole and not rely solely on the information set out in this section.

1. Risk factors relating to the Acquisition

The Acquisition does not proceed

The Acquisition is subject to the satisfaction (or waiver, where applicable) of certain conditions, which include the approval of the Resolution by Shareholders at the General Meeting, the EPUK Group paying dividends or distributions to the Seller prior to Completion in an amount equal to £145,188,608.20, the Premier Group's lending banks and US private placement noteholders providing consents and waivers required in connection with the Acquisition under the terms of its credit facilities agreements and note arrangements, and obtaining confirmation from the Secretary of State that the Acquisition will not result in the revocation of the EPUK Group's petroleum exploration and/or production licences or require any further change of control of the EPUK Group. The Acquisition is also subject to the Purchaser's compliance with its obligations in respect of Completion (which includes delivery of certain guarantees and letters of credit). As at the date of this document two of these conditions have already been satisfied, as the Premier Group's lending banks and US private placement noteholders have now provided the consents and waivers required in connection with the Acquisition and the Acquisition has also received the necessary confirmation from the Secretary of State. Further detail on the conditions to the Acquisition are summarised in Part III of this document.

There is no guarantee that the remaining conditions will be satisfied (or waived, if applicable), in which case the Acquisition will not proceed to Completion. If the Shareholders do not approve the Acquisition at the General Meeting, the Acquisition will not complete. If the Acquisition does not proceed to Completion, the benefits of the Acquisition, identified in the Chairman's Letter in Part I of this document, will not materialise and, in certain circumstances, the Seller would be entitled to retain the Deposit.

Indemnities, warranties and parent company guarantee under the Acquisition Agreements

The Sale and Purchase Agreement contains certain indemnities and warranties given by the Purchaser in favour of the Seller and the Seller Group. In particular, the Sale and Purchase Agreement requires the Purchaser to provide an indemnity in respect of the Seller's continued provision of security in favour of the EPUK Group from Completion, an indemnity in respect of decommissioning liabilities and various letters of credit and guarantees. The Sale and Purchase Agreement also requires Premier to guarantee the Purchaser's payment obligations under certain Acquisition Agreements. Further details of the Acquisition Agreements are set out in Part III of this document. If the Purchaser or Premier is required to make payments under any of the provisions described above this could have an adverse effect on the Enlarged Group's cash flow and financial condition.

The Premier Group may be subject to unforeseen liabilities and risks arising from the Acquisition

Whilst the Premier Group has access to certain information on the Assets as a result of its existing interests in Huntington and has reviewed information disclosed by the Seller during the sale process there can be no assurance that the Assets are not subject to third party rights and liabilities (including, among others, fixed or floating charges, hire purchase agreements and retention of title claims) of which the Premier Group is unaware. Whilst some warranty and other protection is provided for by the Seller under the Acquisition Agreements, these warranties and protections are subject to financial and other customary limitations and there is no certainty that the Purchaser would be able to enforce its contractual or other rights against the Seller or recover the full amount of any losses suffered by the Premier Group. Further details of the Acquisition Agreements are set out in Part III of this document.

Premier may fail to realise the anticipated financial benefits from the Acquisition

There is no assurance that the Acquisition will achieve the financial benefits that Premier anticipates. Premier believes that the consideration for the Acquisition is justified in part by the financial benefits it expects to achieve by acquiring the Assets. However, these expected financial benefits may not develop and other assumptions upon which Premier determined the consideration may prove to be incorrect. To the extent that Premier achieves lower financial benefits than expected, its and the Enlarged Group's results of operations, financial condition and the price of the Ordinary Shares may suffer.

The Premier Group's success will be dependent upon its ability to integrate the Assets

The Premier Group may encounter numerous integration challenges in connection with the Acquisition, including challenges which are not currently foreseeable. In addition, the Premier Group's management and resources may be diverted away from its core business activities due to personnel being required to assist in the integration process. This integration process may take longer than expected, or difficulties relating to the integration, of which the Board is not yet aware, may arise including unforeseen operating difficulties and pose management, administrative and financial challenges. In addition, unanticipated costs may be incurred in respect of the Acquisition and the integration of the Assets. This could adversely affect the implementation of the Premier Group's plans, and the Premier Group may not be successful in addressing risks or problems encountered in connection with the integration and failure to do so may adversely affect its business or financial condition. See further detail below.

2. Risk factors relating to the Enlarged Group

Elgin-Franklin area—exposure to HPHT operations and minority equity

Ownership of the Elgin-Franklin area Assets will expose the Premier Group to producing high pressure, high temperature ("**HPHT**") operations which, compared to "normal" oil and gas operations, have a more onerous design specification and greater operational complexity, leading to higher risk levels. In the event of a hydrocarbon release, HPHT fields also give rise to more significant potential consequences due to both fluid composition and characteristics (large surface volumes and dense gas).

In March 2012, there was a well failure and gas leak at surface from the Elgin platform. The risks associated with potential future gas leaks are well characterised by the operator and are the subject of active management programmes. There is an extensive ongoing workplan to address the abandonment of older wells, and the re-design of newer wells to mitigate the risk. There is also ongoing study work to understand the potential for any further measures that may be required to prevent future leaks. It is anticipated that any similar events would be covered by insurance for the cost impact, but there could still be reputational and cash flow consequences for the Premier Group.

The equity level in the unitised Elgin-Franklin area (5.2%) means that the Premier Group will not have a controlling vote and can therefore be voted in on projects relating to the fields that it may prefer not to carry out. There are consequently risks on the future cost levels associated with the field.

UK gas trading markets

Prior to the Acquisition, the Premier Group has limited gas volumes associated with production operations in the UK. The acquired Assets will provide a significant volume of gas production which requires specialist provisions for trading and operations. The Acquisition also exposes the Premier Group to the risks associated with different market drivers from its current business, for example, seasonal swings in prices and European imports and exports, which could impact the revenue generated by the Assets.

Infrastructure and pipeline ownership

The Southern Gas Basin is a new area for the Premier Group to participate in and the Assets to be acquired include equity in infrastructure and pipelines which are used to transport hydrocarbons for third parties (CMS and ETS). Although the Premier Group will not be operator of these Assets, it will be exposed to the obligations to maintain integrity of the systems, and fulfil the service provisions to the relevant third parties.

There is also an ownership position in infrastructure and pipelines in the Elgin-Franklin area, which are currently used to service both equity and some third party hydrocarbons.

Decommissioning

The Assets to be acquired include a number of fields which are expected to cease production in the medium-term. The detailed plans in relation to the decommissioning of each individual asset will be agreed with the relevant authorities and stakeholders at the time of decommissioning. This is a relatively new area, with a limited number of these projects having been undertaken to date. The risk associated with these projects relates to uncertainty in areas that impact the project costs, namely: stakeholder requirements; specific conditions related to individual assets; costs for major contracts; and rig and vessel rates.

Premier Group functional oversight, assurance and support for production, development and exploration operations and project delivery across the Premier Group

The integration of acquired Assets and associated personnel into the Premier Group management structure will be facilitated by a number of work stream teams, each headed by a functional lead either based in Premier's London office or in its Aberdeen office. The London-based group functional managers' primary role is to provide oversight, technical assurance and support for the range of the Premier Group's current operated production assets and exploration/development projects world-wide. This portfolio includes *inter alia* production asset management in the UKCS (see below), Indonesia (Anoa, Gajah Baru, Naga, Pelikan) and Vietnam (Chim Sao); the Solan and Catcher development projects on the UKCS; the Sea Lion development project in the North Falklands Basin; development projects in Indonesia and Vietnam; and exploration activity in Brazil and Mexico. There is a risk that the additional workload on those group functional managers associated with the integration work streams impacts adversely on their ability to deliver assurance and support for the Premier Group's existing portfolio of activity, resulting in poor operational decisions, sub-optimal production performance (therefore impaired cash flow) and project delivery cost and schedule overruns.

The Premier Group's current production, development and project activity on the UK Continental Shelf

It is currently envisaged that the Premier Group's UK business unit based in Aberdeen will play a major role in the integration of the Assets post-Completion and, thereafter, the associated new Asset management. This business unit currently manages the operated B-block production Assets (Balmoral, Brenda, Nicol and Stirling) and the non-operated Kyle, Huntington and Nelson production assets in the Central North Sea ("**CNS**"), and Wytch Farm (non-operated) in Dorset. The business unit also oversees the management of two significant development projects in the execution phase—Solan (West of Shetland, where first oil is imminent) and Catcher (CNS), and will be managing a number of additional offshore UKCS drilling commitments in 2016. The additional workload which would be placed on this business unit in connection with the integration and management of the Assets presents a risk that its management of the existing UKCS production asset and project portfolio may be adversely affected. This could, among other things, have an adverse impact on production delivery, HSE performance, project delivery or the management of relations with counterparties.

Organisational capability and competency management

There is a risk that the capability of the Premier Group organisation is not adequate to deliver plans for strategic growth, including the integration, effective deployment and retention of personnel associated with the Assets. The capability of the organisation is a function of the quality of its leadership, the competencies of its human resources and the application of its business management systems. Inadequate systems or lack of compliance may lead to loss of value and failure to achieve business objectives. Loss of personnel to competitors, inability to attract and retain quality human resources, and key competency gaps could affect operational performance and delivery of growth strategy. Failure to successfully manage the Enlarged Group's expected growth and development could adversely affect the Enlarged Group.

Fiscal risk

There is a risk that UK tax law may change in the future which could restrict the Premier Group's ability to maximise use of its tax losses.

Hydrocarbon price volatility

Hydrocarbon prices are subject to large fluctuations in response to a variety of factors beyond the Premier Group's control. Price fluctuations can affect the Premier Group's business assumptions, investment decisions and financial position. In particular, an extended period of the current low hydrocarbon price regime may reduce the economic viability of the Premier Group's projects, would result in a reduction in revenues or net income, impair the Premier Group's ability to make planned expenditures and could materially adversely affect the Premier Group's ability to integrate the Assets and associated personnel post-Completion.

The Premier Group mitigates against this risk by maintaining oil and gas price hedging in the derivatives market to underpin its financial strength and protect its capacity to fund its future developments and operations. The Acquisition would add materially to the protection offered by such hedging. The Premier Group uses a set of internal investment criteria to ensure that exploration and appraisal opportunities, development and operations projects, and acquisition and divestment proposals can be tested and are robust to downside price sensitivity scenarios.

Exchange rate fluctuations and devaluations could have a material adverse effect on the Enlarged Group's results of operations

Currency exchange rate fluctuations and currency devaluations could have a material adverse effect on the Enlarged Group's results of UKCS operations from time to time. As the Enlarged Group's reporting currency is the US dollar but it predominantly incurs UKCS operating expenses in pounds sterling, a depreciation of the US dollar against pounds sterling adversely affects the Enlarged Group's reported results of UKCS operations.

Estimation of reserves, resources and production profiles

The estimation of oil and gas reserves, and their anticipated production profiles involves subjective judgments and determinations based on available geological, technical, contractual and economic information. They are not exact determinations. In addition, these judgments may change based on new information from production or drilling activities or changes in economic factors, as well as from developments such as acquisitions and disposals, new discoveries and extensions of existing fields and the application of improved recovery techniques. Published reserve estimates are also subject to correction for errors in the application of published rules and guidance. There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom including many factors that will be beyond the control of the Enlarged Group.

The reserves, resources and production profile data contained in this document are estimates only and should not be construed as representing exact quantities. They are based on production data, prices, costs, ownership, geophysical, geological and engineering data, and other information assembled by the Premier Group. The estimates may prove to be incorrect and potential investors should not place undue reliance on the forward-looking statements contained in this document concerning the Premier Group's reserves and resources or production levels or those of the Assets.

If the assumptions upon which the estimates of the Premier Group's hydrocarbon reserves, resources or production profiles and those of the Assets have been based prove to be incorrect, the Premier Group may be unable to recover and produce the estimated levels or quality of hydrocarbons set out in this document and the Premier Group's business, prospects, financial condition or results of operations could be materially adversely affected.

Production and development delivery

The delivery of the Premier Group's production plans depends on the successful continuation of existing field production operations and the development of key projects. Both of these involve risks normally incidental to such activities including blowouts, oil spills, explosions, fires, equipment damage or failure, natural disasters, availability of technology and engineering capacity, availability of skilled resources, maintaining project schedules and managing costs, as well as technical, fiscal, regulatory, political and other conditions. Such potential obstacles may impair the Premier Group's continuation of existing field production and delivery of key projects and, in turn, adversely affect the Premier Group's operational performance and financial position (including the financial impact from failure to fulfil contractual commitments related to project delivery).

The Premier Group may face interruptions or delays in the availability of infrastructure, including rigs, FPSOs, and pipelines, on which exploration and production activities are dependent. The production performance of the reservoirs and wells may also be different from that forecast due to normal geological or mechanical uncertainties. Such interruptions, delays or performance differences could result in disruptions or changes to the Premier Group's existing production and projects, lower production and increased costs, and may have an adverse effect on the Premier Group's profitability.

Joint venture partner alignment, supply chain delivery and other contractual counterparties

Operations in the oil and gas industry are sometimes conducted in a joint venture environment. A limited number of the Premier Group's major projects are operated by joint venture partners (as will be the Elgin-Franklin field) and the Premier Group's ability to influence these operating partners is sometimes limited due to the Premier Group's limited equity in such ventures. There is a risk that joint venture partners are not aligned in their objectives and drivers and this may lead to operational or production inefficiencies and/or delays, or a disruptive departure by one or more partners from the joint venture. Any mismanagement of these projects by the operator may result in increased costs to the Premier Group which could adversely affect its business, results of operations, cash flow and prospects.

The Premier Group is heavily dependent on supply chain providers to deliver services and products to time, cost and quality criteria. There is a heightened risk during any extended period of downturn in the upstream services sector (such as is currently being experienced) of supply chain counterparties' inability to deliver. This could delay, restrict or lower the profitability and viability of the Premier Group's projects and therefore have a material adverse effect on the Premier Group's business.

The Premier Group has entered into or is subject to agreements with a number of contractual counterparties in relation to the sale and supply of hydrocarbon production volumes. Therefore, the Premier Group is subject to the risk of delayed payment for delivered production volumes or counterparty default. Such delays or defaults could materially affect the Premier Group's business, results of operations and cash flows.

PART III—PRINCIPAL TERMS OF THE ACQUISITION AGREEMENTS

1. Sale and Purchase Agreement

On 31 January 2016, the Purchaser and Premier entered into an amended and restated sale and purchase agreement with the Seller and E.ON in relation to the EPUK Group (the "**Sale and Purchase Agreement**").

The assets of the EPUK Group include legal and beneficial interests in certain petroleum exploration and/or production licences, participating interests in the joint operating agreements and/or unitisation and unit operating agreements relating to such licences, and legal and beneficial interests in certain property and data relating to such licences, together with all rights, liabilities and obligations associated with such interests (the "**Licence Interests**").

SPA Conditions

Completion is conditional upon satisfaction (or waiver, as applicable) of the SPA Conditions, which include:

(A) the Secretary of State having indicated to the Purchaser (or the Premier Group) that it does not intend either to revoke any of the petroleum exploration and/or production licences held by the EPUK Group, or require a further change of control of the EPUK Group, as a result of the sale of the EPUK Group (the "**OGA Condition**");

(B) the passing of the Resolution for the purposes of the Listing Rules (the "**Shareholder Condition**");

(C) if, for any reason, the Acquisition is subsequently reclassified as a reverse takeover for Premier under the Listing Rules, the UKLA approving the associated prospectus for publication and agreeing to readmit Premier's shares to listing on Completion (the "**Reverse Condition**");

(D) the EPUK Group paying dividends or distributions to the Seller on or prior to Completion in an amount equal to £145,188,608.20 (the "**Dividend Condition**"); and

(E) the Premier Group's lending banks and US private placement noteholders providing the consents and waivers required in connection with the Acquisition under the terms of its credit facilities agreements and note agreements (the "**Lender Condition**"),

(together, the "**SPA Conditions**").

If any one or more of the SPA Conditions remains unsatisfied and has not been waived, or becomes impossible to satisfy and has not been waived by the Purchaser, by 30 June 2016 (or such later date as the parties agree in writing), then either the Seller or the Purchaser may give notice to terminate the Sale and Purchase Agreement and the Acquisition will not then proceed to Completion. As at the date of this document, the OGA Condition and the Lender Condition have already been satisfied and EPUK has paid to the Seller, on 24 February 2016, a dividend of £60 million for the year ended 31 December 2015 in partial satisfaction of the Dividend Condition.

The parties have agreed to co-operate in good faith to implement certain pre-Completion restructuring of the EPUK Group in order to create a more efficient capital structure for the EPUK Group following Completion. As part of this restructuring, it is intended that Newco will be inserted as the holding company of EPUK such that the Acquisition is implemented by way of the acquisition by the Purchaser of the entire issued share capital of Newco rather than of the entire issued share capital of EPUK.

The Seller and the Purchaser have agreed to undertake certain actions at Completion, including:

(A) entry into the Tax Deed, the Decommissioning Liability Agreement, and an indemnity in respect of the Huntington chartering arrangements, each as described below;

(B) entry into Bilateral Decommissioning Security Agreements for certain Licence Interests, as described below;

(C) the provision by Premier of acceptable security under field-wide decommissioning security agreements in relation to certain Licence Interests, as described below;

(D) the novation from E.ON to Premier of the letter of comfort provided by E.ON to EPUK in relation to the payment of a £60 million dividend to the Seller on 24 February 2016;

(E) the provision by Premier of acceptable security in favour of E.ON Global Commodities SE in respect of the liabilities of the EPUK Group under various marketing and trading agreements; and

(F) if agreed by the Seller and the Purchaser prior to Completion, entry into the transitional services agreement in respect of transitional services to be provided by the Seller.

If either the Purchaser or the Seller breaches certain of its obligations in respect of Completion, then the non-defaulting party may elect either to effect Completion so far as is practicable or to terminate the Sale and Purchase Agreement and the Acquisition will not then proceed to Completion.

Deposit

The Purchaser has paid a deposit of $1.3 million to the Seller (the "**Deposit**"). The Seller is entitled to keep the Deposit for its own benefit if the Sale and Purchase Agreement is terminated:

(A) due to a failure to satisfy the OGA Condition or the Dividend Condition, where the failure results from the Purchaser's failure to use all reasonable endeavours to satisfy the SPA Conditions, to keep the Seller reasonably informed of progress or to comply with certain of its obligations in respect of Completion;

(B) by the Seller, due to the Purchaser's failure to comply with certain of its obligations in respect of Completion;

(C) if Premier or the Directors adversely modify, amend or withdraw the recommendation to Shareholders to vote in favour of the Resolution and the Acquisition; or

(D) due to a failure to satisfy (or waive) the Lender Condition, the Reverse Condition (if applicable) or the Shareholder Condition.

If the Sale and Purchase Agreement terminates for any reason other than set out above, the Seller will repay the Deposit to the Purchaser.

Consideration and adjustments

The consideration for the acquisition of the EPUK Group provided for in the Sale and Purchase Agreement is a base purchase price (as at 1 January 2015) of $120 million, plus a completion adjustment of $15 million, giving a total consideration of $135 million (the "**Consideration**").

The parties have agreed a locked box mechanism based on the balance sheet of the EPUK Group as at 31 December 2014. At Completion, the Purchaser will pay to the Seller an amount equal to the Consideration less the Deposit, which is then adjusted in accordance with a customary locked box adjustment, the principal purpose of which is to ensure that the Consideration is adjusted downwards in the event that value is transferred from the EPUK Group to the Seller Group (other than permitted value transfers) in the period from 31 December 2014 to Completion.

The parties have agreed to cooperate in good faith to implement certain pre-Completion restructuring of the EPUK Group in order to create a more efficient capital structure for the EPUK Group following Completion.

Pre-completion covenants

The Seller has given certain customary covenants in relation to the period prior to Completion, including a covenant to carry on the EPUK Group's activities in the ordinary and usual course of business.

Warranties, indemnities and liability

Warranties

The Seller has given certain warranties relating to, among other things: its legal status; its entry into the Acquisition Agreements, and in relation to the EPUK Group, its share capital, accounts and financial condition, the petroleum exploration and/or production licences, the operation of certain licences, material contracts, related party arrangements, litigation, employees and benefit arrangements, pension schemes, tax, IP and IT systems, real property and compliance with environmental law. Some of these warranties are repeated at Completion.

The warranties given by the Seller are qualified by, among other things, matters fairly disclosed to the Purchaser, by matters contained or referred to in the Acquisition Agreements and by the actual knowledge of the Purchaser.

Each of the Purchaser, Premier and E.ON has also given certain warranties relating to its legal status, its entry into the relevant Acquisition Agreements, no litigation or other proceedings subsist or are threatened which would materially and adversely affect its ability to perform its obligations, its solvency and, in the case of the Purchaser, that it will have sufficient funds available at Completion to complete the sale and purchase of the EPUK Group.

Parent company guarantees

Pursuant to the Sale and Purchase Agreement, Premier guarantees the discharge by the Purchaser of its obligations to pay amounts due under or in connection with the Sale and Purchase Agreement, the Decommissioning Liability Agreement, the Tax Deed and any transitional services agreement.

Pursuant to the Sale and Purchase Agreement, E.ON guarantees the discharge by the Seller of its obligations to pay amounts due in respect of any claim under or in respect of the Sale and Purchase Agreement and the Tax Deed and amounts due under or in connection with the Decommissioning Liability Agreement.

Limitations on Seller's liability

The Seller has no liability under or in respect of the Sale and Purchase Agreement or the Tax Deed (except for claims in respect of the locked box adjustment ("**Locked Box Claims**")), except to the extent that such liability exceeds in aggregate $1.2 million (in which case the Seller is liable for the entire amount and not just the excess). Other than in respect of Locked Box Claims and claims relating to the termination of the EPUK Group's seismic contracts, no account is taken of claims of $0.25 million or less.

The maximum aggregate liability of the Seller in respect of the aggregate of:

(A) all claims in respect of certain warranties as to title to the EPUK Group and the Licence Interests ("**Asset Title Warranty Claims**"), the warranty as to security provided by the EPUK Group ("**Guarantee Warranty Claims**"), certain warranties in respect of the Seller's title and capacity ("**Fundamental Claims**"), and all claims in respect of the Tax Deed or in respect of the tax warranties ("**Tax Claims**"), is limited to $120 million; and

(B) all other claims under the Sale and Purchase Agreement (except Locked Box Claims) ("**General Claims**"), is limited to $36 million,

and the maximum aggregate liability of the Seller under or in relation to the Sale and Purchase Agreement and the Tax Deed (except for Locked Box Claims) is limited to $120 million.

The Seller is not liable under or in respect of the Sale and Purchase Agreement or the Tax Deed unless it receives written notice of a claim:

(A) in respect of a Locked Box Claim, within 12 months of Completion;

(B) in respect of a Fundamental Claim, Guarantee Warranty Claim or Asset Title Warranty Claim, within 18 months of Completion;

(C) in respect of a Tax Claim, within five years of the end of the last accounting period prior to Completion; and

(D) in respect of any other claim, within 12 months of Completion.

The Sale and Purchase Agreement and the other Acquisition Agreements also contain other customary exclusions and limitations of liability.

Indemnities

Under the Sale and Purchase Agreement, the Purchaser has agreed to indemnify the Seller Group in respect of certain liabilities, including:

(A) decommissioning liabilities (as further described below);

(B) losses incurred by the Seller Group from Completion in connection with its obligations and liabilities under the bareboat chartering arrangements relating to Huntington;

(C) liability under any security provided by the Seller Group which remains in force from Completion (as further described below); and

(D) the Seller Group having to repay, for whatever reason, any dividends or distributions made by the EPUK Group to the Seller in satisfaction of the Dividend Condition.

If, as at 13 April 2017, the Seller Group has not been released from the last of its obligations under the Huntington chartering arrangements, then Premier will pay to the Seller an amount equal to £2.35 million.

Provision of security

The Purchaser must use reasonable endeavours to secure the release at Completion of each member of the Seller Group from any security provided by them in respect of any contract, agreement, commitment or obligation of an EPUK Company that has been disclosed to the Purchaser. Subject to Completion occurring, the Purchaser will indemnify the Seller Group against all loss which it or any of them may incur or suffer under or in connection with any such security.

The Purchaser must use reasonable endeavours to release the guarantee provided by E.ON UK plc in respect of EPUK's leasehold interests and provide acceptable security from Premier in its place.

The Purchaser is also required to provide acceptable security from Premier at Completion in favour of E.ON Global Commodities SE, in respect of the liabilities of the EPUK Group under various marketing and trading agreements.

Decommissioning liability and security

Pursuant to the Sale and Purchase Agreement, the Seller and the Purchaser have agreed to enter into customary bilateral decommissioning security agreements (each a "**Bilateral Decommissioning Security Agreement**") at Completion with respect to each Licence Interest which does not have, at Completion, a field-wide decommissioning security agreement in place (which, as at the date of this document, means Elgin-Franklin, Scoter, Ravenspurn North, Merganser, Johnston, Glenelg, Caister, Minke, GAEL Northern, GAEL Southern, SEAL, ETS and CMS). Pursuant to each Bilateral Decommissioning Security Agreement, the Purchaser gives an indemnity to the Seller in respect of decommissioning liabilities, and provides security for decommissioning costs in favour of the Seller (where required by the terms of the relevant agreement).

For those Licence Interests with a field-wide decommissioning security agreement in place at Completion (which, as at the date of this document, means Huntington, Babbage, Rita and Hunter), and pursuant to decommissioning arrangements in place at Completion for Ravenspurn North and Johnston, Premier has agreed to provide acceptable security where required by the terms of the relevant agreements.

Tax liabilities

Pursuant to the Sale and Purchase Agreement, the Seller and the Purchaser have agreed to enter into a tax deed at Completion, the main purpose of which is to provide the Purchaser with protection, in the form of an indemnity from the Seller, against non-ordinary course pre-completion tax liabilities of the EPUK Group (subject to certain customary exceptions) (the "**Tax Deed**").

The Tax Deed also provides for the Purchaser to reimburse the Seller in respect of any tax overprovisions or repayments relating to pre-Completion periods of the EPUK Companies and for the Seller to be able to direct the Purchaser to procure that the EPUK Companies claim from or surrender to members of the Seller Group any such group relief as it may direct (in each case subject to certain customary exceptions).

The Tax Deed also apportions responsibility for the conduct of third party (including tax authority) claims which could give rise to a claim by the Purchaser against the Seller under the Tax Deed, as well as apportioning responsibility for the preparation of the tax returns of the EPUK Companies for pre- and post-Completion periods and for dealing with tax authorities in relation to such periods.

Termination

The Sale and Purchase Agreement may be terminated if any of the SPA Conditions remain unsatisfied and have not been waived, or if either the Purchaser or the Seller breaches its obligations in respect of Completion, each as further described above. In the case of any such termination, the Acquisition will not proceed to Completion.

The Purchaser may also terminate the Sale and Purchase Agreement on the occurrence of a material adverse change in respect of Elgin-Franklin, which is defined as certain events that result or that a reasonable and prudent operator would expect to result in total production at Elgin-Franklin falling under a certain threshold (calculated as a 90% reduction to average daily net production (boe) during the year ended 30 December 2015).

Governing law

The Sale and Purchase Agreement is governed by English law.

2. Additional Restructuring Indemnity Deed

On 31 January 2016, the Seller and the Purchaser also entered into an additional restructuring indemnity deed, as subsequently amended and restated on 23 February 2016 (the "**Additional Restructuring Indemnity Deed**"), pursuant to which the Purchaser agreed, conditional on the Seller procuring the payment by EPUK of a £60 million pre-Completion cash dividend to the Seller (which was paid on 24 February 2016), to indemnify the Seller in respect of any tax liability of any member of the Seller Group which arises or is increased as a result of the Acquisition being carried out in accordance with the Sale and Purchase Agreement as amended and restated on 31 January 2016 (including the pre-Completion restructuring of the EPUK Group), to the extent that the amount of such tax liability exceeds the expected aggregate amount of £1.65 million (subject to certain customary exceptions).

The Additional Restructuring Indemnity Deed provides on the other hand for the Seller to pay to the Purchaser an amount equal to the value of any tax benefit to any member of the Seller Group which arises or is increased as a result of the pre-Completion restructuring of the EPUK Group.

The Additional Restructuring Indemnity Deed also contains cooperation provisions pursuant to which the Seller and the Purchaser agree to discuss in good faith the anticipated tax treatment of the pre-Completion restructuring of the EPUK Group with a view to minimising any tax liability of the Seller Group arising therefrom. The Seller also agrees to use all reasonable endeavours to fully support as favourable a tax position as is reasonably possible in relation to the taxation of the Acquisition.

3. Decommissioning Liability Agreement

The Seller and the Purchaser have agreed to enter into a decommissioning liability agreement (the "**Decommissioning Liability Agreement**") at Completion to divide between them certain decommissioning costs and expenses in respect of Johnston and Ravenspurn North (the "**Decommissioning Costs**").

Pursuant to the Decommissioning Liability Agreement:

(A) the Premier Group will be responsible for the first £40 million of the EPUK Group's interest share of the Decommissioning Costs;

(B) the next £90 million of the EPUK Group's interest share of the Decommissioning Costs (i.e., from £40,000,001 to £130 million) will be borne in the proportions 70% by the Seller and 30% by the Premier Group;

(C) the Premier Group will be responsible for the EPUK Group's further interest share of the Decommissioning Costs (i.e., in excess of £130 million); and

(D) the Premier Group will be responsible for any other losses relating to decommissioning.

The Seller and the Purchaser have also agreed to divide between them the provision of security under the relevant decommissioning security agreements in respect of the EPUK Group's interest share of the Decommissioning Costs. Where a member of the Premier Group is required to provide security in relation to such Decommissioning Costs, and the aggregate amount of such security exceeds £40 million, then the Seller shall provide an affiliate guarantee (where permitted by the relevant unitisation and unit operating agreement) or a letter of credit, each in the required form, in an amount equal to 70% of the amount by which the required security exceeds £40 million. The aggregate amount of any affiliate guarantees and letters of credit provided by the Seller shall not exceed £63 million.

The Purchaser is required to make, and to procure that each member of the Premier Group makes, all claims and elections in order to utilise any tax relief (a "**Relevant Decommissioning Relief**") that arises to any member of the Premier Group in respect of the Seller's share of any Decommissioning Costs to reduce the relevant entity's liability to tax in priority to any other available tax relief or to obtain a repayment of tax.

If and to the extent that any Relevant Decommissioning Relief is utilised by a member of the Premier Group to reduce a liability to make an actual payment of tax or results in a repayment of tax to any member of the Premier Group (or would in either case have done had the Purchaser complied with its obligations in the paragraph above), then the Purchaser is required to pay to the Seller an amount equal to the lower of the amount of the Seller's share of the relevant Decommissioning Costs and the amount of tax saved or the tax repaid (as applicable).

PART IV—COMPETENT PERSONS' REPORTS

In view of its size relative to that of Premier, the Acquisition constitutes a Class 1 transaction under the Listing Rules. Consequently, Premier is required by Listing Rule 13.4.6(1) to include an independent mineral expert's reports in this document on the Assets, along with a glossary of the technical terms used in the mineral experts' report. Premier commissioned DeGolyer and MacNaughton and RISC (UK) Limited to prepare the independent mineral experts' reports (referred to as the Competent Persons' Reports), which are set out in full below.

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

April 7, 2016

Premier Oil and Gas Services Limited
23 Lower Belgrave Street
London, SW1W 0NR
United Kingdom

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of January 1, 2015, of the extent of the proved, probable, and possible oil, condensate, and liquefied petroleum gas (LPG) and marketable gas reserves and of the value of the proved and proved-plus-probable reserves for the Elgin, Franklin, West Franklin, Glenelg, Huntington, Merganser, and Scoter fields, offshore the United Kingdom, in which Premier Oil Plc (Premier) has represented that it owns or will acquire an interest. The effective date of this report is specific to a transaction date as represented by Premier. This report was prepared in February 2016; therefore, certain events that may have occurred before the preparation of this report but after the as-of date of January 1, 2015, which might have affected the reserves, prices, costs, and values used in the estimates presented herein, were not taken into account. However, from a subsequent review of data provided by Premier from the interval between the as-of date and the preparation of this report, it appears that, other than production during the interval which reduces reserves and without consideration of reserves changes due to price variances, any other reserves revisions would not be material.

Estimates of proved, probable, and possible reserves have been prepared according to the Petroleum Resources Management System (PRMS) approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. PRMS is a referenced standard in published guidance of the United Kingdom Listing Authority. The reserves definitions are discussed in detail under the Definition of Reserves heading of this report.

This report is compliant with the Competent Persons Report requirements as published in the European Securities and Markets Authority (ESMA) update of the Committee of European Securities Regulators' recommendations for the implementation of the European Commission Regulation on Prospectuses No. 809/2004 dated March 20, 2013 (ESMA/2013/319).

Reserves estimated in this report are expressed as gross and net reserves. Gross reserves are defined as the total estimated petroleum to be produced from the fields after December 31, 2014. Net reserves are defined as that portion of the gross reserves to be produced from the fields attributable to the interests owned or to be acquired by Premier, as of January 1, 2015, and evaluated herein.

This report presents values for proved and proved-plus-probable reserves that have been estimated using prices and costs provided by Premier and are expressed in thousands of United States dollars (10^3U.S.$). All monetary values in this report are expressed in 10^3U.S.$. An explanation of the future price and cost assumptions is included under the Valuation of Reserves heading of this report.

Values for proved and proved-plus-probable reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. The future gross revenue is defined as that revenue to be realized from the sale of the net reserves plus from tariff revenue, if any. Future net revenue is defined as the future gross revenue less tariffs paid and operating expenses, abandonment and capital costs, and host country taxes. Operating expenses include field operating expenses, estimated expenses of direct supervision, and an allocation of overhead that directly relates to production activities. Host country taxes (as described herein) have been estimated based on information provided by Premier. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold. In this report, present worth values using discount rates of 8 and 10 percent are reported as totals.

Estimates of petroleum reserves and future net revenue should be regarded only as estimates that may change as additional information becomes available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

In this report, key information has been provided by Premier on the fields evaluated herein. As far as we are aware, there are no special factors that would affect the interests owned or to be acquired by Premier that would require additional information for the proper evaluation of these fields. All evaluations herein are considered in the context of current agreements and regulations and do not consider uncertainties that might be associated with political conditions.

Information used in the preparation of this report was obtained from Premier. In the preparation of this report we have relied upon information furnished by or directed to be furnished by Premier with respect to the property interests to be evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sales of production, concession expiration dates, and various other information and data that were accepted as represented. Although we have not had independent verification, the information used in this report appears reasonable. The technical staff of Premier involved with the assessment and implementation of development of Premier's petroleum assets are represented as adherent to the generally accepted practices of the petroleum industry. The staff members appear to be experienced and technically competent in their fields of expertise. No site visit to the fields evaluated herein was made by DeGolyer and MacNaughton. However, existing production data, reports from third parties, and photographic evidence of the fields were considered adequate because the fields are in an established producing venue.

Executive Summary

Premier has represented that it owns or will acquire an interest in the Elgin, Franklin, West Franklin, Glenelg, Huntington, Merganser, and Scoter fields, offshore the United Kingdom, for which reserves and revenue have been estimated herein.

The Elgin, Franklin, West Franklin, Huntington, Merganser, and Scoter fields are currently producing. The Glenelg field previously produced but is currently shut in, waiting on a workover to restore production. For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on January 1, 2015, have been considered to be valid for their stated terms, as represented by Premier.

Estimated reserves are presented in thousands of barrels (10^3bbl) for oil, condensate, and LPG, millions of cubic feet (10^6ft^3) for gas, and thousands of barrels of oil equivalent (10^3boe) for oil, condensate, LPG, and marketable gas. Marketable gas quantities were converted to barrels of oil equivalent (boe) using energy equivalencies. Marketable gas was converted to boe using a factor of 5,620 cubic feet per boe.

Estimates of the gross proved, probable, and possible oil, condensate, and LPG and marketable gas reserves for the fields evaluated in this report, as of January 1, 2015, are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

Gross Reserves								
Oil, Condensate, and LPG			Marketable Gas			Oil Equivalent		
Proved (10^3bbl)	Probable (10^3bbl)	Possible (10^3bbl)	Proved (10^6ft^3)	Probable (10^6ft^3)	Possible (10^6ft^3)	Proved (10^3boe)	Probable (10^3boe)	Possible (10^3boe)
234,182	81,673	59,670	1,306,030	463,073	300,026	466,571	164,070	113,055

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Marketable gas includes fuel gas as described herein and has been converted to oil equivalent using an energy equivalent factor of 5,620 cubic feet per boe.

Estimates of the net proved, probable, and possible oil, condensate, and LPG and marketable gas reserves attributable to the interests evaluated herein, as of January 1, 2015, for the fields evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

Net Reserves								
Oil, Condensate, and LPG			Marketable Gas			Oil Equivalent		
Proved (10^3bbl)	Probable (10^3bbl)	Possible (10^3bbl)	Proved (10^6ft^3)	Probable (10^6ft^3)	Possible (10^6ft^3)	Proved (10^3boe)	Probable (10^3boe)	Possible (10^3boe)
14,953	4,875	5,910	80,391	27,049	20,472	29,257	9,688	9,551

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Marketable gas includes fuel gas as described herein and has been converted to oil equivalent using an energy equivalent factor of 5,620 cubic feet per boe.

Estimates of future net revenue and present worth of the reserves estimated in this report were prepared using a Base Case scenario and four price sensitivities. The Base Case price is reflective of the lowest near-term price scenario. Condensate and LPG prices are 70 percent of the Brent oil price. An explanation of the Base Case and four price sensitivity assumptions is included under the Valuation of Reserves heading of this report.

Estimated future net revenue and present worth at 8 and 10 percent of the future net revenue attributable to the interests evaluated herein for the proved and proved-plus-probable reserves, as of January 1, 2015, utilizing the five economic scenarios are summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation Summary

	Proved			Proved plus Probable		
	Future Net Revenue (10^3U.S.$)	Present Worth at 8 Percent (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 8 Percent (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
Base Case	216,946	135,832	120,822	365,595	215,966	190,688
Sensitivity Case 1	251,854	165,277	149,131	409,395	252,270	225,411
Sensitivity Case 2	412,281	259,780	233,030	641,123	383,644	341,107
Sensitivity Case 3	371,944	233,957	209,631	584,252	348,555	309,577
Sensitivity Case 4	360,793	227,658	204,081	568,217	339,950	302,070

Note: Values for probable reserves and quantities have not been risk adjusted to make them comparable to values for proved reserves and quantities.

Reserves estimates herein are based on the Base Case price scenario projected to an economic limit, and quantities in the sensitivity cases are those included to the limit of projected Base Case production or when an annual economic limit is reached, whichever occurs first. Details of the annual pricing and cost assumptions are presented under the Valuation of Reserves heading of this report.

Ownership and Infrastructure

Premier has represented that it owns or will own an interest in the Elgin, Franklin, West Franklin, Glenelg, Huntington, Merganser, and Scoter fields offshore the United Kingdom, described as follows:

Field	Working Interest (percent)
Elgin	5.2000
Franklin	5.2000
West Franklin	5.2000
Glenelg	18.5700
Huntington	25.0000
Merganser	7.9185
Scoter	12.0000

These interests are held through contractual instruments that are common in the petroleum industry. We had an opportunity to review certain segments of pertinent agreements; however, we, as engineers, cannot express an opinion as to the accounting or legal aspects of those agreements.

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on January 1, 2015, have been considered to be valid for their stated terms, as represented by Premier.

The infrastructure in the area of these fields is very advanced. The offshore United Kingdom petroleum production province is an elaborate composite of platforms, pipelines, and portable structures. There are numerous established bases along the coast of the United Kingdom, and there is an extensive established network of service companies to allow developments of all types, including complex mechanical and operational elements. Power options, including electrical, gas, and diesel sources, are available to operators in this venue.

There are certain environmental considerations in any venue of petroleum production. We are not aware of any extraordinary environmental elements associated with the properties evaluated herein. As such, we have included abandonment costs, as appropriate, to accomplish routine and safe removal of subsurface and surface equipment at the offshore installation. Reclamation costs, if any, are not included in the evaluation herein, unless specifically referenced.

Definition of Reserves

Estimates of proved, probable, and possible reserves presented in this report have been prepared in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American

Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. The petroleum reserves are defined as follows:

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

> *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-percent probability that the quantities actually recovered will equal or exceed the estimate.
>
> *Unproved Reserves* – Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.
>
>> *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-percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves – Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest 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 Reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10-percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Reserves Status Categories – Reserves status categories define the development and producing status of wells and reservoirs.

Developed Reserves – Developed Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves – Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

The extent to which probable and possible reserves ultimately may be recategorized as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Estimates of probable and possible reserves in this report have not been adjusted in consideration of these additional risks to make them to comparable estimates of proved reserves.

Estimation of Reserves

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, development plans provided by Premier, and analyses of areas offsetting existing wells with test or production data, reserves were categorized as proved, probable, or possible.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trend or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production.

In certain cases, elements of the reserves estimates incorporated information based on analogy with similar wells or reservoirs for which more complete data were available.

Reserves estimates presented herein are based on data available through December 31, 2014, and are supported by details of drilling results, analyses of available geological data, well-test results, pressures, available core data, and production performance. This report takes into account all relevant information provided to us by Premier.

The oil, condensate, and LPG reserves estimated in this report are reported in 10^3bbl where 1 barrel equals 42 United States gallons. Oil, condensate, and LPG reserves are to be recovered by conventional field and plant operations.

Gas quantities included in this report are marketable gas and sales gas expressed at a pressure base of 14.7 pounds per square inch absolute (psia) and a temperature base of 60 degrees Fahrenheit (°F) and are reported in 10^6ft^3. Marketable gas reserves are defined as the total gas after reduction for shrinkage resulting from field separation, processing, including removal of nonhydrocarbon gas to meet pipeline specifications and LPG extraction, and flare and other losses but not from fuel usage. For the Huntington field, fuel gas estimates range from 2 to 6 percent of the marketable gas and is included as reserves. For all other fields, fuel gas is estimated to be 7 percent of the marketable gas and is included as reserves. The marketable gas is converted to boe using a factor of 5,620 cubic feet per boe for reporting herein. Sales gas is the quantity of gas to be delivered into a gas pipeline for sale after reduction for fuel. The fuel gas quantities included are a portion of marketable gas reserves and are as follows, expressed in millions of cubic feet (10^6ft^3):

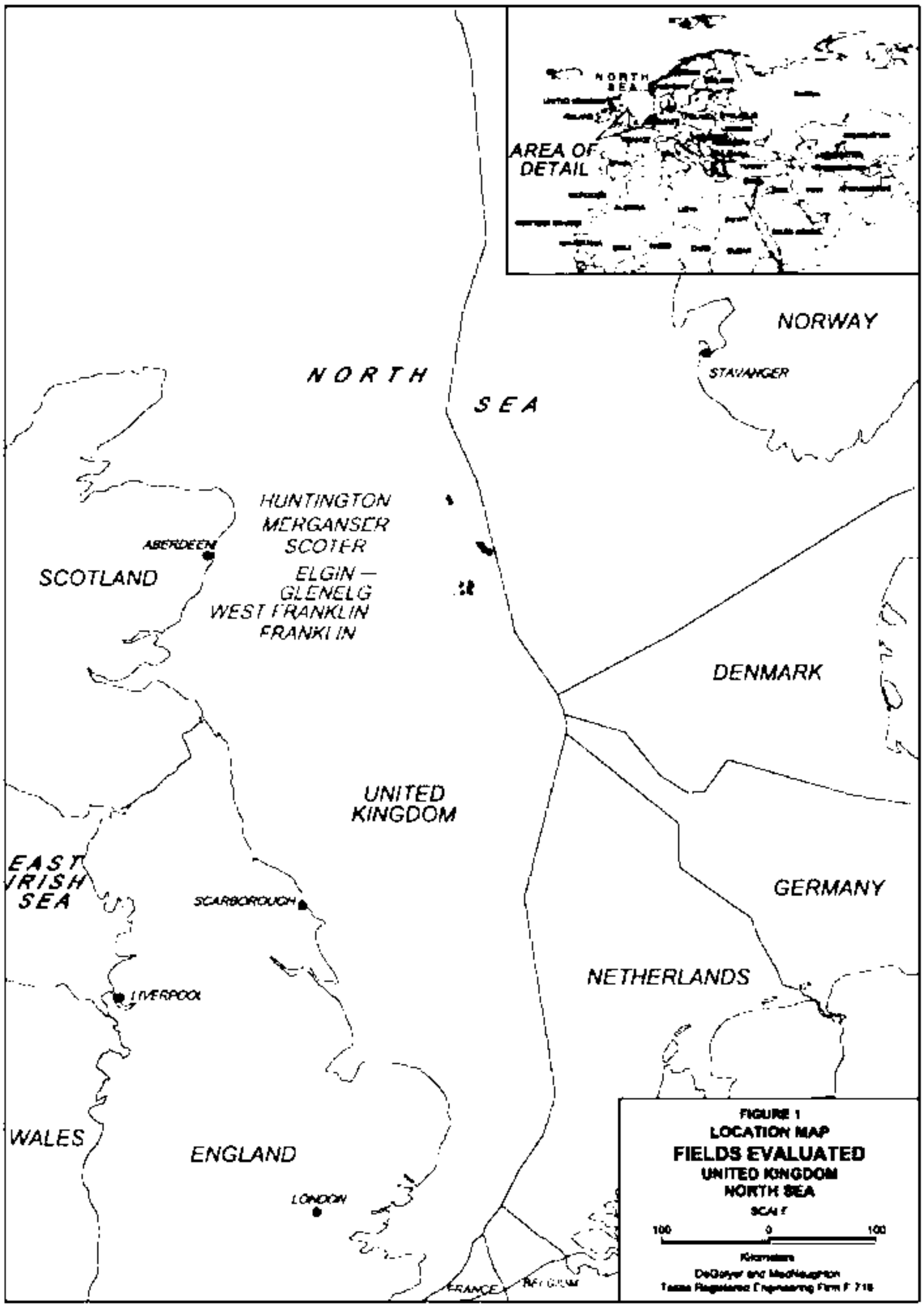
	Fuel Gas Portion of Marketable Gas Reserves	
	Gross ($10^6 ft^3$)	**Net ($10^6 ft^3$)**
Proved		
Developed	41,282	2,717
Undeveloped	51,159	3,166
Total Proved	**92,441**	**5,883**
Probable	32,349	1,875
Possible	23,193	1,983

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on January 1, 2015, are considered to be valid for their stated terms, as represented by Premier.

Methodology

There are seven fields offshore the United Kingdom evaluated in this report: Elgin, Franklin, West Franklin, Glenelg, Huntington, Merganser, and Scoter.



The reserves estimates for the fields were based on the available performance data, incorporating analogy when appropriate.

The Elgin field is located in blocks 22/30bF1, 22/30c, and 295b in the South Central Graben, approximately 240 kilometers east of Aberdeen. The field was discovered in 1991 and began producing in 2001. The Elgin structure is a complex domal shape delimited by a normal fault to the northeast and normal faults to the west and south. The main producing reservoirs are the Jurassic Fulmar sandstones at depths ranging from 5,000 to 5,600 meters subsea. The field is a high pressure, high temperature gas-condensate accumulation. Porosity ranges from 15 to 17 percent, water saturation ranges from 43 to 60 percent, and permeability ranges from 10 to 400 millidarcys.

Proved developed reserves were estimated for one producing well and one planned workover. Proved undeveloped reserves were estimated for three additional wells, with recovery and performance based on analogy to existing wells in the field. Probable and possible reserves were estimated based on better performance as compared to proved reserves, additional workovers, and two additional wells to be drilled.

The Franklin field is located in block 29/5b in the South Central Graben, approximately 240 kilometers east of Aberdeen. The field was discovered in 1986 and began producing in 2001. The Franklin structure is an elongated northwest/southeast-fault block dipping towards the southwest and bounded by a major fault to the northeast. The main producing reservoirs are the Jurassic Fulmar sandstones at depths ranging from 5,000 to 5,600 meters subsea. The field is a high pressure, high temperature gas-condensate accumulation. Porosity ranges from 15 to 17 percent, water saturation ranges from 40 to 43 percent, and permeability ranges from 25 millidarcys to 1 darcy.

Proved developed reserves were estimated for two producing wells and one planned workover. Proved undeveloped reserves were estimated for two additional wells based on analogy to other wells in the field. Probable and possible reserves were estimated based on better performance as compared to proved reserves and three additional drilled wells.

The West Franklin field is located in blocks 29/5b and 29/4d, approximately 240 kilometers east of Aberdeen. The field was discovered in 2003 and began producing in 2007 from the F7 well in the Fulmar Formation. The field is a high pressure, high temperature gas-condensate accumulation. Porosity ranges from 15 to 17 percent, water saturation ranges from 43 to 60 percent, and permeability ranges from 10 to 400 millidarcys.

Proved developed reserves were estimated for three producing wells. Proved undeveloped reserves were estimated for two additional wells to be drilled, based on analogy to the performance of other wells in the field. Probable and possible reserves were estimated based on better performance as compared to proved reserves and one additional well to be drilled.

The Glenelg field is located in blocks 29/4d and 29/5b in the central North Sea, approximately 240 kilometers east of Aberdeen. The field was discovered in 1999 and began producing in 2006 from the G10 well. The field is a high pressure, high temperature gas-condensate accumulation. Porosity ranges from 15 to 20 percent and water saturation ranges from 40 to 60 percent.

The only producing well is currently shut in, waiting on a workover. Proved undeveloped reserves were based on restoring the well to production. Probable and possible reserves were based on improved performance of that well.

The Huntington field is located in block 24/14b in the central North Sea, immediately southwest of the Everest gas-condensate field. The discovery well, 22/14b-5, was drilled in 2007 and tested the Paleocene Forties sandstone. Production in the Huntington field is from the Forties reservoir, which is a high-quality turbidite system containing stacked channel sequences deposited in a submarine fan system. The field contains a combined pinchout and stratigraphic accumulation. For the Forties reservoir, porosity ranges from 19 to 22 percent, and water saturation ranges from 45 to 59 percent.

Estimates of reserves were based on performance methods. Proved developed reserves were estimated for four producing wells. Probable and possible reserves estimates considered improved performance as compared to proved reserves.

The Merganser field is located in blocks 22/30a and 22/25a in the East Central Graben of the central North Sea. The Merganser field was discovered in 1995 by exploration well 22/30a-14 and began producing in 2006. Merganser is a salt diapir flank structure with radial faulting and is composed of a stacked sequence of the Forties, Andrew, and Maureen sandstone members with highly complex reservoir character. Porosity ranges from 11 to 19 percent and water saturation ranges from 30 to 54 percent. The field produces from the Forties and Andrew reservoirs and consists of two subsea wells tied into the Scoter pipeline.

Proved developed reserves were estimated based on performance for two producing wells. Probable and possible reserves estimates considered more efficient recovery as compared to proved reserves.

The Scoter field is located in blocks 23/26d and 22/30a in the East Central Graben of the central North Sea. The Scoter field was discovered in 1989 by the 22/30a-5 exploration well in the Forties reservoir and began producing in 2004. It is situated above a major regional northwest/southeast-trending fault zone. The Scoter field is a dome-like structure, slightly elongated in a northwest/southwest-direction. In the Forties reservoir interval, porosity ranges from 14 to 26 percent and water saturation ranges from 29 to 45 percent.

Proved developed reserves were estimated for two producing wells based on performance analysis. Probable and possible reserves estimates included better performance as compared to proved reserves.

Estimated reserves for the fields evaluated herein are presented in thousands of barrels (10^3bbl) for oil, condensate, and LPG, millions of cubic feet (10^6ft^3) for marketable gas, and thousands of barrels of oil equivalent (10^3boe) for oil, condensate, LPG, and marketable gas. Marketable gas quantities were converted to boe using energy equivalencies. Marketable gas was converted to boe using a factor of 5,620 cubic feet per boe.

Estimates of the gross proved, probable, and possible reserves for the properties evaluated in this report, as of January 1, 2015, are summarized as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3), as well as in thousands of barrels of oil equivalent (10^3boe):

	Gross Reserves								
	Oil, Condensate, and LPG			Marketable Gas			Oil Equivalent		
Field	Proved (10^3bbl)	Probable (10^3bbl)	Possible (10^3bbl)	Proved (10^6ft^3)	Probable (10^6ft^3)	Possible (10^6ft^3)	Proved (10^3boe)	Probable (10^3boe)	Possible (10^3boe)
Elgin	105,674	24,426	9,112	464,402	97,716	40,144	188,308	41,813	16,255
Franklin	55,398	22,872	5,188	363,952	150,576	34,471	120,158	49,665	11,322
West Franklin	54,817	30,144	30,362	333,541	190,577	190,221	114,166	64,054	64,209
Glenelg	8,431	3,106	2,272	53,999	19,891	19,435	18,039	6,645	5,730
Huntington	7,754	1,052	12,616	6,308	919	10,395	8,876	1,216	14,466
Merganser	735	45	66	41,436	2,531	3,697	8,108	495	721
Scoter	1,373	28	54	42,392	863	1,660	8,916	182	349
Total	**234,182**	**81,673**	**59,670**	**1,306,030**	**463,073**	**300,026**	**466,571**	**164,070**	**113,055**

Notes:

1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Marketable gas includes fuel gas as described herein and has been converted to oil equivalent using an energy equivalent factor of 5,620 cubic feet per boe.
3. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves in the calculation of boe.

Estimates of the net proved, probable, and possible reserves, as of January 1, 2015, attributable to the interests evaluated herein are listed as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

	Net Reserves					
	Oil, Condensate, and LPG			Marketable Gas		
Field	Proved (10^3bbl)	Probable (10^3bbl)	Possible (10^3bbl)	Proved (10^6ft^3)	Probable (10^6ft^3)	Possible (10^6ft^3)
Elgin	5,495	1,271	475	24,149	5,081	2,087
Franklin	2,880	1,190	270	18,925	7,830	1,793
West Franklin	2,850	1,567	1,578	17,344	9,910	9,892
Glenelg	1,566	577	422	10,028	3,694	3,609
Huntington	1,939	263	3,154	1,577	230	2,599
Merganser	58	4	5	3,281	200	293
Scoter	165	3	6	5,087	104	199
Total	**14,953**	**4,875**	**5,910**	**80,391**	**27,049**	**20,472**

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

Estimates of the net oil equivalent evaluated herein are listed as follows, expressed in thousands of barrels of oil equivalent (10^3boe):

	Net Oil Equivalent				
Field	**Proved (10^3boe)**	**Probable (10^3boe)**	**Proved plus Probable (10^3boe)**	**Possible (10^3boe)**	**Proved plus Probable plus Possible (10^3boe)**
Elgin	9,792	2,175	11,967	846	12,813
Franklin	6,247	2,583	8,830	589	9,419
West Franklin	5,936	3,330	9,266	3,338	12,604
Glenelg	3,350	1,234	4,584	1,064	5,648
Huntington	2,220	304	2,524	3,616	6,140
Merganser	642	40	682	57	739
Scoter	1,070	22	1,092	41	1,133
Total	**29,257**	**9,688**	**38,945**	**9,551**	**48,496**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves in the calculation of boe.
2. Marketable gas includes fuel gas as described herein and has been converted to oil equivalent using an energy equivalent factor of 5,620 cubic feet per boe.

Valuation of Reserves

This report has been prepared using initial prices and costs and future price and cost assumptions specified by Premier. Estimates of future net revenue and present worth of proved and proved-plus-probable reserves have been prepared in accordance with PRMS. Five economic scenario cases were evaluated, with future prices and costs as described below. Gross and net reserves estimated herein are based on the Base Case price and cost estimations. The sensitivity cases are projected to the Base Case projected limit or the economic limit, whichever occurs first. Only prices are varied in each economic scenario.

In this report, values for proved and proved-plus-probable reserves are based on projections of estimated future production and revenue prepared for these properties with no risk adjustment applied to the probable reserves. Probable reserves involve substantially higher risks than proved reserves. Revenue values for proved-plus-probable reserves have not been adjusted to account for such risks; this adjustment would be necessary in order to make the values for the probable reserves comparable with values for proved reserves.

Revenue values of the proved and proved-plus-probable reserves were established utilizing methods generally accepted by the petroleum industry. Production forecasts of the proved and proved-plus-probable reserves were based on the development plan for the fields. The future net revenue and present worth of the fields' reserves were estimated using the price and cost assumptions, monetary conversion values, and the appropriate concession terms provided by Premier.

The present worth attributable to the fields evaluated has been estimated using the Base Case assumptions and the four price sensitivity scenarios provided by Premier. The price assumptions are as follows:

Oil, Condensate, LPG, and Gas Prices

Base Case Price Assumptions

Oil, condensate, and LPG prices were based on the dated Brent oil price of U.S.$52.39 per barrel in 2015, U.S.$35.00 in 2016, U.S.$40.00 in 2017, U.S.$45.00 in 2018, U.S.$60.00 in 2019, and were escalated 2.0 percent per year each year thereafter. Condensate and LPG prices were 70 percent of the Brent price. Revenue from gas is based on sales gas quantities. Initial sales gas prices were based on current sales gas prices in the fields evaluated herein. Base Case sales gas prices were U.S.$6.60 per thousand cubic feet (10^3ft^3) in 2015, U.S.$4.95 in 2016, U.S.$5.10 in 2017, U.S.$5.25 in 2018, U.S.$5.40 in 2019, and were escalated 2.0 percent per year each year thereafter.

Price Sensitivity Case 1

Oil, condensate, and LPG prices for this low price sensitivity case were based on the dated Brent oil price of U.S.$52.39 per barrel in 2015, U.S.$50.00 in 2016, U.S.$51.00 in 2017, U.S.$52.02 in 2018, U.S.$53.06 in 2019, and were escalated 2.0 percent per year each year thereafter. Condensate and LPG prices were 70 percent of the Brent price. Revenue from gas is based on sales gas quantities. Sales gas prices were U.S.$6.60 per 10^3ft^3 in 2015, U.S.$6.10 in 2016, U.S.$6.22 in 2017, U.S.$6.35 in 2018, U.S.$6.47 in 2019, and were escalated 2.0 percent per year each year thereafter.

Price Sensitivity Case 2

Oil, condensate, and LPG prices for this highest price sensitivity case were based on the dated Brent oil price of U.S.$52.39 per barrel in 2015, U.S.$60.90 in 2016, U.S.$71.65 in 2017, U.S.$79.11 in 2018, U.S.$86.92 in 2019, and were escalated 2.0 percent per year each year thereafter. Condensate and LPG prices were 70 percent of the Brent price. Revenue from gas is based on sales gas quantities. Sales gas prices were U.S.$6.60 per 10^3ft^3 in 2015, U.S.$6.10 in 2016, U.S.$6.22 in 2017, U.S.$6.35 in 2018, U.S.$6.47 in 2019, and were escalated 2.0 percent per year each year thereafter.

Price Sensitivity Case 3

Oil, condensate, and LPG prices for this mid-range price sensitivity case were based on the dated Brent oil price of U.S.$52.39 per barrel in 2015, U.S.$55.00 in 2016, U.S.$61.50 in 2017, U.S.$68.29 in 2018, U.S.$86.15 in 2019, and were escalated 2.5 percent per year each year thereafter. Condensate and LPG prices were 70 percent of the Brent price. Revenue from gas is based on sales gas quantities. Sales gas prices were U.S.$6.60 per 10^3ft^3 in 2015, U.S.$6.00 in 2016, U.S.$6.15 in 2017, U.S.$6.30 in 2018, U.S.$6.46 in 2019, and were escalated 2.5 percent per year each year thereafter.

Price Sensitivity Case 4

Oil, condensate, and LPG prices for this mid-range price sensitivity case were based on the dated Brent oil price of U.S.$52.39 per barrel in 2015, U.S.$52.96 in 2016, U.S.$62.30 in 2017, U.S.$68.79 in 2018, U.S.$75.58 in 2019, and were escalated 2.0 percent per year each year thereafter. Condensate and LPG prices were 70 percent of the Brent price. Revenue from gas is based on sales gas quantities. Sales gas prices were U.S.$6.60 per 10^3ft^3 in 2015, U.S.$6.10 in 2016, U.S.$6.22 in 2017, U.S.$6.35 in 2018, U.S.$6.47 in 2019, and were escalated 2.0 percent per year each year thereafter.

Operating Expenses, Tariffs, Capital Costs, and Abandonment Costs

Current operating expenses and operating expense forecasts provided by Premier were used in estimating future expenses required to operate the fields for all five economic scenarios. In certain cases, future expenses, either higher or lower than current expenses, may have been used because of anticipated changed operating conditions. Pipeline and processing tariffs are paid for access to markets. The Elgin and Franklin fields receive tariff revenue from the Glenelg field for transportation and processing. Future capital expenditures and abandonment costs were estimated using current forecasts provided by Premier. No cost escalation or inflation factor per year was applied. Generally, abandonment costs were assigned the year after cessation of production, except where other anticipated abandonment dates were represented by Premier. Economic limits for each field have been estimated prior to any abandonment obligations and any host country tax.

Royalty

No royalty is applicable for these United Kingdom fields.

Exchange Rate

Where applicable, an exchange rate of U.S.$1.50 per 1.00 United Kingdom pound was used for this report.

Host Country Taxes

United Kingdom income taxes have been estimated based on data provided by Premier and were compiled at the field level for this report. In the United Kingdom, there is a 50-percent combined tax rate on income, consisting of a 30-percent ring fence corporate tax rate and a 20-percent supplemental charge. Premier's corporate tax position was not considered in this report. If taxes were considered at the corporate level, the estimate of taxes would include consideration of tax-loss carryforward balances and group relief (where available), which would potentially reduce estimated taxes below taxes estimated herein. Annual taxes are actually paid in two portions: a component in the current year and the balance in the subsequent year.

As in any evaluation, there may be risk of unexpected cost variances and timing delays or accelerations. For this evaluation, consideration has been given to these elements to the extent possible. The resulting scheduling of production and costs is represented as a reliable estimate incorporating contingencies and timing delays where reasonable.

The oil, condensate, and LPG price assumptions for each case are presented below, expressed in United States dollars per barrel (U.S.$/bbl). The gas price assumptions for each case are also presented below, expressed in United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3):

Oil Prices (U.S.$/bbl)

Year	Base Case	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 3	Sensitivity Case 4
2015	52.39	52.39	52.39	52.39	52.39
2016	35.00	50.00	60.90	55.00	52.96
2017	40.00	51.00	71.65	61.50	62.30
2018	45.00	52.02	79.11	68.29	68.79
2019	60.00	53.06	86.92	86.15	75.58
2020 Forward	+2.0% p.a.	+2.0% p.a.	+2.0% p.a.	+2.5% p.a.	+2.0% p.a.

Condensate and LPG Prices (U.S.$/bbl)

Year	Base Case	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 3	Sensitivity Case 4
2015	36.67	36.67	36.67	36.67	36.67
2016	24.50	35.00	42.63	38.50	37.07
2017	28.00	35.70	50.15	43.05	43.61
2018	31.50	36.41	55.38	47.80	48.15
2019	42.00	37.14	60.84	60.31	52.91
2020 Forward	+2.0% p.a.	+2.0% p.a.	+2.0% p.a.	+2.5% p.a.	+2.0% p.a.

Gas Prices (U.S.$/$10^3$ft^3)

Year	Base Case	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 3	Sensitivity Case 4
2015	6.60	6.60	6.60	6.60	6.60
2016	4.95	6.10	6.10	6.00	6.10
2017	5.10	6.22	6.22	6.15	6.22
2018	5.25	6.35	6.35	6.30	6.35
2019	5.40	6.47	6.47	6.46	6.47
2020 Forward	+2.0% p.a.	+2.0% p.a.	+2.0% p.a.	+2.5% p.a.	+2.0% p.a.

Note: References to "p.a." mean per annum.

Estimated Base Case future revenue and costs attributable to the interests evaluated herein for the proved and proved-plus-probable reserves, as of January 1, 2015, are summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

	Valuation of Reserves Summary Base Case	
	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)
Product Revenue	1,026,698	1,383,459
Tariff Revenue	670	670
Future Gross Revenue	1,027,368	1,384,129
Tariff Paid and Operating Expenses	271,061	289,952
Abandonment and Capital Costs	208,965	249,525
Before Tax Future Net Revenue	547,342	844,652
Before Tax Present Worth at 8 Percent	366,605	521,041
Before Tax Present Worth at 10 Percent	333,948	467,439
Host Country Taxes	330,396	479,057
Future Net Revenue	216,946	365,595
Present Worth at 8 Percent	135,832	215,966
Present Worth at 10 Percent	120,822	190,688

Note: Values for probable reserves have not been risk adjusted to make them comparable to values for proved reserves.

For the sensitivity case economic scenarios, estimates of future revenue and costs attributable to the interests evaluated herein for the proved and proved-plus-probable quantities, as of January 1, 2015, are summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

	Valuation Summary							
	Sensitivity Case 1		Sensitivity Case 2		Sensitivity Case 3		Sensitivity Case 4	
	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)
Product Revenue	1,087,967	1,471,061	1,417,378	1,934,492	1,336,695	1,820,754	1,314,387	1,788,681
Tariff Revenue	670	670	670	670	670	670	670	670
Future Gross Revenue	1,088,637	1,471,731	1,418,048	1,935,162	1,337,365	1,821,424	1,315,057	1,789,351
Tariff Paid and Operating Expenses	262,516	289,952	271,061	289,952	271,061	289,952	271,061	289,952
Abandonment and Capital Costs	208,965	249,525	208,965	249,525	208,965	249,525	208,965	249,525
Before Tax Future Net Revenue	617,156	932,254	938,022	1,395,685	857,339	1,281,947	835,031	1,249,874
Before Tax Present Worth at 8 Percent	423,304	590,966	605,361	814,022	555,616	776,433	543,480	739,853
Before Tax Present Worth at 10 Percent	387,985	533,745	548,210	754,671	503,531	691,458	492,923	680,123
Host Country Taxes	365,302	522,859	525,741	754,562	485,395	697,695	474,238	681,657
Future Net Revenue	251,854	409,395	412,281	641,123	371,944	584,252	360,793	568,217
Present Worth at 8 Percent	165,277	252,270	259,780	383,614	233,957	348,555	227,658	339,950
Present Worth at 10 Percent	149,134	225,414	233,030	341,107	209,631	309,577	204,081	302,070

Note: Values for probable quantities have not been risk adjusted to make them comparable to values for proved quantities.

For reference, the increments during the period of January 1, 2015, through December 31, 2015, of net reserves, future net revenue, and present worth of future net revenue discounted at 10 percent associated with the Base Case of the fields evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), thousands of cubic feet (10^3ft^3), and thousands of United States dollars (10^3U.S.$), respectively:

	2015 Estimates Base Case	
	Proved	Proved plus Probable
Net Oil Production, 10^3bbl	1,939	2,202
Net Condensate and LPG Production, 10^3bbl	818	819
Net Sales Gas Production, 10^6ft^3	7,424	7,662
Before Tax Future Net Revenue, 10^3U.S.$	70,373	78,187
Before Tax Present Worth at 10 Percent, 10^3U.S.$	66,706	74,106
After Tax Future Net Revenue, 10^3U.S.$	(18,022)	(12,167)
After Tax Present Worth at 10 Percent, 10^3U.S.$	(17,083)	(11,532)

Professional Qualifications

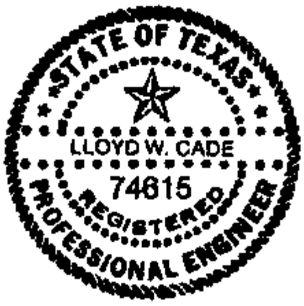
DeGolyer and MacNaughton is a Delaware Corporation with offices at 5001 Spring Valley Road, Suite 800 East, Dallas, Texas 75244, U.S.A. The firm has been providing petroleum consulting services throughout the world since 1936. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists are engaged in the independent evaluation of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry. Except for the provision of professional services on a fee basis, DeGolyer and MacNaughton has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

The evaluation has been supervised by Mr. Lloyd W. Cade, a Senior Vice President with DeGolyer and MacNaughton, in the firm's Europe Africa Division, a Registered Professional Engineer in the State of Texas, and a member of the International Society of Petroleum Engineers. He has over 33 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716



Lloyd W. Cade, P.E.

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

Private and confidential

Competent Person's Report
Valuation of Certain UK assets on behalf of Premier Oil and Gas Services Limited

Prepared by: Gavin Ward

7th April 2016

15.0092

[redacted]

Declaration

Premier Oil and Gas Services Limited ("Premier") has commissioned RISC (UK) Ltd ("RISC") to provide an independent valuation of the Reserves and a review of the Contingent and Prospective Resources of E.On E & P UK Limited and E.On E & P UK EU Limited ("E.On") to form a Competent Person's Report.

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from a data room as well as information in the public domain. The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and key Premier staff.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances, regulations that apply to this asset(s). RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

RISC has no pecuniary interest, other than to the extent of the professional fees receivable for the preparation of this report, or other interest in the assets evaluated, that could reasonably be regarded as affecting our ability to give an unbiased view of these assets.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

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Prepared By	Simon Douse		14 March 2016
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Editorial Review By	Gavin Ward		30 March 2016
Authorised For Release By	Gavin Ward		30 March 2016

Revision History

Revision	Date	Description	Checked by	Approved by
#1	8-Feb-2016	Final review by G.Salter	G.Ward	G.Ward
#2	10-Feb-2016	Update to price assumptions	G.Ward	G.Ward
#3	17-Feb-2016	Amend text & charts	G.Ward	G.Ward
#4	25-Feb-2016	Add Reserves & NPV @ 31 Dec 2015	G.Ward	G.Ward
#5	14-Mar-2016	Add valuation of pipelines	G.Ward	G.Ward
#6	24-Mar-2016	Correction to reservoir ages in tables	G.Ward	G.Ward
#7	30-Mar-2016	Amend title and date on title page	G.Ward	G.Ward

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1. Executive Summary

E.On Exploration and Production through its subsidiaries, E.On E & P UK Limited and E.On E & P UK EU Limited ("E.On") is divesting its interests in the UK North Sea. The E.On assets assessed in this report include producing fields, fields which have ceased production, undeveloped fields, key prospects and immature discoveries, and exploration leads.

E.On's UK assets also include seven producing fields in the Central North Sea (Elgin, Franklin, West Franklin, Scoter, Merganser, Glenelg & Huntington), which are not addressed in this report and have been addressed by another independent assessor.

This report presents the conclusions of an independent evaluation by RISC of E.On's UK assets excluding the omitted fields (Elgin, Franklin, West Franklin, Scoter, Merganser, Glenelg & Huntington). The data and information used in this report were obtained from a data room run by E.On, data supplied by Premier and public data.

Unless stated otherwise, the effective date of 1st January 2015 has been chosen for reserves (Table 1-1) and values in this report to align with a Sale and Purchase agreement between Premier Oil and E.On.

The reserves and net present values have also been calculated with an effective date of 31st December 2015 to meet the requirements of the UK Listing Authority (Table 1-2).

RISC has not advised Premier on the acquisition strategy or price bid for E.On's interests.

Key attributes of the portfolio (excluding the Omitted Fields) are:

- Proved+Probable (2P) gas reserves of 208.2 Bcf net to E.On on a working interest basis at 1st January 2015.
- Net 2P average daily production of approximately 28 MMscf/d in 2016
- Addition of 43 MMscf/d net average daily 2P sales production from Tolmount development in 2019, rising to 84 MMscf/d in 2020.

The location of E.On's interests are shown in Figure 1-1 and the producing assets are summarised in Table 1-3. E.On's development interests are summarised in Table 1-4, while discoveries and key prospects are shown in Table 1-5 and additional prospectivity in Table 1-6.

Table 1-1 Summary of Reserves as at 1 January 2015

Field Gas Reserves	Age	Gross Field Reserves (Bcf)			E.On Working Interest (%)	E.On Net Working Interest Reserves (Bcf)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	40.1	54.5	91.7	47.00%	18.8	25.6	43.1
Johnston	Permian	13.0	15.6	18.3	50.10%	6.5	7.9	9.2
Hunter	Triassic	1.5	1.5	1.5	79.00%	1.2	1.2	1.2
Rita	Carboniferous	2.2	2.2	2.2	74.00%	1.6	1.6	1.6
Caister	Triassic & Carb	1.5	1.5	1.5	40.00%	0.6	0.6	0.6
Orca	Carboniferous	1.6	1.6	1.7	23.47%	0.4	0.4	0.4
Ravenspurn Nth	Permian	6.4	6.7	6.9	28.80%	1.8	1.9	2.0
Tolmount	Permian	0	338.8	833.4	50.00%	0	169.4	416.5
Total		**66.3**	**421.6**	**956.8**		**30.9**	**208.2**	**474.6**

Field Oil+Condensate Reserves	Age	Gross Field Reserves (MMstb)			E.On Working Interest (%)	E.On Net Working Interest Reserves (MMstb)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	0	0	0	47.00%	0	0	0
Johnston	Permian	0	0	0	50.10%	0	0	0
Hunter	Triassic	0	0	0	79.00%	0	0	0
Rita	Carboniferous	0.014	0.014	0.014	74.00%	0.010	0.010	0.010
Caister	Triassic & Carb	0.008	0.008	0.008	40.00%	0.003	0.003	0.003
Orca	Carboniferous	0	0	0	23.47%	0	0	0
Ravenspurn Nth	Permian	0	0	0	28.80%	0	0	0
Tolmount	Permian	0	3.098	7.396	50.00%	0	1.549	3.698
Total		**0.022**	**3.12**	**7.418**		**0.013**	**1.562**	**3.711**

Field Oil Equivalent Reserves	Age	Gross Field Reserves (MMboe)			E.On Working Interest (%)	E.On Net Working Interest Reserves (MMboe)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	6.68	9.08	15.28	47.00%	3.13	4.27	7.18
Johnston	Permian	2.17	2.60	3.05	50.10%	1.08	1.32	1.53
Hunter	Triassic	0.25	0.25	0.25	79.00%	0.20	0.20	0.20
Rita	Carboniferous	0.38	0.38	0.38	74.00%	0.28	0.28	0.28
Caister	Triassic & Carb	0.26	0.26	0.26	40.00%	0.10	0.10	0.10
Orca	Carboniferous	0.27	0.27	0.28	23.47%	0.07	0.07	0.07
Ravenspurn Nth	Permian	1.07	1.12	1.15	28.80%	0.30	0.32	0.33
Tolmount	Permian	0	59.43	146.23	50.00%	0	29.72	73.11
Total		**11.08**	**73.39**	**166.88**		**5.16**	**36.28**	**82.80**

Notes: 1) Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field from 1st January 2015. 2) Oil equivalent converted at 6,000 scf = 1 Boe.

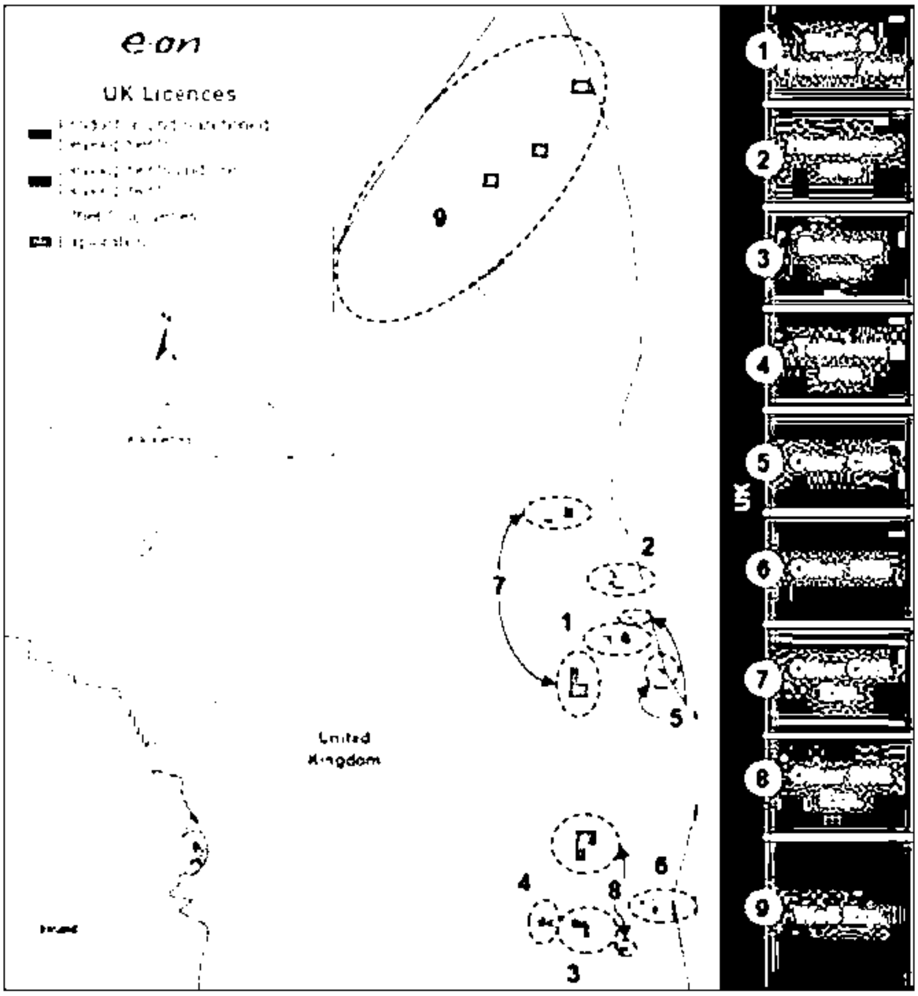
Table 1-2 Summary of Reserves as at 31 December 2015

Field Gas Reserves	Age	Gross Field Reserves (Bcf)			E.On Working Interest (%)	E.On Net Working Interest Reserves (Bcf)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	26.4	40.6	78.0	47.00%	12.4	19.1	36.7
Johnston	Permian	10.3	12.9	15.5	50.10%	5.2	6.5	7.7
Hunter	Triassic	0.9	0.9	0.9	79.00%	0.7	0.7	0.7
Rita	Carboniferous	0	0	0	74.00%	0	0	0
Caister	Triassic & Carb	0	0	0	40.00%	0	0	0
Orca	Carboniferous	0	0	0	23.47%	0	0	0
Ravenspurn Nth	Permian	0	0	0	28.80%	0	0	0
Tolmount	Permian	0	338.8	833.4	50.00%	0	169.4	416.5
Total		**37.7**	**392.4**	**927.4**		**18.3**	**195.3**	**461.6**

Field Oil+Condensate Reserves	Age	Gross Field Reserves (MMstb)			E.On Working Interest (%)	E.On Net Working Interest Reserves (MMstb)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	0	0	0	47.00%	0	0	0
Johnston	Permian	0	0	0	50.10%	0	0	0
Hunter	Triassic	0	0	0	79.00%	0	0	0
Rita	Carboniferous	0	0	0	74.00%	0	0	0
Caister	Triassic & Carb	0	0	0	40.00%	0	0	0
Orca	Carboniferous	0	0	0	23.47%	0	0	0
Ravenspurn Nth	Permian	0	0	0	28.80%	0	0	0
Tolmount	Permian	0	3.098	7.396	50.00%	0	1.549	3.698
Total		**0**	**3.098**	**7.396**		**0**	**1.549**	**3.698**

Field Oil Equivalent Reserves	Age	Gross Field Reserves (MMboe)			E.On Working Interest (%)	E.On Net Working Interest Reserves (MMboe)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	4.4	6.8	13.0	47.00%	2.1	3.2	6.1
Johnston	Permian	1.7	2.2	2.6	50.10%	0.9	1.1	1.3
Hunter	Triassic	0	0	0	79.00%	0	0	0
Rita	Carboniferous	0	0	0	74.00%	0	0	0
Caister	Triassic & Carb	0	0	0	40.00%	0	0	0
Orca	Carboniferous	0	0	0	23.47%	0	0	0
Ravenspurn Nth	Permian	0.4	0.4	0.4	28.80%	0.1	0.1	0.1
Tolmount	Permian	0	59.43	146.23	50.00%	0	29.72	73.11
Total		**6.5**	**68.83**	**162.23**		**3.1**	**34.12**	**80.61**

Notes: 1) Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field from 31st December 2015. 2) Oil equivalent converted at 6,000 scf = 1 Boe.



REGION	Producing			Exploration
1 – Elgin, Franklin	Not part of this report		Corfe	West Franklin Terrace, Elgin West
2 – Huntington Area	Not part of this report			Ekland
3 - Babbage Area	Babbage, Johnston, Ravenspurn North		Cobra, Hawking	Ada, Newton, Python, Newton Deep, Dodgson, Joly, Adder, Viper, Boa
4 – Tolmount Area		Tolmount	Artemis, Mongour	Artemis East, Malin, Cluin
5 – Other CNS	Not part of this report		Arran, Austen	
6 – Other SNS	Caister, Hunter, Orca, Rita & Minke (ceased production), CMS, ETS			North Rita, Deep Hunter
7 – Other CNS Exploration				TR7, Tumbleweed, Chimera
8 - Other SNS Exploration				Lyra
9 – West of Shetlands				Colza, Mardyke, Gunnison
Note: Third Party Revenue analyses for Huntington, Babbage and Tolmount areas are not included in this report				

Figure 1-1 Location map and key of main E.On licenced UK blocks and fields

Table 1-3 E.On's Production Interests

Area	Asset Name	Status	Operator	E.On's Working Interest (%)
Southern North Sea	Babbage	Producing	E.On	47.00
Southern North Sea	Caister	Ceased Production in 2015	ConocoPhillips	40.00
Southern North Sea	Hunter	Restarted Production in 2015	E.On	79.00
Southern North Sea	Johnston	Producing	E.On	50.10
Southern North Sea	Minke	Ceased Production	GDF Suez	42.67
Southern North Sea	Orca	Producing	GDF Suez	23.47
Southern North Sea	Ravenspurn North	Producing	Perenco	28.80
Southern North Sea	Rita	Currently Shut-in	E.On	74.00
Southern North Sea	Caister Murdoch System	Infrastructure	ConocoPhillips	20.00
Southern North Sea	Esmond Transportation System	Infrastructure	Perenco	30.00

Table 1-4 E.On's Development Interests

Area	Asset Name	Status	Operator	E.On's Working Interest (%)
Central North Sea	Arran	Awaiting development sanction	Dana	5.12
Central North Sea	Austen	Under review	GDF Suez	25.00
Southern North Sea	Tolmount	Development pending FID	Eon	50.00

Table 1-5 E.On's Discoveries and Key Prospect Interests

Area	Asset Name	Field Area	Eon's Working Interest (%)
Central North Sea	Corfe Discovery	Elgin/Franklin	25
Central North Sea	Ekland Prospect	Huntington	40
Southern North Sea	Cobra Discovery	Babbage	50
Southern North Sea	Hawking Discovery	Babbage	50
Southern North Sea	Ada Prospect	Babbage	47
Southern North Sea	Newton Prospect	Babbage	50
Southern North Sea	Python Prospect	Babbage	50
Southern North Sea	Artemis Discovery	Tolmount	100
Southern North Sea	Artemis East Prospect	Tolmount	100
Southern North Sea	Mongour Discovery	Tolmount	50
Southern North Sea	Malin prospect	Tolmount	50

Table 1-6 E.On's Additional Prospectivity Interests (Leads)

Area	Asset Name	Field Area	Eon's Working Interest (%)
Southern North Sea	Cluin	Tolmount	50
Southern North Sea	Newton Deep	Babbage	50
Southern North Sea	Dodgson	Babbage	50
Southern North Sea	Joly	Babbage	50
Southern North Sea	Adder	Babbage	50
Southern North Sea	Viper	Babbage	50
Southern North Sea	Boa	Babbage	50
Southern North Sea	North Rita	Rita	74
Southern North Sea	Deep Hunter	Caister	79
Southern North Sea	Lyra	Breagh	35
Central North Sea	West Franklin Terrace	Elgin/Franklin	5.2
Central North Sea	Elgin West	Elgin/Franklin	5.2
Central North Sea	TR7	Galley	40
Central North Sea	Tumbleweed	Kittiwake	40
Central North Sea	Chimaera	Galley	40
West of Shetland	Colza	-	100
West of Shetland	Mardyke	-	100
West of Shetland	Gunison	-	100

1.1. Production Assets and Reserves

RISC estimates that Eon's assets have 208.2 Bcf of 2P gas reserves and 1.562 MMstb of 2P oil+condensate reserves as at 1st January 2015 on a net working interest basis. This reduces to 195.3 Bcf and 1.549 MMstb of 2P oil+condensate with an effective date of 31st December 2015. Table 1-7 and Table 1-8 summarise the reserves derived from these assessments. Deterministic methods have been used to estimate reserves.

Table 1-7 E.On Net Reserves as at 1 January 2015 (Price Scenario A)

Field	Status	E.On WI	Case	Economic Limit	Gas Bcf[1]	Condensate MMBbl	Gas+Liquids Equivalent MMboe[2]
Ravenspurn North	Producing	29%	1P	2016	1.8	0	0.30
			2P	2016	1.9	0	0.32
			3P	2016	2.0	0	0.33
Johnston	Producing	50%	1P	2028	6.5	0	1.09
			2P	2028	7.9	0	1.30
			3P	2028	9.2	0	1.54
Caister	Ceased Production	40%	1P	2016	0.6	0.003	0.10
			2P	2016	0.6	0.003	0.10
			3P	2016	0.6	0.003	0.10
Babbage	Producing	47%	1P	2021	18.8	0	3.14
			2P	2024	25.6	0	4.27
			3P	2030	43.1	0	7.19
Orca	Producing	23%	1P	2016	0.3	0	0.06
			2P	2016	0.3	0	0.06
			3P	2016	0.3	0	0.07
Hunter	Producing	79%	1P	2018	1.2	0	0.19
			2P	2018	1.2	0	0.19
			3P	2018	1.2	0	0.19
Rita	Currently Shut-in	74%	1P	2016	1.6	0.010	0.28
			2P	2016	1.6	0.010	0.28
			3P	2016	1.6	0.010	0.28
Tolmount	Development pending FID	50%	1P		0	0	0
			2P	2040	169.0	1.549	29.72
			3P	2043	416.5	3.698	73.11

[1] NPV's based on energy units Trillion British Thermal Units (TBTU). 1 TBTU is equivalent to 1 Billion Cubic Feet of Gas assuming that the calorific value/heating content of the gas is 1 therm = 1,000 BTU. The calorific value will depend upon the percentage of inert gases such as nitrogen and carbon dioxide in the sales gas and RISC has converted TBTU to Bcf of each field based on the specific calorific value of the gas in that field eg: Orca field : 737 BTU/standard cubic feet of gas (0.737 TBTU = 1 Bcf).
[2] Calculated using an average conversion factor of 6 Mscf per barrel of oil equivalent (boe)

Table 1-8 E.On Net Reserves as at 31 December 2015 (Price Scenario A)

Field	Status	E.On WI	Case	Economic Limit	Gas Bcf[3]	Condensate MMBbl	Gas+Liquids Equivalent MMboe[4]
Ravenspurn North	Producing	29%	1P	2016	0	0	0
			2P	2016	0	0	0
			3P	2016	0	0	0
Johnston	Producing	50%	1P	2028	5.18	0	0.89
			2P	2028	6.46	0	1.11
			3P	2028	7.74	0	1.33
Caister	Ceased Production	40%	1P	2016	0	0	0
			2P	2016	0	0	0
			3P	2016	0	0	0
Babbage	Producing	47%	1P	2021	12.41	0	2.14
			2P	2024	19.10	0	3.29
			3P	2030	36.67	0	6.32
Orca	Producing	23%	1P	2016	0	0	0
			2P	2016	0	0	0
			3P	2016	0	0	0
Hunter	Producing	79%	1P	2018	0.72	0	0.12
			2P	2018	0.72	0	0.12
			3P	2018	0.72	0	0.12
Rita	Currently Shut-in	74%	1P	2016	0	0	0
			2P	2016	0	0	0
			3P	2016	0	0	0
Tolmount	Development pending FID	50%	1P		0	0	0
			2P	2040	169.0	1.549	29.72
			3P	2043	416.5	3.698	73.11

The following Net Present Values (Table 1-9 to

[3] NPV's based on energy units Trillion British Thermal Units (TBTU). 1 TBTU is equivalent to 1 Billion Cubic Feet of Gas assuming that the calorific value/heating content of the gas is 1 therm = 1,000 BTU. The calorific value will depend upon the percentage of inert gases such as nitrogen and carbon dioxide in the sales gas and RISC has converted TBTU to Bcf of each field based on the specific calorific value of the gas in that field eg: Orca field : 737 BTU/standard cubic feet of gas (0.737 TBTU = 1 Bcf).

[4] Calculated using an average conversion factor of 6 Mscf per barrel of oil equivalent (boe)

Table 1-12) have not been adjusted for other factors (eg analogous transactions, strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value.

Four price scenarios have been evaluated at two different effective dates, 01-Jan-2015 and 31-Dec-2015:

- RISC's base case price estimate (Scenario A)
- Sensitivities on RISC's base case price estimate, representing the higher prices achieved in the last twelve months (Scenarios B, C and D).

The economic results for the pipelines are independent of the oil and gas price scenarios. A single scenario was evaluated for each of the Esmond Transmission System (ETS) and Caister Murdoch System (CMS) working interests, at each of the effective dates.

Table 1-9 Pre-Tax Valuation Summary (NPV at 10% discount rate in US$MM at 1 January 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	0	0	0	0
			2P	0	0	0	0
			3P	0	0	0	0
Ravenspurn North	Producing	29%	1P	-60	-60	-60	-60
			2P	-59	-59	-59	-59
			3P	-59	-59	-59	-59
Johnston	Producing	50%	1P	5	9	7	10
			2P	10	14	12	15
			3P	14	19	16	21
Caister	Ceased Production	40%	1P	-37	-37	-37	-37
			2P	-37	-37	-37	-37
			3P	-37	-37	-37	-37
Babbage	Producing	47%	1P	4	16	10	21
			2P	20	39	30	47
			3P	51	78	66	90
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-11	-10	-10	-10
			2P	-11	-10	-10	-10
			3P	-11	-10	-10	-10
Minke	Ceased Production	43%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Tolmount	Development pending FID	50%	1P	-33	-33	-33	-33
			2P	111	214	160	267
			3P	584	789	682	897
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		29	29	29	29
Total (Including Pipelines)			**1P**	**-139**	**-122**	**-130**	**-116**
			2P	**27**	**154**	**89**	**216**
			3P	**535**	**773**	**651**	**895**

Table 1-10 Post Tax[5] Valuation Summary (NPV at 10% discount rate in US$MM at 1 January 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	0	0	0	0
			2P	0	0	0	0
			3P	0	0	0	0
Ravenspurn North	Producing	29%	1P	-60	-60	-60	-60
			2P	-59	-59	-59	-59
			3P	-59	-59	-59	-59
Johnston	Producing	50%	1P	5	9	7	10
			2P	10	14	12	15
			3P	14	17	16	17
Caister	Ceased Production	40%	1P	-37	-37	-37	-37
			2P	-37	-37	-37	-37
			3P	-37	-37	-37	-37
Babbage	Producing	47%	1P	4	16	10	20
			2P	20	31	27	36
			3P	42	54	49	58
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-11	-10	-10	-10
			2P	-11	-10	-10	-10
			3P	-11	-10	-10	-10
Minke	Ceased Production	43%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Tolmount	Development pending FID	50%	1P	-33	-33	-33	-33
			2P	28	81	53	108
			3P	256	363	307	418
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		17	17	17	17
Total (Including. Pipelines)			**1P**	**-151**	**-134**	**-142**	**-129**
			2P	**-68**	**1**	**-33**	**34**
			3P	**186**	**309**	**247**	**368**
Consolidated Tax benefit			**2P[6]**	76	71	75	66

Table 1-11 Pre-Tax Valuation Summary (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Ravenspurn North	Producing	29%	1P	-62	-62	-62	-62
			2P	-62	-62	-62	-62
			3P	-62	-62	-62	-62
Johnston	Producing	50%	1P	-1	3	1	4
			2P	3	8	6	10
			3P	8	13	10	15
Caister	Ceased Production	40%	1P	-43	-43	-43	-43
			2P	-43	-43	-43	-43
			3P	-43	-43	-43	-43
Babbage	Producing	47%	1P	-24	-10	-18	-5
			2P	-7	13	4	23
			3P	25	55	41	68
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-12	-11	-11	-11
			2P	-12	-11	-11	-11
			3P	-12	-11	-11	-11
Minke	Ceased Production	43%	1P	-13	-13	-13	-13
			2P	-13	-13	-13	-13
			3P	-13	-13	-13	-13
Tolmount	Development pending FID	50%	1P	-36	-36	-36	-36
			2P	122	235	176	294
			3P	656	882	763	1,000
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		32	32	32	32
Total (Including Pipelines)			**1P**	**-195**	**-176**	**-186**	**-170**
			2P	**-16**	**123**	**53**	**194**
			3P	**555**	**817**	**681**	**950**

[5] Tax losses acquired in respect of EPUK EU have been applied

[6] Consolidated tax benefit calculated for arithmetic total of field 2P cash flows only

Table 1-12 Post Tax[7] Valuation Summary (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Ravenspurn North	Producing	29%	1P	-62	-62	-62	-62
			2P	-62	-62	-62	-62
			3P	-62	-62	-62	-62
Johnston	Producing	50%	1P	-1	3	1	4
			2P	3	8	6	10
			3P	8	13	10	15
Caister	Ceased Production	40%	1P	-43	-43	-43	-43
			2P	-43	-43	-43	-43
			3P	-43	-43	-43	-43
Babbage	Producing	47%	1P	-24	-10	-18	-5
			2P	-7	13	4	23
			3P	25	44	38	49
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-12	-11	-11	-11
			2P	-12	-11	-11	-11
			3P	-12	-11	-11	-11
Minke	Ceased Production	43%	1P	-13	-13	-13	-13
			2P	-13	-13	-13	-13
			3P	-13	-13	-13	-13
Tolmount	Development pending FID	50%	1P	-36	-36	-36	-36
			2P	31	89	58	119
			3P	295	413	352	473
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		18	18	18	18
Total (Including Pipelines)			**1P**	**-209**	**-190**	**-200**	**-184**
			2P	**-121**	**-37**	**-79**	**5**
			3P	**180**	**323**	**253**	**390**
Consolidated Tax benefit			**2P[8]**	84	78	82	73

[7] Tax losses acquired in respect of EPUK EU have been applied

[redacted] [redacted]

1.2. Processing Terminals and Pipelines

RISC has valued the net tariff income and abandonment liability of the Caister Murdoch System and Esmond Transmission System pipelines. The costs associated with the Freon replacement project at Theddlethorpe Gas Terminal, which is used by the Caister, Rita and Hunter fields is part of a cost share agreement with the users of the terminal and this cost forms part of field Operating Expenditure (Opex).

The following Net Present Values (Table 1-13) have not been adjusted for other factors (eg analogous transactions, strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value.

The economic results for the pipelines (Table 1-13) are independent of the oil and gas price scenarios. A single scenario was evaluated for each of the ETS and CMS working interests at the effective date of 31-Dec-2015.

Table 1-13 Pre-Tax & Post-Tax Valuation (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Pre-Tax NPV	Post-Tax NPV
Caister Murdoch System Pipeline	Facility	20%	-4	-4
Esmond Transportation System	Facility	30%	32	18

[8] Consolidated tax benefit calculated for arithmetic total of field 2P cash flows only

1.3. Contingent Resources

RISC has reviewed the Contingent Resource volumes.

Table 1-14 Contingent Resources

Field	Status	E.On WI	Case	Net Gas Resource Bcf	Net Condensate Resource MMstb	Gas+Liquids Equivalent MMboe
Producing Field Projects						
Ravenspurn North	Upside wells plus sub-economic production	29%	1C	27.4		4.57
			2C	47.2		7.87
			3C	68.0		11.33
Babbage	J infill well plus sub-economic production	47%	1C	14.4		2.40
			2C	23.3		3.88
			3C	27.1		4.52
Rita	Currently Shut-in		1C	3.8	0.02	0.65
			2C	4.5	0.03	0.78
			3C	5.1	0.04	0.89
Orca	Sub-economic production	23%	1C	0.3		0.05
			2C	0.5		0.08
			3C	0.7		0.12
Undeveloped discoveries						
Tolmount	Development pending FID	50%	1C	76.9	0.666	13.50
			2C	0	0	0
			3C	0	0	0
Austen	Development too immature to assess volumes	25%	1C	-	-	-
			2C	-	-	-
			3C	-	-	-
Arran	Development pending decision	5%	1C	5.1	0.138	0.99
			2C	8.0	0.215	1.54
			3C	11.4	0.328	2.23

1.4. Exploration Potential

RISC has not valued the Exploration potential. There are eleven prospects which have reached a mature level in order to be relatively confident of a calibrated Geological Chance of Success. There are a further fifteen leads in the Southern and Central North Sea, and a further three leads in the West of Shetlands blocks.

1.5. Opportunities and Risks

In addition to the uncertainty expressed by the ranges of resource volumes, costs and prices identified above, the group of assets are characterised by the following opportunities and risks:

Risks:

- Facility and pipeline integrity in the mature assets could lead to unforeseen outages
- Tariff/cost share uncertainties where gas is exported in third party infrastructure
- Tolmount (and other) project delays due to lack of confidence in current environment
- Significant number of late life mature assets with uncertain abandonment liability
- Eleven suspended wells which will require either permanent abandonment or regular monitoring in line with guidance given by the Oil and Gas Authority.

Opportunities:

- New field development at Tolmount, which has a field life of over twenty years in the 2C volume case
- Contingent resources in undeveloped fields indicate potential for reserves additions
- Operating cost reductions with move to unmanned/not normally manned installations
- Capital and operating cost reductions as operators find efficiencies and suppliers become more competitive in the current market
- Abandonment cost reductions as the North Sea industry gains experience and perhaps economies of scale with multi-field abandonment campaigns. Greater cooperation between operators leading to efficiencies and cost reductions
- Third party revenues in CMS and ETS pipelines

2. Basis of Assessment

2.1. Data Availability and Methodology

In preparing this Competent Person's Report, RISC has relied on information provided by E.On and Premier as well as information from the public domain. A RISC team visited E.On's physical data room during June 2015 and December 2015 and accessed a Virtual Data Room (VDR) to review seismic data, well data, geological models, reservoir engineering models, cost data and commercial terms.

The dataset included data provided between June 2015 and January 2016.

RISC has reviewed basic and interpreted data as presented by E.On and made adjustments as required to form an independent view of future production, resources, costs, schedule for selected assets.

Reserves and Net Present Values have been reported as at 1st January 2015 to align with the Effective Date of a Sale and Purchase Agreement between Premier Oil and E.On.

A total of four price scenarios have been run with Price Scenario 'A' representing RISC's view of future prices. The three other scenarios (Price Scenario 'B', Price Scenario 'C' & Price Scenario 'D') represent price sensitivities above RISC's base scenario.

We have not conducted a site visit.

2.2. Qualifications

RISC is an independent oil and gas advisory firm. All of the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have in excess of 20 years. The preparation of this report has been managed by Mr Gavin Ward. Mr Ward has a B.Sc (Hons) Geology & Physics (Aston University), an MBA from the Cranfield School of Management, is a Chartered Accountant and Fellow of the Association of Chartered Certified Accountants (FCCA). Mr Ward has 28 years of experience in the sector, is a member of the Society of Petroleum Engineers and is a Council Member of the Petroleum Exploration Society of Great Britain. Mr Ward is a Competent Person as defined in London Stock Exchange, AIM Guidance Note for Mining, Oil and Gas Companies, March 2006.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately forty highly experienced professional staff at offices in Perth, Brisbane, Jakarta and London. We have completed over 2,000 assignments in sixty eight countries for nearly 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

2.3. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The E.On assets assessed in this report comprise producing fields, fields which have ceased production, undeveloped fields, key prospects and immature discoveries, and exploration leads. Additional assets that form part of the proposed transaction but which are not included in this report and are referred to as the 'Omitted Fields'.

The Net Present Value estimates presented in this report have not been adjusted for hedging contracts or other factors (eg strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value. The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for, or warrant the accuracy or reliability of our conclusions, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances and regulations that apply to these assets.

RISC has not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

2.4. Independence

RISC makes the following disclosures:

- RISC is independent with respect to E.On and Premier and confirms that there is no conflict of interest with any party involved in the assignment.
- Under the terms of engagement between RISC and Premier for the provision of this report, RISC will receive a fee, payable by Premier. The payment of this fee is not contingent on the intended purpose of this report.
- Neither RISC Directors nor any staff involved in the preparation of this report hold interests in Premier.

2.5. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers in 2007 and European Securities and Markets Authority (ESMA).

2.6. Consent

Neither the whole nor any part of this report nor any reference to it may be included in or attached to any prospectus, document, circular, resolution, letter or statement without the prior consent of RISC.

3. Production Assets

The producing assets covered in this report are all in the Southern North Sea. The E.On assets assessed in this section include five producing fields, two fields which have ceased production and one currently shut-in.

3.1. Southern North Sea Regional Geology

The evolution of the Southern North Sea Basin occurred through several main phases in geological history. Firstly was the creation of the Sub-Cambrian peneplain, before the Caledonia Orogeny in the late Silurian to Devonian. The Variscan Orogeny followed throughout the Carboniferous and into the Permian causing folding and faulting of Carboniferous strata. This generated a dominant north west to south east orientated structural grain in the Southern North Sea Basin with a subordinate orthogonal north east to south west (De Keysers) fault set exhibiting a dominant strike-slip offset rather than vertical movement. These fault trends controlled the early deposition of the Permian sandstones that provide the dominant reservoir rocks in the Southern North Sea, with deposition unconformable above a largely peneplaned Carboniferous subcrop. Basinal extension and subsidence throughout the Permian and into the Mesozoic provided accommodation space. Deposition of the Permian Zechstein evaporites followed Permian clastic deposition, providing the regional seal for the Permian Sandstone play. Continued extension and regional subsidence into the Mesozoic resulted in widespread continental clastic deposition in the Triassic before sea level rise towards the end of the Triassic resulted in marine conditions in the Jurassic and Cretaceous Periods. Uplift during Late Cretaceous and Tertiary inversions, associated with the Alpine orogeny, resulted in almost all of the Late Mesozoic section being eroded. Undifferentiated Quaternary-Tertiary marine sands and clays top the regional stratigraphy.

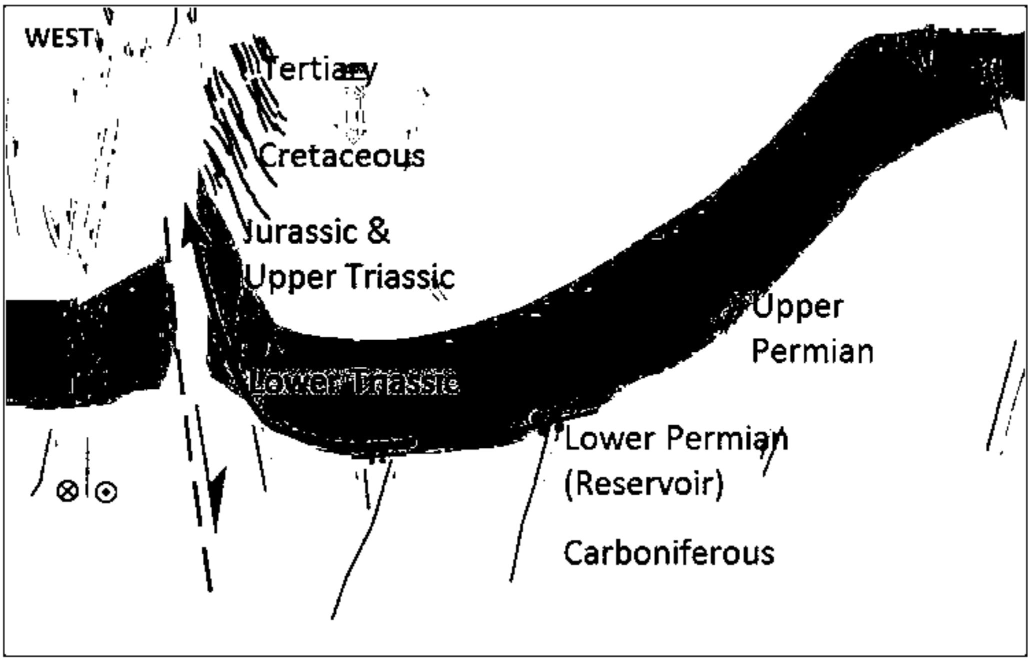


Figure 3-1 Regional geological cross section through Southern North Sea

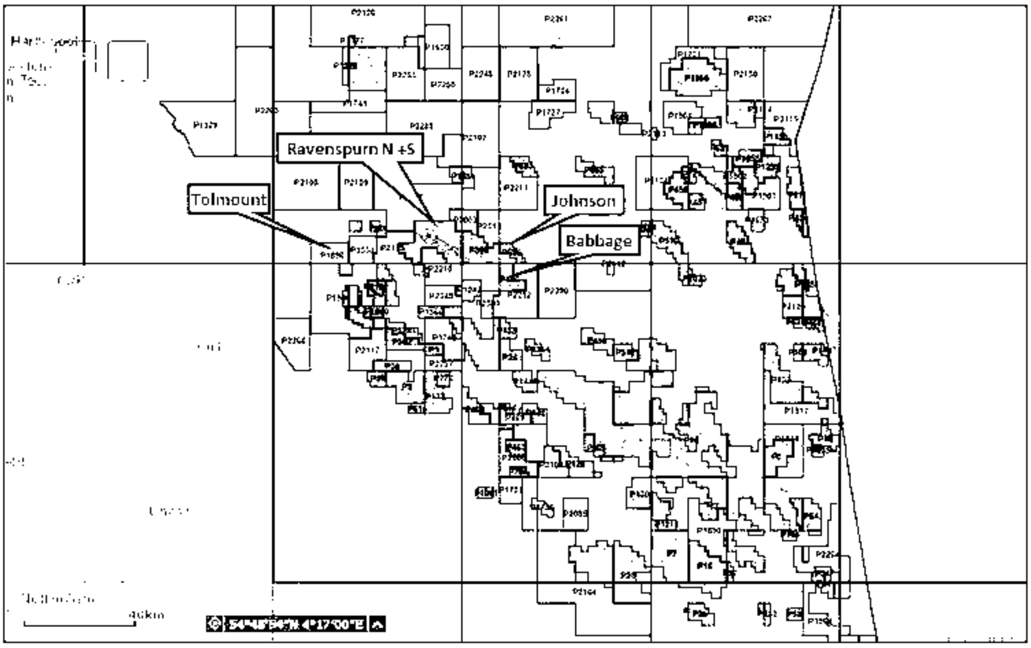


Figure 3-2 Southern North Sea Location Map

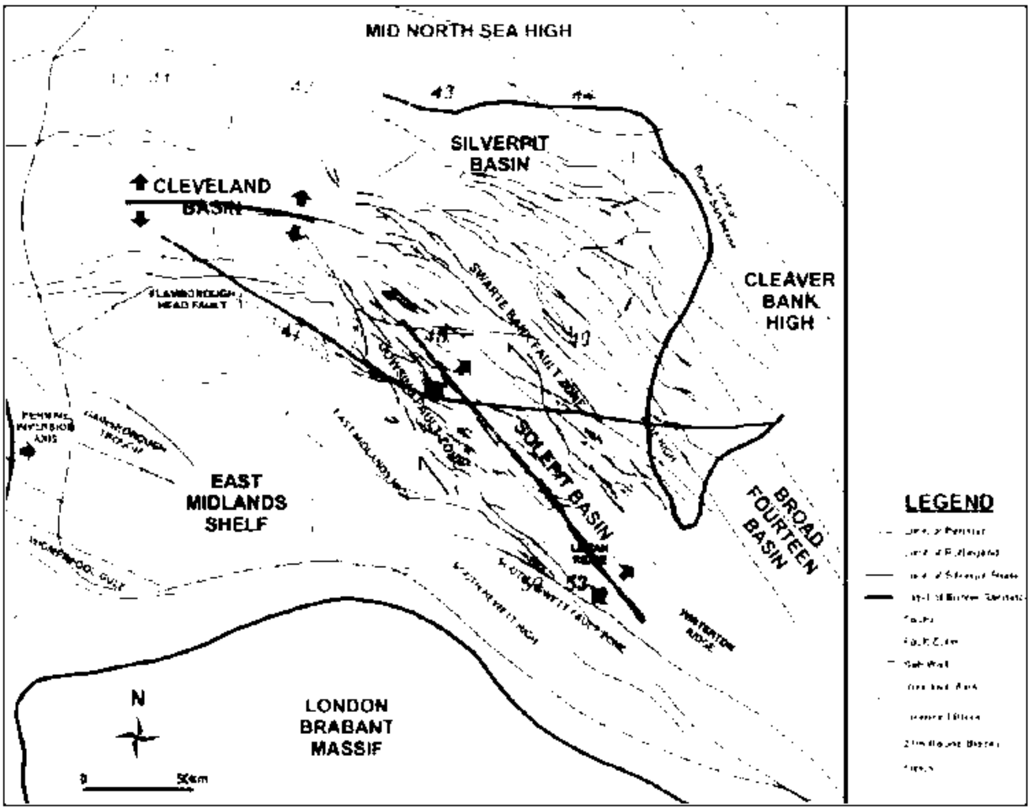


Figure 3-3 Southern North Sea Structural Elements

3.1.1. Source Rocks

Hydrocarbons encountered in the Southern North Sea are thought to be sourced from Carboniferous Westphalian Coals and Namurian marine shales. These either directly underlie the Permian reservoir sands or lie adjacent to eroded palaeohighs, such as around the Babbage Field. As a consequence migration pathways are generally short and often vertical with intra-Carboniferous sands acting as carrier beds. Gas quality and composition are known to vary across the basin in relation to local geological conditions.

3.1.2. Reservoirs

The primary reservoir exploited in the region is the Lower Leman Sandstone Formation of Rotliegendes (Permian) age, comprising aeolian, fluvial and sabkha facies, deposited along the southern margin and to the south of the Silverpit Lake (Figure 3-4). Reservoir facies and thickness are known to vary locally in relation to local structural setting and climatic controls. Aeolian deposition dominates to the south and west, whilst fluvial influence increases with proximity to the Silverpit Lake which itself is characterised by mudstone and evaporitic facies. Reservoir quality is heavily dependent on depositional facies with the aeolian sequences providing the best quality reservoir.

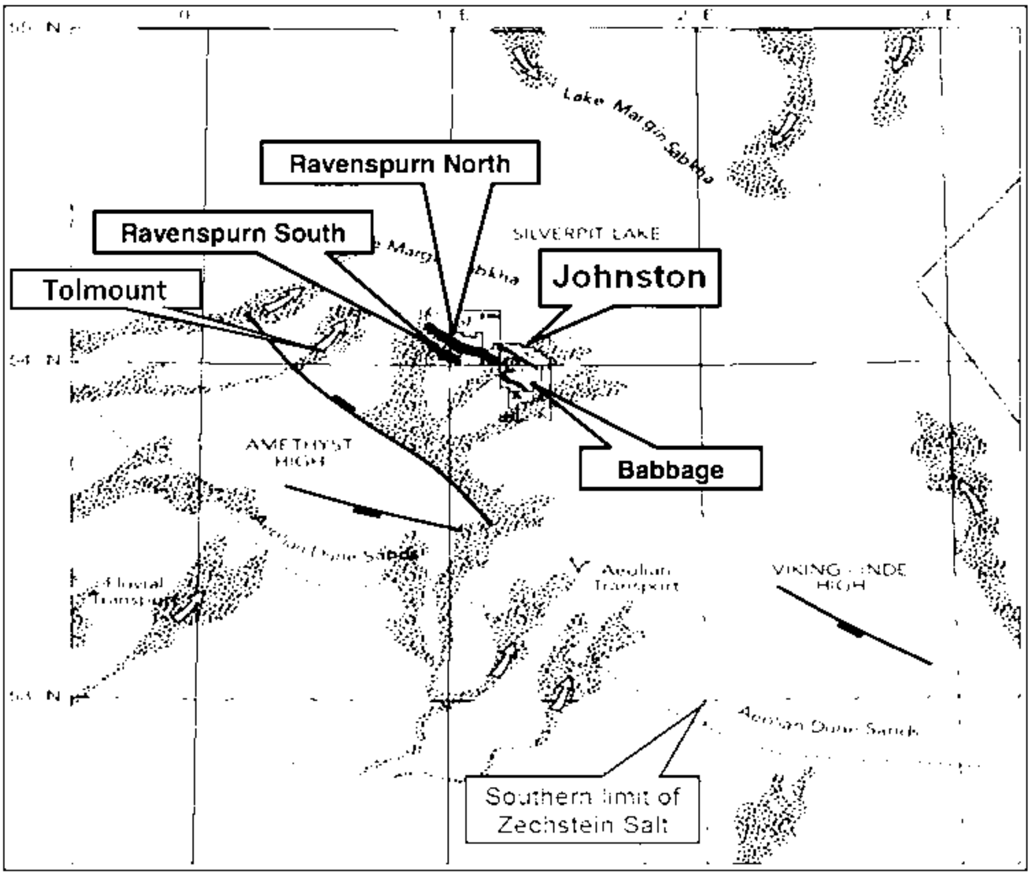


Figure 3-4 Leman Palaeogeography

3.1.3. Traps

All producing fields in the Southern North Sea are wholly structural traps apart from Ravenspurn North which lies on the fringe of the basin and has an element of stratigraphic trapping on the northern flank due to pinch out of the reservoir. Traps are dominantly fault bound structural closures where the top seal is provided by the Silverpit mudstones (where developed) or the Zechstein evaporites. Fault seal is commonly provided by juxtaposition of Leman Sandstones against Silverpit Mudstones.

3.2. Babbage Gas Field, Block 48/2a (Licence P.456)

3.2.1. Overview

Babbage Field was discovered by the 48/2-2 well in 1988. The well flowed at a rate of 3.8 MMscf/d and was considered uneconomical for development at the time. A second well, 48/2a-4, was drilled onto the crest of the structure in 2006 which achieved a flow rate of 11 MMscf/d on test, establishing the presence of a significant gas accumulation. E.On have a 47% interest in the Babbage development area that includes Babbage Field and earlier development of Johnston and Ravenspurn North Fields. Although they are part of the same development area, E.On holds different interests in Johnston (50%) and Ravenspurn North (29%).

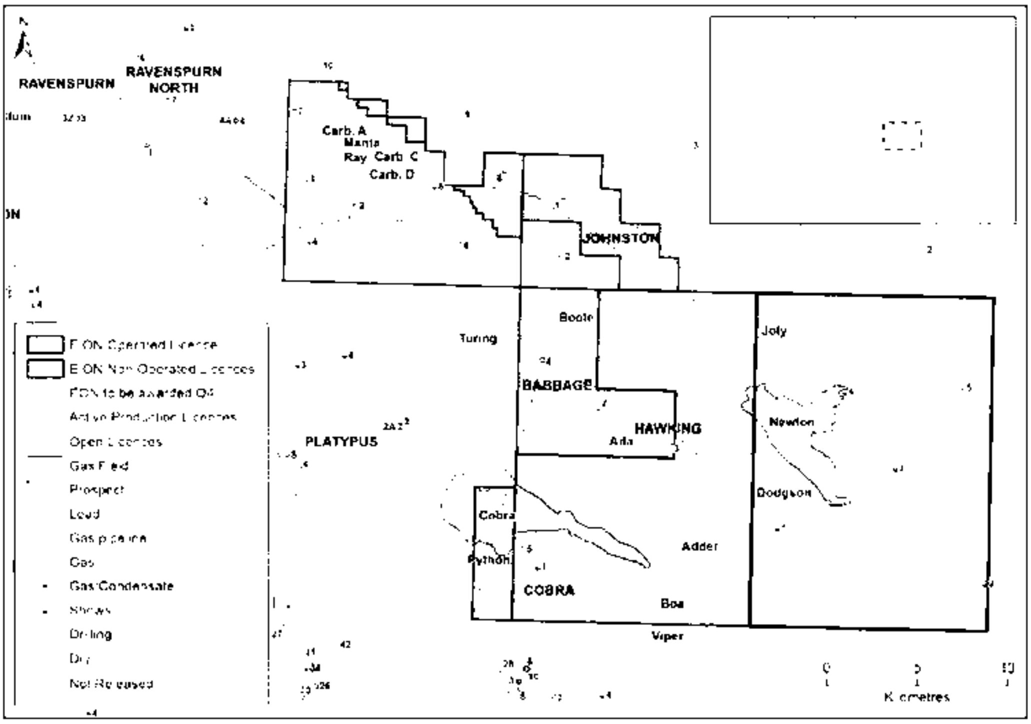


Figure 3-5 Babbage Feld Location

3.2.2. Development and current status

Babbage has undergone two phases of development well drilling to-date. In Phase 1, between 2008 and 2010, three horizontal, multi-fracced wells were drilled (B1, B2z and B3), along with installation of the nine-slot minimum facilities platform. First gas was achieved in August 2010. Phase 2 comprised the drilling of two horizontal, multi-fracced wells (B4 and B5y) from the platform in 2012-2013, with resultant first gas in October 2013.

The platform has a 50 MMscf/d test separator and produced water treatment, cyclone for sand (proppant) removal, power generation, crane, helideck, utilities and accommodation for thirty people. Gas is exported to West Sole through a 28" & 14" pipeline and 80 km on to Dimlington Gas Terminal through a 24" pipeline. The platform has initially been manned to support well drilling, fraccing and clean-up operations. However there are plans to reduce manning to daylight hours only. It has a capacity of 75 MMscf/d.

Production peaked at 60 MMscf/d in 2011 and was restored in 2014 with the two new wells. 2015 production up to August averaged 43 MMscf/d. The gas is largely methane with 1 mole% CO_2, 2.4 mole% nitrogen and minor condensate (0.1 bbl/MMscf).

Phase 3 of development is currently in the planning stage and, subject to all approvals, may include: an infill well ('J'-well); an 'Ada' appraisal well and if successful development drilling and tie-back; well workovers; and changes to facilities.

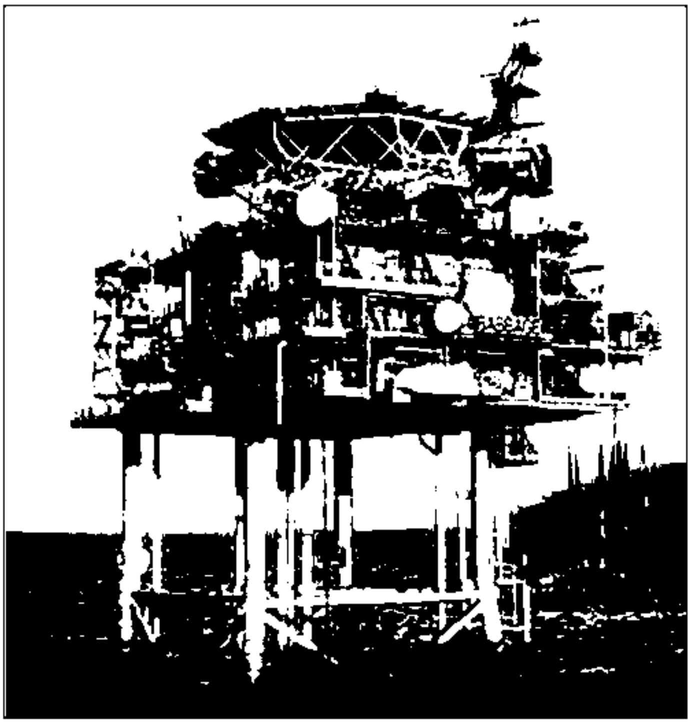


Figure 3-6 Babbage Platform

3.2.3. Reservoir description and In Place Volumes

Located in UKCS Block 48/2 in the Sole Pit Basin of the Southern Gas Basin, the Babbage Field sits in a north-west trending tilted fault block, with tightly fault-sealed compartments. The gas producing interval is from a Lower Leman Sandstone Formation reservoir of Rotliegendes age, which lies at a depth of 10,500 ft TVDSS. The reservoir is composed of an 80 ft thick upper interval and a 200 ft thick lower interval of aeolian, fluvial and sabkha facies. On both a local and regional scale these facies have been extensively studied and are fairly well understood. The diagenetic overprint on the facies is particularly significant due to the occurrence of illite which, where present, can significantly reduce permeability in the reservoir (blocking the pore throats). There appears to be a regional correlation between illite precipitation and timing and maximum depth of burial. Babbage appears to have been affected by such illitisation, in particular within the fluvial facies where permeability is markedly lower than in the associated aeolian facies. Aeolian and fluvial facies make up the large proportion of the reservoir, the remainder being sabkha, which acts as an effective barrier to vertical flow.

An additional control on reservoir quality and therefore its production, is the presence of fracture systems which intercept the wellbores of B1 and B3. These are naturally occurring and have been the subject of extensive study, both regionally and locally, and their impact modelled dynamically to account for the presence of water influx in the wells at high drawdown (i.e. scenarios are modelled in which the fractures are extended into the aquifer).

In 2014, the Operator adopted a five-layer lithostratigraphic, reservoir zonation scheme, developed by PM Geos, based solely on the 48/2-2 well data (including core). This scheme identifies the major wet-dry cycles and lithology packages. The major shale intervals mark layer boundaries and the scheme divides the Leman into units of similar lithology and reservoir properties (Figure 3-7). It has been recognised, however, that there is a larger variability of facies across the field than seen in this one well: for example, in 48/2a-4, the equivalent aeolian dune succession in 42/2-2 shows greater variability in frequency and variation in fluvial and aeolian facies, resulting in greater variability in reservoir quality. This, along with regional, offset well and field data, forms the basis for the Operator's static field model and consequently for dynamic reservoir simulation modelling. A number of revisions have been undertaken by the Operator and are still ongoing in order to obtain a better representation of the reservoir and its performance. The most recent full field modelling resulted in a downgrade of the 2007 GIIP of 461 Bcf to a range from 262 Bcf (P90) to 376 Bcf (P10). The Operator's 'Best Technical' case is 328 Bcf.

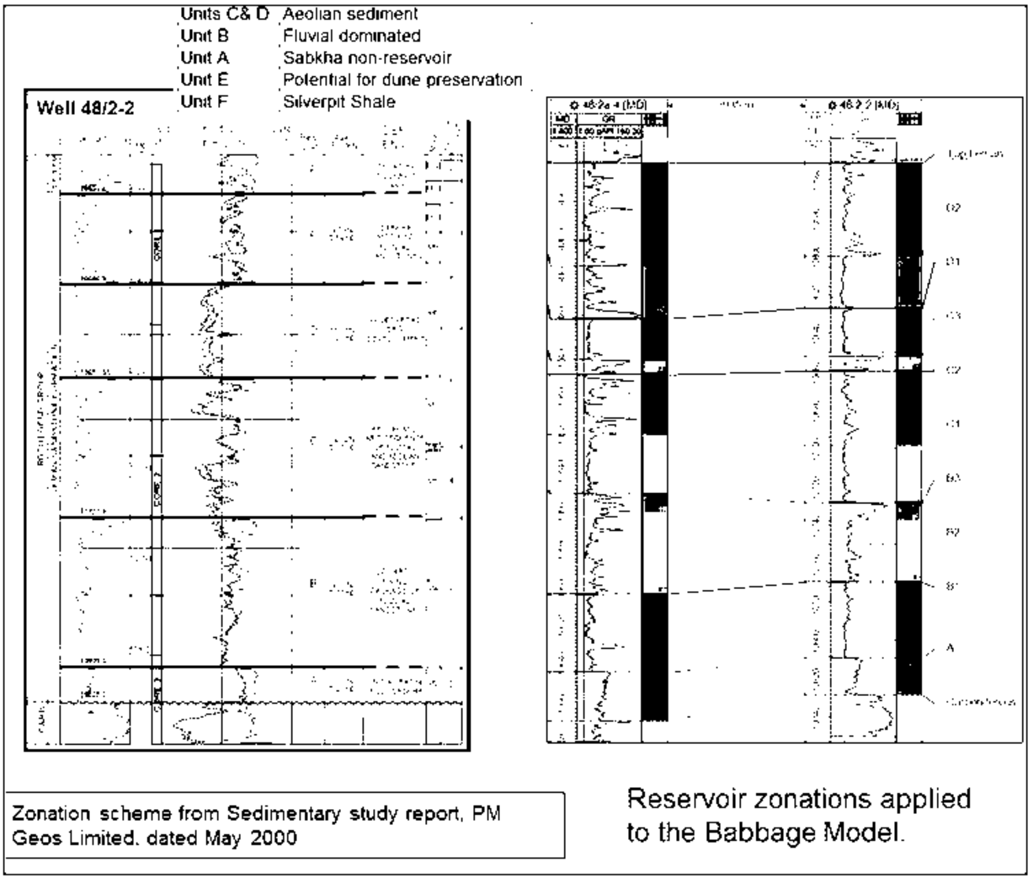


Figure 3-7 Lithostratigraphic sub-units of the Babbage Field

3.2.3.1. In Place Volumes

E.On has estimated the developed GIIP for the Babbage Field at 231 bcf in what they refer to as their 'Best Technical Case' and total GIIP 328 bcf.

Table 3-1 Babbage Field Gross Gas Initially in Place by Fault Block

Developed segments	E.On Preferred Technical Case (Bcf)	P90 (Bcf)	P10 (Bcf)	Undeveloped segment	E.On Preferred Technical Case (Bcf)	P90 (Bcf)	P10 (Bcf)
B3 Block	89	64	94	SW Block (Ada)	48	41	64
B1 Block	49	36	56	NW Block	7	5	9
B2 Block	84	77	101	NE Block	15	10	16
B5y Block	9	7	10	48/2-2 Block	27	21	28
Developed Total	**231**			**Undeveloped[9] Total**	**97**		

[9] Arithmetic addition of probabilistic volumes is a mathematically incorrect method of assessing the P90 or P10 totals.

3.2.3.2. *Depth Mapping*

The Operator performed an internal review of the seismic data quality, interpretation and depth conversion, using the CGG 2007 PrSTM Depth Migrated seismic across the Johnston and Babbage areas. This review has revealed that the existing interpretation is still relevant for Johnston and Babbage, but the results are not sufficiently confident over Ada (possible extension of Babbage, to the SE) to proceed with further work on the prospect. Consequently, an update of the inversion study using the 2011 GXT seismic, refined interpretation, wavelet and seismic velocity (for creating the low frequency model) is proposed to further de-risk the 'J' well area and Ada. Technical work is ongoing at this stage.

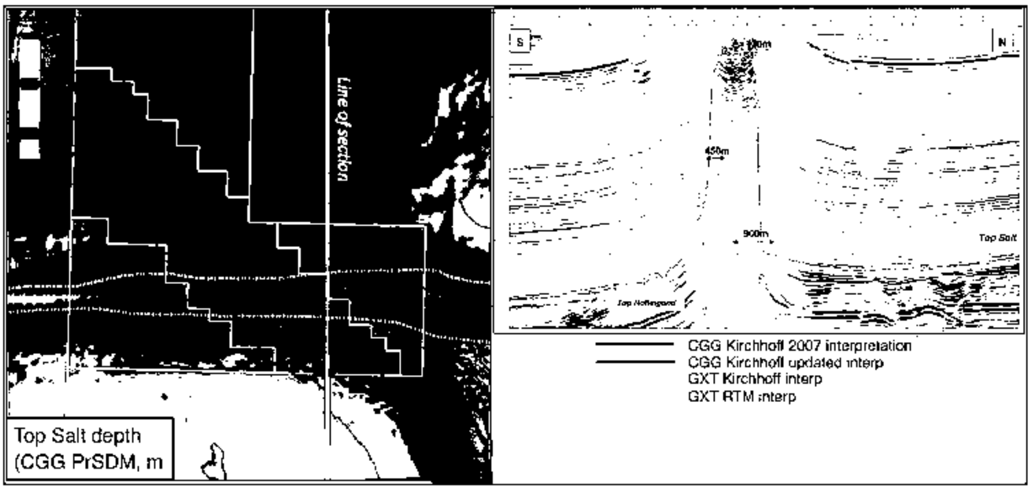


Figure 3-8 Salt Topography

3.2.4. Reservoir Performance and Production Forecasts

Figure 3-9 shows the field gas production history by well.

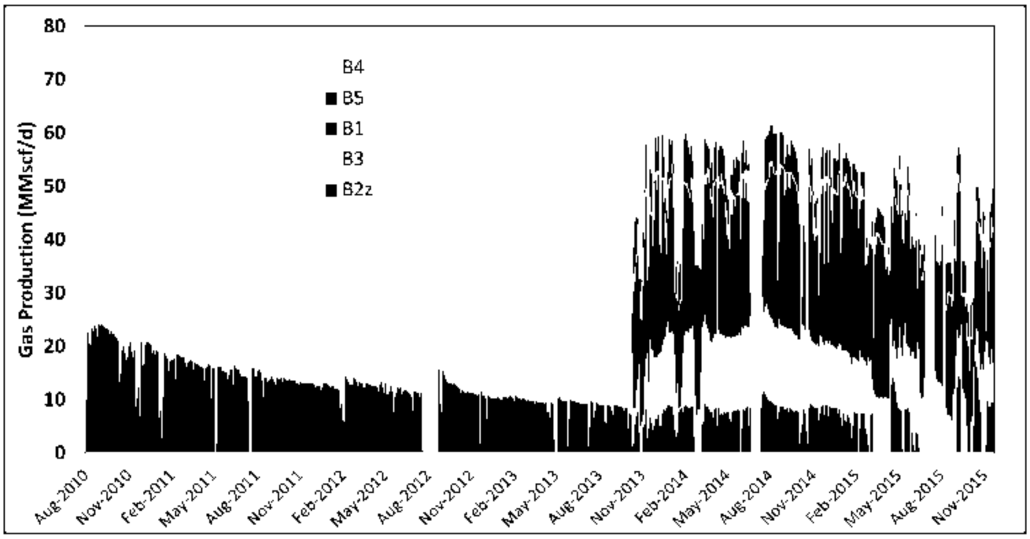


Figure 3-9 Babbage Well Production History

Declining gas rates are apparent in the three Phase-1 wells. However, production has been constrained by gas demand and facility constraints since the two Phase-2 wells were added. Figure 3-10 shows the data from Phase-2 well B5y.

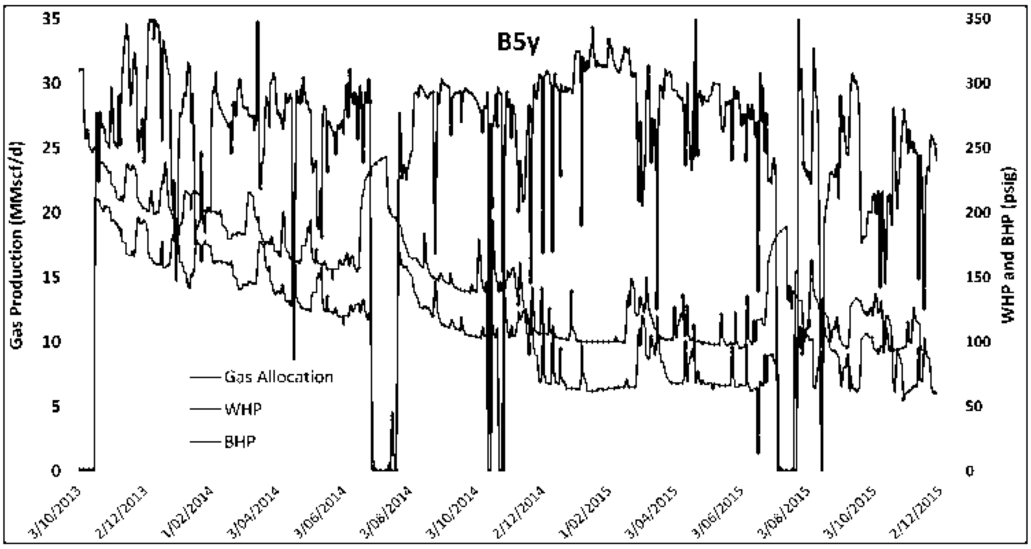


Figure 3-10 Babbage Phase-2 Well B5y Production History

Allocated gas production from well B5y has remained reasonably constant at 30 MMscf/d over two years of production. However, the flowing WHP (wellhead pressure) and BHP (bottom hole pressures) have declined or been reduced to maintain gas production. At a certain point the minimum WHP required for gas export will be reached and the gas rate will decline. Traditional production decline analysis is not appropriate in this situation so RISC has conducted flowing material balance analysis to analyse field performance.

RISC has also conducted exponential and harmonic rate decline analysis on wells where well head pressures have been uniform. Figure 3-11 shows exponential decline analysis of well B3, using a period of relatively uniform WHP.

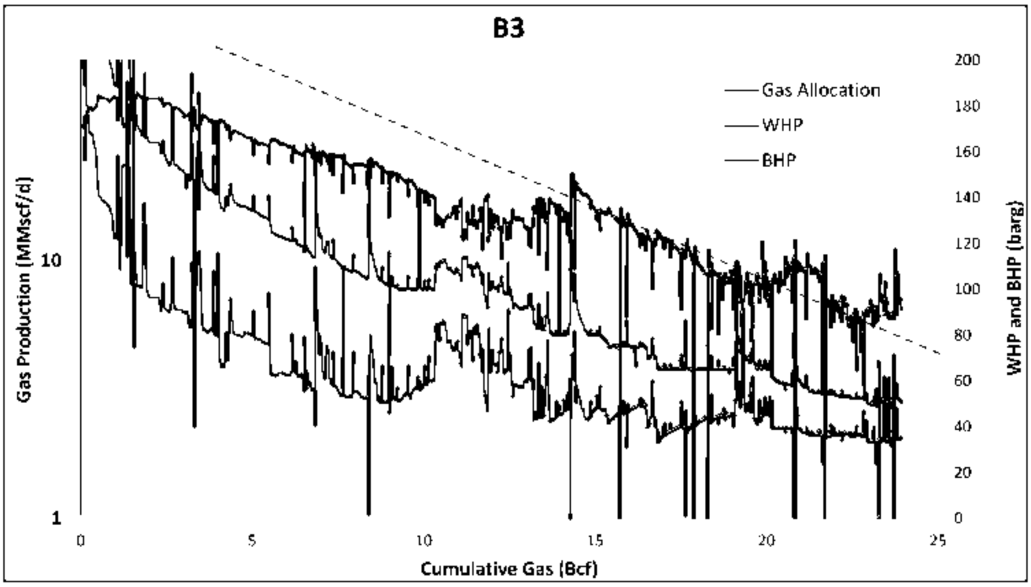


Figure 3-11 Babbage Well B3 Rate Decline Analysis

Babbage is divided into a number of fault segments as illustrated in Figure 3-12 with the development well locations.

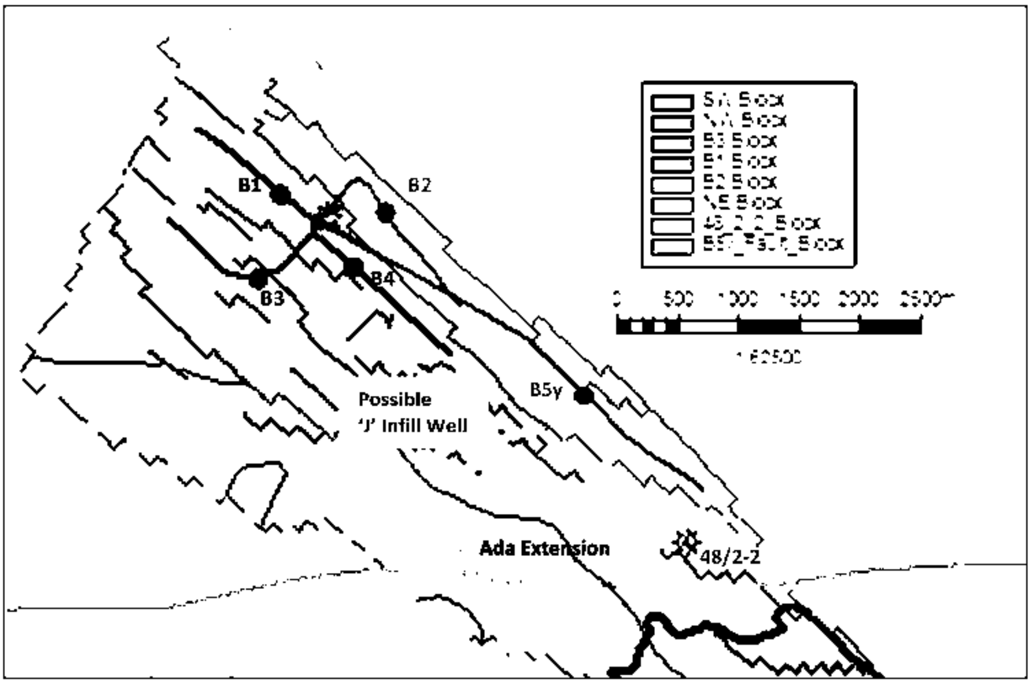


Figure 3-12 Babbage Fault Segments and Planned Wells

Communication between wells is limited due to faulting and the low permeability reservoir. RISC has conducted flowing material balance analysis for each individual well to estimate the GIIP connected to each well. Figure 3-13 shows an example of the analysis for well B1.

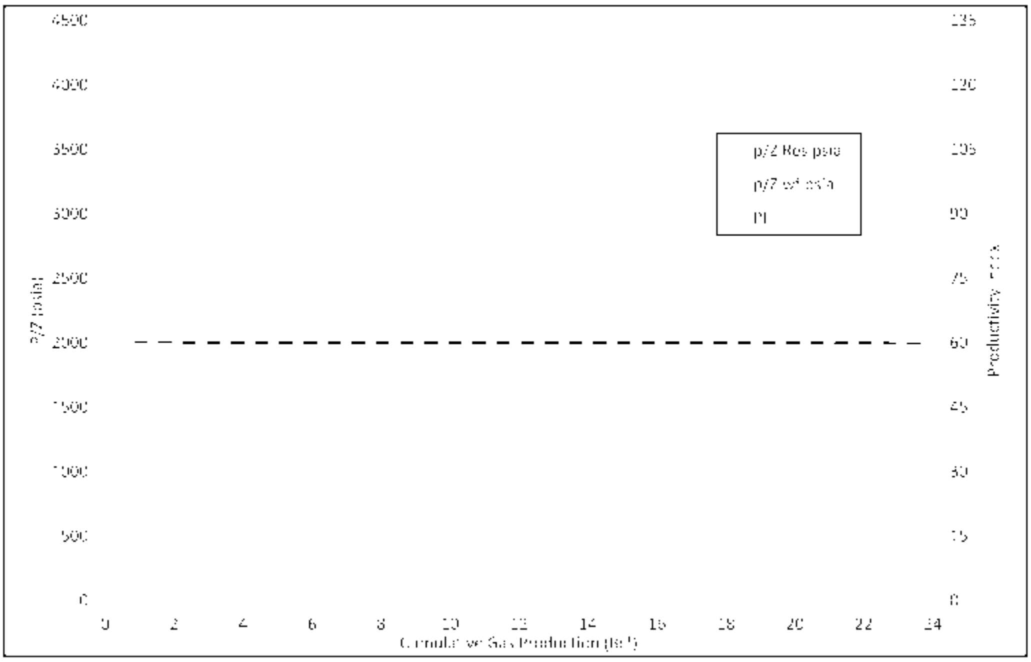


Figure 3-13 Babbage Well B1 Flowing Material Balance Analysis

The GIIP estimated by E.On from geological modelling and by RISC from flowing material balance for each well are shown in Table 3-2.

Table 3-2 Babbage GIIP (Bcf) by well

Well	GIIP from E.On Geological Modelling (Bcf)			GIIP Method #1 (RISC Flowing Material Balance)
	P90	P50	P10	
B1	36	49	56	22
B4				12
B3	64	89	94	37
Infill				n/a
B2	77	84	101	50
B5				75

There is reasonable agreement between the total GIIP ranges estimated from the different sources of data and analysis methods. The flowing material balance connected GIIP estimate supports E.On's developed Best Technical Case GIIP in aggregate.

The B3 segment contains well B3 and the proposed southern infill well. The infill well is targeting the GIIP not accessed by well B3.

RISC has estimated production forecasts (Figure 3-14) using the flowing material balance models and Decline Curve Analysis where appropriate.

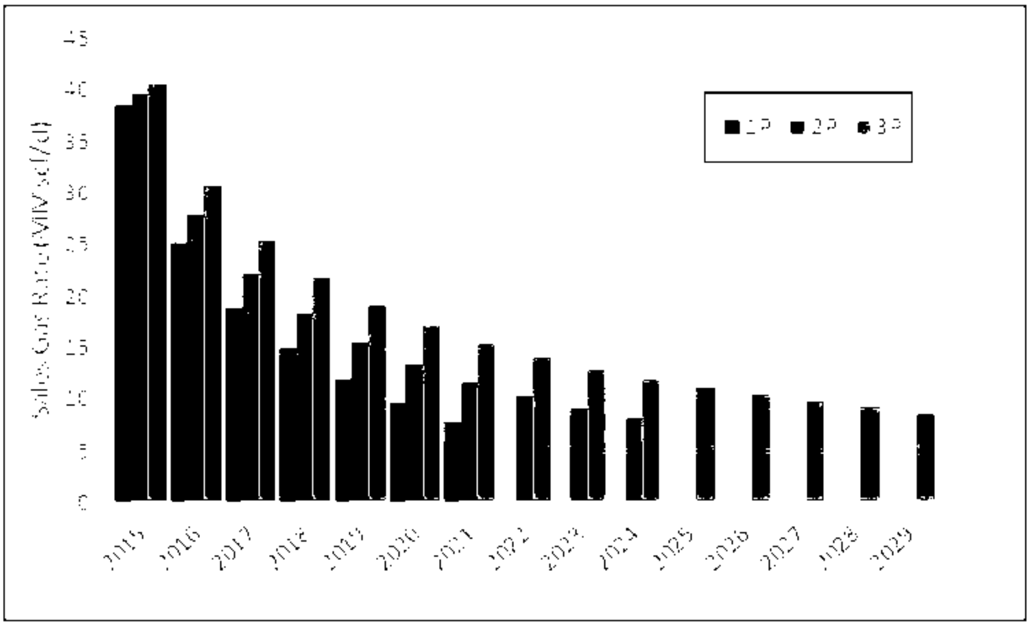


Figure 3-14 Babbage Gas Sales Forecasts

The Operator's forecast is based on a 3D simulation model. RISC has reviewed results presented by E.On in their 10 Nov 2014 Babbage dynamic simulation model report. The dynamic modelling work appears thorough with reasonable matches to well test results, PLTs and production history. The Operator's forecast is approximately mid way between RISC exponential and harmonic decline forecasts, and similar to RISC flowing material balance forecast.

RISC has used the exponential and harmonic decline forecasts for 1P and 3P developed reserves and used a mid forecast for 2P.

Babbage sales gas has 1 mole% CO_2, 2.4 mole% nitrogen and an estimated heating value (HHV) of 37.8 MJ/m^3 (1015 BTU/scf). Condensate production is effectively zero.

3.2.5. Future Development and Costs

3.2.5.1. Babbage 'J' Infill well (Block 2-2)

The Babbage 'J' infill well (48/2-2 area) is targeted in a region to the SE of the platform to access undrained gas areas. In the October 2014 TCM the well was described as having a 3,500m step-out (from the platform) with a 4,000ft horizontal section and five fracs, at a cost of £77.5 MM (or £76.3 MM for a subsea well). This well is still in planning and under discussion within the JV. A proposed schedule for well design, planning and approvals is shown in Figure 3-17 below.

If the J well is successful, E.On plans to develop of potential southeast extension of Babbage called Ada (discussed in section 6.4.1).

The Operator's mid-case GIIP for J infill is 68 Bcf, with estimated recovery of 28 Bcf, with marginal economics.

If drilled the proposed infill well would target the GIIP in fault segment B3 not accessed by well B3. RISC estimates that it will access 30 to 50 Bcf GIIP, and has generated a range of production forecasts as shown in Figure 3-15.

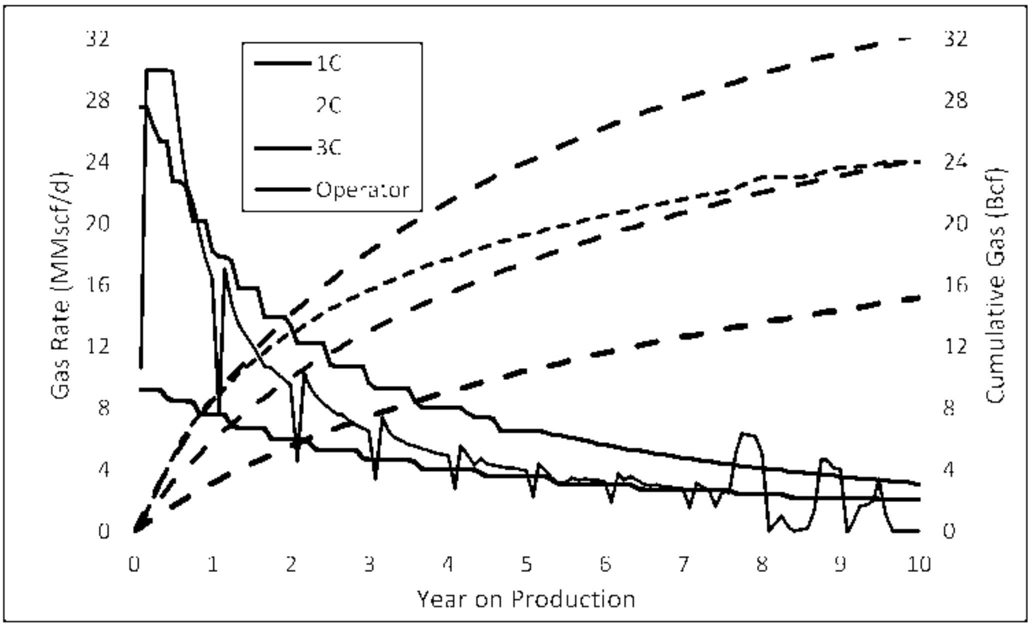


Figure 3-15 Babbage Southern Infill Well Gas Sales Forecasts

Babbage wells have had initial rates of between 10 and 45 MMscf/d (average 24). RISC estimate an initial rate for the southern infill of 10 to 30 MMscf/d. The Operator has presented a similar P50 recovery as RISC but higher initial well rate. The resources associated with the potential southern infill well are classified as contingent. Table 3-3 shows the potential gas recovery over 15 years.

Table 3-3 Babbage Contingent Resources

Contingent Resource Sales Gas (Bcf) Gross	1C	2C	3C
J Infill Well	18	28	37

The block also contains the Hawking and part of the Cobra gas discoveries. These require further appraisal and are currently viewed as uneconomic (discussed in sections 6.4.2 and 6.4.4). There are also exploration prospects in the permit.

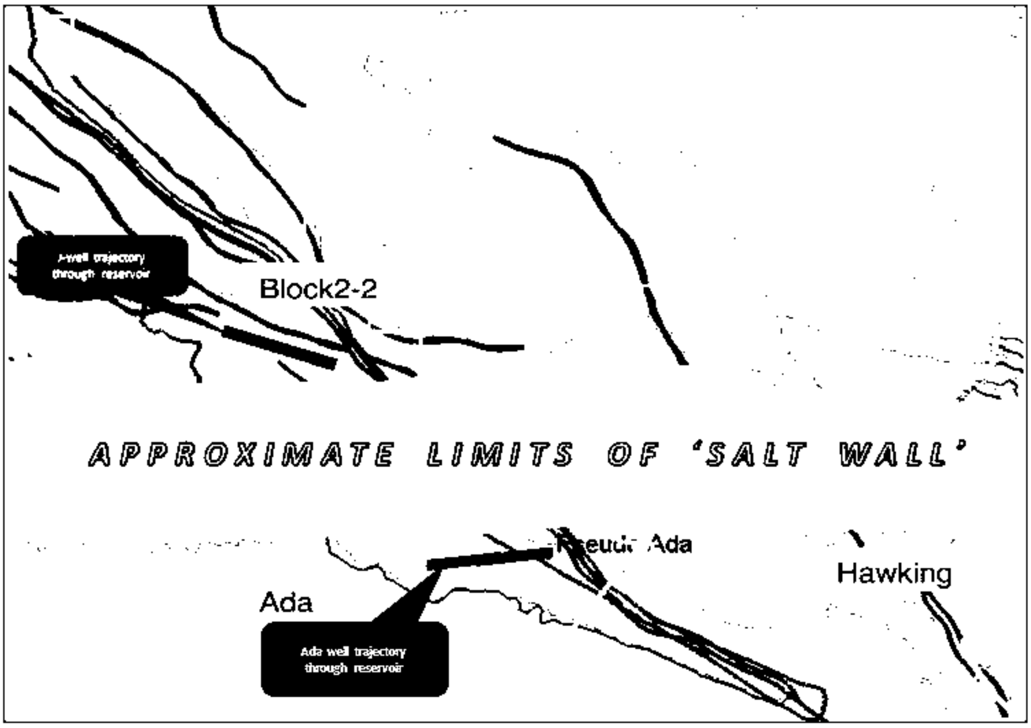


Figure 3-16 Babbage Infill Well and Ada Locations

Both the Babbage 'J' infill well in Block 48/2-2 and the 'Ada' Prospect targets lie immediately adjacent to the 'salt wall' which straddles the southern portion of the Babbage structure.

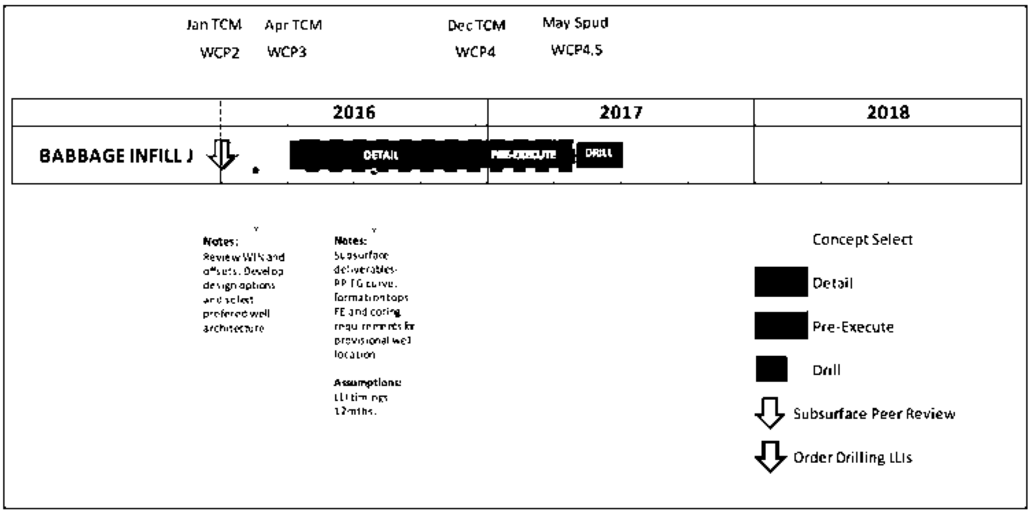


Figure 3-17 Babbage 'J' Infill Well Project Schedule

3.2.5.2. *Capital Costs*

The results of the infill well are not included in our production forecasts for reserves and no other development activities are planned hence no capital costs are forecast.

3.2.5.3. *Operating Costs*

Operating costs were approximately £25m gross in 2015, this included approximately £7m gross for the Dimlington Freon removal project. According to the 2016 budget there are no further costs for this project in 2016 as costs were accrued in 2015. Gross operating costs are forecast to be approximately £23-30m (£12-15m net) in 2016 depending on whether a well intervention (coiled tubing campaign) is conducted. We assume that the historical performance on which our production forecast is based will have included some well intervention activity therefore have included it in our cost forecast. Beyond 2016 gross operating costs are budgeted to be £15-20m gross 2017-2019, with gradual reductions thereafter.

3.2.5.4. *Decommissioning Costs*

The plan is to P&A wells and remove all facilities. E.On have conducted a level 1 (-50%/+75%) cost estimate based on engineering judgements and analogy. The estimate is £78m gross, RISC considers this to be reasonable. £2.8m gross is budgeted for abandonment of 48/02-1 exploration well in 2016.

3.2.6. Reserves

RISC's estimates of reserves at 1/1/2015 are shown in Table 3-4.

Table 3-4 RISC Estimate for Babbage Field Reserves as at 1 January 2015

Babbage Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	18.8	0	25.6	0	43.1	0

3.2.7. Contingent Resources

Additional volumes that could be produced in the event of higher gas prices, by an extension of field life beyond the economic limit, have been assigned as contingent resources.

Table 3-5 RISC Estimate for Babbage Field Contingent Resources

Babbage Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Contingent Resources after the Economic Limit	5.9	0	10.2	0	9.7	0
J Well	8.5	0	13.1	0	17.4	0

3.3. Caister Murdoch System and Quadrant 44 Area

3.3.1. Overview

The Caister Murdoch System (CMS) consists of the Murdoch complex with E.On tiebacks from Caister NUI, subsea wells in Hunter and Rita. Gas is aggregated at Murdoch and exported via the CMS export line to Theddlethorpe gas terminal. E.On has field interests in the CMS Area (Table 3-6).

Table 3-6 E.On interests in CMS Area

Field	E.On Interest	Development
Caister	40%	NUI tied back to Murdoch K Platform
Hunter	79%	One subsea well tied back to Murdoch, stopped production in 2010 and restarted in 2015
Rita	74%	Dual lateral well tied back via Hunter. Shut-in during 2015
Orca	23.4685%	Three well platform development exporting to D/15-FA in Dutch sector
Minke	42.67%	Single subsea well tied to D-15. Ceased production in 2011
Infrastructure		
CMS Pipeline	20%	

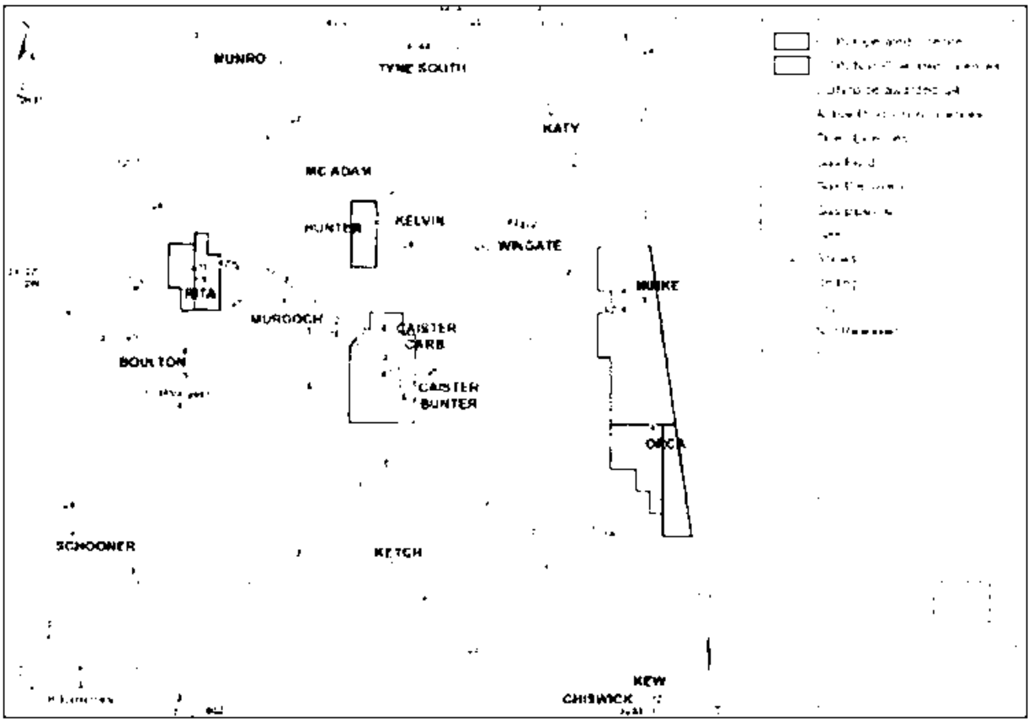


Figure 3-18 Location Map of Caister Murdoch System Fields

The Minke and Orca Fields straddle the UK/Netherlands border.

The Caister Murdoch System is centred on the Murdoch complex. The fields in which E.On has an interest are Caister, Hunter and Rita. Caister is developed with eight wells and a Normally Unmanned Installation (NUI) satellite platform. Rita is developed with a dual lateral well tied back to the Hunter field via a 14km, 8" carbon steel pipeline. Hunter was developed with a single subsea well and an 8km, 8" subsea tieback to Murdoch. Production ceased in 2012 but the subsea pipeline is still used for Rita production. In 2015 Rita was shut-in and production restarted from Hunter. There is also a flexible flowline from Rita to Murdoch that was disconnected in 2012. Gas is aggregated at Murdoch and end exported via the 26", 188km CMS export line to Theddlethorpe gas terminal. The NUI is remotely operated from Theddlethorpe. The layout of Hunter, Caister and Rita is shown schematically below:

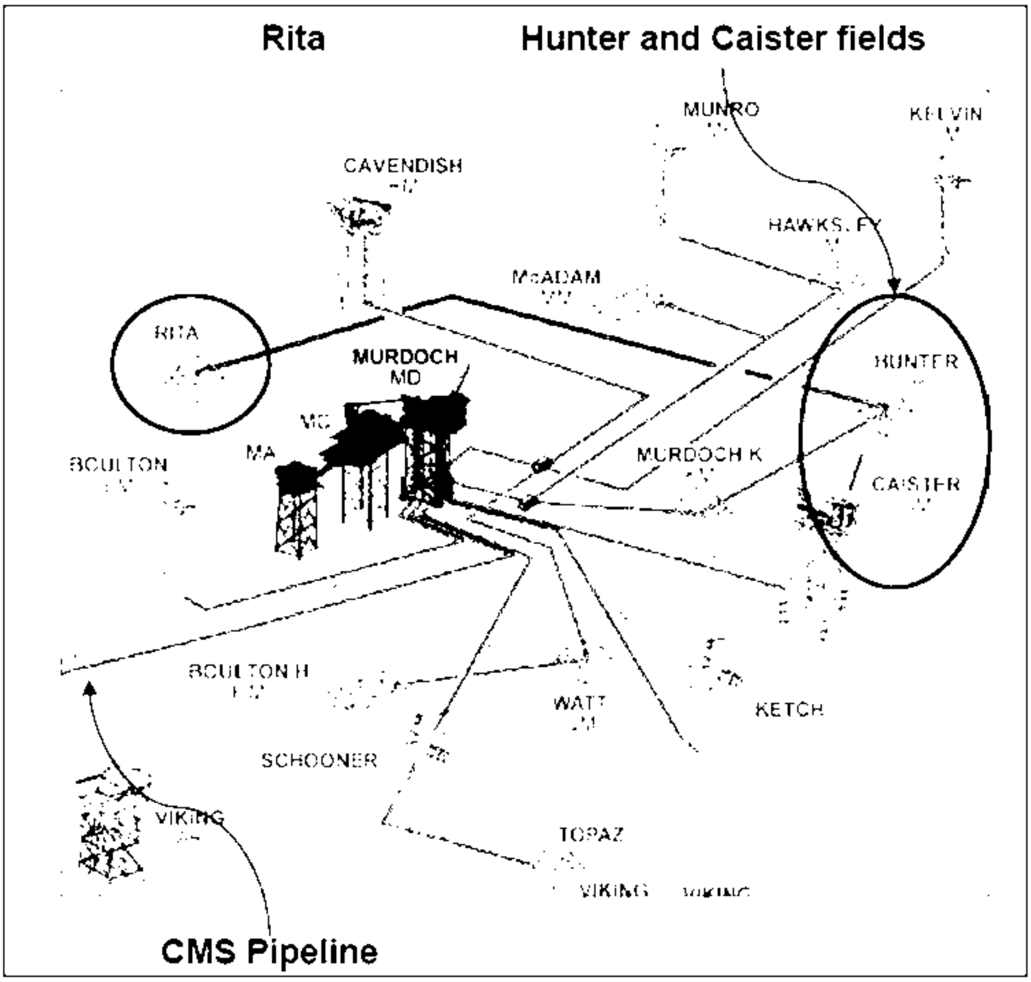


Figure 3-19 Hunter, Caister and Rita Development Schematic

3.4. Caister Gas-Condensate Field, block 44/23a (Licence P.452)

3.4.1. Overview

The field consists of two reservoir formations discovered in 1968. Production started in 1993 via a NUI with eight production wells drilled. The gas has a CGR of about 5 bbl/MMscf.

3.4.2. Development and Current Status

Developed in 1993 using a NUI in 42m water depth with twenty-five year design life. Asset Integrity Rectification (AIR) campaign is essential to allow for extended life and continued operations beyond end-2015. Integrity issues mean that facility is unlikely to continue production beyond its twenty-five year design life (2018). According to the Operator's 'Cessation of Production' document (January 2016), "The asset integrity rectification project is deeply uneconomic and there are no known remaining development opportunities in the Caister Field."

No further reservoir development is planned.

3.4.3. Reservoir Description and In Place Volumes

The Bunter reservoir is good quality with an active aquifer developed with three wells A1, A3 and A8. E.On estimate a GIIP of 172 Bcf with 77 Bcf or 45% recovery to date. Bunter reservoir gas contains 15 mole% CO_2. Production from the Bunter reservoir has ceased.

The Carboniferous reservoir is divided into northern and southern accumulations. E.On estimate the north, developed with two wells A4 and A5, to contain 62 Bcf GIIP. It has recovered 18 Bcf or 30% recovery to date. The southern accumulation is estimated to contain 187 Bcf GIIP, developed with three wells A2, A5 and X9. It has recovered 134 Bcf or 79% to date. Only two wells (A5 and X9) can produce continuously at 4 and 7 MMscf/d respectively, with occasional cyclic production from A2 due to water loading. Carboniferous reservoir gas contains less than 3 mole% CO_2.

3.4.4. Reservoir Performance and Production Forecasts

The Bunter reservoir has not produced in 2015 and the Carboniferous reservoir produced at up to 9 MMscf/d with an average of 5 MMscf/d.

Figure 3-20 shows Caister gas sales history since Jan-2014 with sales declining from 10 to 5 MMscf/d.

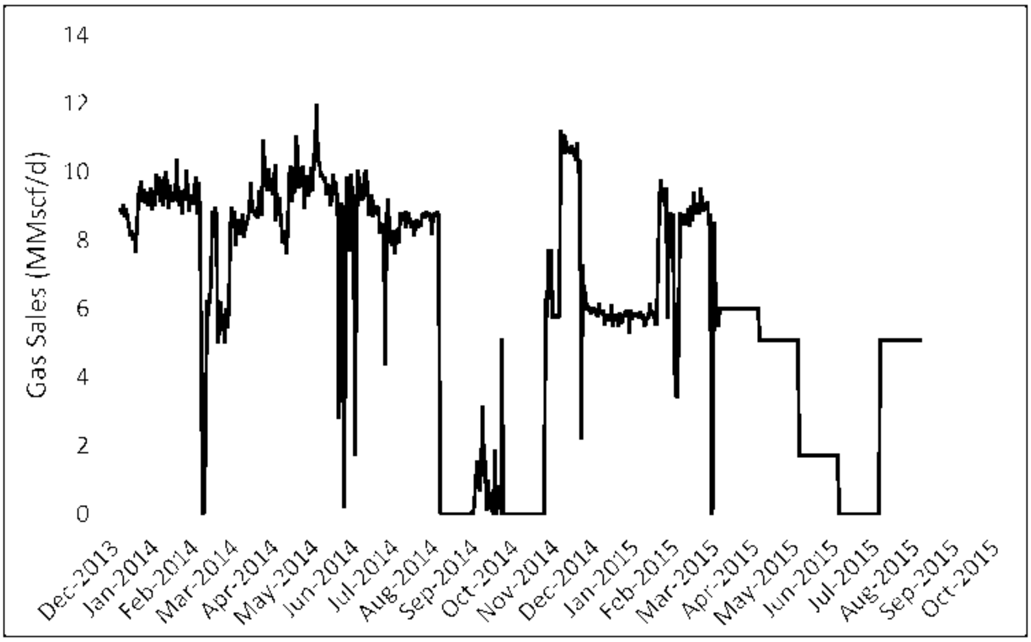


Figure 3-20 Caister Recent Gas Sales History

No further production is expected from Caister.

3.4.5. Future Development and Costs

The Caister NUI was to reach the end of its design life in 2018, however integrity rectification works are required to maintain asset integrity to meet design life. Production ceased in late 2015, with no further planned development activity.

3.4.5.1. Capital Costs

E.On was treating rectification works as operating costs therefore there are no capital costs for these late life assets.

3.4.5.2. Operating Costs

Operating costs are very sensitive to whether production from Caister proceeds beyond 2015. We have assumed production ceased at end 2015 but surveillance costs of £1m pa gross will be incurred until decommissioning occurs in 2018.

3.4.5.3. Decommissioning Costs

Decommissioning plans involve full removal of topsides and jacket with onshore disposal, flushing of pipelines and P&A of wells.

A detailed Caister decommissioning cost estimate has not been prepared. The estimated range of costs is £50m – £100m. We recommend using a mid point until firm plans are drawn up and experience is gained from other abandonment programmes by the same Operator (Conoco Phillips, who are also abandoning the V fields).

Hunter and Rita P&A and decommissioning cost estimates are very immature. Abandonment of Rita subsea well and subsea facilities is estimated to cost £12m gross and Hunter £14m gross.

3.4.6. Reserves

RISC's estimates of reserves are shown below. As production is currently shut-in, the reserves effective 1/1/15 are equal to 2015 production. As a result the 1P, 2P and 3P are identical.

Table 3-7 RISC Estimate for Caister Field Reserves as at 1 January 2015

Caister Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	0.6	0.003	0.6	0.003	0.6	0.003

3.5. Hunter Gas-Condensate Field, block 44/23e (Licence P.452)

3.5.1. Overview

Hunter was discovered in 1992 and was acquired by E.On in September 2005. Hunter started production in 2006 from a single subsea well tied back to Murdoch K Platform.

3.5.2. Development and Current Status

Hunter was developed with single subsea well and an 8km, 8" subsea tieback to Murdoch. Gas from the Hunter field is exported via the Murdock K to the Murdoch platform and onward via the Caister Murdoch System (CMS) to the ConocoPhillips-operated facilities at Theddlethorpe. Hunter production ceased in 2010 but the subsea pipeline remained in use for Rita production. With Rita offline in late 2015, Hunter's production was restarted with cyclic production.

3.5.3. Reservoir Description and In Place Volumes

The Bunter Sandstone reservoir comprises braided fluvial and alluvial plain deposits characterized by sandstones and siltstones with local shales. Reservoir quality is generally moderate with average porosity at 15% and permeabilities in the 1-10 mD range (up to 1000 mD). E.On estimated GIIP in 2006 to be 9.1 – 21.5 – 58 Bcf (P90 – P50 – P10).

3.5.4. Reservoir Performance and Production Forecasts

Production ceased in 2010 with an estimated 2.2 Bcf produced giving an implied recovery factor of 10%. ROV work may be required to maintain long-term production. However, cyclical production is expected and it is unclear whether further subsea work will progress.

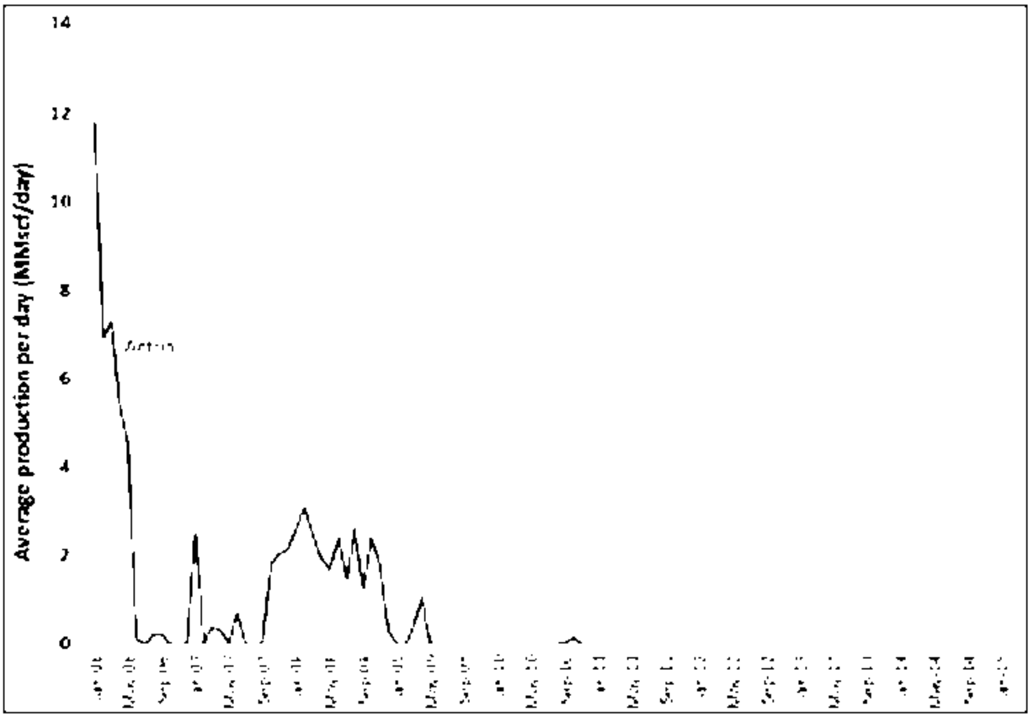


Figure 3-21 Hunter Gas Production History

Given that production from Rita is currently shut-in (and therefore doesn't back out Hunter production), we have assumed intermittent production from Hunter for the next two years as summarised below (Table 3-8 & Figure 3-22).

Table 3-8 Hunter field forecast production

Quarter	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4
Gas rate, MMscf/d	4.0	0	4.0	0	2.0	0	2.0	0

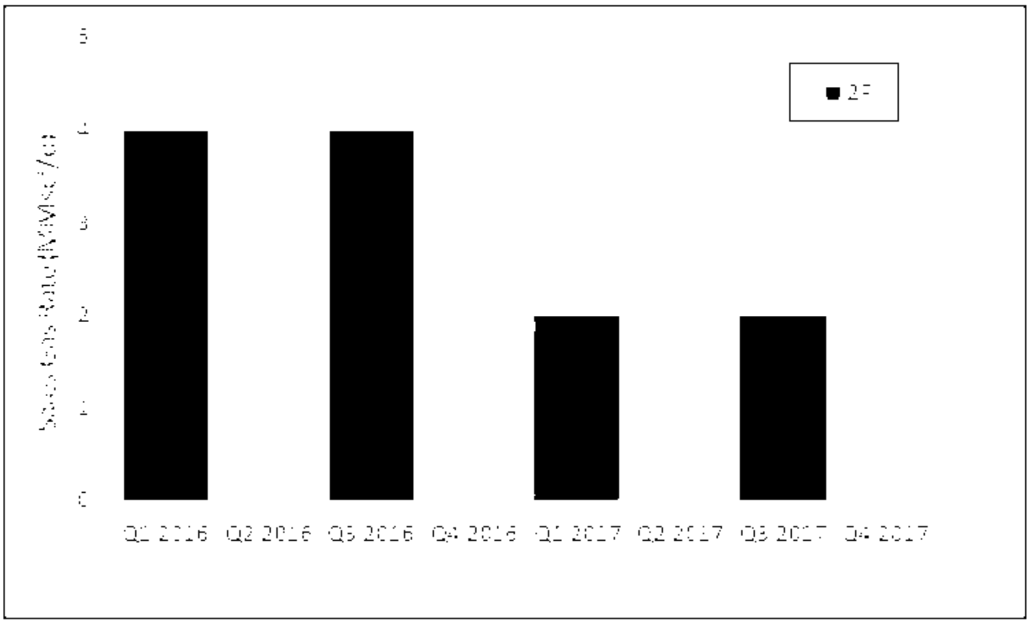


Figure 3-22 Hunter Gas Sales Forecasts, Annual Quarterly Rates

3.5.5. Future Development and Costs

Operating costs are estimated to be approximately £1 million pa gross. Decommissioning costs are estimated to be £14 million gross.

3.5.6. Reserves

RISC's estimates of reserves are shown in Table 3-9.

Table 3-9 RISC Estimate for Hunter Field Reserves as at 1 January 2015

Hunter Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	1.2	0	1.2	0	1.2	0
The Net Present Value for Hunter was calculated using 830 Btu/scf.						

3.5.7. Contingent Resources

RISC assigns no Contingent Resources.

3.6. Johnston Gas Field, Block 43/27a (Licence P360)

3.6.1. Overview

The Johnston Field is a dry gas accumulation located within blocks 43/26a and 43/27a in the UK Southern North Sea in approximately 39 m depth of water, 85km north-east of Easington. Gas is transported across Ravenspurn North to the Easington Gas Processing Terminal. E.On is the Operator with 50.1% interest.

3.6.2. Development and Current Status

The discovery well was drilled in 1990 and after drilling one appraisal well in 1991, a development plan was submitted and approved in 1993. Initially two horizontal development wells were drilled from a four slot subsea template, tied back to Ravenspurn North through a 12" pipeline. Commercial production commencing in October 1994. An additional four subsea wells have been drilled with two tied back to the template. Wells J1, J2 and J3 have watered out, J4 produces cyclically due to liquid loading. There are no firm plans for further development.

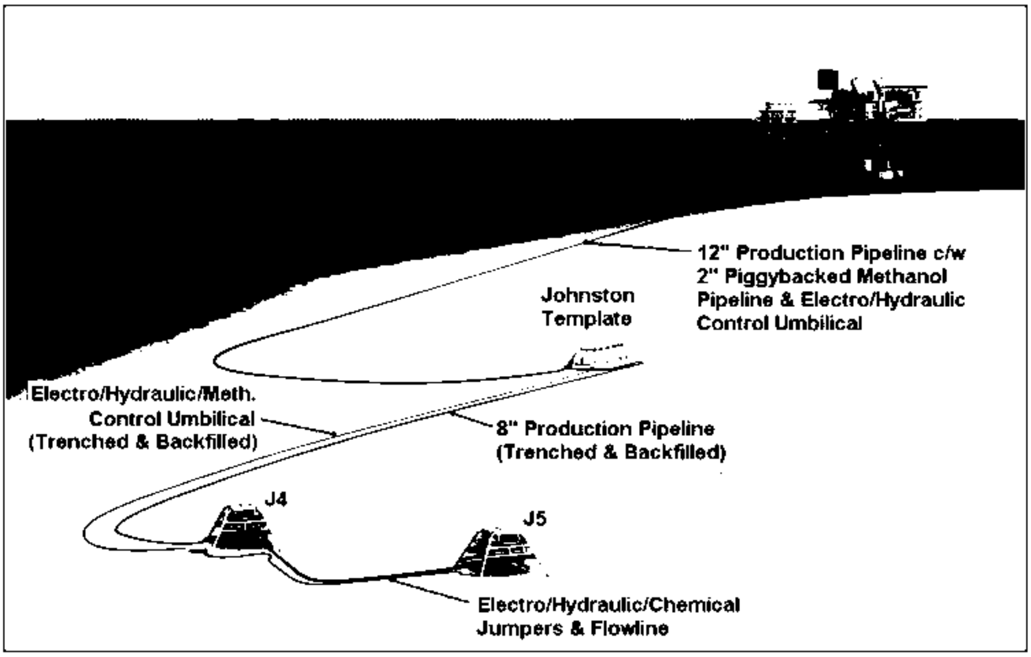


Figure 3-23 Johnston Subsea Tieback

The last well J6 was drilled in October 2013 but performance has been disappointing and hydraulic fracturing is being considered. The well is currently shut-in due to a mechanical failure at the subsea wellhead. It is unclear if and when the wellhead will be repaired to restore production.

2015 production up to end August has averaged 8.2 MMscf/d.

3.6.3. Reservoir Description In Place Volumes

The field is a structural trap, fault bounded to the SW and dip-closed to the north, east and south. High quality 3D seismic data, enhanced by seismic attribute analysis has been used to establish the field geometry and optimum well locations. The sandstone reservoir is Early Permian, Lower Leman Sandstone Formation of the Upper Rotliegend Group. This reservoir is a series of interbedded aeolian dune, fluvial, and clastic sabkha lithofacies resulting in variable reservoir quality. The top seal and fault bounding side seal are provided by the overlying clay stone of the Silverpit Shale Formation and the evaporite dominated Zechstein Supergroup.

E.On estimate the P50 GIIP to be between 378 and 402 Bcf from material balance and history matched simulation.

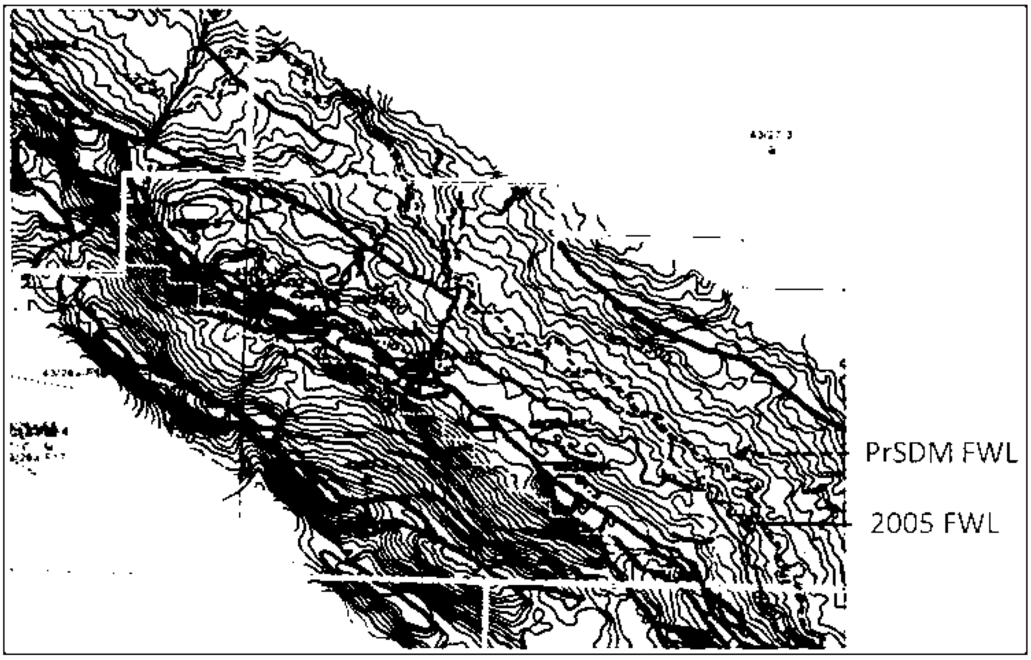


Figure 3-24 Depth Structure Map of Johnston Field

3.6.4. Reservoir Performance and Production Forecasts

Gas production started in Sept-1994 with a peak monthly production of 90 MMscf/d. Cumulative production at end 2014 was 237 Bcf with a rate of 15 MMscf/d.

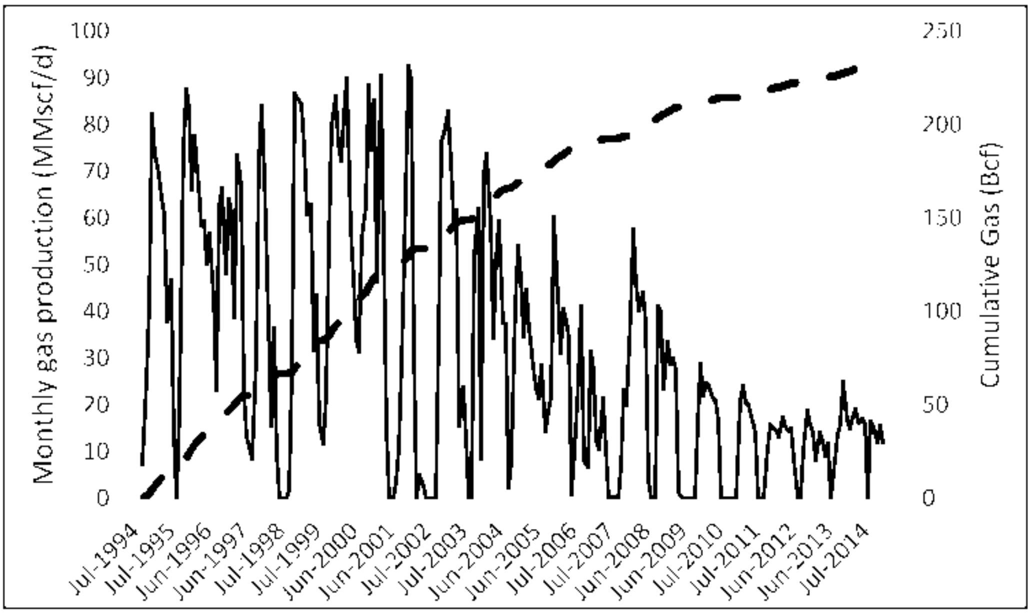


Figure 3-25 Johnston Gas Production History

The recent daily production history of the three active wells is shown below. Field monthly production is shown from Mar-Aug 2015.

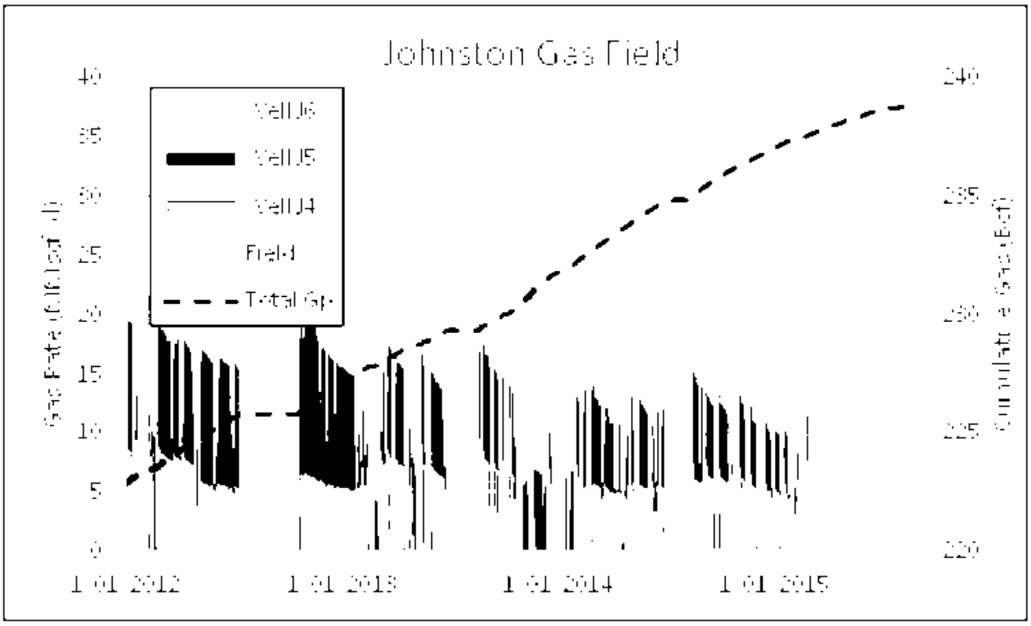


Figure 3-26 Johnston Recent Gas Production History

- Well J4 cannot produce stably due to a high and increasing Water-Gas-Ratio (WGR) of 63 bbl/MMscf and pressure depletion. It is produced cyclically with shut-in period to re-charge reservoir pressure. The historic well uptime has been 54%.
- Well J5 producers stably with a WGR of 18 bbl/MMscf. The historic well uptime has been 80%.
- Well J6 was shut in Jan-2015 due to mechanical problem with the subsea tree. It is not clear if and when the tree will be repaired. The WGR has increased from an initial 10 bbl/MMscf to 120 bbl/MMscf.

RISC has reviewed the historic decline trend of the three active wells up to 28/2/2015 and generated production forecast as follows:

- Decline analysis has been conducted on each producing well using daily production data up to 28 Feb 2015. The forecast has then been matched to total field production up to end August 2015 and forecast from that point.
- The 1P forecast is based on exponential decline fitted to well J4 and J5. Well uptime is estimated at 75% reducing to 45% once well rates drop below the critical rate and production becomes cyclic.
- The 3P forecast is based on harmonic decline fitted to well J4 and J5. Well uptime is estimated at 85% reducing to 65% once well rates drop below the critical rate and production becomes cyclic.
- The 2P forecast is mid way between the 1P and 3P.

The developed reserves forecasts are shown in Figure 3-27.

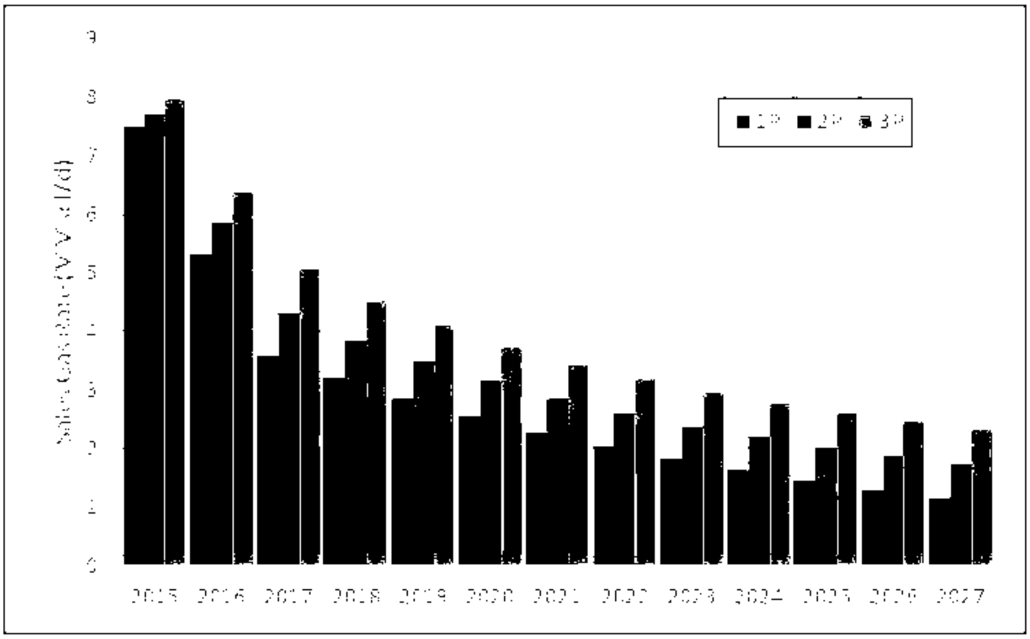


Figure 3-27 Johnston Gas Production Forecast

Gas sales are estimated to be 97.2% of production based on historical data. The gas heating value (HHV) is estimated to be 37.2 MJ/m3 (998 BTU/scf).

3.6.5. Future Development and Costs

No further development of the field is expected.

3.6.5.1. Capital Costs

No further capital expenditure is forecast.

3.6.5.2. Operating Costs

E.On forecasts net annual OPEX to reduce from \$2.2m (£2.8m gross) in 2015 to \$1.5m (£2.0m gross) in 2016 to \$0.7m (£0.9m gross) in 2017 and more modest (10% pa) reductions beyond 2017. RISC has seen no information on operating costs and the rationale for the reductions. We understand some of the costs will be tariff related and therefore will decline with production. We also expect cost reduction measures to be implemented in the current environment. However in the absence of explanation we believe the forecast reductions to be optimistic. We therefore estimate a 25% reduction in OPEX from 2015 levels in 2016 and 2017 and 10% pa thereafter. This assumes that no material campaign maintenance or well or subsea intervention is required over remaining field life.

3.6.5.3. Decommissioning Costs

E.On estimates £47m (gross) decommissioning costs. We consider this estimate to be reasonable.

3.6.6. Reserves

RISC's estimates of reserves are shown in Table 3-10.

Table 3-10 RISC Estimate for Johnston Field Reserves as at 1 January 2015

Johnston Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Sales Gas (Bcf)	Condensate (MMBbl)	Sales (Bcf)	Condensate (MMBbl)	Sales (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	6.5	0	7.9	0	9.2	0

3.6.7. Contingent Resources

RISC assigns no Contingent Resources.

3.7. Minke-Orca Gas-Condensate Fields, blocks 44/29b & Q44/30 (Licences P454, P611)

3.7.1. Overview

Minke and Orca gas field straddle the UK/Dutch border. Minke is a single well subsea development tieback to the D15 Platform facility in Dutch waters with gas exported via the Noordgastransport pipeline to Netherlands. Minke started production in 2007 and ceased in 2011 after producing 5.5 Bcf. Decommissioning is required. The D15 reception facilities are now used by Orca.

3.7.2. Development and Current Status

Orca was developed with three wells from the Orca Platform with gas exported 20 km to the D/15-FA facility.

From D/15-FA gas is transported via the 36-inch diameter, 130 kilometre long Noordgastransport (NGT) extension to L/10, for onward transportation via the existing Noordgastransport pipeline to the Uithuizen terminal.

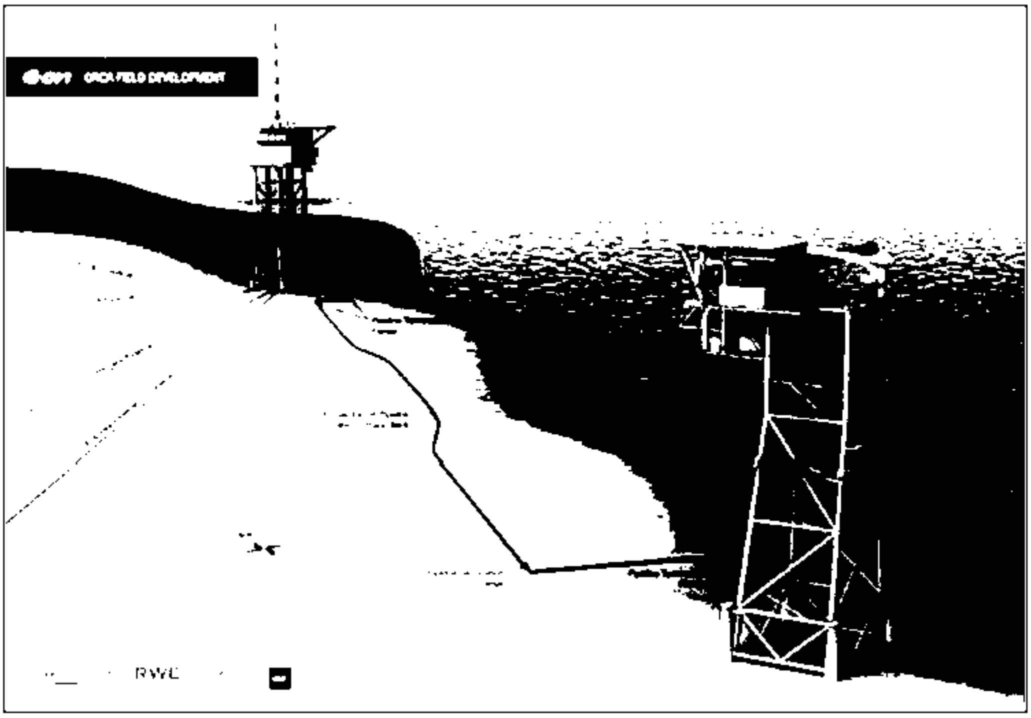


Figure 3-28 Schematic of Orca Development

Orca has been unitised with UK share set at 49%. E.On's share of Orca is 23.4685%.

3.7.3. Reservoir Description and In Place Volumes

The gas has 3 mole% CO_2 and 20-26% Nitrogen. Less than 0.3 bbl/MMscf of condensate is extracted. Due to the high Nitrogen content, the heating value (HHV) is low at 737 BTU/scf (27.5 MJ/m3).

3.7.4. Reservoir Performance and Production Forecasts

Orca gas production peaked at 35 MMscf/d early 2014 and declined to 5 MMscf/d. Well A2 watered out and stopped production in Feb-2014. Well A3 started production after A2 watered out but production has become cyclical and effectively stopped July-2014. Well A1 produces steadily.

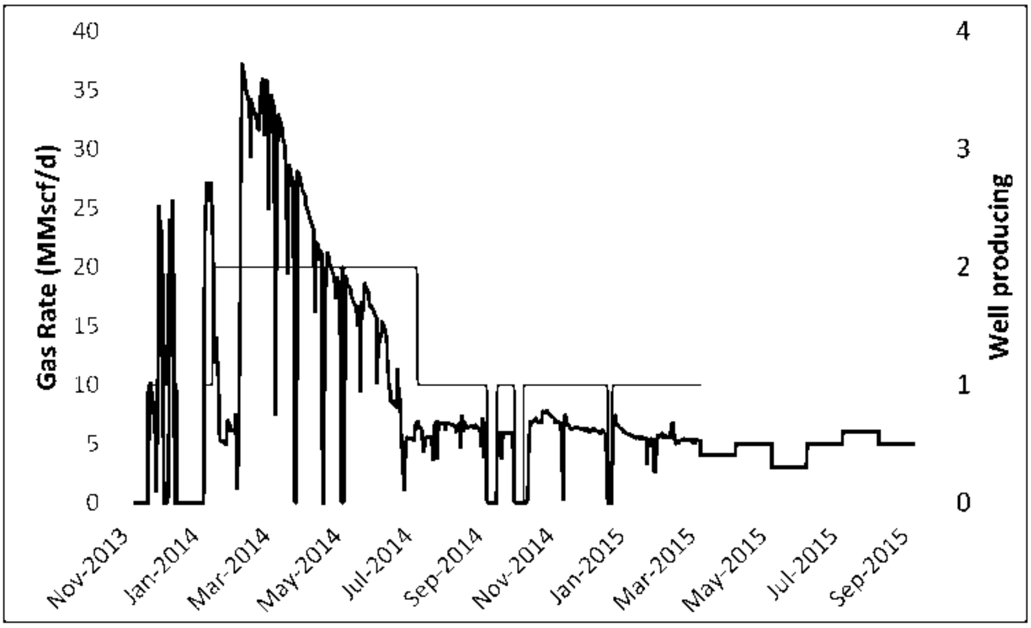


Figure 3-29 Orca Production History

RISC has analysed uptime and fitted a range of decline curves and used these to generate production forecasts. The forecasts to the economic limit are shown in Figure 3-30.

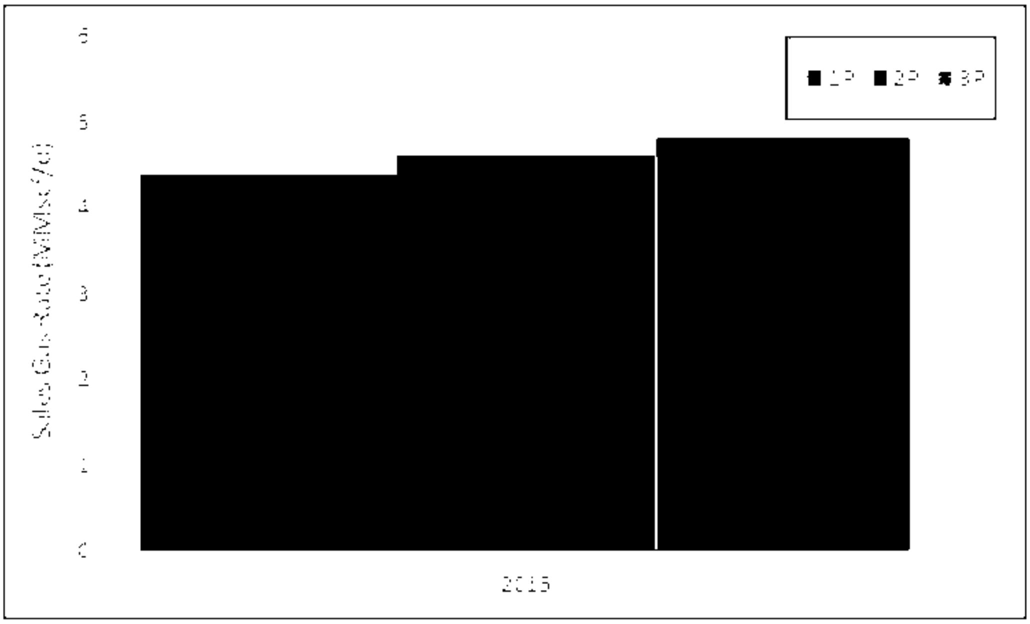


Figure 3-30 Orca Production Forecasts

Gas sales are estimated to be 97% of production based on historical data. The gas heating value (HHV) is estimated to be 27.5 MJ/m3 (737 BTU/scf). Condensate production is negligible.

3.7.5. Future Development and Costs

No further development is planned.

[redacted]

3.7.5.1. *Operating Costs*

Orca field 2016 OPEX is forecast to be approximately £10m gross (£4m net) beyond this OPEX is forecast to be approximately £4m gross (£1.5m net).

3.7.5.2. *Decommissioning Costs*

It is planned to remove the Orca topsides and jacket with piles cut 6m below the mudline. Wells will be P&A and also cut 6m below the mudline. Pipelines will be flushed and left in situ. E.On estimate platform and pipeline costs of €81m (£65m) gross, this appears to exclude well P&A costs however the pipeline cost estimate of €34m appears high if the pipeline is to be left on the seabed. We estimate facility decommissioning and well P&A costs of £60m gross (£14m net).

Minke P&A and decommissioning costs is estimated to be £22m gross although a full decommissioning study has not been conducted.

3.7.6. Reserves

RISC's estimates of reserves are shown in Table 3-11.

Table 3-11 RISC Estimate for Orca Field Reserves as at 1 January 2015

Orca-Minke Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Sales Gas (Bcf)	Condensate (MMBbl)	Sales Gas (Bcf)	Condensate (MMBbl)	Sales Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	0.3	0	0.3	0	0.3	0
The Net Present Value for Orca was calculated using 737 Btu/scf.						

As Minke production ceased in 2011, there are zero reserves at the effective date of 1/1/15.

3.7.7. Contingent Resources

Additional volumes that could be produced in the event of higher gas prices, by an extension of field life beyond the economic limit have been assigned as contingent resources (Table 3-12). RISC assigns no Contingent Resources from additional infill drilling.

Table 3-12 RISC Estimate for Orca Field Contingent Resources

Orca-Minke Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Contingent Resources beyond Economic Limit	0.3	0	0.5	0	0.7	0

3.8. Ravenspurn North Gas Field, blocks 42/30a & 43/26a (Licence P380)

3.8.1. Overview

Ravenspurn North is a dry gas field discovered in 1984 within blocks 42/30a and 43/26a in the UK Southern North Sea. It came on-stream in 1990, had a peak rate of approximately 450 MMscf/d in 1997 and is currently producing 25 MMscf/d. Perenco is the Operator (71.255%) and E.On has the remaining 28.745% interest.

The field is a fault and dip closed faulted anticline broken into a series of fault blocks (Figure 3-31).

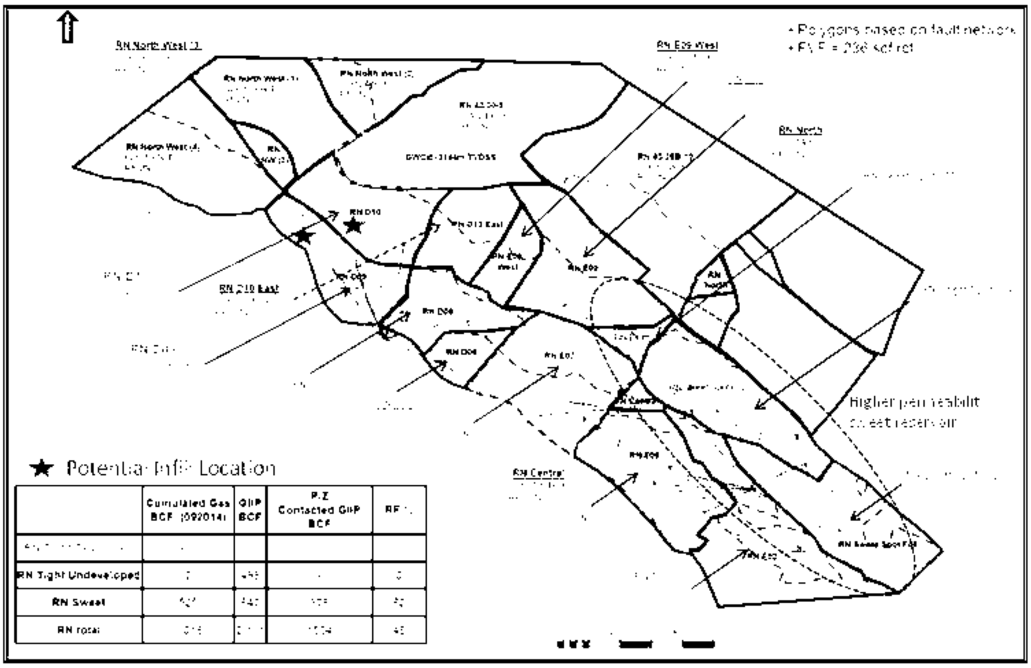


Figure 3-31 Ravenspurn North field segments

The gas has a low CGR of 1.6 bbl/MMscf, 1 mole% CO_2 and minor (<1ppm) amounts of H2S.

[redacted]

3.8.2. Development and Current Status

The Ravenspurn North field development consists of a gravity based concrete platform with accommodation, process facilities and compression linked to a steel wellhead platform. Two additional wellhead platforms were subsequently installed. Gas is exported to the Cleeton facilities then onward via the Cleeton/Ravenspurn South line to the Perenco operated terminal at Dimlington.

Forty-two development wells have been drilled although three were not completed. Wells are largely deviated and hydraulically fractured. There are two horizontal wells.

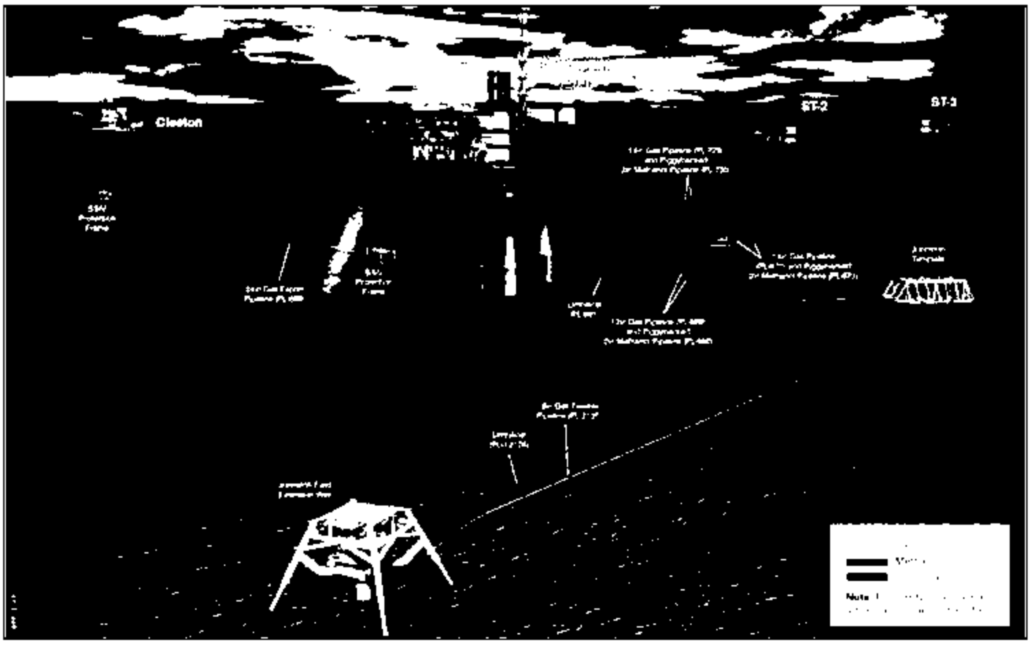


Figure 3-32 Ravenspurn North Surface Layout

3.8.3. Reservoir Description and In Place Volumes

The Lower Permian Rotliegendes Leman sandstone at 3,000 mTVDSS consists of aeolian sands and low permeability sabkha and fluvial sands. As shown in Figure 3-31 the reservoir is divided into areas of:

- Better permeability (1-50 mD) or 'Sweet Developed' reservoir with an estimated GIIP of 606-640 Bcf (E.On)
- Low permeability (<1 mD)or 'Tight Developed' reservoir with an estimated GIIP of 958-972 Bcf (E.On)
- Low permeability or 'Tight Undeveloped' reservoir with an estimated GIIP of 498 Bcf (E.On)

3.8.4. Reservoir Performance and Production Forecasts

Historic gas sales are shown in Figure 3-33. There has been negligible water production in any well.

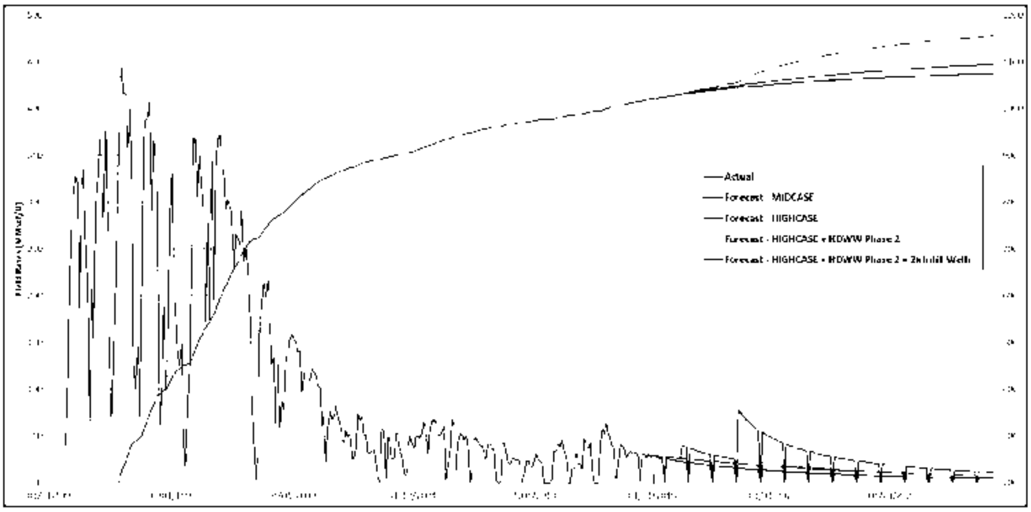


Figure 3-33 Ravenspurn North Historic and Forecast Gas Production (Gross 100%)

Of the forty-two development wells, three never produced (tight), nineteen have died and twenty are still producing. The gas recovery per well varies from zero to 107 Bcf with an average of 24 Bcf/well. The range is shown in Figure 3-34.

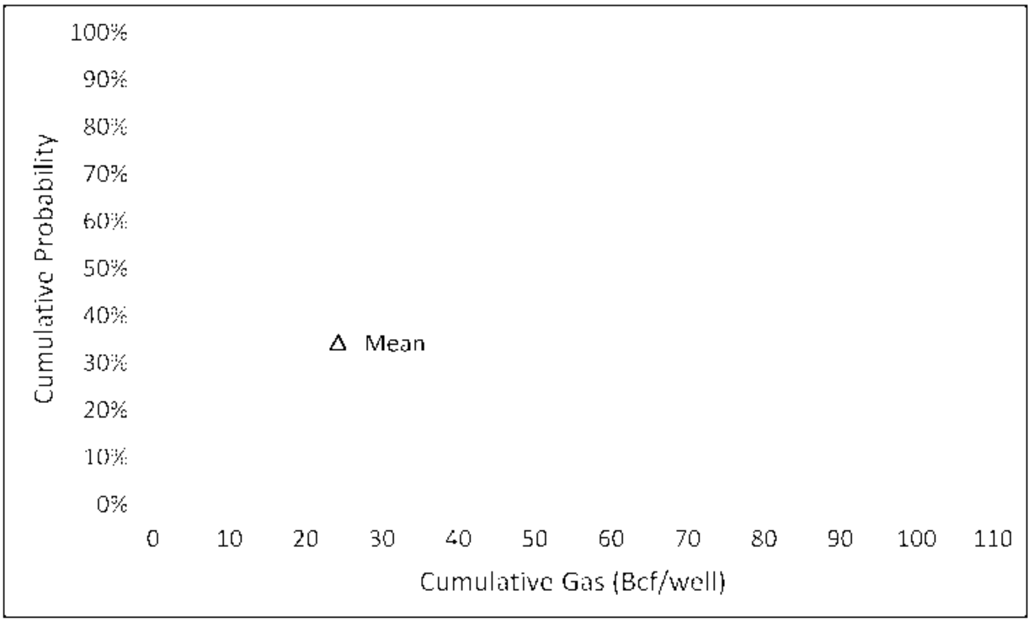


Figure 3-34 Ravenspurn North Historic Cumulative Gas per well

The last well drilled (F17) was horizontal and started production in 1997 and produced 34 Bcf to date. The other horizontal well, F10 died in 1999 after producing 30 Bcf.

Figure 3-35 shows the monthly gas production over the past 3 years.

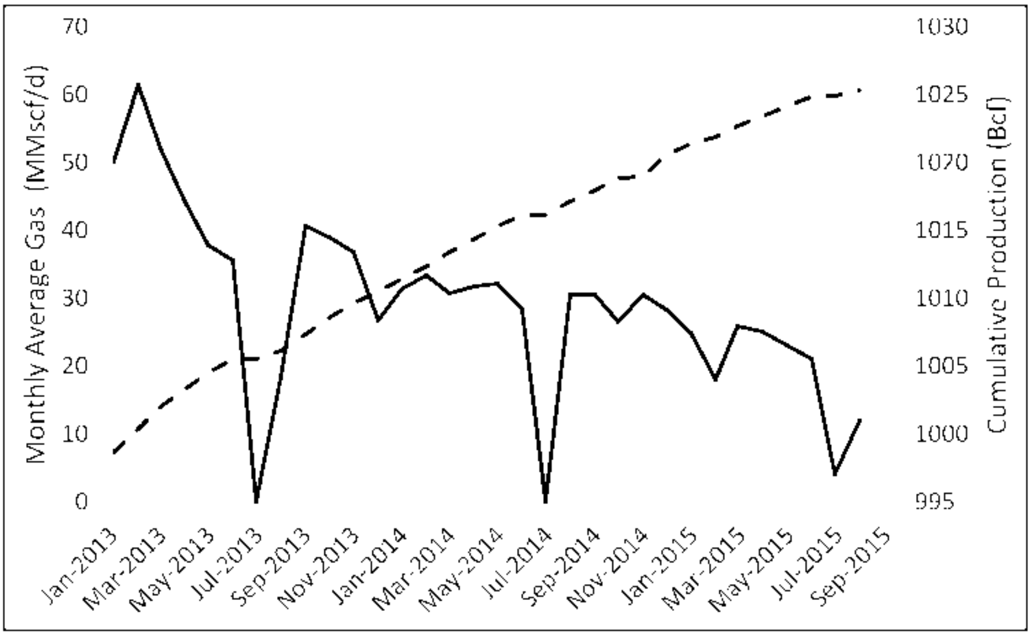


Figure 3-35 Ravenspurn North Recent Historic Production

The average gas production in 2014 was 27.8 MMscf/d. The 2015 average up to end August has been 19.2 MMscf/d although there appears to have been a lengthy shutdown in July-Aug 2015.

RISC has reviewed the historic decline trend of the field and generated production forecast based upon:

- The forecast matched to actual field production up to end August 2015 and forecast from that point.
- The 3P forecast is based on harmonic decline fitted to the field decline. Based on historic production, well uptime is estimated at 56%. The uptime is low because on average wells are only open 17 days per month. Most wells are on cyclical production with shut-in periods to re-charge reservoir pressure.
- The 1P forecasts is based on exponential decline fitted to the field decline. A lower well uptime of 45% is used to account for potential deterioration in well uptime.
- The 2P forecast is mid way between the 1P and 3P.

The economic cutoff leads to uneconomic production in 2016, so reserves are based on 2015 only. This truncated forecast is shown in Figure 3-36 below.

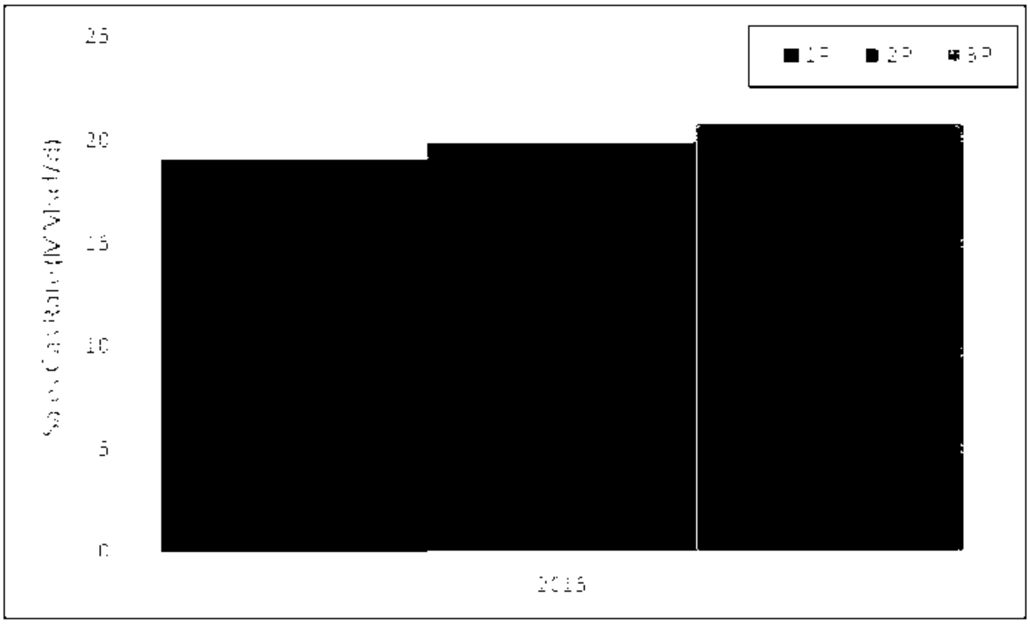


Figure 3-36 Ravenspurn North Production Forecast (Developed Reserves)

Ravenspurn North gas sales are estimated to be 91.4% of production based on historical data, with the remained used for offshore fuel including compression. The gas heating value (HHV) is estimated to be 37.5 MJ/m3 (1006 BTU/scf).

3.8.5. Future Development and Costs

There is no firm further development planned. Workovers are being considered to install velocity strings. It appears this work has not been suspended by the JV so we have not included the benefit in our reserves assessment.

3.8.6. Upside Opportunities (Contingent Resources)

Two upside opportunities have been identified:

- One or two horizontal infill wells in the North, with multistage fracs, expected to recover 25 Bcf over 15 years from mid 2018
- A second phase of Heavy Duty Well Work on shut-in wells D2, D3, D4, D6 and D14 starting 2Q 2016. The objective is to clear proppant from the wellbores using coiled tubing and restore production. The cost is estimated to be £13.2 million and recover an incremental 6.6 Bcf.

The previous Operator (BP) conducted a similar operation and restored production in D1, D12 and D13. However, the fill in three other wells was too extensive and could not be removed. The Phase-2 work was proposed in 2012 but not been carried out yet. RISC classifies the resources as contingent, being contingent on the project progressing.

As an example of the five clean-out candidates, Well D4 is an average well. It stopped production in 2008 at a rate of 1.5 MMscf/d and has been confirmed to contain proppant fill.

Figure 3-37 shows the stream day production history and exponential decline analysis.

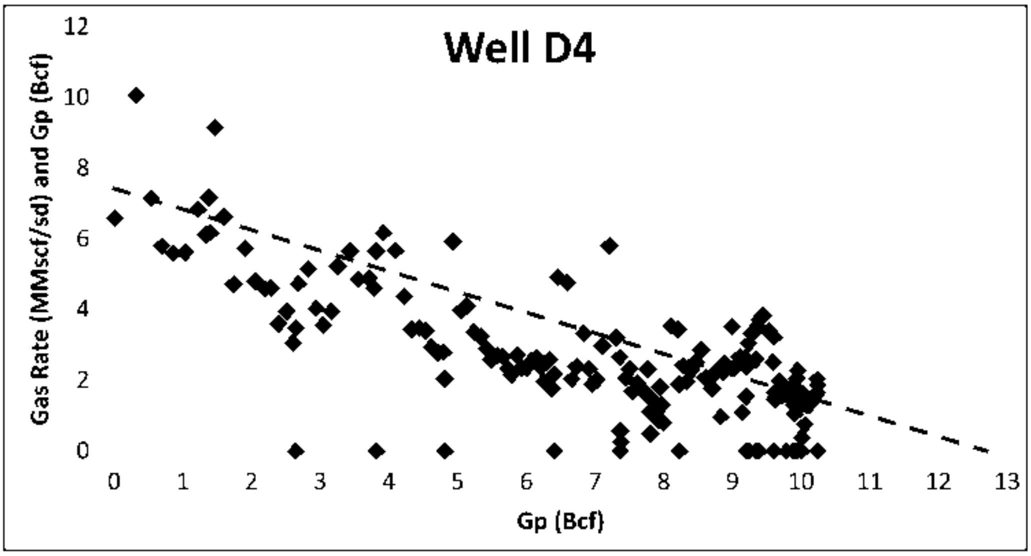


Figure 3-37 Ravenspurn North Well D4 Exponential Decline

Successful restart of D4 could recover an additional 2 Bcf from an initial rate of 1.5 MMscf/d. However reservoir depletion since the well last produced in 2008 may reduce this resource.

RISC has analysed the historic production of the well work candidates, estimated the potential incremental recovery, well rate and forecast as shown in Figure 3-38.

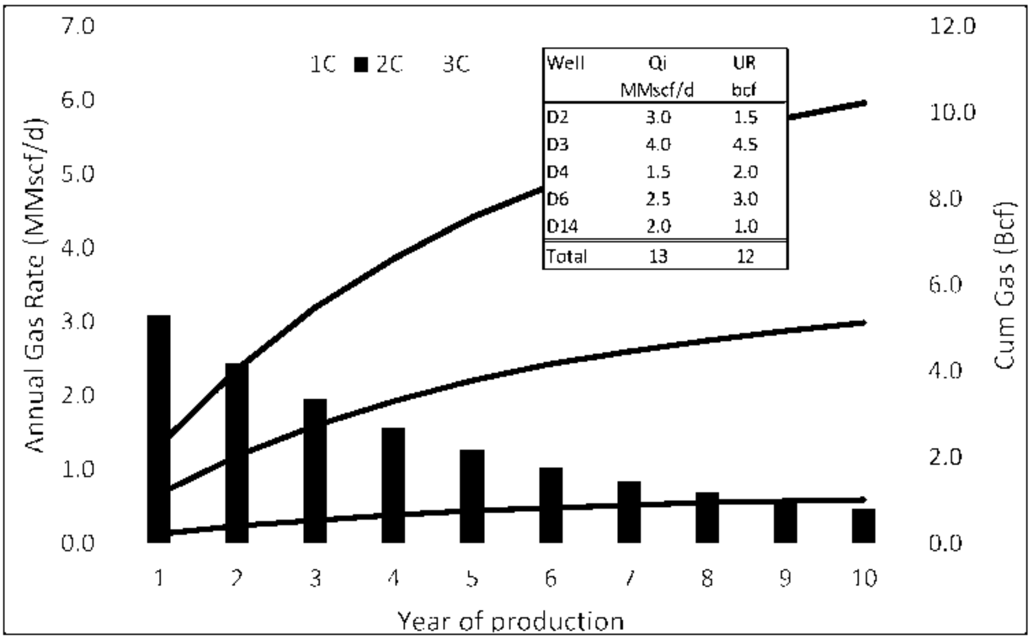


Figure 3-38 Ravenspurn North Well Work Forecast

The 3C forecast is based on the coiled tubing operations restoring the pre shut-down performance in each well. 10 Bcf of the 12 Bcf technical ultimate recovery is recovered in 10 years. The 2C assumes 50% discount rate (compared to the 3C case) to account for the potential risk of depletion and risk of mechanical failure of the clean-up operations. The 1C assumes 10% of the 3C case.

In addition to the workovers, two horizontal infill wells have been proposed in the tight reservoir in the north.

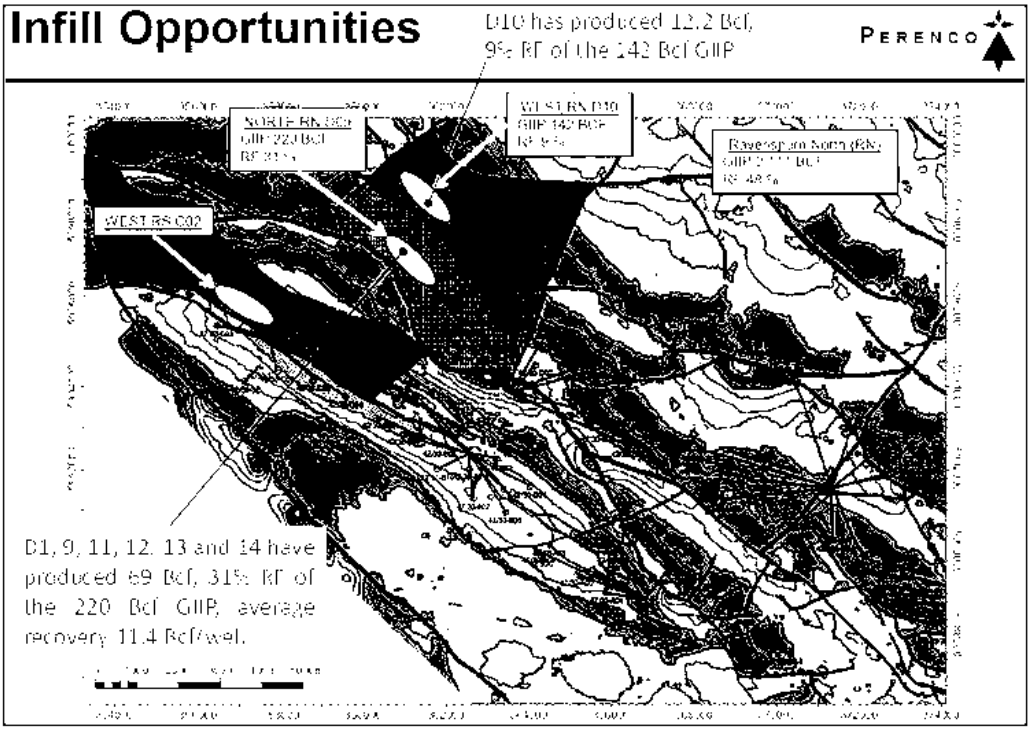


Figure 3-39 Ravenspurn North Proposed Infill Opportunities

- An infill well north of D09 in a block of 220 Bcf GIIP with 31% recovery factor to date from D01, D09, D11, D12, D13 and D14. Average recovery per well to date is 11.4 Bcf.
- An infill well north of D10 in a block of 142 Bcf GIIP and only 9% recovery factor to date from D10. Production from D10 is shown below:

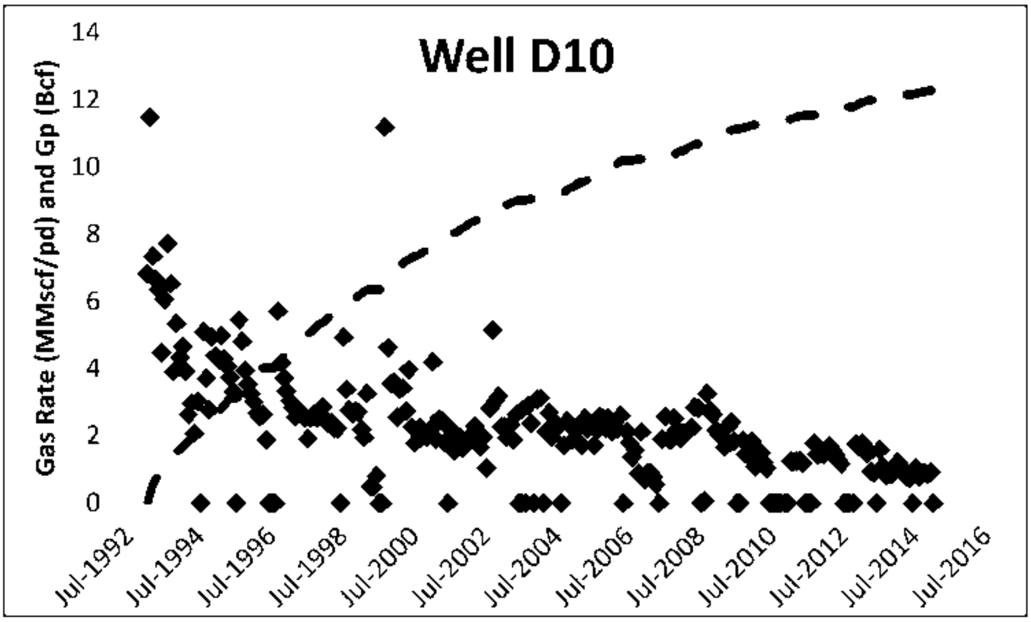


Figure 3-40 Ravenspurn North Well D10 Production History

A second well in the D10 block is likely to have similar performance +/- 50%.

RISC estimates that the infill opportunities could recover the same as previous wells in the block with the higher productivity horizontal design offsetting potential depletion. Therefore RISC estimates the flowing contingent resources.

Table 3-13 Ravenspurn North Contingent Resources

Contingent Resource (Bcf, wellhead) Gross	1C	2C	3C
D-09 Infill	6	12	18
D-10 Infill	6	12	18
Well Work	1	5	10
Total	13	29	46

3.8.6.1. Capital Costs

E.On report £2.8m gross of CAPEX in 2015 for base production. It is not clear what activity this covers and RISC was unable to validate if it was incurred. However RISC has included this sum in its forecasts.

In the upside case E.On forecast £13m gross ($4m net) in 2016 for workovers to remove proppant from 5 wells (wells D2, D3, D4, D6 and D14) and install velocity strings. Production as a result of these activities are classified as contingent resources.

The two potential horizontal infill wells in the tight reservoir in the North of the field are estimated by E.On to cost £120m gross. As the production for Contingent Resources are is not included in our forecasts we have not included these costs.

3.8.6.2. *Operating Costs*

Operating costs at Ravenspurn North are forecast to cost £35m pa gross ($10m pa net) for 7 years. We forecast reductions 10% pa after that. There is no incremental OPEX associated with the contingent resources as production would come from existing wells.

Costs at this level are likely to be unsustainable given the modest production. This would also impact Johnston as Ravenspurn North is the host platform for the Johnstone subsea tieback.

3.8.6.3. *Decommissioning Costs*

E.On forecast decommissioning costs of £92m gross. We consider this to be too low and estimate costs in the range £100-£200m. There is considerable uncertainty as we are unsure of the plans for decommissioning the concrete gravity structure.

3.8.7. Reserves

RISC's estimates of reserves are shown in Table 3-14.

Table 3-14 RISC Estimate for Ravenspurn North Field Reserves as at 1 January 2015

Ravenspurn North Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	1.8	0	1.9	0	2.0	0

3.8.8. Contingent Resources

This first line in the table below is the additional volume that could technically be produced in the event of higher gas prices, by an extension of the reserves forecast field life beyond an the economic limit. The second line in the table refers to the sum of the upside development wells.

Table 3-15 RISC Estimate for Ravenspurn North Field Contingent Resources

Ravenspurn North Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Contingent Resources not Classified as Economic Reserves	14.4	0	18.2	0	22.0	0
Upside Development Wells	13	0	29	0	46	0

3.9. Rita Gas-Condensate Field, blocks 44/22c & 44/21b (Licence P766 & P771)

3.9.1. Overview

Rita is a dual lateral subsea well tied back via Hunter to CMS.

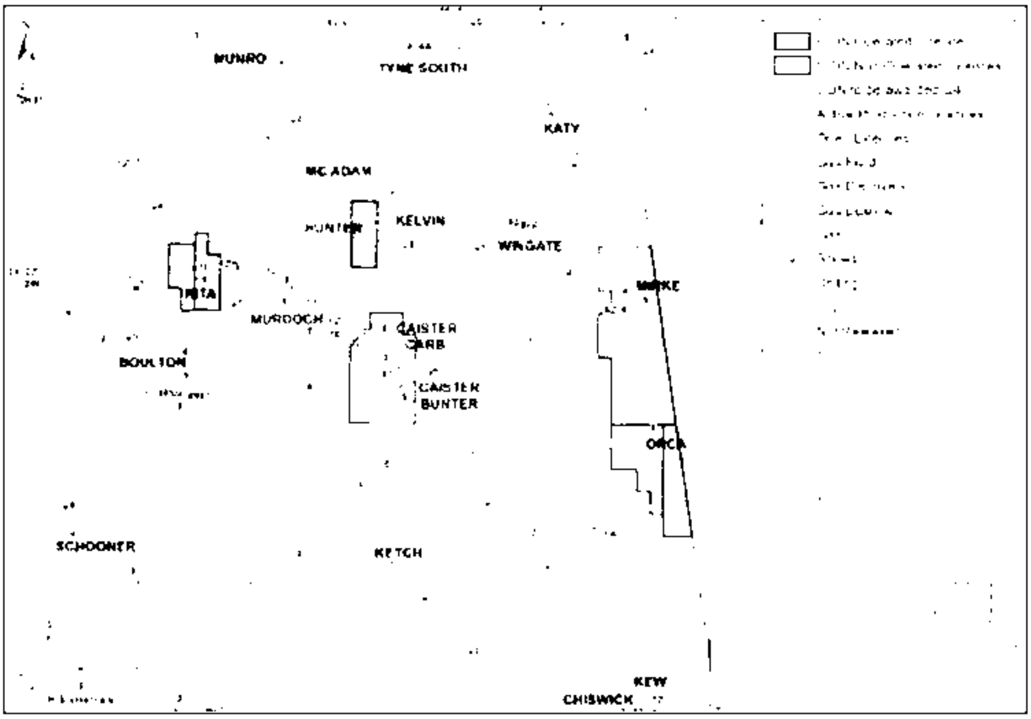


Figure 3-41 Location Map of Caister Murdoch System Fields

3.9.2. Development and Current Status

Rita is developed with a dual lateral well tied back to the Hunter field via a 14km, 8" carbon steel pipeline. Hunter was developed with single subsea well and an 8km, 8" subsea tieback to Murdoch. Hunter production ceased in 2012 but the subsea pipeline was used for Rita production. There is also a flexible flowline from Rita to Murdoch that was disconnected in 2012. Gas is aggregated at Murdoch and exported via the 26" 188km CMS export line to Theddlethorpe gas terminal. The NUI is remotely operated from Theddlethorpe. The layout of Hunter, Caister and Rita is shown in Figure 3-42 below.

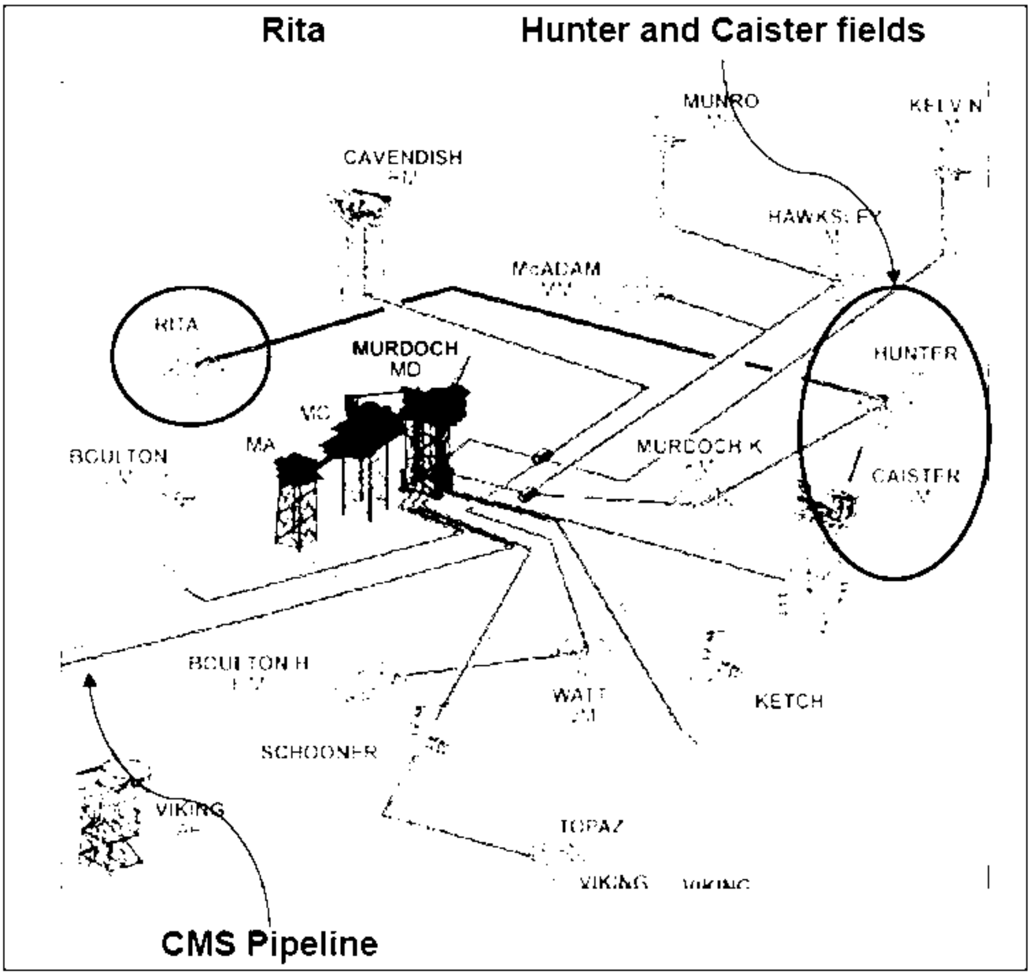


Figure 3-42 Hunter, Caister and Rita Development Schematic

Rita was discovered in 1996, appraised in 1998 and started production in April 2009. No further development is planned. The field has experienced several long outages due to pipeline and umbilical integrity issues.

3.9.3. Reservoir Description and In Place Volumes

The Rita structure comprises two adjacent tilted fault block compartments, Rita West and Rita East, accessed via two horizontal wells 44/22c-12 and 44/22c-12z respectively. The reservoir for the Rita field is the Carboniferous Westphalian C/D sands characterised by fluvial channel sandstones preserved beneath the Base Permian Unconformity. Individual channel sands are up to 50 ft thick with overall net to gross around 25% and porosities ranging from 6% to 10 %. E.On estimate a base case GIIP for Rita of 55 Bcf (estimated 48.9 Bcf recoverable – 89% recovery) with an upside GIIP estimate of 71 Bcf (estimated 51.2 Bcf recoverable – 72% recovery).

3.9.4. Reservoir Performance and Production Forecasts

Initial production of 70 MMscf/d declined to 30 MMscf/d in 2011 when production stopped due to issues with the flexible flowline. A new rigid flowline was installed and production restarted in 2013. Production declined to 11 MMscf/d after producing 39 Bcf.

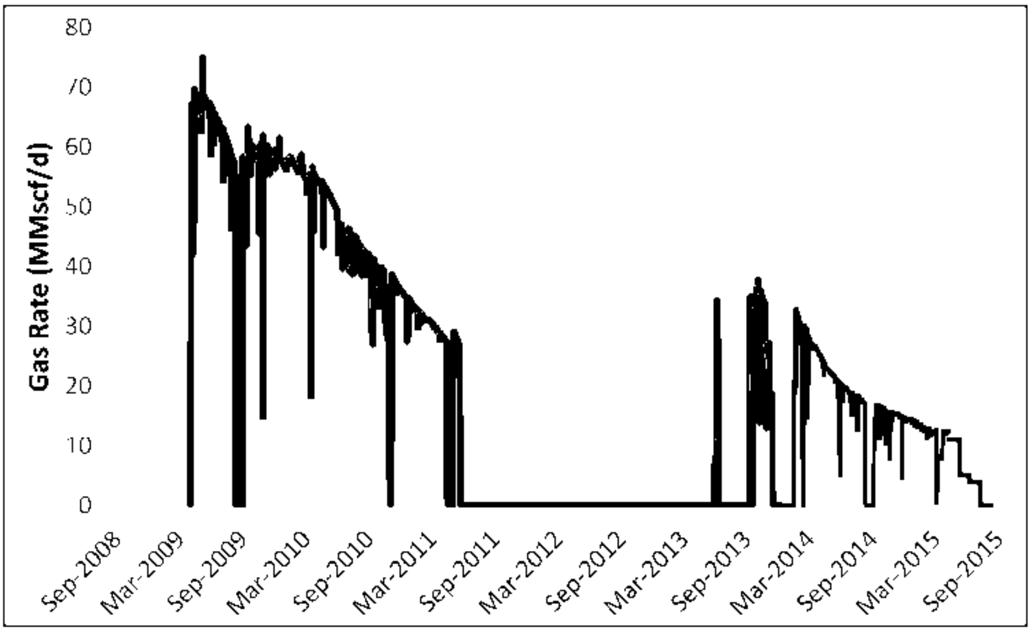


Figure 3-43 Rita Gas Production History

Rita's production was shut-in from late 2015. Investigations are underway as to cause and possible remedy to the well failure. In the absence of clear plans and costs to reinstate production, for the purposes of current valuation, we assume the field remains shut-in.

Figure 3-44 shows the production forecasts, based on production decline modelling, for production being restarted. The volumes after 2015 are attributed to the Contingent Resources, not reserves.

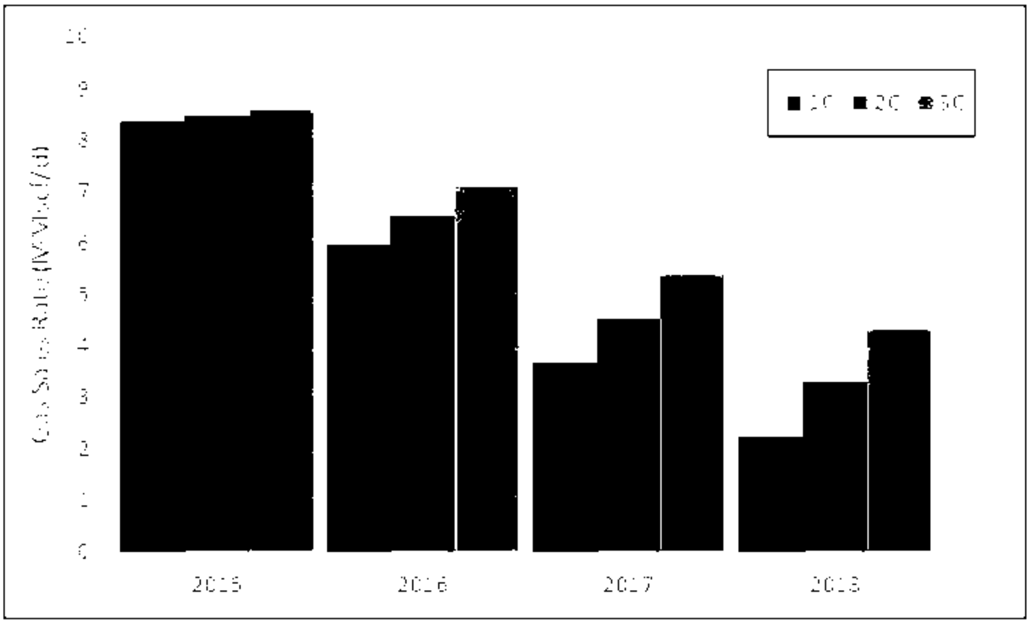


Figure 3-44 Rita Field Production Forecasts (Contingent Resources)

3.9.5. Future Development and Costs

No further development is planned.

3.9.6. Reserves

RISC's estimates of reserves are shown in Table 3-16. These are the volumes produced during 2015.

Table 3-16 RISC Estimate for Rita Field Reserves as at 1 January 2015

Rita Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	1.6	0.01	1.6	0.01	1.6	0.01

3.9.7. Contingent Resources

This is the volume that could technically be produced by restarting production (Table 3-17). RISC assigns no Contingent Resources from additional infill drilling.

Table 3-17 RISC Estimate for Rita Field Contingent Resources

Rita Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Contingent Resources not Classified as Economic Reserves	3.8	0.02	4.5	0.03	5.1	0.04

4. Undeveloped Discoveries

4.1. Overview

E.On have three undeveloped fields in the portfolio (Figure 4-1). RISC has reviewed these and offers the following comments.

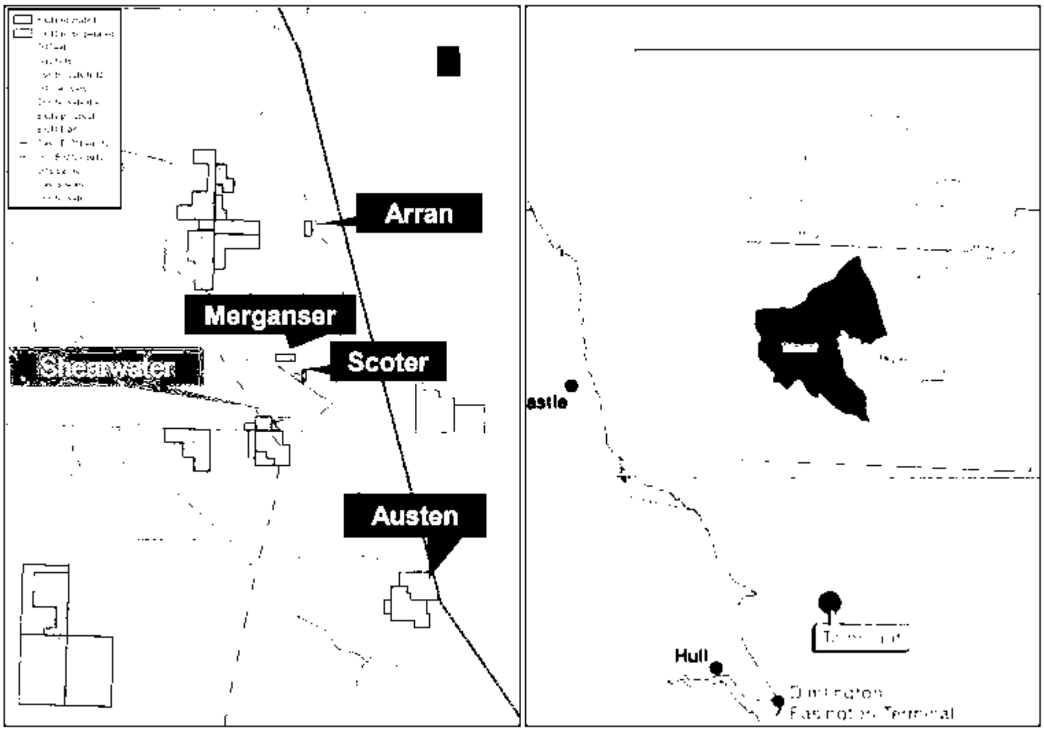


Figure 4-1 Arran, Austen & Tolmount Field Location Map

4.2. Tolmount Gas Field, block 42/28d (licence P1330)

4.2.1. Overview

The Tolmount Field is situated in the UK Southern North Sea, Block 42/28d, Licence P.1330. The licence was originally awarded, in the 23rd Licencing Round, to Dana in 2005 with 100% equity, with E.On farming-in at 50% equity and assuming Operatorship in 2010.

Tolmount Field was discovered by well 42/28d-12 in 2011, with further appraisal drilling of wells 42/28d-13 and -13z in 2013 confirming the presence of high quality, Lower Leman Sandstone Formation reservoir. A work programme of PSDM seismic to evaluate and rank prospectivity, and mature locations to 'drill-ready' status was underway at the time of the Information Memorandum (June 2015). Project SELECT Phase activities were also ongoing in the form of subsurface activities, drilling studies, offshore surveys and pre-development studies. The Final Investment Decision (FID) is expected in Q1 2017, with First Gas 2019.

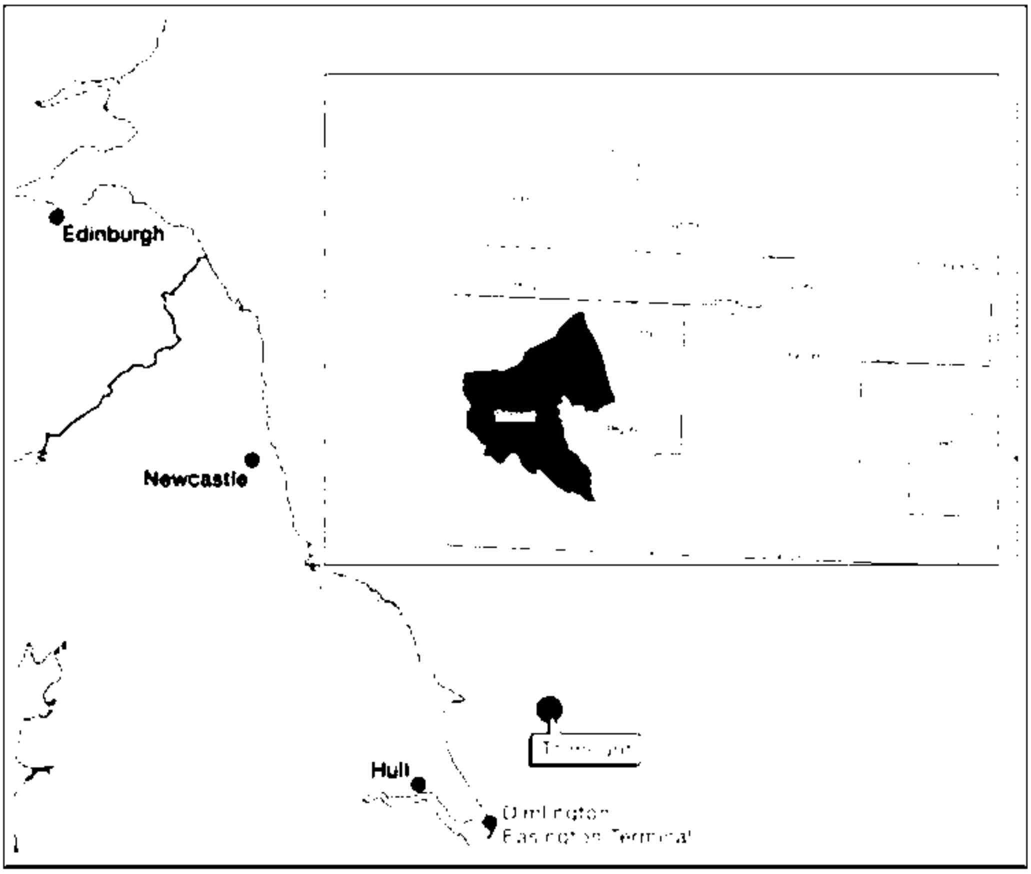


Figure 4-2 Area Map of Tolmount Field and surrounding prospects

4.2.2. Reservoir Description and In Place Volumes

The Tolmount Field sits within the Lower Leman Sandstone Formation Play Fairway to the south of the Permian 'Silver Pit Lake' and north of the 'Amethyst High'. Aeolian dunes and fluvial sands predominate, with local sabkha and 'wet'/'damp' inter-dune facies, deposited unconformably on the Carboniferous (Base Permian Unconformity) terrain. Prevailing easterly winds dominate the orientation of dune deposition, whilst the fluvial transport is predominantly from the south and southwest (Figure 4-3).

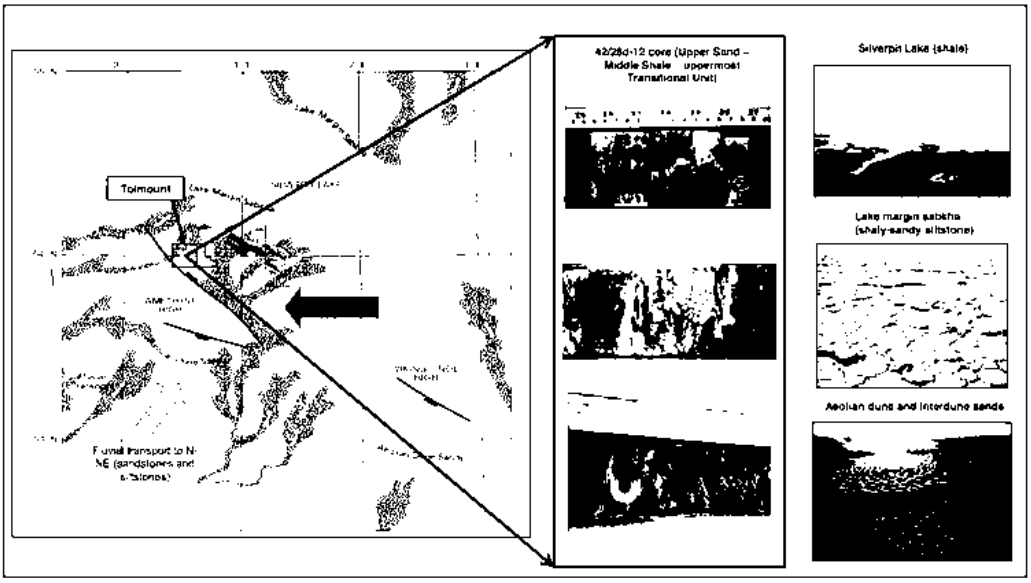


Figure 4-3 Lower Leman Sandstone Fm – Depositional Setting

4.2.2.1. Structure

The structure of Tolmount is linear, with a crest striking broadly northwest-southeast, with parallel faulting setting up the structure, along with a set of faults perpendicular to strike. As a consequence of these two fault sets, compartmentalisation is likely to be an issue. A Badley's Fault Seal study has concluded that the northwest-southeast striking faults have a higher seal potential than those striking northeast-southwest. Gas pressures appear to be on the same gradient and PVT analysis indicates no significant compositional differences or evidence of gravitational gradient, suggesting equilibration over the geological time scale. Overall, the Operator concludes there is a small risk of compartmentalisation. Where compartmentalisation appears to be a risk, it can be mitigated to a large degree by drilling wells into the largest 'compartments' and if necessary, across faults to maximise drainage.

4.2.2.2. Depth Mapping

RISC reviewed the quality of the data provided by E.On in the data room and found it good quality but limited in detail. The data room contained extensive data from the latest E.On depth conversion, the associated E.On depth conversion report and a depth conversion report from an independent contractor which was completed a year earlier.

E.On has elected to produce a 10 layer depth conversion in model MV09v6. The layers reflect the major velocity changes observed in the southern North Sea and is accepted as standard practice in depth conversion in this area of the Southern North Sea. The surfaces both Two Way Time (TWT) and depth included Seabed, Top Chalk, Base Chalk, Top Corallian, Top Bunter, Top Zechstein, Top Rotliegendes, Top Leman and Carboniferous.

The TWT interpretation was validated by RISC in Premier's office from the screen captures of various seismic lines from the 3D seismic survey. The TWT grids honoured the seismic data apart from the edges of the grids, which may have been an issue in the production of the grids, where the interpretation area had not been defined. The Top Corallian TWT grid has been smoothed by E.On in order to remove the depth conversion artefacts seen below Top Corallian, due to the extensive faulting of the Corallian. Inevitably this issue and approach will lead to some potentially large uncertainties in the depth conversion.

Table 4-1 E.On Depth Model 10 layer cake

Layer	Interval	Velocity Model
1	Water	1,500 m/s
2	Tertiary	2,200 m/s
3	Chalk	V = -5.1T + Vo(map)
4	Base Chalk - Top Corallian	Interval velocity map
5	Top Corallian - Top Bunter	V =- 1.1Z + V0(map)
6	Bunter	V = 0.85Z + Vo(map)
7	Zechstein Salt	Interval velocity map
8	Zechstein Anhydrite and Dolomite	6,000 m/s
9	Silverpit	4,481 m/s
10	Leman	4,422 m/s

The lower Cretaceous and upper Jurassic is dominated by lower velocity mudstones and claystones which push the top reservoir seismic pick down in TWT. The remaining Jurassic and Triassic has significantly more evaporates and limestones which are higher velocity and represent a pull up in TWT. The splitting of the Zechstein into high velocity Anhydrite (circa 20,000 ft/s) and lower velocity Halite (circa 15,000 ft/s) in principle is a sound method, especially when the high velocity anhydrite layers can be mapped as in many areas of the gas basin. However, E.On has not directly mapped the thickness of the Anhydrite and has assumed a constant thickness. E.On has used an interval velocity of 6,000m/s (19,685 ft/s), which is acceptable in the Southern Gas Basin.

An audit of the E.On velocities has been carried out by producing Interval velocity maps from E.On TWT and depth maps. In addition, the Interval velocities at the wells have been calculated from E.On well tops and TWTs. The TWT values at the wells are understood to be pseudo TWTs. Interval velocities at wells have been posted on interval velocity maps to observe how well the interval velocities used in the depth conversion ties the interval velocity derived from the well data. Graphs of TWT at top and base of seismic interval vs interval velocity were derived from E.On tops and time files and plotted on the velocity maps as a further audit of the E.On model.

The Chalk interval velocity map exhibits the poorest tie to the interval velocity at the wells, with the map showing 300 m/s higher interval velocities at Tolmount. The Base Chalk to Corallian interval velocity map has reasonable ties to the wells, although it does show lower interval velocities at Tolmount and may compensate for the higher velocities of the Chalk. The interval velocity map of Top Corallian to Top Bunter and Bunter interval velocity map match the well velocities and suggests that the E.On Modelling of this layer is acceptable. E.On has elected to split the Zechstein into an Anhydrite layer of 120m with a velocity of 6,000m/s and a Halite layer where they have depth converted by contouring the Halite interval velocities. The derived Anhydrite interval velocity map shows the 6,000m/s velocity and slightly lower Anhydrite well velocities at Tolmount. The derived Halite map is more uncertain, as it shows an increasing velocity trend to the north that is not readily visible in the derived well interval velocities. A single interval velocity of 4,440 m/s (14,566 ft/s) for Halite may be more appropriate for the Tolmount area. The analysis indicates that E.On have used a slightly higher Anhydrite velocity and slightly lower Halite velocity over Tolmount that will compensate but will result in a larger error residual at Top Rotligendes reservoir. Overall, the E.On Depth conversion appears sound with the Chalk and Zechstein layers giving the largest error residuals. The single interval velocities at the Silverpit of 4,481m/s is reasonable though slightly higher than the 4,400 and 4,100m/s seen at the Tolmount wells.

The E.On interval velocities were validated by producing new interval velocity maps for each of the layers an example is shown below.

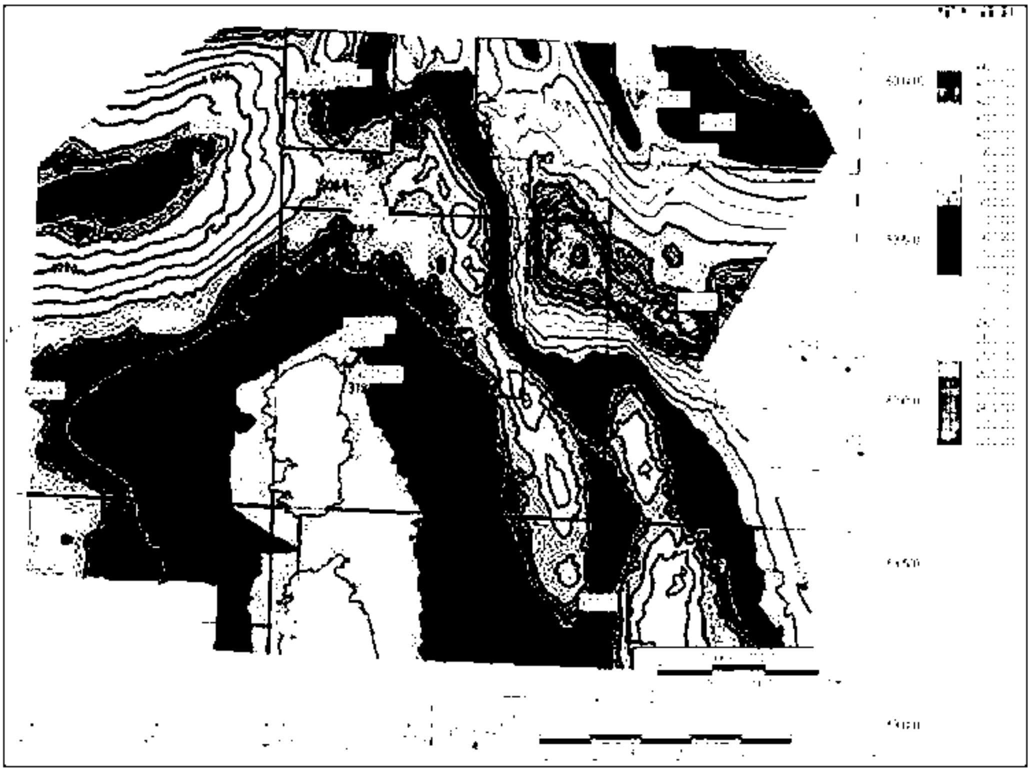


Figure 4-4 Interval Velocity map Top Corallian-Bunter

The map shows all the wells in the area used to plot the TWT against the Interval velocity to give a correlation of R^2= 0.7554.

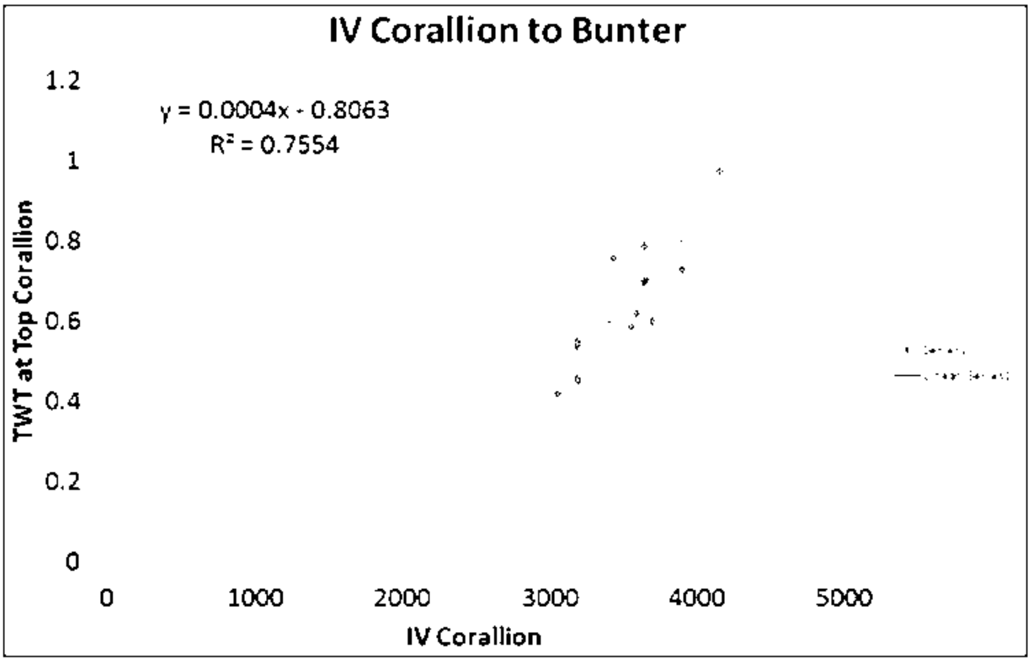


Figure 4-5 Associated TWT vs Velocity plot

4.2.2.3. Gross Rock Volume estimation

The Top Leman depth map shows structural closure to the south and west of Tolmount at the GWC of 3,119 mTVDSS. There is no structural closure to the North and West. The maps show that Tolmount can be closed by the faulting to the north and west but it includes the area to the east named Mayar by E.On and defined by the Cyan polygon on the map. There is no structural separation of Tolmount and Mayar and it requires the Top Leman surface to be depressed by 75m locally to separate the areas. The Leman isopach shows clear thinning between Tolmount and Mayar to 25-30m. The seismic in this area is below seismic resolution and it is quite possible that the reservoir is not deposited in this area at the northerm limit of the Leman fairway. The separation of Mayar and Tolmount has been chosen on this basis.

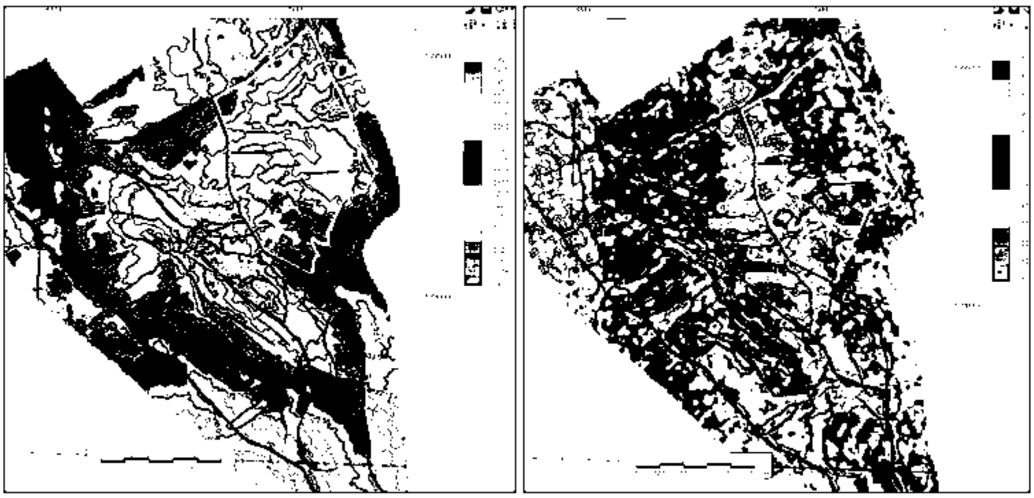


Figure 4-6 Leman Depth Map and Leman Isopach

The two polygons Tolmount (red) and Mayar (blue) illustrated on Leman depth and isopach structure map were used to calculate the P50.

The P50 GRV was calculated to the GWC of 3119m within each of the polygons for both Tolmount and Mayar.

4.2.2.4. P10 and P90 GRV cases

RISC estimate Top Leman depth uncertainty across the Tolmount structure to be up to 3% or 75-105m at any point away from well control, with an average total structure uncertainty of +/-1%.

A residual error map has been derived by scaling the Top Leman depth map by a factor of 0.01 giving an isopach ranging between 25-35m. The residual error map has been added to the Top Leman depth map to flex the surface deeper away from the wells. The error residual was also applied to the Top Carboniferous and both surfaces were used to calculate the P90 GRV using a GWC at 3119m. The same process was used to calculate the P10 surface, except the isopach was subtracted from both surfaces flexing them shallower away from the wells.

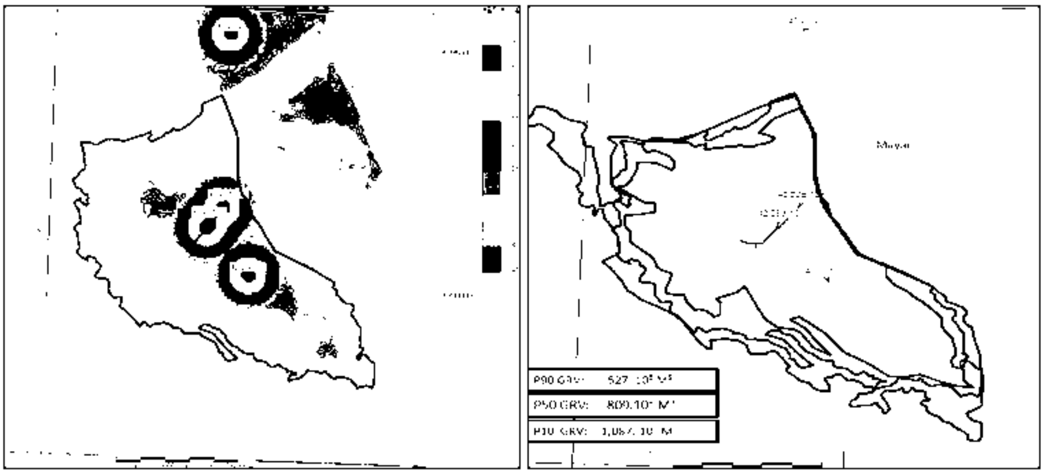


Figure 4-7 Tolmount Residual Error Map and resulting areas

On Mayar the area is predominantly above the GWC at 3,119 even on the P90 depth case. The main variable that affects GRV on Mayar is Leman thickness. The P90 and P10 GRV cases on Mayar have been derived by varying the Leman thickness by +/- 10%.

Table 4-2 Tolmount and Mayer GRV

GRV	Tolmount	Mayar
P90	527 x10^6 m^3	510 x10^6 m^3
P50	809 x10^6 m^3	560 x10^6 m^3
P10	1,087 x10^6 m^3	606 x10^6 m^3

4.2.2.5. Reservoir

The reservoir envelope has been defined by the Operator using seismic horizons at 'Top Leman' and 'Base Permian Unconformity' (Top Carboniferous) across Tolmount and Mayar. Core and well log data from well 42/28d-12 indicate reservoir quality in the Leman Sandstone to be very good in sheet flood and aeolian rock facies, with porosity typically in the 15-20% range, and permeability in the sheet flood facies of 10s mD and in the aeolian facies in the 100s mD to 1000 mD. The well flowed at 51 MMscf/d and 525 bpd condensate under test, with the majority of flow coming from the aeolian dune facies (based on the Production Logging Tool). The Operator has subdivided the reservoir into four main lithostratigraphic packages: Lower Sand, Transitional Unit, Middle Shale and Upper Sand (Figure 4-8). Further characterisation by the Operator of the reservoir into facies, using core and logs has been undertaken.

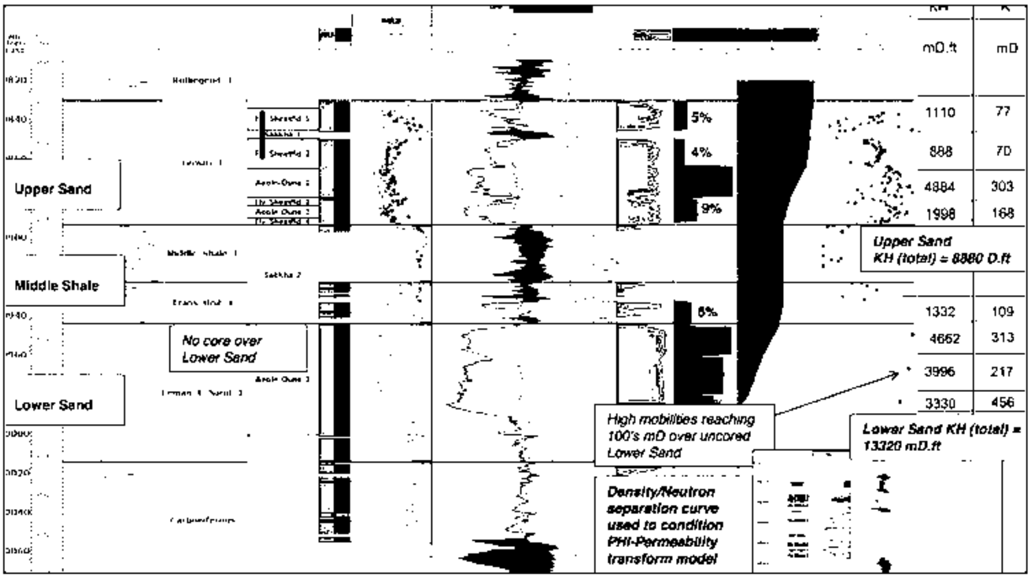


Figure 4-8 Tolmount Reservoir Quality, well 42/28d-12

Reservoir: Lower Leman Sandstone Formation which is sub-divided into four zones based on lithostratigraphic correlation and identification of climatic cycles:

- **Lower Sand:** Predominantly clean aeolian sands with large dune packages interpreted from image log data
- **Transitional Unit:** Two wetting-drying cycles present in Tolmount wells
- **Middle Shale:** Playa lake and sabkha deposition attributed to the expansion of the Silverpit Lake
- **Upper Sand:** Heterogeneous interval comprising aeolian dune, fluvial sheetflood, sabkha and ponded (lacustrine-type) facies

Source: Type II/III, presumably Carboniferous Coal Measures and some marine shale inputs. Condensates in the appraisal and discovery wells have similar compositions indicating good reservoir connectivity

Seal: Provided by Silverpit Formation sabkha and lacustrine shale succession and overlying Zechstein Group evaporites

Trap: Faulted anticline with fault closure to north, east and west with dip closure to south

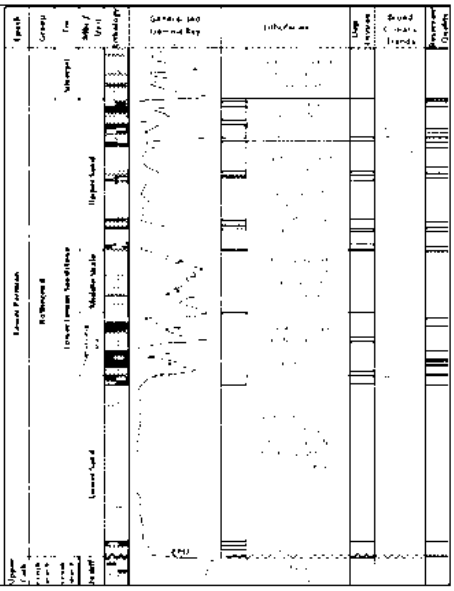


Figure 4-9 Tolmount Geological Summary

A Free Water Level has been interpreted at 3119 mTVDSS in -13z. No clear water leg has been identified in any of the Tolmount wells in the reservoir. However, the Tolmount gas leg does intercept the regional aquifer (wells 42/28a-4 and 42/29-5) at 3118 mTVDSS (Figure 4-10). To the N of the Field is the Mongour discovery well (48/28-2). With very similar reservoir to Tolmount, it has a contact at 2994m, which may be more representative of a Free Water Level in the Mayar area than the observed contact in the Tolmount well. Consequently, this has been used in modelling Mayar (a Rectangular distribution has been used: 2994m to 3119m).

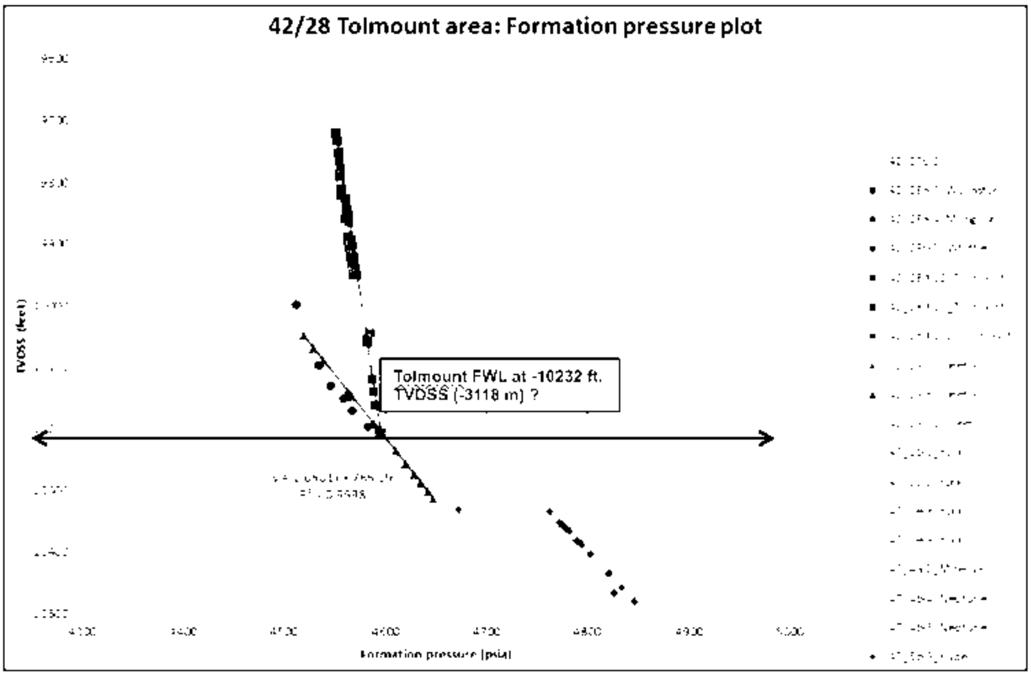


Figure 4-10 42/28 Tolmount Area Free-Water-Level

The Operator uses a Saturation Height function to model water saturation in the reservoir. Because only limited core capillary pressure data are available, which indicate an enhanced transition zone and anomalously high irreducible water saturation (Swirr), considerable modelling efforts appear to have been made to better understand water saturation, both as a function of height above FWL and in relation to facies (permeability). A modified Lambda function has been used in the most recent work, height-dependent Sw (water saturation) honouring Tolmount mercury injection data combined with log-derived Swirr component, the Operator's Reference Case for reservoir modelling, as well as a variety of other methods to test the sensitivity of the reservoir model to Sw. This Reference Case methodology seems to provide a good match to the log-derived Sw (using the Archie equation).

4.2.2.6. Gas Initially In Place

The Operator has produced two Reference Case geological models for Tolmount/Mayar: one made available to the Client in June 2015 and a second in August 2015. Upon request, E.On provided RISC with outputs from a modified June 2015 model. RISC has reviewed this model and used it as a basis for producing a probabilistic range of GRVs for Tolmount and Mayar. These were output to REP (probabilistic resource software) to estimate a probabilistic range of GIIP.

RISC's probabilistic modelling of GIIP uses a simplistic approach to Sw/H modelling for water saturation, by using the default Lambda function available in REP, providing a reasonable representation of Sw/H without taking into account changes in facies/permeability.

Porosity has been derived using calibrations of well core data to well log data by the Operator which appears to be robust.

Net-to-Gross is extremely high in the wells which have penetrated the reservoir. The Operator has used VSH <0.40, Porosity >6% and Sw 0.70 as cut-offs. RISC have used representative average values from wells -12 and -13 and used a log normal distribution.

Table 4-3 Tolmount and Mayar GIIP Estimates (RISC)

	Raw Gas (Bcf, Gross)		
Tolmount Field In Place Volumes	P90	P50	P10
RISC Estimate	**285**	**500**	**769**

	Raw Gas (Bcf, Gross)		
Mayar Area In Place Volumes	P90	P50	P10
RISC Estimate	**30**	**152**	**382**

RISC calculated In-place volumes for Tolmount and Mayar independently.

Based on E.On's updated interpretation of the depth conversion, their static reservoir model was updated. No representation of this model was made available to RISC.

4.2.3. Reservoir Performance and Production Forecasts

This gas field is under development planning and has not started production. RISC has evaluated the Tolmount field reserves and production forecast at 1P/1C, 2P/2P and 3P/3C confidence levels.

4.2.3.1. Material Balance Methodology

RISC has created a material balance model with separate tanks representing the estimated volumes drained by each well. The 1P/1C case is based on a high degree of compartmentalization and the 3P/3C case is based on wells depleting the full field.

Deterministic cases were based on RISC's P90, P50 and P10 volumetrics. This provided RISC's estimates of the 1P/1C, 2P/2C and 3P/3C gas and condensate production profiles.

4.2.3.2. Production Forecast

Reservoir fluid properties are based on downhole fluid samples that indicate consistent properties across a range of samples. RISC used the reservoir fluid composition with standard industry correlations to estimate the fluid properties of the gas. The condensate properties were based on PVT reports conducted on the downhole samples.

In generating the production forecasts, RISC has assumed that four wells are drilled in the period 2019-2020. In the 3P/3C case a further well is added for Tolmount East (Mayar).

Production is curtailed at 2040, in line with the expiry of the current estimated economic limit of approximately 3 MMscf/d in the 2C case.

RISC's gas production forecast is shown below. We note that E.On has presented more optimistic forecasts, due to an increase in interpreted GIIP as a result of recent work.

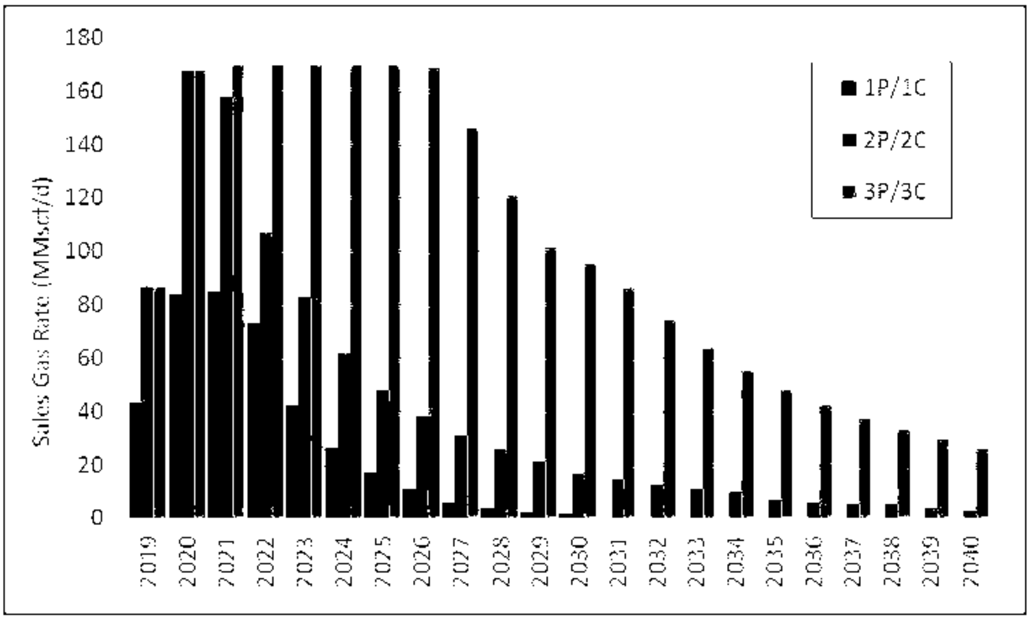


Figure 4-11 Production Forecast Summary for Tolmount Field

The recovery factors for the 1P/1C, 2P/2C and 3P/3C cases are 52%, 70% and 75% respectively. The variation is due to the different drainage volumes for the wells in each of the cases. The 1P/1C case with the lowest recovery factor is restrained by the wells' limited drainage area, due to faulting and compartmentalisation.

4.2.4. Future Development Plan

At the time of review, the project was at the Select Phase with ongoing subsurface activities, drilling studies, offshore surveys and pre-development studies. The Final Investment Decision (FID) is expected in Q1 2017, with First Gas 2019.

The development plan assumed in this evaluation comprises:

- 6 slot Minimum facilities, not normally manned platform (Topsides weight 1,456 tonnes) in 52m water
- 3 platform wells and 1 subsea at Tolmount plus 1 further subsea well for Tolmount East (Mayar) assumed only in the 3C case
- Subsea well tied back with 8" infield pipeline, 3" methanol line and control umbilical
- Vertical/low angle deviated wells completed in both major reservoir sands
- 5 ½" completions with sand control
- 49 km, 18" pipeline + 3" methanol line to an onshore terminal
- Plant arrival pressure of 85 bar from 2019, with compression to 35 bar to maintain the plateau rate, reducing further to 10 bar
- Plateau of 200 MMscf/d for 2P/2C and 3P/3C cases, 100 MMscf/d for 1P/1C case.
- Combined field and facility availability of 93%, plus 3 weeks of planned shutdown annually.

As part of the Concept Select studies E.On are also reviewing an option to develop the field with a 12", 14km tieback to a separate third party facility.

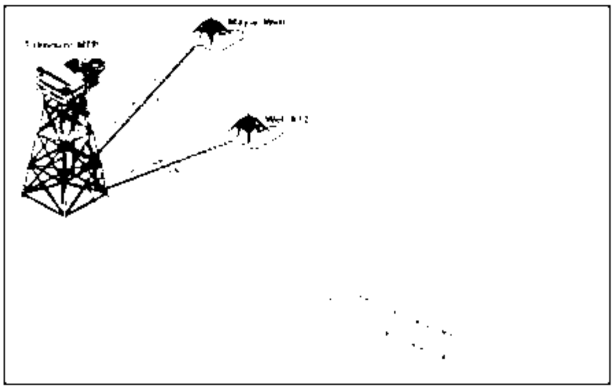


Figure 4-12 Tolmount Development Schematic

4.2.5. Reserves

RISC has classified the Tolmount volumes as Reserves rather than Contingent Resources, as an economic development has been found and the field is progressing towards development. SPE and PRMS guidelines allow for Tolmount to be classified as Reserves under these circumstances even though the field has not reached a Financial Investment Decision. The Joint Venture group is currently investigating an alternative development option, which may prove to be more economically attractive.

RISC's estimates of reserves are shown in Table 4-4. As the Proven (1P) volumes are not economic, there are no reserves at the 1P level for Tolmount. These volumes are therefore placed in the Contingent 1C category.

Table 4-4 RISC Estimate for Tolmount Field Reserves as at 1 January 2015

Tolmount Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	0	0	169.4	1.549	416.7	3.698

4.2.6. Contingent Resources

Tolmount's 1C volumes would be recategorised as reserves if an approved, economic development scenario is achieved.

Table 4-5 RISC Estimate for Tolmount Field Contingent Resources as at 1 January 2015

Tolmount Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Remaining Technical Recovery from 01 January 2015	72.6	0.666	0	0	0	0

4.3. Arran Gas-Condensate field, blocks 23/11, 23/16b, 23/16c (Licences P359, P1051, P1720)

Arran was formerly known as the Barbara-Phyllis field in the East Central Graben. Barbara is a Tertiary, Forties sand discovery at 8,500 – 9,600 ft TVDSS on the northern flank of a salt diapir, and Phyllis is a stratigraphic pinchout of Paleocene Forties reservoir draped across a southern low relief feature.

The Fallow licence status expired in 2015 and an Environmental Survey would be required to extend this licence. RISC has received no further update.

Dana Petroleum is the Operator (20.43207%) and E.On has 5.120% interest.

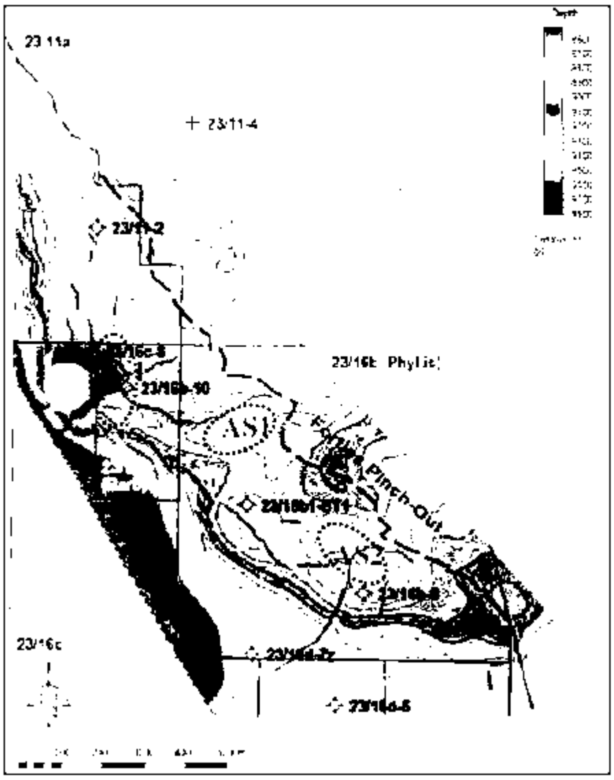


Figure 4-13 Arran Field Structure Map

RISC has not reviewed the volumes of the Contingent Resources. The table below represent the volume estimates of the Operator, based on simulations.

Table 4-6 Arran Field, Operator's Range of Simulated Cases

Contingent Resources (Gross)	P90	P50	P10
GIIP (Bcf)	221.3	347.0	543.2
Gas Production (Bscf)	99.5	155.8	223.2
Condensate Production (MMSTB)	2.7	4.2	6.4

Since April 2013 the Arran group have been working toward a revised development scheme for the field. Current studies focus on a three well subsea development tied back to the Shearwater Platform. Engineering studies are in progress to confirm the technical and commercial viability of this option and were expected to be complete mid-2015. RISC has received no further update.

The Arran group was working in parallel with other nearby undeveloped field owners to identify potential development synergies, which could better secure an economically viable development with earliest development sanction in late 2016.

4.3.1. Contingent Resources

These volumes could be expected to be recategorised as reserves if an approved, economic development scenario is achieved.

Table 4-7 Estimate for Arran Field Contingent Resources as at 1 January 2015

Arran Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Remaining Technical Recovery from 01 January 2015	5.1	0.138	8.0	0.215	11.4	0.328

4.4. Austen Gas-Condensate Field, block 30/13b (Licence P1823)

The Austen field is located in block 30/13b (licence P079), east Central Graben, south of ConocoPhillips' J-Block area, and includes a gas condensate discovery and two oil discoveries with several unappraised compartments. The Operator is GDF Suez.

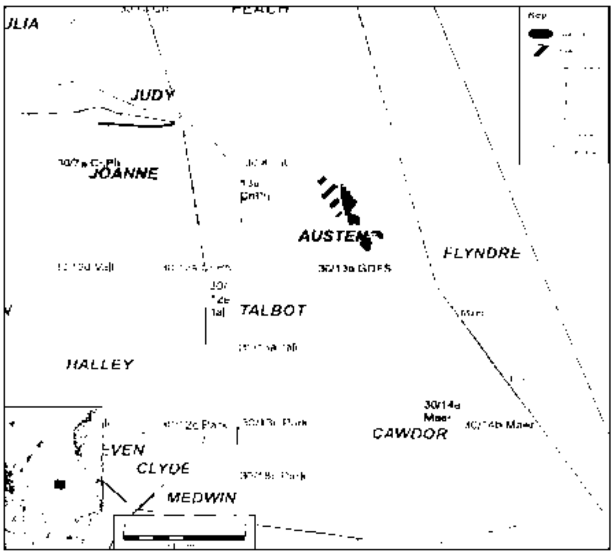


Figure 4-14 Austen Field Location Map

Austen was formerly known as the Josephine field and the initial licence term had an expiry of January 2015 with a second term ending in January 2019. RISC has received no further update. There is an outstanding contingent well into the Triassic which is contingent on seismic and the Operator has requested Oil and Gas Authority to waive this.

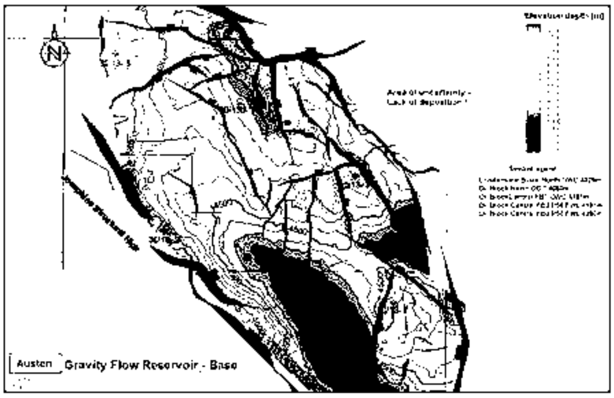


Figure 4-15 Austen Field Depth Map

The joint venture group was seeking project sanction in 2016, with first gas in 2019. Although the field qualifies for small fields tax allowance, Austen is not viable as a standalone development and requires a joint development with the nearby Talbot field (operated by Talisman) tied back over ConocoPhillips' J-Block. Talbot requires a Field Development Plan to be submitted by the end of 2015, with first oil projected in November 2017.

RISC has not reviewed the volumes of the Contingent Resources. The Operator holds a range of gross field recoverable volumes from approximately 46 Bcf to 87 Bcf based on modelling estimates from different models.

5. Processing Terminals and Pipelines

5.1. Caister Murdoch System (CMS)

The CMS facilities consist of a 26", 180 km pipeline to Theddlethorpe Gas Terminal (TGT). Although CMS has capacity to take further gas, it is planned to be decommissioned in 2018. The Caister and Murdoch fields each own a 50% share in CMS. E.On holds a 20% interest from its 40% interest in the Caister field. All costs and revenues, including tariff income, are shared on the same equity basis. Caister and Murdoch do not pay a tariff to CMS for transportation of their own gas and under the respective Transportation and Processing Agreements (TPAs). CMS is required to pay a part of the tariff to the TGT owners (ConocoPhillips 50% and BP 50%) to have gas processed and redelivered at the entry point to the National Transmission System.

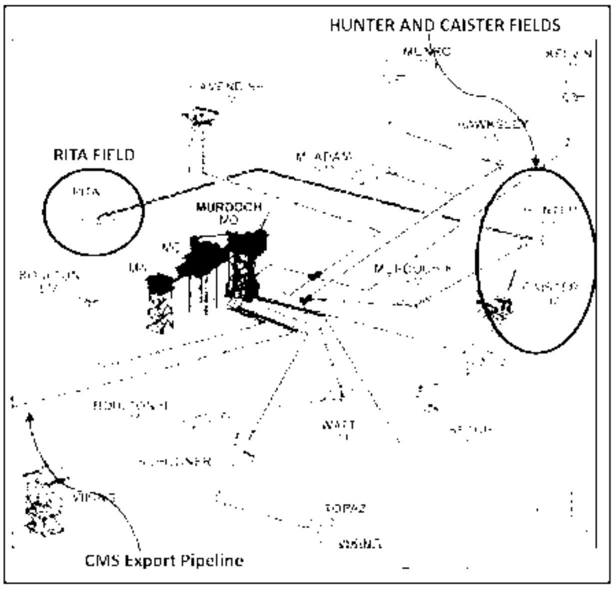


Figure 5-1 Location Map of CMS

All the TGT User fields should now be in Cost Share negotiated with TGT Operator ConocoPhillips based on Firm Capacity bookings. The exception is Hunter field, which has a zero Firm Capacity booked. The CMS owners ConocoPhillips and BP have elected to put User Fields into cost share because of low tariff receipts compared to the operating costs and also the imminent departure of ConocoPhillips as operator of TGT, which is expected within the next three to four years.

2015 Opex was £25.9 million & 2015 Capex was £3.0 million. Forecast Opex and Capex from the 2016 Budget are £33.8 million and 2.7 million. Beyond 2015, virtually all gas passing through the CMS pipeline will be from 3rd party fields operating on a cost share basis. RISC has therefore assumed no tariff revenue and that all operating costs are paid by third parties until the pipeline ceases operation in 2018, with decommissioning in 2019. As a result, there is no net income or costs until abandonment.

There are discussions related to life extensions beyond 2018, however these are considered upside scenarios only and have not been valued due to the uncertainty.

5.2. Esmond Transportation System (ETS)

The Trent and Tyne Fields and the Esmond Transmission System (ETS) pipeline (E.On 30%) are operated by Perenco UK as a single system known as the East Anglia Gas and Liquids Evacuation System ("EAGLES"). The system operates under the EAGLES Operating Agreement. Under the EAGLES Operating Agreement, all ETS operating costs are allocated to the Trent and Tyne Field owners' account. The ETS owners incur no operating costs or capital costs. ETS Pipeline abandonment costs are to be shared 50:50 with the Trent and Tyne Field owners.

ETS abandonment is likely to consist of flooding the pipeline, capping and leaving it in situ. E.On do not appear to carry abandonment costs (based on data provided by E.On in the data room) and RISC has assumed £20 million.

The Cygnus field, operated by GDF Suez, is a large gas development located in the southern North Sea with reserves of approximately 600 Bcf, first gas anticipated in 2016 and with a field life of 20 years. The field is contracted to use ETS and therefore ETS is unlikely to face abandonment in the near term. E.On advises net revenue from Cygnus is forecast to be £4.2m pa when the field is on plateau. This will decrease when the field drops off plateau, forecast to be around 2020.

Due to the age of the pipeline and the long forecast period, RISC's scenario is that after 10 years some pipeline remediation work is required of approx £10 million. According to the terms of the Transportation agreement, this will result in 50% tariff being payable for an eight year period.

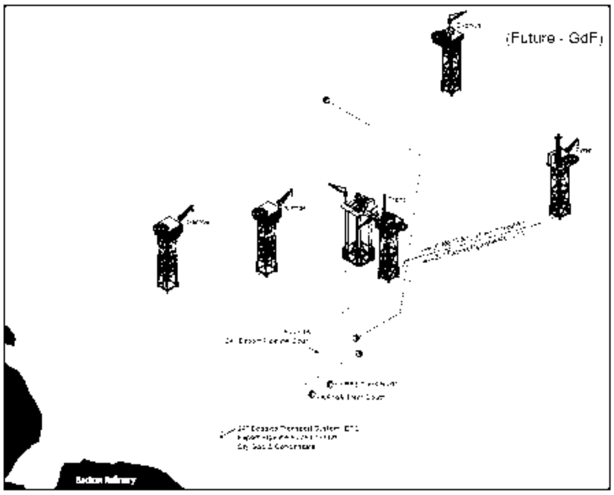


Figure 5-2 Location Map of ETS

5.3. Theddlethorpe Gas Terminal (TGT)

As operators of TGT, ConocoPhillips have established a new agreement with Shippers (terminal users) to share £153 million of costs under a new agreement for the Freon replacement project at Theddlethorpe Gas Terminal (TGT), which is required to stop usage of chlorofluorocarbons. The proposed new agreement affects the CMS fields in which E.On have an interest (Caister, Rita, Hunter).

There are provisions under the existing Transport and Processing Agreements to allow TGT owners ConocoPhillips and BP to recover costs. These fall into three categories:

1. Cost share
2. Modification cost
3. Tariff renegotiation

TGT shippers pay a share of TGT Freon Project costs in accordance with this supplemental agreement. This is equivalent to an increase in operating costs for the CMS fields.

The original 2013 installed total cost estimate has doubled to approximately £219 million gross. The new agreement applied from 1st October 2014 and runs for the remainder of the TGT Freon Project. The Freon replacement project is due to complete in 2016.

6. Exploration Potential

6.1. Overview

E.On have identified a significant portfolio of discoveries and exploration opportunities in the form of prospects and leads from three distinctly different geological regions of the UK North Sea and comprising a wide range of subsurface risks. The portfolio comprises discoveries and mature exploration opportunities, both near to existing producing fields and infrastructure and within exploration licences away from their core areas.

RISC has reviewed the Operator's interpretation for a selection of key discovery and prospect assessments (Table 6-1) and provides the following summary comments. The discoveries and prospects discussed here are deemed to be either sufficiently advanced in their technical assessment and/or low risk and/or with significant estimated recoverable resources. In addition, RISC has carried out an independent assessment of Geological Chance of Success (GCoS) for each but has not been supplied with enough data to independently derive volume estimates. The Operator's Chance of Success (where available) and best estimate Prospective Resource are reported in this section of the report.

Table 6-1 Discoveries and Key Prospects

Region	Prospect/Discovery Name	Field Area	Operator's Best Estimate Prospective Resource (MMboe)
Central North Sea	Corfe Discovery	Elgin & Franklin	17
Central North Sea	Ekland Prospect	Huntington	67
Southern North Sea	Cobra Discovery	Babbage	33
Southern North Sea	Hawking Discovery	Babbage	14.3
Southern North Sea	Ada Prospect	Babbage	3
Southern North Sea	Newton Prospect	Babbage	32
Southern North Sea	Python Prospect	Babbage	10.7
Southern North Sea	Artemis Discovery	Tolmount	27
Southern North Sea	Artemis East Prospect	Tolmount	7.9
Southern North Sea	Mongour Discovery	Tolmount	14.1
Southern North Sea	Malin prospect	Tolmount	27

6.2. Elgin/Franklin Field Area

E.On are non-operator partners in the Elgin-Franklin Field licences as well as the P1262 exploration licence to the west. The 2015 Corfe Discovery is discussed in section 6.2.1, with additional prospectivity summarised in Table 6-12. Elgin, Franklin and West Franklin are high pressure-high temperature (HPHT) gas-condensate fields in the Central North Sea operated by Total.

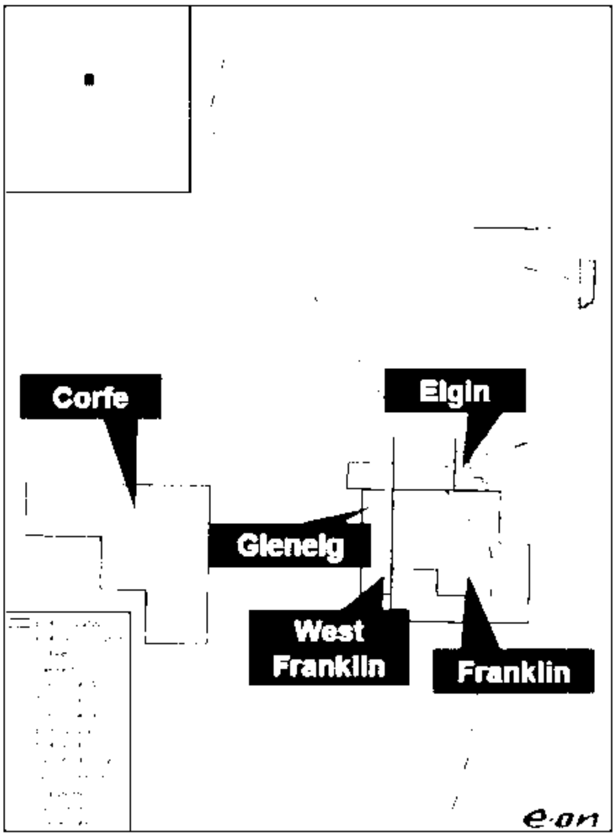


Figure 6-1 Location Map for Elgin and Franklin Fields and near field prospectivity

6.2.1. Corfe Discovery, block 29/3b (P1626 Licence)

The High Pressure, High Temperature (HPHT) Corfe Prospect in Block 29/3b was drilled in Q1-Q2 2015 with the primary target being the Joanne and Judy sands of the Triassic Skagerrak Formation and a secondary target of the Jurassic Fulmar Formation. The main Triassic objective was found to be water wet and the secondary Fulmar objective found to be gas bearing (gas shows, logs and sample). Volumes were initially reported to be in the range of 8 – 17 – 32 MMboe gross recoverable. HP and HT conditions were reported as 14,873 psia and 168°C respectively.

The Fulmar Corfe discovery is defined as a tilted fault block with 3 way dip closure and fault closure to the northeast. The lateral fault seal is against the Kimmeridge Clay Formation. The Fulmar appears to be thin in this area (17m gross thickness in the well) and is interpreted as a wedge that thins towards the fault, causing problems with imaging as the Fulmar is below tuning thickness across most of the defined area of the discovery. This is highlighted by an absence of amplitude anomaly over the discovery coincident with the area within tuning. Reservoir thickness appears to be one of the main uncertainties for the discovery. This has been addressed by sensitivity modelling where different wedge models and Fulmar thicknesses were used to generate a set of post-well volumes for the Corfe Discovery.

Prospective resources are reported to range from P90 - 3.58 MMboe to P10 - 56 MMboe as dependant on the sensitivity model as outlined in the table below.

Table 6-2 E.On's Post Corfe well analysis – sensitivity on gross prospective resources (MMboe)

Gross Prospective Resources (MMboe)	Thin Fulmar Modelled Pinch-out	Thick Fulmar Modelled Pinch-out	Fulmar 30m Constant Thickness	Thin Fulmar Faulted Model (thicker crest)	Thick Fulmar Faulted model (thicker crest)
P90	3.58	9.3	8.15	8.49	13.8
P50	7.72	21.3	15.6	17.3	28.1
P10	15.7	43.3	29.1	33.3	56

The same petrophysical parameters were used for all cases above with porosity ranging from 15-17.3-20% (P90-P50-P10) and Net to Gross ranging from 40-55-70% (P90-P50-P10) (the saturation range was not reported). The contacts used were 4,955m – MIN and 5,150m – MAX which are approximately based on Gas Down To (GDT) and the deepest structural contour with amplitude anomaly conformance respectively.

The latest TCM meetings available in the data room are from June 2014, pre-drill. It is assumed that the post well evaluation work on the discovery is ongoing. In the absence of definitive volumes, the recoverable resource range of 8-17-32 (gross) MMboe initially reported post drilling is deemed appropriate. This range covers the majority of outcomes characterised by the sensitivity analysis reported by the Operator in August (Table 6-2).

6.3. Huntington Area

E.On participate as operators and non-operators in two exploration licences south of the Huntington Field. The main prospect, Ekland, targets the Fulmar Formation. The Skagerrak Formation provides a secondary target.

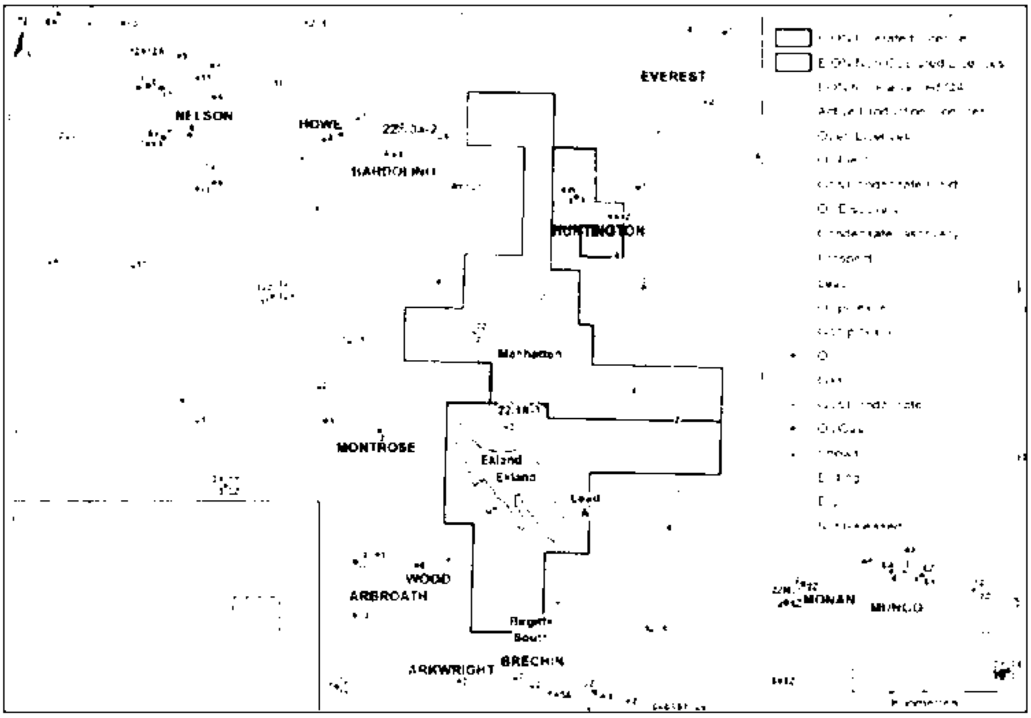


Figure 6-2 Location Map for Huntington Field and near field prospectivity

6.3.1. Ekland Prospect (P2184 Licence)

The Ekland Prospect is located in Blocks 22/18c and 22/19d which were awarded to E.On as operator in December 2014 as part of the 28th offshore licencing round. The prospect is located approximately 20km south of the Huntington Field on a fault terrace to the east of the Forties/Montrose high. The Operator identifies the key risk as reservoir presence.

Operator's Ekland Best Estimate[10] Prospective Resource (Gross Unrisked): 67 MMboe. Operator's Ekland GCoS: 30%.

[10] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.3.1.1. *RISC estimation of Geological Chance of Success for Ekland*

Table 6-3 RISC GCoS for the Ekland Prospect

Ekland Prospect	**GCoS (%)**		**GCoS (%)**	**Key Risks**
Trap	90	Containment	54	Main structural trap is well defined fault bound and dip closed fault terrace. The Fulmar play requires stratigraphic trapping with a wedge of Fulmar interpreted within the main structure. Trap is well defined, despite requiring stratigraphic closure, but this risk is captured in reservoir presence. Top seal is provided by Cretaceous chalk and marls. Base seal from underlying Triassic is required to give separate Jurassic accumulation, otherwise a fault seal is required for a joint Jurassic/Triassic accumulation.
Seal	60			
Reservoir presence	50	Reservoir	50	Reservoir presence is inferred between the BCU and the top Triassic seismic reflectors. The two closest wells, already drilled on the main structure, did not contain Fulmar Formation. However, well 22/18-6 (Wood Field) approx. 10km to the southwest did contain oil bearing Fulmar Fm. Immediately beneath the BCU proving the concept can work in this area. If reservoir is present it is likely to be of good quality, analogous to the Wood Field.
Reservoir effectiveness	100			
Source	100	Source	80	Proven hydrocarbon generation from the Kimmeridge Clay Formation within the East Central Graben. Migration is seen as low risk given the Wood Field to the west and the Birgitta discovery to the south. Gas condensate is the expected HC phase.
Timing and Migration	80			
RISC GCoS (%)	22		22	
Description of key risks	The key risk identified on the Ekland prospect is reservoir presence. The Fulmar Fm is inferred on seismic and Fulmar is absent in the two closest wells to the prospect. Seal is also considered a risk, with the requirement for a base seal to separate Jurassic sand from underlying Triassic sands and if both are connected the requirement for a fault seal to the east.			

6.4. Babbage Area

There are a number of Discoveries, Prospects and Leads in the immediate area around Babbage including Ada, Hawking, Newton, Cobra and Python discussed here. These are all discoveries in, or targeted at, the Lower Leman Sandstone reservoir, although in some cases there is either Carboniferous reservoir immediately underlying or Carboniferous potential.

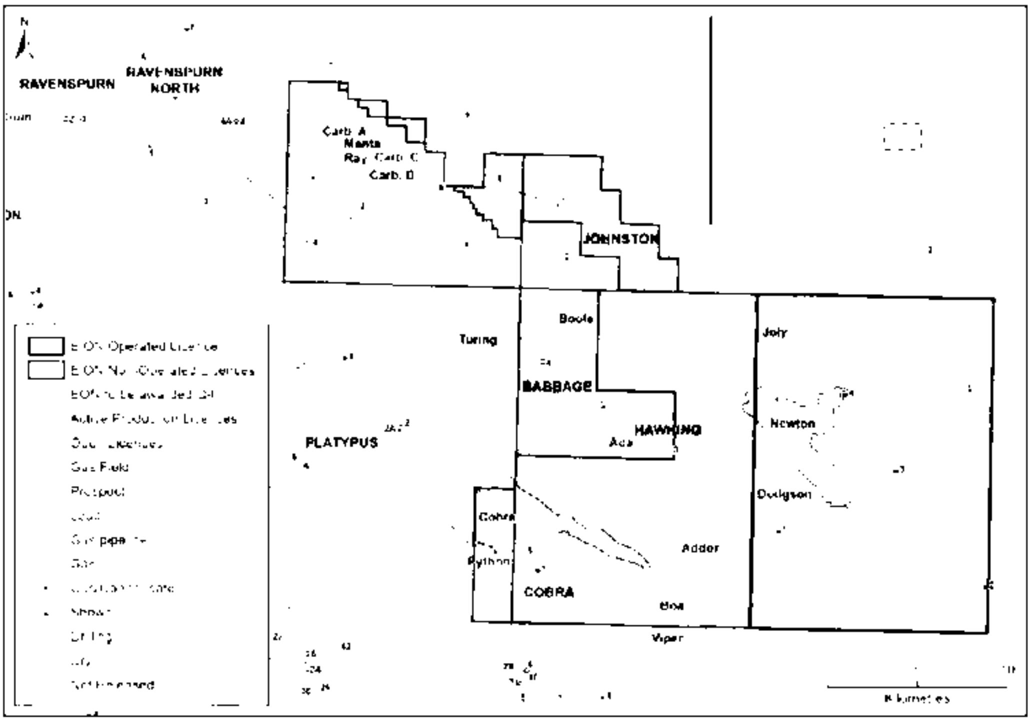


Figure 6-3 Location Map for Babbage Field and near field prospectivity

6.4.1. Ada Prospect, block 48/2

The 'Ada' prospect (formerly 'Babbage South') is an undeveloped area to the SE of Babbage, largely beneath the 'salt wall' which runs W-E across the structure. If successful it will likely require subsea tie-backs to the platform. No decision yet to drill: scheduled 'Drill/No drill' was June 2015, but does not appear to have been made (disagreement within JV).

Seismic attribute work by the Operator suggests that reservoir quality may be better than seen in Babbage and may not need to be fracced, but it is recognised that further risk reduction is unlikely and the well therefore needs to be drilled to properly assess the prospect.

The Operator carries a mid-case GIIP of 127 bcf with prospective resources of 18 bcf (14% RF).

Operator's Ada Best Estimate[11] Prospective Resource (Gross Unrisked): 3 MMboe.

[11] E.On E&P North Sea Information Memorandum Volume 2 June 2015

Table 6-4 RISC GCoS for the Ada Prospect

Ada Prospect	GCoS (%)		GCoS	Key Risks
Trap	90	Containment	81	The trapping mechanism is unclear due to the 'salt wall': may be a structural dip closure or fault combination. The lateral Seal may be a combination of fault seal and overlying shales of the Silverpit, or Zechstein evaporites/carbonates.
Seal	90			
Reservoir presence	90	Reservoir	81	The reservoir is assumed to be the same as the adjacent Babbage field. Reservoir effectiveness therefore is likely to be similar to Babbage wells, i.e. aeolian, fluvial and some associated lacustrine (sabkha) facies.
Reservoir effectiveness	90			
Source	100	Source	100	Hydrocarbon generation is proven from the underlying Carboniferous coals, with negligible risk to Timing and Migration due to proximity of Babbage. Gas is the expected HC phase.
Timing and Migration	100			
RISC GCoS (%)	66		66	
Description of key risks	This is a near-field step-out and, but for the presence of the 'salt wall' would likely be considered a development well rather than appraisal.			

6.4.2. Hawking Discovery, Block 48/2b

Hawking is a one-well gas discovery (48/2b-3) characterised as a high relief tilted fault block adjacent to the southern extent of the Babbage Field. The fluid contact is interpreted by the Operator as a GDT at 3280m that could be potentially deeper. The Operator mapped the structure using the 2011 GXT reprocessed seismic data which has revealed a larger structure than originally mapped suggesting, in a high case that the spill point may be aligned with Babbage FWL at 3370m. Potential upside exists if there is a sealing De Keyser fault between Babbage and Hawking.

This structure is high relief with dip closure to the south and west. Structural spill point is mapped close to the Babbage FWL and may therefore be in communication. Trapping is by fault seal and dip closure, with the lateral Seal formed in part by fault seal and part by overlying shales and silts of the Silverpit Formation. Situated along the margin of the Leman Fairway, the Leman Sandstone reservoir is present in the discovery well and surrounding fields. Reservoir facies are likely to be similar to offset wells in the area, i.e. aeolian, fluvial and associated lacustrine (sabkha) facies. Reservoir effectiveness is expected to be poor, as in Babbage, with low permeability (due to illitisation) observed in the discovery well. Interception of natural fracture networks or hydraulic fracturing will likely be required for successful development wells.

Operator's Hawking Best Estimate[12] Prospective Resource (Gross Unrisked): 14.3 MMboe. Operator's Hawking GCoS: 81%.

[12] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.4.3. Newton Prospect 48/3b

Lies in a tilted fault block, similar to the producing Johnston Field, approximately 10 km east of the Babbage Field. The reservoir appears not to have been as deeply buried as Babbage. The trap is defined as a large 3-way dip closure against a clearly defined fault to the southwest. Structural dip is considered critical in the NW direction to maintain gas migration through the Leman from the south. The Operator considers dip closure rather than up-dip fault closure to be the key control on gas emplacement and protection from illitisation.

Operator's Newton Best Estimate[13] Prospective Resource (Gross Unrisked): 32 MMboe. Operator's Newton GCoS: 32%.

6.4.3.1. RISC estimation of Geological Chance of Success for Newton

Table 6-5 RISC GCoS for the Newton Prospect

Newton Prospect	GCoS (%)		GCoS (%)	Key Risks
Trap	70	Containment	49	Formed of a tilted fault block, dip closed to the NW. Trapping by fault seal and dip closure, with lateral Seal formed in part by fault seal and part by overlying shales and silts of the Silverpit Fm.
Seal	70			
Reservoir presence	90	Reservoir	54	Situated along the margin of the Leman Fairway, 'tight' reservoir is present in the 48/3-4 well, down dip and in surrounding fields. Reservoir effectiveness is likely similar to nearby wells, i.e. aeolian, fluvial and some associated lacustrine (sabkha) facies, and would require wells to intercept natural fracture networks and/or multi-fracced, like Babbage.
Reservoir effectiveness	60			
Source	100	Source	70	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration into the Leman is well established (residual gas in the 48/3-4 well). Gas is the expected HC phase.
Timing and Migration	70			
RISC GCoS (%)	19		19	
Description of key risks	Key risks are Containment and Reservoir effectiveness. Size of the structure is a risk despite the extensive seismic processing work. Reservoir effectiveness appears to rely on early gas migration into the structure to keep it 'illite-free', otherwise fracc'ing would be required in a success case. Despite Operator comment that 'illite-free' unpredictable, E.On has chosen to use un-illitised field analogues (28th Round Application, App.B).			

[13] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.4.4. Cobra Discovery and Python Prospect 48/1b, 48/2b (Licence P.2212) and 48/1c (P2301)

Cobra is a two well discovery, with a tight gas reservoir. The GDT implies a larger structure than the original mapping could be shown to close. Re-mapping using 2011 GXT seismic data resulted in an interpretation by the Operator of a suspected De Keyser fault sealing at the NW end of Babbage and continuing on past the northwestern up-dip part of the greater Cobra structure. Fault seal analysis predicts a sealing capacity to within seismic resolution (15m) of the GDT. Therefore the structure is broken into several segments, with Python considered as a separate prospect.

The Cobra discovery trap relies on fault seal and dip closure with the lateral seal formed in part by fault seal and part by the overlying shales and silts of the Silverpit Formation. The Leman Formation sandstone reservoir is present in the discovery wells and in surrounding fields with the reservoir characterised as aeolian and fluvial facies with some associated lacustrine (sabkha) facies. Migration into the Leman is proven in one segment of the discovery by the discovery wells. However, the timing of fault seal may be important for the charging of further fault bound segments, including the Python Prospect, if pathways rely on 'fill-and-spill' model.

Operator's Cobra Best Estimate[14] Prospective Resource (Gross Unrisked): 33 MMboe. Operator's Cobra GCoS: 80%.

Operator's Python Best Estimate[15] Prospective Resource (Gross Unrisked): 10.6 MMboe. Operator's Python GCoS: 80%.

[14] E.On E&P North Sea Information Memorandum Volume 2 June 2015

[15] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.4.4.1. *RISC estimation of Geological Chance of Success for Python*

Table 6-6 RISC GCoS for the Python Prospect

Python Prospect	GCoS (%)		GCoS (%)	Key Risks
Trap	70	Containment	49	Dip closure against seismically defined fault/s. Trapping relies on fault seal and dip closure, and lateral Seal is formed in part by fault seal and part by the overlying shales and silts of the Silverpit Fm. (or Zechstein evaporites/ carbonates).
Seal	70			
Reservoir presence	90	Reservoir	81	Situated along the margin of the Leman Fairway, the reservoir is present in offset wells and nearby fields. Reservoir effectiveness is likely similar to surrounding area wells, i.e. aeolian, fluvial and some associated lacustrine (sabkha) facies.
Reservoir effectiveness	90			
Source	100	Source	63	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration dependent on timing of fault seal. Gas is the expected HC phase.
Timing and Migration	70			
RISC GCoS (%)	28		28	
Description of key risks	Although proved in Cobra, the main risks to this Prospect within the play fairway remain on Trap and Seal, and Migration.			

6.5. Tolmount Area

A number of Discoveries, Prospects and Leads can be found in the immediate area around the Tolmount Field including Artemis, Artemis East, Mongour and Malin discussed here. These are all discoveries in, or targeted at, the Lower Leman Sandstone reservoir.

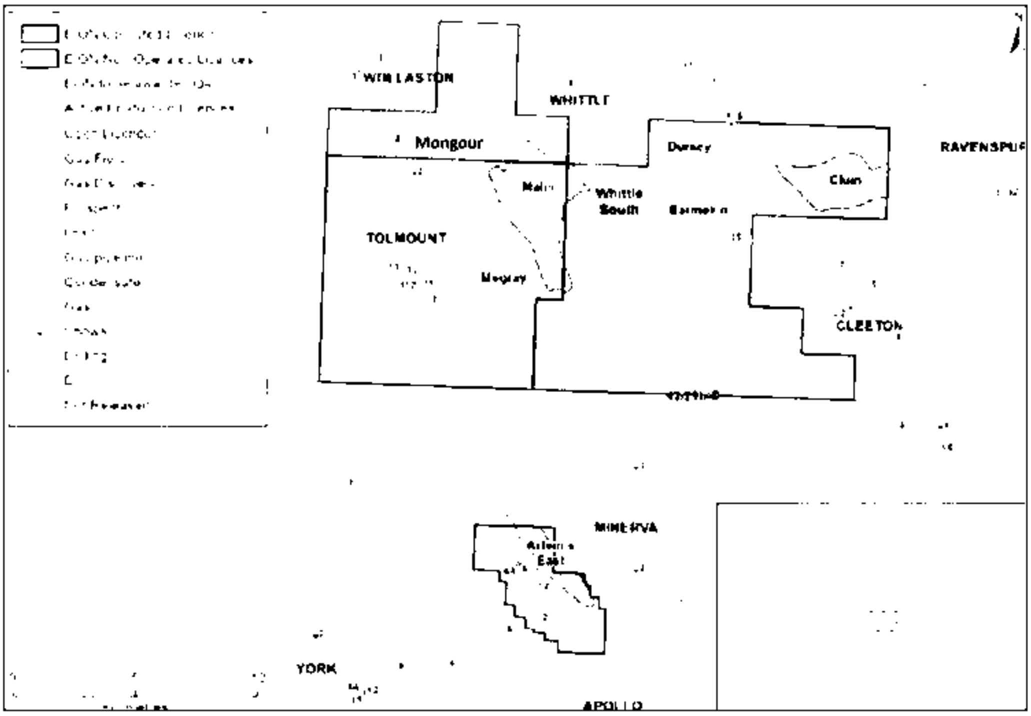


Figure 6-4 Location Map for Tolmount Field and near field prospectivity

6.5.1. Artemis Discovery and Artemis East Prospect (Licence P2136)

Artemis is a tight gas discovery, located in Block 47/3k between the Apollo and Minerva Fields, approximately 10km south of the Tolmount Field. The discovery well 47/3-2, drilled in 1974 encountered gas bearing Leman Sandstone reservoir which was appraised by well 47/3b-6A. Both wells were tested with low flow rates due to tight reservoir being encountered. In 2002 BG drilled a horizontal well 47/3b-12 in an attempt to develop the Field in a similar fashion to the Minerva and Apollo Fields. The well was ultimately a failure, intersecting poorer reservoir quality sands than expected with the well returning sub commercial flow rates.

The trap is well defined and is described as a fault-bounded anticline trending northwest – southeast with faults to the northeast and southwest and dip closure to the northwest and southeast. The FWL was not penetrated in either of the two vertical wells and is interpreted to be 10850 ft TVDSS from regional pressure data. The Artemis East prospect to the northeast has the same structural configuration as the Artemis discovery.

The reservoir is the Leman Sandstone comprising a complex interfingering mix of Aeolian, sabkha and fluvial facies with the fluvial facies dominant. Reservoir quality is moderate in terms of porosity and poor in terms of permeability. Matrix permeability is occluded by secondary illite precipitation, which is at odds to the adjacent Apollo and Minerva Fields, leading to the interpretation that the Artemis structure may have been more deeply buried before inversion during the Cretaceous. It is thought likely that the reservoir within the Artemis East Prospect would be similar. The Operator plans to develop the reservoir via long horizontal / sub-horizontal fracced wells. Consequently, the high cost of developing Artemis East (if drilled and successful) with its relatively small volume is only thought economically viable if the Artemis Discovery is developed first.

Operator's Artemis Best Estimate[16] Prospective Resource (Gross Unrisked): 27 MMboe. Operator's Artemis GCoS: 80%.

Operator's Artemis East Best Estimate[17] Prospective Resource (Gross Unrisked): 7.9 MMboe. Operator's Artemis East GCoS: 80%.

6.5.1.1. RISC estimation of Geological Chance of Success for Artemis East Prospect

Table 6-7 RISC GCoS for the Artemis East Prospect

Artemis East Prospect	**GCoS (%)**		**GCoS (%)**	**Key Risks**
Trap	90	Containment	72	Well defined northwest – southeast trending fault bound anticline. Fault closure to the northeast and southwest with dip closure to the northwest and southeast. Top seal provided by the overlying Silverpit claystones and Zechstein evaporites. Lateral fault seal is juxtaposition of Leman sands against Silverpit claystones. In the high case Artemis East may be connected to the Artemis Discovery.
Seal	80			
Reservoir presence	100	Reservoir	90	Situated along the margin of the Leman Fairway, the reservoir is present in the surrounding discoveries and fields. However, 'tight' reservoir is present in the wells on Artemis and similar reservoir properties can be expected at Artemis East. Gas was successfully flowed to surface in the wells drilled on Artemis, but at sub-economic rates. Successful development is likely to require long horizontal / sub-horizontal fracced wells.
Reservoir effectiveness	90			
Source	100	Source	100	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration into the Leman is well established. Gas is the expected HC phase.
Timing and Migration	100			
RISC GCoS (%)	65		65	
Description of key risks	Key risks is reservoir effectiveness. As in the Artemis Discovery successful development of a potential discovery at Artemis East is likely to involve fraccing.			

6.5.2. Mongour Discovery (Licence P1330)

The Mongour Discovery is located in Block 42/28C, between the Tolmount Field and the Wollaston Field. The discovery well 42/28-2 was drilled in 1973 discovered gas-bearing sands within the Leman Sandstone interval with a GDT of 9800 ft TVDSS. Another well, 42/28-4 drilled approximately 1.5km to the northwest, penetrated a thicker section of Leman Sandstones but was found to be dry. This well is mapped within a topographic low whilst the 42/28-2 well is mapped as a small 4-way dip closure.

RISC recognises value in a future development only if the discovery forms part of a larger structure, extending to the north and south, bound by faults. The Operator proposes this as a high case scenario, for which RISC provides a GCoS below.

[16] E.On E&P North Sea Information Memorandum Volume 2 June 2015
[17] E.On E&P North Sea Information Memorandum Volume 2 June 2015

Operator's Mongour Best Estimate[18] Resource (Gross Unrisked): 14.1 MMboe.

Operator's Mongour High Case Estimate[19] Resource (Gross Unrisked): 33.4 MMboe.

6.5.2.1. *RISC estimation of Geological Chance of Success for Mongour Discovery (High Case)*

Table 6-8 RISC GCoS for the Mongour Discovery (high case)

Mongour Discovery High Case	GCoS (%)		GCoS (%)	Key Risks
Trap	80	Containment	32	Using the GDT in the 42/28-2 well gives two separate small closures within the prospect area. The high case trap is reliant on fault seals to the north separating the prospect from the Wollaston Field and to the south. The fault seal to the south is likely to be effective as suggested by a deeper GWC in the Tolmount Field. Top seal is provided by the overlying shales and silts of the Silverpit Fm. Some mapping and depth conversion uncertainty exists relating to the faulted region in the centre of the larger closure and the topographic low associated with the dry 42/28-4 well.
Seal	40			
Reservoir presence	100	Reservoir	100	The Leman Sandstone is proven in the two wells drilled within the main structure and reservoir is shown to be effective from core data in these wells.
Reservoir effectiveness	100			
Source	100	Source	100	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration into the Leman is established by the discovery wells and surrounding discovered fields. Gas is the expected HC phase.
Timing and Migration	100			
RISC GCoS (%)	32		32	
Description of key risks	The key risk is identified as containment. A gas discovery in the 42/28-2 well proves the low case volume, however in the high case sealing faults are required to the north and south with some uncertainty on the exact size of the container.			

6.5.3. Malin Prospect (P1330 Licence)

The Malin Prospect is located 2km east of the Tolmount Field in Block 42/28d. The trap is described as a tilted fault block with fault closure to the west and north, but the closure to the south and east is unclear due to poor imaging as a result of a salt wall. The reservoir target is the Permian Leman Sandstones proven in the adjacent fields and discoveries. Source and charge are also well proven in this area.

Operator's Malin Best Estimate[20] Prospective Resource (Gross Unrisked): 27 MMboe. Operator's Malin GCoS: 27%.

[18] E.On E&P North Sea Information Memorandum Volume 2 June 2015
[19] E.On E&P North Sea Information Memorandum Volume 2 June 2015
[20] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.5.3.1. *RISC estimation of Geological Chance of Success for Malin Prospect*

Table 6-9 RISC GCoS for the Malin Prospect

Malin Prospect	**GCoS (%)**		**GCoS (%)**	**Key Risks**
Trap	30	Containment	24	The trap is poorly defined on the southern and western margins due to imaging problems associated with a salt wall. Further work to improve the seismic image quality could de-risk the prospect. Fault closures to the north and west appear to offset Leman against the overlying shales of the Silverpit Fm. which also provides the top seal for the prospect.
Seal	80			
Reservoir presence	90	Reservoir	90	The presence and reservoir quality of the Leman Sandstone is proven in the adjacent Tolmount and Whittle Fields and Mongour Discovery.
Reservoir effectiveness	100			
Source	100	Source	100	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration into the Leman is established by the discovery wells and surrounding discovered fields. Gas is the expected HC phase.
Timing and Migration	100			
RISC GCoS (%)	22		22	
Description of key risks	The key risk is trap definition. A viable trap cannot be defined on the current dataset.			

6.5.4. Prospective Resources Summary

RISC has not valued the Exploration potential. There are six prospects, which have reached a mature level in order to be relatively confident of a calibrated Geological Chance of Success. However, six is not a statistically significant population, and therefore a calculation of Estimated Monetary Value (EMV) of the portfolio of exploration prospects will have wide error bars and will not fully reflect the range of potential outcomes.

Table 6-10 Operator's gross Prospective resources of key discoveries

Contingent Resources	
Discovery	**Operator Best Estimate Gross Prospective Resource (MMboe)**
Hawking	14.3
Cobra	33
Artemis	27
Mongour	14.1
Corfe	17
TOTAL	**105.4**

Table 6-11 Operator's gross recoverable resources with RISC's GCoS and risked recoverable resources

Prospective Resources			
Prospect	**Operator Best Estimate Gross Recoverable Resource (MMboe)**	**RISC GCoS**	**Risked Gross Resource (MMboe)**
Ada	3	66	2.0
Newton	32	19	6.1
Python	10.7	28	3.0
Artemis East	7.9	65	5.1
Malin	27	22	5.9
Ekland	67	22	14.7
TOTALS	**147.5**	-	**36.8**

6.6. Additional Prospectivity

6.6.1. Central and Southern North Sea Leads

A number of leads that have been identified by E.On are summarised below. These volumes are considered indicative and have not been evaluated by RISC. RISC do not consider these leads well enough calibrated to be used for EMV calculation.

Table 6-12 Summary of additional Central and Southern North Sea Prospectivity identified by E.On

Lead Name (HC Phase)	Lead Name	Licence	Operator	Partners	Blocks	Licence Award Date	Major Licence Commitments	Operator Best Estimate Gross Recoverable Resource (MMboe)	Operator GCoS
Cluin (Gas)	Cluin	P2105	E.On (50%)	Dana (50%)	42/28e, 42/29d	20.12.2013	Drill or Drop decision by 20.12.2017	17	30%
Newton Deep (Gas)	Newton Deep	P2290	E.On (50%)	Bayerngas (50%)	48/3	01.09.2015	1 Firm Well on the licence	6.8	35%
Dodgson (Gas)	Dodgson							7	48%
Joly (Gas)	Joly							7.2	36%
Adder (Gas)	Adder	P2212	E.On (50%)	Bayerngas (50%)	48/2b	01.12.2014	1 Firm Well on the licence	6.3	48%
Viper (Gas)	Viper							3.2	40%
Boa (Gas)	Boa							4	40
North Rita (Gas)	North Rita	P771, P766	E.On (74%)	GDF Suez (26%)	44/22c, 44/21b	14.06.1991	Licence due expiry 14.06.2025	1.3	n/a
Deep Hunter (Gas)	Deep Hunter	P452	E.On (79%)	GDF Suez (21%)	44/23e	11.05.1983	Licence due expiry 10.05.2019	4.17	n/a
Lyra (Gas)	Lyra	P2271	E.On (35%)	Bayerngas (35%), Dyas (30%)	43/1, 43/2, 43/6	01.09.2015	Drill or Drop 01.09.2019	51	17%
West Franklin Terrace (Gas + Condensate)	West Franklin Terrace	P188, P362, P666, P2068	Total (46.17%)	ENI (21.87%), BG (14.11%), E.On (5.2%), ExxonMobil (4.38%), Chevron (3.9%), Dyas (2.19%), Summit Petroleum (2.19%)	22/30b, 22/30c, 29/5b, 29/5c, 29/4d	P188 – 16.03.1972 P362 – 17.12.1980 P666 – 20.07.1989 P2068 – 01.01.2013	P188 – Due expiry 15.03.2018 P362 – Due expiry 16.12.2016 P666 – Due expiry 19.07.2025 P2068 – Initial term end date 01.01.2019	50**	48%
Elgin West (Gas + Condensate)	Elgin West							37**	40%
TR7 (Oil)	**TR7**	P2161	E.On (40%)	Edison (30%), Bayerngas (30%)	15/27b	01.12.2014	Drill or Drop decision by 01.01.2018	88	18%

Lead Name (HC Phase)	Lead Name	Licence	Operator	Partners	Blocks	Licence Award Date	Major Licence Commitments	Operator Best Estimate Gross Recoverable Resource (MMboe)	Operator GCoS
Tumbleweed (Oil)	Tumbleweed	P2178	E.On (40%)	Edison (30%), Bayerngas (30%)	21/17b, 21/18b	01.12.2014	Drill or Drop decision by 01.01.2018	22	46%
Chimaera (Gas + Condensate)	Chimaera	P2303	E.On (40%)	Edison (30%), Bayerngas (30%)	15/24a	Awaiting official confirmation	Drill or Drop 4 years after award	36	29%

**Numbers represent in-place estimates.

6.6.2. West of Shetlands

E.On hold three exploration licences in the West of Shetlands as Operator. E.On were recently participant in three other licences as non-operator but these are due to be relinquished in Q1 2016. The table below lists the licences with Blocks, identified leads, Operator best estimate recoverable volume and key licence information. RISC do not consider these leads well enough calibrated to be used for EMV calculation.

Table 6-13 Summary of West of Shetland Prospectivity identified by E.On

Lead Name (HC Phase)	Lead Name	Licence	Operator	Partners	Blocks	Licence Award	Outstanding Licence Commitments	Operator Best Estimate Gross Recoverable Resource (MMboe)	Operator GCoS
Colza (Gas)	Colza	P2023	E.On (100%)	-	208/14, 208/15	01.01.2013	Drill or Drop decision by 01.01.2017	68	25%
Mardyke (Gas)	Mardyke	P2073	E.On (100%)	-	209/4, 209/5	01.01.2013	Drill or Drop decision by 01.01.2017	100	17%
Gunnison (Oil or Gas)	Gunnison	P2012	E.On (100%)	-	219/13, 219/14, 219/15	01.01.2013	Drill or Drop decision by 01.01.2017	34	15%

[redacted] [redacted]

7. Economics

7.1. Fiscal Terms

Upstream oil and gas activities in fields on the UK Continental Shelf (UKCS) are subject to several layers of taxation which are summarized below:

Fiscal Term	Description
License Term	Block specific
Royalties	No state royalties apply
Petroleum Revenue Tax (PRT)	PRT is a tax on "supra-normal" profits from individual fields with development consents prior to 16 March 2003. PRT is ring-fenced at a field level and deductible against RFCT and SCT. The only Southern North Sea E.On field subject to PRT is Ravenspurn North where PRT is applied at a rate of 50% in 2015 and 35% thereafter. PRT assessable profit is calculated as follows: + Sales Revenue + Tariff revenue - Opex, exploration & appraisal costs and capex (35% uplift on qualifying capex) - Abandonment losses - Field losses carried forward/back - Oil allowance Application of PRT is further subject to Payback and Safeguard limits under which PRT only applies after payback is achieved (defined as cumulative revenues exceeding cumulative costs), and Safeguard during which PRT is charged on 80% of adjusted profit less 15% of the ending balance of cumulative capex for the chargeable period. The Safeguard period is defined as 1.5 times the chargeable periods up to the achievement of Payback.
Ring Fence Corporation Tax (RFCT)	RFCT is levied on the Upstream profits from oil & gas activities at a rate of 30%. Allowable deductions include: ▪ PRT ▪ Opex ▪ Capital allowances of which o Capex other than long life assets (>25 years) is written down 100% as it is incurred o Capex on long life assets is written down by 24% in the 1st year and 6% pa declining balance thereafter o Abandonment expenses expensed as it is incurred ▪ Interest expenses ▪ Ring Fence Expenditure Supplement ▪ RFCT losses carried forward indefinitely or backward for up to 3 years.
Supplementary Charge (SCT)	SCT is levied on Upstream profits from oil & gas activities at a rate of 20% on a similar base to RFCT with the exceptions of interest being excluded from deductions and additional field allowances allowable as deductions.

7.2. Economic Analysis

Economic assessment of E.On's Southern North Sea producing fields have been based on discounted cash flow analyses incorporating production and cost profiles and the fiscal terms described above.

A total of four price scenarios have been run with Price Scenario 'A' representing RISC's view of future prices. The three other scenarios (Price Scenario 'B', Price Scenario 'C' & Price Scenario 'D') represent prices forecast by Premier. E.On sells its gas to other E.On subsidiaries at National Balancing Point (NBP) prices with hedging at a corporate level. RISC has not valued the hedges.

A summary description of the assumptions used in the models follows.

7.2.1. Key Assumptions

7.2.1.1. Valuation Date

The valuation has been carried out in US Dollars with an Effective Date of 1st January 2015 to align with the Sale and Purchase agreement between Premier Oil and E.On (Table 7-4 & Table 7-5). The reserves and net present values have also been calculated with an effective date of 31st December 2015 (Table 7-6 & Table 7-7) to meet the requirements of the UK Listing Authority.

7.2.1.2. Field allowances

Ravenspurn North is subject to PRT and eligible for oil allowance to reduce potential PRT payable. Information supplied by Premier indicates Ravenspurn North has a remaining oil allowance balance of 109,382 tonnes out of a total of 2.5 million tonnes and a maximum of 125,000 tonnes per chargeable period. Analysis shows Ravenspurn North generates insufficient revenue to incur any PRT charges or make use of the oil allowance hence the oil allowance is immaterial.

7.2.1.3. Tax loss pools

Premier has provided the following information on apportioned tax losses/pool deductible against Southern North Sea fields.

Table 7-1 Southern North Sea Fields Share of tax losses (Opening Position 1.1.2015 - Net £MM)

	EPUK	EU	Aggregate
RFCT Loss	9.248	60.203	69.451
SCT Loss	9.276	37.492	46.768
Plant and machinery Pool	21.759	7.223	28.982
Mineral extraction allowance	0.899	9.644	10.543

RISC has utilised EU allowances from Table 7-1.

7.2.1.4. *Commodity Prices*

A total of four price scenarios have been considered. The 2015 gas production is assumed to have been sold at monthly average of day-ahead contract prices as reported by Ofgem and liquids sold at the average of the dated Brent monthly price. Price Scenario 'A' represents RISC's view of future prices. Price scenarios B, C & D represent mid, low and high prices forecast by Premier. The prices are exclusive of any hedge contracts in place at the time of the transaction.

Table 7-2 Commodity Prices

	2015	2016	2017	2018	2019+
Oil Price (US$/bbl)					
Price Scenario 'A'	52.40	35.00	40.00	45.00	60 (2016 real +2.5% pa) i.e. 65
Price Scenario 'B'	52.40	55.00	60.00	65.00	80 (2016 real +2.5% pa) i.e. 86
Price Scenario 'C'	52.40	45.00	50.00	55.00	65 (2016 real +2.5% pa) i.e. 70
Price Scenario 'D'	52.40	55.00	70.00	75.00	95 (2016 real +2.5% pa) i.e. 102
Gas Prices – UK NBP spot (GBp/th)					
Price Scenario 'A'	44.2	33.0	34.0	35.0	+2.5% pa
Price Scenario 'B'	44.2	40.0	41.0	42.0	+2.5% pa
Price Scenario 'C'	44.2	37.5	38.0	39.0	+2.5% pa
Price Scenario 'D'	44.2	42.5	44.0	45.0	+2.5% pa

7.2.1.5. *Economic parameters*

Table 7-3 Economic Parameters

	2015	2016	2017	2018	2019+
Cost Inflation	0%	0%	0%	0%	+2.5% pa
Exchange $/£	1.5	1.5	1.5	1.5	1.5

7.2.1.6. *Discount Rate*

Project NPVs are reported at a discount rate of 10% nominal. Discount rates of 8% and 12% nominal are considered as valuation sensitivities.

7.2.1.7. *Cases*

RISC has evaluated 1P, 2P and 3P cases for producing fields and fields under development under the fiscal terms and economic parameters described above.

7.2.1.8. *Economic limit*

RISC estimates field economic limits using a look-back value methodology whereby a field is abandoned at a time beyond which operations would erode economic value.

7.3. Economic Results as of 1st January 2015

Economics have been run using the discounted cash flow method for the four price scenarios based on estimates of future production of assessed reserves/resources and forecasts of future capital and operating costs with an effective date of 1st January 2015.

The following Net Present Values have not been adjusted for other factors (eg analogous transactions, strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value.

The economic results for the pipelines are independent of the oil and gas price scenarios. A single scenario was evaluated for each of the ETS and CMS working interests at the effective date of 1st January 2015.

Table 7-4 Pre-Tax Valuation Summary (NPV at 10% discount rate in US$MM at 1st January 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	0	0	0	0
			2P	0	0	0	0
			3P	0	0	0	0
Ravenspurn North	Producing	29%	1P	-60	-60	-60	-60
			2P	-59	-59	-59	-59
			3P	-59	-59	-59	-59
Johnston	Producing	50%	1P	5	9	7	10
			2P	10	14	12	15
			3P	14	19	16	21
Caister	Ceased Production	40%	1P	-37	-37	-37	-37
			2P	-37	-37	-37	-37
			3P	-37	-37	-37	-37
Babbage	Producing	47%	1P	4	16	10	21
			2P	20	39	30	47
			3P	51	78	66	90
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-11	-10	-10	-10
			2P	-11	-10	-10	-10
			3P	-11	-10	-10	-10
Minke	Ceased Production	43%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Tolmount	Development pending FID	50%	1P	-33	-33	-33	-33
			2P	111	214	160	267
			3P	584	789	682	897
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		29	29	29	29
Total (Incl. Pipelines)			**1P**	**-139**	**-122**	**-130**	**-116**
			2P	**27**	**154**	**89**	**216**
			3P	**535**	**773**	**651**	**895**

Table 7-5 Post Tax Valuation Summary (NPV at 10% discount rate in US$MM at 1st January 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	0	0	0	0
			2P	0	0	0	0
			3P	0	0	0	0
Ravenspurn North	Producing	29%	1P	-60	-60	-60	-60
			2P	-59	-59	-59	-59
			3P	-59	-59	-59	-59
Johnston	Producing	50%	1P	5	9	7	10
			2P	10	14	12	15
			3P	14	17	16	17
Caister	Ceased Production	40%	1P	-37	-37	-37	-37
			2P	-37	-37	-37	-37
			3P	-37	-37	-37	-37
Babbage	Producing	47%	1P	4	16	10	20
			2P	20	31	27	36
			3P	42	54	49	58
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-11	-10	-10	-10
			2P	-11	-10	-10	-10
			3P	-11	-10	-10	-10
Minke	Ceased Production	43%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Tolmount	Development pending FID	50%	1P	-33	-33	-33	-33
			2P	28	81	53	108
			3P	256	363	307	418
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		17	17	17	17
Total (Incl. Pipelines)			**1P**	**-151**	**-134**	**-142**	**-129**
			2P	**-68**	**1**	**-33**	**34**
			3P	**186**	**309**	**247**	**368**
Consolidated Tax benefit			**2P**[21]	76	71	75	66

7.3.1. Field Valuation Sensitivities

The sensitivity of valuations considered include discount rates, sales prices and costs and are summarized for each fields 2P reserves case below. The sensitivities are applied to Price Scenario 'A'.

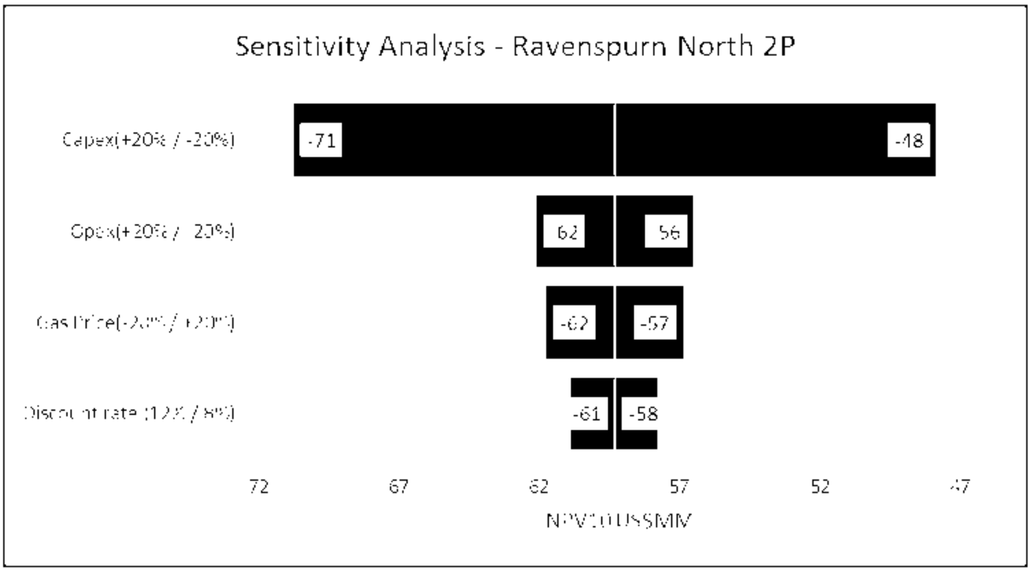


Figure 7-1 Ravenspurn North Sensitivity Analysis

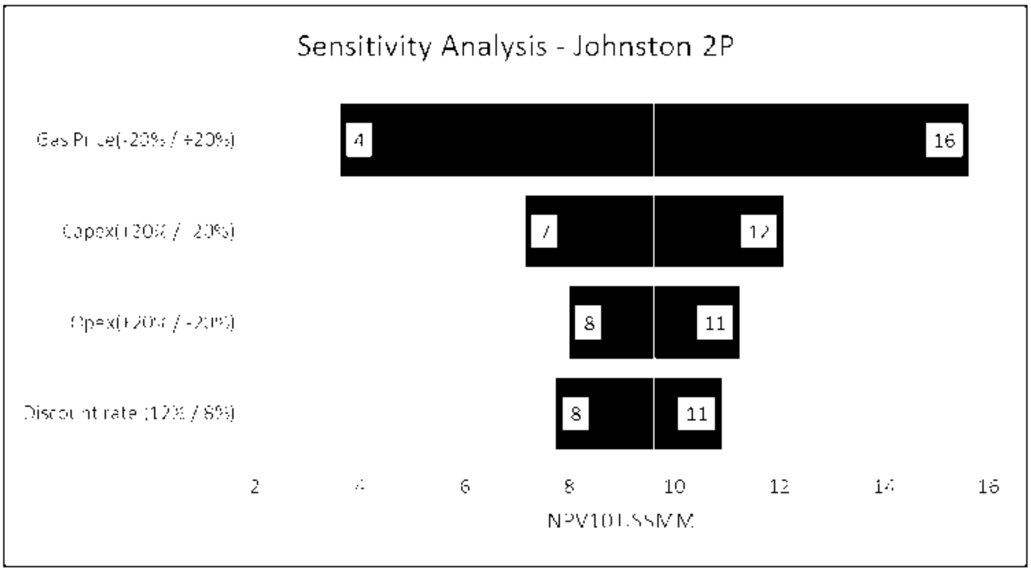


Figure 7-2 Johnston Sensitivity Analysis

[21] Consolidated tax benefit calculated for arithmetic total of field 2P cash flows only

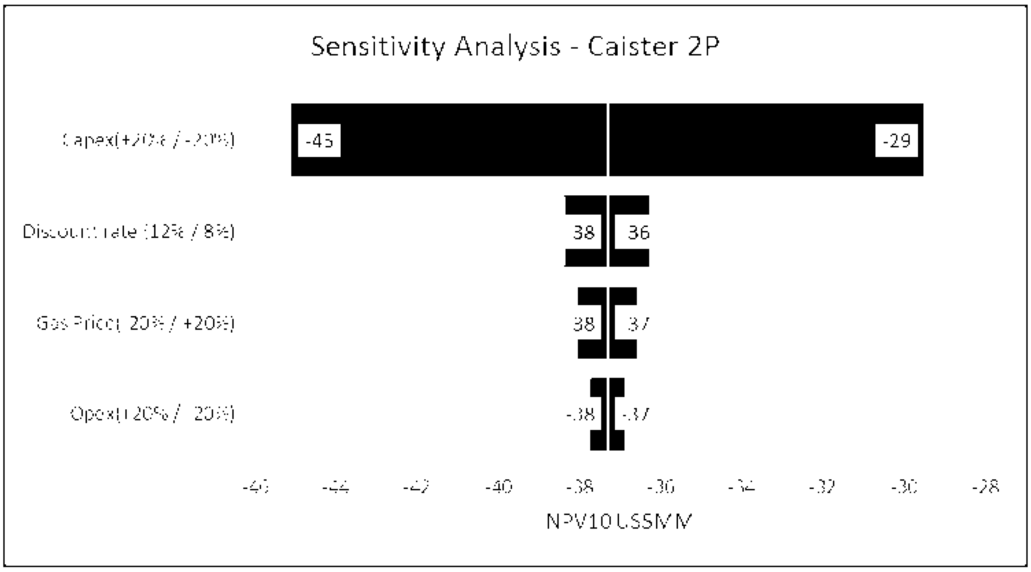


Figure 7-3 Caister Sensitivity Analysis

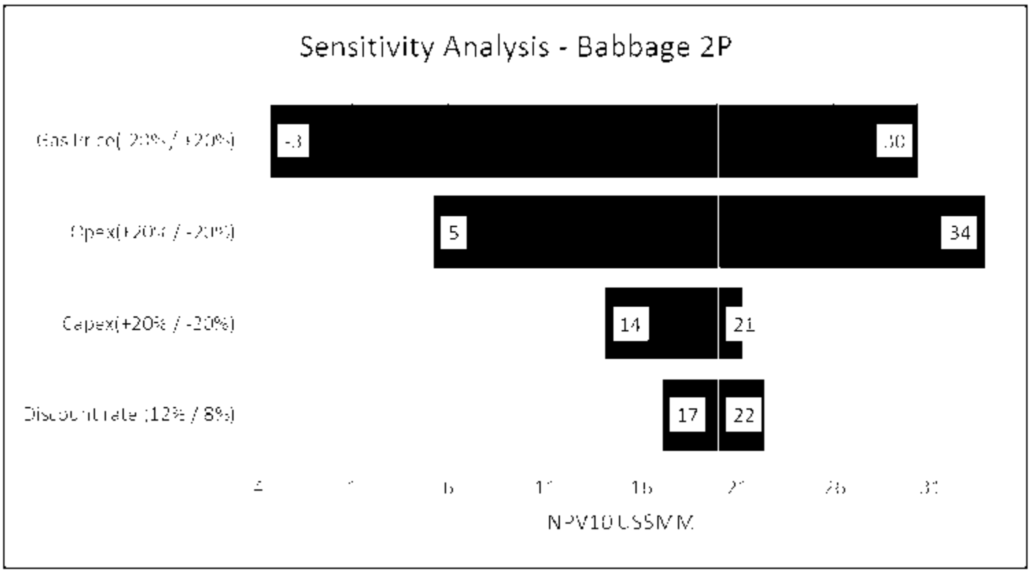


Figure 7-4 Babbage Sensitivity Analysis

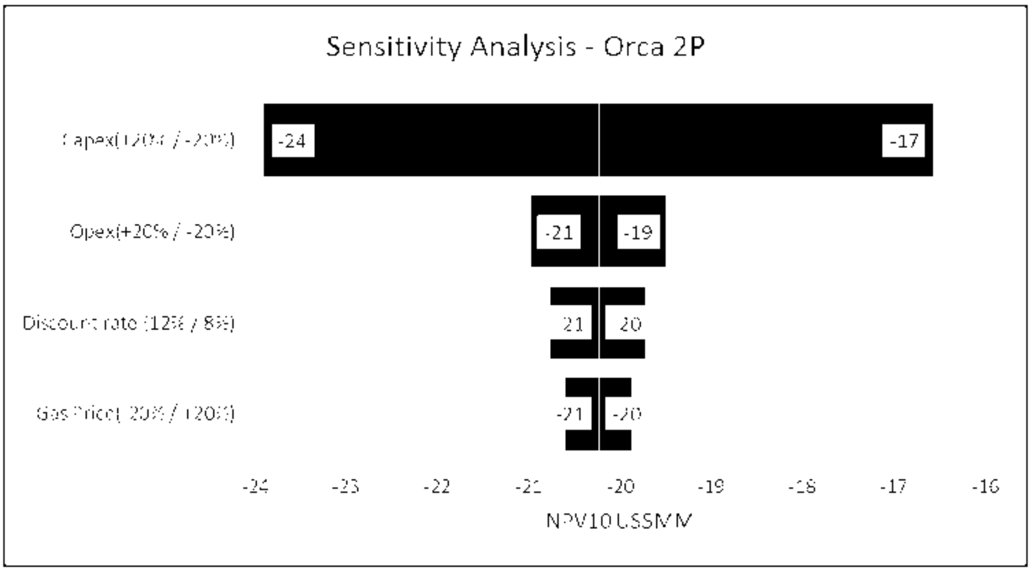


Figure 7-5 Orca Sensitivity Analysis

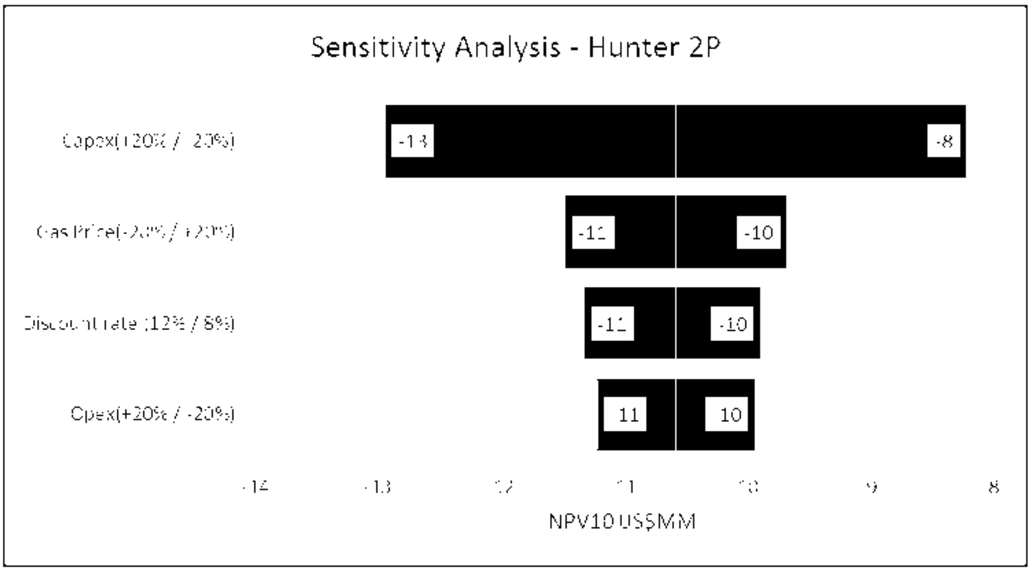


Figure 7-6 Hunter Sensitivity Analysis

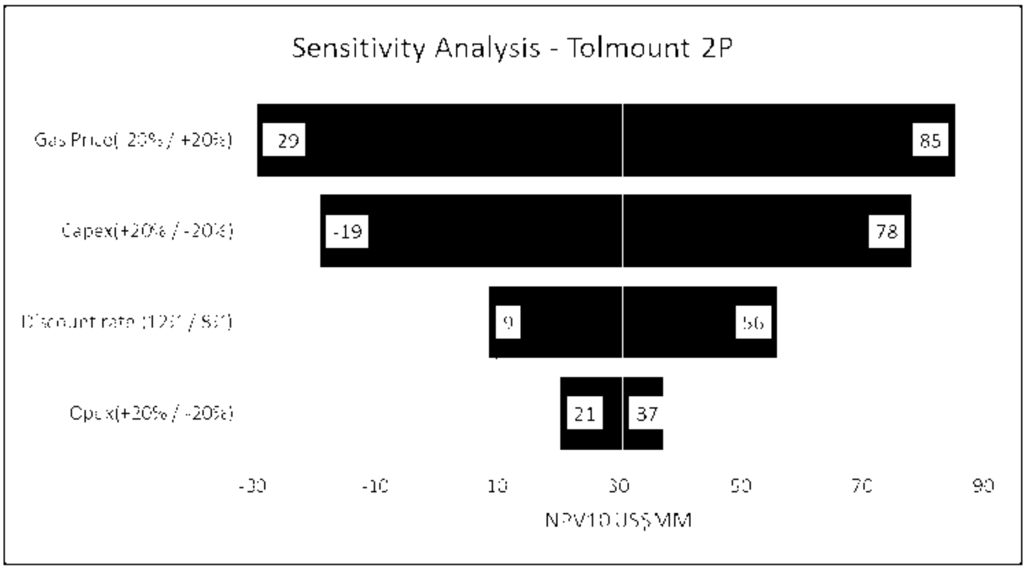


Figure 7-7 Tolmount Sensitivity Analysis

7.4. Economic Results as of 31st December 2015

Economics have also been run using the discounted cash flow method for the four price scenarios based on estimates of future production of assessed reserves/resources and forecasts of future capital and operating costs with an effective date of 31st December 2015.

The following Net Present Values have not been adjusted for other factors (eg analogous transactions, strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value.

The economic results for the pipelines are independent of the oil and gas price scenarios. A single scenario was evaluated for each of the ETS and CMS working interests at the effective date of 1st January 2015.

Table 7-6 Pre-Tax Valuation Summary (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Ravenspurn North	Producing	29%	1P	-62	-62	-62	-62
			2P	-62	-62	-62	-62
			3P	-62	-62	-62	-62
Johnston	Producing	50%	1P	-1	3	1	4
			2P	3	8	6	10
			3P	8	13	10	15
Caister	Ceased Production	40%	1P	-43	-43	-43	-43
			2P	-43	-43	-43	-43
			3P	-43	-43	-43	-43
Babbage	Producing	47%	1P	-24	-10	-18	-5
			2P	-7	13	4	23
			3P	25	55	41	68
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-12	-11	-11	-11
			2P	-12	-11	-11	-11
			3P	-12	-11	-11	-11
Minke	Ceased Production	43%	1P	-13	-13	-13	-13
			2P	-13	-13	-13	-13
			3P	-13	-13	-13	-13
Tolmount	Development pending FID	50%	1P	-36	-36	-36	-36
			2P	122	235	176	294
			3P	656	882	763	1,000
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		32	32	32	32
Total (Incl. Pipelines)			**1P**	**-195**	**-176**	**-186**	**-170**
			2P	**-16**	**123**	**53**	**194**
			3P	**555**	**817**	**681**	**950**

Table 7-7 Post Tax Valuation Summary (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Ravenspurn North	Producing	29%	1P	-62	-62	-62	-62
			2P	-62	-62	-62	-62
			3P	-62	-62	-62	-62
Johnston	Producing	50%	1P	-1	3	1	4
			2P	3	8	6	10
			3P	8	13	10	15
Caister	Ceased Production	40%	1P	-43	-43	-43	-43
			2P	-43	-43	-43	-43
			3P	-43	-43	-43	-43
Babbage	Producing	47%	1P	-24	-10	-18	-5
			2P	-7	13	4	23
			3P	25	44	38	49
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-12	-11	-11	-11
			2P	-12	-11	-11	-11
			3P	-12	-11	-11	-11
Minke	Ceased Production	43%	1P	-13	-13	-13	-13
			2P	-13	-13	-13	-13
			3P	-13	-13	-13	-13
Tolmount	Development pending FID	50%	1P	-36	-36	-36	-36
			2P	31	89	58	119
			3P	295	413	352	473
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		18	18	18	18
Total (Incl. Pipelines)			**1P**	**-209**	**-190**	**-200**	**-184**
			2P	**-121**	**-37**	**-79**	**5**
			3P	**180**	**323**	**253**	**390**
Consolidated Tax benefit			**2P**[22]	84	78	82	73

[22] Consolidated tax benefit calculated for arithmetic total of field 2P cash flows only

8. UK Blocks licensed by E.On

Table 8-1 Blocks licensed by E.On E & P UK Limited

E.ON E&P UK LIMITED	15/27b	40%	E ON E&P UK LIMITED	P2161
	21/17d	40%	E.ON E&P UK LIMITED	P2178
	21/18b	40%	E.ON E&P UK LIMITED	P2178
	22/13b	22.50%	NEXEN PETROLEUM U.K. LIMITED	P1420
	22/14b	25%	E.ON E&P UK LIMITED	P1114
	22/14d REST	22.50%	NEXEN PETROLEUM U.K. LIMITED	P1801
	22/18b	22.50%	NEXEN PETROLEUM U.K. LIMITED	P1801
	22/18c	40%	PA RESOURCES NORTH SEA LIMITED	P2184
	22/19b	22.50%	NEXEN PETROLEUM U.K. LIMITED	P1801
	22/19d	40%	PA RESOURCES NORTH SEA LIMITED	P2184
	22/25a MERG	65.99%	BRITOIL LIMITED	P111
	22/27a A	20%	CNR INTERNATIONAL (U.K.) LIMITED	P114
	22/29b	5.20%	TOTAL E&P UK LIMITED	P2068
	22/30b ELGN	5.20%	TOTAL E&P UK LIMITED	P188
	22/30c	5.20%	TOTAL E&P UK LIMITED	P666
	23/26d A	100%	E.ON E&P UK LIMITED	P264
	28/15 NORTH	15%	STATOIL (U K.) LIMITED	P2067
	28/20 NORTH	15%	STATOIL (U K.) LIMITED	P2067
	28/20 SW	15%	NEXEN PETROLEUM U.K. LIMITED	P2067
	29/2a A	20%	CNR INTERNATIONAL (U K) LIMITED	P224
	29/3b	25%	TOTAL E&P UK LIMITED	P1626
	29/4d	18.57%	TOTAL E&P UK LIMITED	P752
	29/5b	5.20%	TOTAL E&P UK LIMITED	P362
	29/5c	5.20%	TOTAL E&P UK LIMITED	P666
	29/16 SE	15%	STATOIL (U K.) LIMITED	P2067
	30/12e	20%	TALISMAN SINOPEC ENERGY UK LIMITED	P1939
	30/13a WEST	15%	TALISMAN SINOPEC ENERGY UK LIMITED	P79
	30/13b	25%	GDF SUEZ E&P UK LTD	P1823
	42/28d	50%	E ON E&P UK LIMITED	P1330
	42/28e	50%	E.ON E&P UK LIMITED	P2105
	42/29d	50%	E.ON E&P UK LIMITED	P2105
	44/21b	68.31%	E.ON E&P UK LIMITED	P766
	44/22c	76%	E.ON E&P UK LIMITED	P771
	44/23a AREAA	40%	CONOCOPHILLIPS (U K) LIMITED	P452
	44/23c D	79%	E.ON E&P UK LIMITED	P452
	44/24a	42.67%	GDF SUEZ E&P UK LTD	P611
	44/29b A	35%	GDF SUEZ E&P UK LTD	P454
	44/29b B	42.67%	GDF SUEZ E&P UK LTD	P454
	44/30a	42.67%	GDF SUEZ E&P UK LTD	P611
	47/3k	100%	E.ON E&P UK LIMITED	P2136
	48/1b	50%	E.ON E&P UK LIMITED	P2212
	48/2b	50%	E.ON E&P UK LIMITED	P2212
	48/10c	50%	E ON E&P UK LIMITED	P2103
	205/16d	50%	FAROE PETROLEUM (U.K.) LIMITED	P2011
	205/17b	50%	FAROE PETROLEUM (U.K.) LIMITED	P2011
	205/21c	50%	FAROE PETROLEUM (U.K.) LIMITED	P2011
	205/22b	50%	FAROE PETROLEUM (U.K.) LIMITED	P2011
	208/14	100%	E.ON E&P UK LIMITED	P2023
	208/15	100%	E.ON E&P UK LIMITED	P2023
	209/4	100%	E ON E&P UK LIMITED	P2073
	209/5	100%	E.ON E&P UK LIMITED	P2073
	213/5	30%	OMV (U.K) LIMITED	P1997
	214/1	30%	OMV (U.K.) LIMITED	P1997
	214/4c	30%	OMV (U.K.) LIMITED	P2080
	215/30	30%	OMV (U.K) LIMITED	P1997
	216/26	30%	OMV (U.K.) LIMITED	P1997
	216/27	30%	OMV (U K) LIMITED	P1997
	219/13	100%	E.ON E&P UK LIMITED	P2012
	219/14	100%	E ON E&P UK LIMITED	P2012
	219/15	100%	E.ON E&P UK LIMITED	P2012

Table 8-2 Blocks licenced by E.On E & P UK EU Limited

Equity Holder	Block / Subarea	Interest	Operator	Licence
E.ON E&P UK EU LIMITED	23/16c	30%	DANA PETROLEUM (E&P) LIMITED	P1720
	43/26a RAVE (CA)	35.94%	BP EXPLORATION OPERATING COMPANY LIMITED	P380
	43/26a RAVEA	35.94%	E.ON E&P UK EU LIMITED	P380
	43/26a RAVEB	35.94%	E.ON E&P UK EU LIMITED	P380
	43/26a RESID	72.22%	E.ON E&P UK EU LIMITED	P380
	43/27a	42.22%	E.ON E&P UK EU LIMITED	P686
	48/2a	47%	E.ON E&P UK EU LIMITED	P456

9. List of terms

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
1Q	1st Quarter
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2Q	2nd Quarter
2D	Two Dimensional
3D	Three Dimensional
4D	Four Dimensional – time lapsed 3D in relation to seismic
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context.
3Q	3rd Quarter
4Q	4th Quarter
AFE	Authority for Expenditure
Bbl	US Barrel
BBL/D	US Barrels per day
BCF	Billion (10^9) cubic feet
BCM	Billion (10^9) cubic meters
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
BTU	British Thermal Units
BOEPD	US barrels of oil equivalent per day
BWPD	Barrels of water per day
°C	Degrees Celsius
Capex	Capital expenditure
CAPM	Capital asset pricing model
CGR	Condensate Gas Ratio – usually expressed as bbl/MMscf
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
CO2	Carbon dioxide
CP	Centipoise (measure of viscosity)
CPI	Consumer Price Index
DEG	Degrees
DHI	Direct hydrocarbon indicator
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
DST	Drill stem test
E&P	Exploration and Production
EG	Gas expansion factor. Gas volume at standard (surface) conditions / gas volume at reservoir conditions (pressure & temperature)

Term	Definition
EIA	US Energy Information Administration
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
ESP	Electric submersible pump
EUR	Economic ultimate recovery
Expectation	The mean of a probability distribution
F	Degrees Fahrenheit
FDP	Field Development Plan
FEED	Front End Engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating Production Storage and offtake unit
FWL	Free Water Level
FVF	Formation volume factor
GIIP	Gas Initially In Place
GJ	Giga (10^9) joules
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GSA	Gas sales agreement
GTL	Gas To Liquid(s)
GWC	Gas water contact
H2S	Hydrogen sulphide
HHV	Higher heating value
ID	Internal diameter
IRR	Internal Rate of Return is the discount rate that results in the NPV being equal to zero.
JV(P)	Joint Venture (Partners)
Kh	Horizontal permeability
km2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability
kPa	Kilo (thousand) Pascals (measurement of pressure)
Mstb/d	Thousand Stock tank barrels per day
LIBOR	London inter-bank offered rate
LNG	Liquefied Natural Gas
LTBR	Long-Term Bond Rate
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)
MJ	Mega (10^6) Joules
MMbbl	Million US barrels
MMscf(d)	Million standard cubic feet (per day)

Term	Definition
MMstb	Million US stock tank barrels
MOD	Money of the Day (nominal dollars) as opposed to money in real terms
MOU	Memorandum of Understanding
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels
MPa	Mega (10^6) pascal (measurement of pressure)
mss	Metres subsea
MSV	Mean Success Volume
mTVDss	Metres true vertical depth subsea
MW	Megawatt
NPV	Net Present Value (of a series of cash flows)
NTG	Net to Gross (ratio)
ODT	Oil down to
OGIP	Original Gas In Place
OOIP	Original Oil in Place
Opex	Operating expenditure
OWC	Oil-water contact
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
PJ	Peta (1015) Joules
POS	Probability of Success
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest 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.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.
Proved Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty 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. Often referred to as 1P, also as "Proven".
PSC	Production Sharing Contract
PSDM	Pre-stack depth migration

Term	Definition
PSTM	Pre-stack time migration
psia	Pounds per square inch pressure absolute
p.u.	Porosity unit e.g. porosity of 20% +/- 2 p.u. equals a porosity range of 18% to 22%
PVT	Pressure, volume & temperature
QA/QC	Quality Assurance/ Control
rb/stb	Reservoir barrels per stock tank barrel under standard conditions
RFT	Repeat Formation Test
Real Terms (RT)	Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day
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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.
RT	Measured from Rotary Table or Real Terms, depending on context
SC	Service Contract
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
Sgr	Residual gas saturation
SRD	Seismic reference datum lake level
SPE	Society of Petroleum Engineers
SPE-PRMS	Petroleum Resources Management System, approved by the Board of the SPE March 2007 and endorsed by the Boards of Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers.
s.u.	Fluid saturation unit. e.g. saturation of 80% +/- 10 s.u. equals a saturation range of 70% to 90%
stb	Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
TCM	Technical committee meeting
Tcf	Trillion (10^{12}) cubic feet
TJ	Tera (10^{12}) Joules
TLP	Tension Leg Platform
TRSSV	Tubing retrievable subsurface safety valve
TVD	True vertical depth
US$	United States dollar
US$ million	Million United States dollars
WACC	Weighted average cost of capital
WHFP	Well Head Flowing Pressure
Working interest	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.
WPC	World Petroleum Council
WTI	West Texas Intermediate Crude Oil

PART V—HISTORICAL FINANCIAL INFORMATION RELATING TO THE EPUK GROUP

Section A: Draft Report on the Historical Financial Information Relating to the EPUK Group

The Directors
Premier Oil plc
4th Floor
Saltire Court
20 Castle Terrace
Edinburgh, EH1 2EN

RBC Europe Limited (the "**Sponsor**")
Riverbank House
2 Swan Lane
London, EC4R 3BF

7 April 2016

Dear Sirs

The EPUK Group

We report on the financial information relating to the EPUK Group set out in section B of Part V below (the "**Financial Information Table**"). The Financial Information Table has been prepared for inclusion in the Class 1 Circular dated 7 April 2016 (the "**Circular**") of Premier Oil plc (the "**Company**") on the basis of the accounting policies set out in note 2 to the Financial Information Table. This report is required by item 13.5.21R of the Listing Rules and is given for the purpose of complying with that item and for no other purpose.

Responsibilities

The Directors of the Company are responsible for preparing the Financial Information Table in accordance with International Financial Reporting Standards as adopted by the European Union.

It is our responsibility to form an opinion as to whether the Financial Information Table gives a true and fair view, for the purposes of the Circular and to report our opinion to you.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and which we may have to shareholders of the Company as a result of the inclusion of this report in the Circular, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such person as a result of, arising out of, or in accordance with this report or our statement, required by and given solely for the purposes of complying with item 13.4.1R(6) of the Listing Rules, consenting to its inclusion in the Circular.

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the Target's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the financial information is free from material misstatement whether caused by fraud or other irregularity or error.

PricewaterhouseCoopers LLP, 1 Embankment Place, London, WC2N 6RH T: +44 (0) 2075 835 000, F: +44 (0) 2072 124 652, www.pwc.co.uk

Opinion

In our opinion, the Financial Information Table gives, for the purposes of this Circular dated 7 April 2016, a true and fair view of the state of affairs of the EPUK Group as at the dates stated and of its profits and losses, cash flows and changes in equity for the periods then ended in accordance with International Financial Reporting Standards as adopted by the European Union.

Emphasis of Matter—Going concern

In forming our opinion on the Financial Information Table, which is not modified, we have considered the adequacy of the disclosure made in note 2 to the Financial Information Table concerning the EPUK Group's ability to continue as a going concern.

As disclosed in note 2, following completion of the Acquisition, the EPUK Group will be part of the Premier Group and will become a guarantor company under the Premier Group's banking facilities. There is a forecast breach of certain financial covenants in the Premier Group's principal financing arrangements based on certain assumptions in respect of the testing periods ending on 30 June 2016 and 31 December 2016. A breach of one or more financial covenant(s) would cause an event of default under the financing arrangements which contain such covenant(s), which could in turn trigger cross-defaults into the other financing arrangements of the Premier Group. This could result in the Premier Group's financing arrangements becoming repayable.

Premier has issued a qualified working capital statement in paragraph 9 of Part VII of this Circular. In order to address the risk of a covenant breach, the Premier Group will seek to modify or temporarily waive the existing covenants and/or implement certain potential mitigating actions as set out in paragraph 9 of Part VII of this Circular prior to the time at which the financial covenants for the testing period ending 30 June 2016 are required to be tested (when the financial statements and compliance certificate in respect of this period are delivered).

This condition indicates the existence of a material uncertainty which may cast significant doubt about the EPUK Group's ability to continue as a going concern. The Financial Information Table does not include the adjustments that would result if the EPUK Group was unable to continue as a going concern.

Yours faithfully

PricewaterhouseCoopers LLP
Chartered Accountants

PricewaterhouseCoopers LLP, 1 Embankment Place, London, WC2N 6RH T: +44 (0) 2075 835 000, F: +44 (0) 2072 124 652, www.pwc.co.uk

Section B: Historical Financial Information of the EPUK Group

Group Consolidated statement of profit or loss and other comprehensive income

	Note	2013	2014	2015
		£000	£000	£000
Sales revenues	5	251,811	320,522	257,057
Cost of sales	6	(191,068)	(261,545)	(231,519)
Impairment charge on property, plant and equipment	12	(27,357)	(122,707)	(180,024)
Exploration expense	11	(4,600)	(13,563)	(32,534)
Pre-licencing exploration costs		(11,774)	(9,139)	(1,931)
General and administration costs		(13,612)	(9,124)	(16,703)
Operating profit/(loss)		3,400	(95,556)	(205,654)
Interest revenue, finance and other gains	8	572	312	957
Finance costs, other finance expenses and losses	8	(8,544)	(9,662)	(8,127)
Gain on commodity derivative financial instruments	19	1,508	74,323	2,861
Loss before tax		(3,064)	(30,583)	(209,963)
Tax	9	10,635	(15,820)	94,565
Profit/(loss) after tax		7,571	(46,403)	(115,398)
Earnings/(loss) per share (pence):				
Basic and diluted (pence):	10	359	(2,199)	(5,469)
Other comprehensive income, after tax:				
Items that cannot be reclassified to profit or loss		—	—	—
Items that may be reclassified subsequently to profit or loss		—	—	—
Other comprehensive income for the year, net of tax		—	—	—
Total comprehensive income/(expense) for the year		7,571	(46,403)	(115,398)

The results relate entirely to continuing operations.

All comprehensive income is attributable to the equity holders of the parent.

CONSOLIDATED BALANCE SHEET

	Note	1 January 2013	2013	2014	2015
		£000	£000	£000	£000
Non-current assets:					
Intangible exploration and evaluation assets	11	38,035	64,617	65,919	72,404
Property, plant and equipment	12	495,067	540,512	354,378	216,793
Derivative financial instruments	19	8,667	6,651	28,279	11,947
		541,769	611,780	448,576	301,144
Current assets:					
Inventories	13	463	6,156	4,122	794
Trade and other receivables	14	75,501	67,467	45,627	33,368
Tax recoverable		17,417	—	20,371	3,686
Derivative financial instruments	19	2,885	3,534	42,332	49,578
Cash and cash equivalents	15	13,404	2	85,151	148,853
		109,670	77,159	197,603	236,279
Total assets		651,439	688,939	646,179	537,423
Current liabilities:					
Trade and other payables	16	(66,251)	(57,971)	(40,953)	(37,320)
Provisions	18	(650)	(11,815)	(13,099)	(12,749)
Derivative financial instruments	19	(5,930)	(4,829)	—	(381)
Other financial liability	15	—	(16,109)	—	—
		(72,831)	(90,724)	(54,052)	(50,450)
Net current assets/(liabilities)		36,839	(13,565)	143,551	185,829
Non-current liabilities:					
Derivative financial instruments	19	(23,170)	(21,396)	(12,328)	—
Deferred tax liabilities	20	(97,958)	(85,680)	(116,472)	(20,324)
Long-term provisions	18	(159,862)	(185,950)	(204,541)	(323,261)
		(280,990)	(293,026)	(333,341)	(343,585)
Total liabilities		(353,821)	(383,750)	(387,393)	(394,035)
Net assets		297,618	305,189	258,786	143,388
Equity and reserves:					
Share capital	21	211,000	211,000	211,000	211,000
Retained earnings/(deficit)		86,618	94,189	47,786	(67,612)
		297,618	305,189	258,786	143,388

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

		Attributable to the equity holders of the parent		
	Note	Share capital	Retained earnings	Total
		£000	£000	£000
At 1 January 2013		211,000	86,618	297,618
Total comprehensive income		—	7,571	7,571
At 31 December 2013		211,000	94,189	305,189
Total comprehensive expense		—	(46,403)	(46,403)
At 31 December 2014		211,000	47,786	258,786
Total comprehensive expense		—	(115,398)	(115,398)
At 31 December 2015		211,000	(67,612)	143,388

CONSOLIDATED CASH FLOW STATEMENT

	Note	2013	2014	2015
		£000	£000	£000
Net cash from operating activities	22	108.252	134,524	120,606
Investing activities:				
Capital expenditure		(137,900)	(33,290)	(57,727)
Interest income received		572	312	957
Net cash used in investing activities		(137,328)	(32,978)	(56,770)
Financing activities:				
Interest paid		(435)	(288)	(134)
Net cash from financing activities		(435)	(288)	(134)
Net (decrease)/increase in cash and cash equivalents		(29,511)	101,258	63,702
Cash and cash equivalents at the beginning of the year		13.404	(16,107)	85,151
Cash and cash equivalents at the end of the year	15	(16,107)	85,151	148,853

Notes to the historical financial information

1. General information

E.ON E&P UK Limited ("**EPUK**") is a company incorporated and domiciled in the UK. EPUK and its subsidiaries (collectively, the "**EPUK Group**") are focused on oil and gas exploration, development and production, and the sale of oil and natural gas produced by third parties. The entities which comprise the EPUK Group are incorporated and domiciled in the UK. The principal trading and holding subsidiaries of the EPUK Group for the three years ended 31 December 2015 are disclosed in note 27.

The historical financial information of the EPUK Group for the three years ended 31 December 2015 have been prepared in accordance with the basis of preparation as set out below.

This historical financial information is presented in pounds sterling and all values are rounded to the nearest thousand pounds sterling (£000) except when otherwise indicated. The functional currency of EPUK is pounds sterling.

2. Basis of preparation

The historical financial information consolidates the financial information of EPUK and its subsidiaries using the accounting policies adopted by Premier in its latest audited financial statements. EPUK has not previously prepared consolidated financial information as EPUK took advantage of the exemption available under Companies Act 2006 from the preparation of consolidated financial statements, as the results of EPUK and its subsidiaries were being consolidated in the financial statements of E.ON.

The principal accounting policies applied in the preparation of the consolidated historical financial information are set out below. These policies have been consistently applied to all the periods presented, unless otherwise stated. The financial information presented is at and for the years ended 31 December 2013, 31 December 2014 and 31 December 2015.

The historical financial information has been prepared in accordance with the requirements of the Prospectus Directive Regulation, the Listing Rules and in accordance with International Financial Reporting Standards ("**IFRS**") as adopted by the European Union (the "**EU**"), IFRS Interpretation Committee ("**IFRS IC**") interpretations as adopted by the European Union. The historical financial information has been prepared on the going concern basis and under the historical cost convention, as modified by the revaluation of financial assets and financial liabilities (including derivative instruments) at fair value through profit or loss and inventories that are held at the lower of cost or net realisable value.

Following completion of the Acquisition, the EPUK Group will be part of the Premier Group and will become a guarantor company under the Premier Group's banking facilities. Premier has included a qualified working capital statement in paragraph 9 of Part VII of this document as a result of a forecast breach of certain of the Premier Group's financial covenants contained in certain of its principal financing arrangements based on certain assumptions in respect of the testing periods ending on 30 June 2016 and 31 December 2016.

A breach of one or more financial covenant(s) would cause an event of default under the financing arrangements which contain such covenant(s), which could in turn trigger cross-defaults into the other financing arrangements of the Premier Group. This could result in the Premier Group's financing arrangements becoming repayable.

In the absence of the successful implementation of the mitigating actions described in paragraph 9 of Part VII of this document, the Premier Group's management reasonably expect that the covenant renegotiation with its debt holders can be completed by the time the financial covenants for the testing period ending 30 June 2016 are required to be tested (when the financial statements and compliance certificate in respect of this period are delivered) or that a temporary waiver or amendment of the financial covenants would be agreed until the current renegotiation is finalised. Agreement of the terms of the renegotiation and/or possibly a combination of some of the other mitigating actions will need to occur to successfully avoid a breach of financial covenant in respect of the testing periods ending 30 June 2016 and 31 December 2016. However, all of these actions involve agreement from third parties and are therefore outside of the control of management.

The Directors have a reasonable expectation that the Premier Group can secure any necessary financial covenant modification or waiver and/or implement some of the mitigating actions described in paragraph 9 of Part VII of this document so as to avoid a financial covenant breach during the Working Capital Period.

2. Basis of preparation (Continued)

If the Premier Group can achieve that, it will have sufficient working capital for its present purposes, that is, for at least the next 12 months from the date of this document.

The uncertainty regarding the availability of Premier's banking facilities creates a material uncertainty that the EPUK Group would be able to access funding from Premier and therefore may cast significant doubt on the EPUK Group's ability to continue to apply the going concern basis of accounting. The Premier Directors have a reasonable expectation that the Premier Group will avoid a covenant breach and accordingly have adopted the going concern basis of accounting in preparing this historical financial information on the EPUK Group.

Under IFRS1, "First Time Adoption of International Financial Reporting Standards", a number of exemptions are permitted to be taken in preparing the consolidated balance sheet at the date of transition to IFRS. The EPUK Group has assumed a transition date to IFRS of 1 January 2013 and has therefore presented a consolidated balance sheet as at that date.

3. Accounting policies

Adoption of new and revised standards

In the current year the following new and revised Standards and Interpretations have been adopted, none of which have a material impact on the EPUK Group's annual results:

- IAS 19 (amendments) Defined Benefit Plans: Employee Contributions;
- Annual Improvements to IFRSs: 2010–2012 Amendments to: IFRS 2 Share-based Payment, IFRS 3 Business Combinations, IFRS 8 Operating Segments, IFRS 13 Fair Value Measurement, IAS 16 Property, Plant and Equipment, IAS 24 Related Party Disclosures and IAS 38 Intangible Assets; and
- Annual Improvements to IFRSs: 2011–2013 Amendments to: IFRS 1 First-time Adoption of International Financial Reporting Standards, IFRS 3 Business Combinations, IFRS 13 Fair Value Measurement and IAS 40 Investment Property.

At the date of approval of the historical financial information, the following standards and interpretations which have not been applied in these financial statements were in issue but not yet effective (and in some cases had not yet been adopted by the European Union):

- IFRS 9 Financial Instruments (effective for annual periods commencing on or after 1 January 2018);
- IFRS 15 Revenue from Contracts with Customers (effective for annual periods commencing on or after 1 January 2018);
- IFRS 16 Leases (effective for annual periods commencing on or after 1 January 2019);
- IFRS 11 (amendments) Accounting for Acquisitions of Interests in Joint Operations (effective for annual periods commencing on or after 1 January 2016);
- IAS 16 and IAS 38(amendments) Clarification of Acceptable Methods of Depreciation and Amortisation (effective for annual periods commencing on or after 1 January 2016); and
- Annual Improvements to IFRSs: 2012–2014 Cycle Amendments to: IFRS 5 Non-current Assets Held for Sale and Discontinued Operations, IFRS 7 Financial Instruments: Disclosures, IAS 19 Employee Benefits and IAS 34 Interim Financial Reporting (effective for annual periods commencing on or after 1 January 2016).

Beyond the information above, it is not practicable to provide a reasonable estimate of the effect of IFRS 9, IFRS 15 and IFRS 16 until a detailed review has been completed. The Directors do not expect that the adoption of the Standards listed above will have a material impact on the historical financial information of the EPUK Group in future periods, except that IFRS 9 will impact both the measurement and disclosures of financial instruments, IFRS 15 may have an impact on revenue recognition and related disclosures and IFRS 16 may impact the recognition and measurement of leases.

The principal accounting policies adopted are set out below.

3. Accounting policies (Continued)

Basis of consolidation

The historical financial information incorporates the financial statements of EPUK and entities controlled by EPUK (its subsidiaries) made up to 31 December each year. Control is achieved when a company is exposed, or has rights, to variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity.

Where necessary, adjustments are made to the financial statements of subsidiaries to bring the accounting policies used into line with those used by other members of the EPUK Group.

All significant inter-company transactions and balances between EPUK Group entities are eliminated on consolidation.

Interest in joint arrangements

A joint arrangement is one in which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Most of the EPUK Group's activities are conducted through joint operations, whereby the parties that have joint control of the arrangement have the rights to the assets, and obligations for the liabilities, relating to the arrangement. The EPUK Group reports its interests in joint operations by reporting the EPUK Group's share of the assets, liabilities, income and expenses of the joint operation are combined with the equivalent items in the historical financial information on a line-by-line basis.

Where the EPUK Group transacts with its joint operations, unrealised profits and losses are eliminated to the extent of the EPUK Group's interest in the joint operation.

Sales revenue and other income

Sales revenue reflects sales of oil and gas from production activities, and includes the sale of gas purchased for resale, exclusive of value added tax. Sales revenue is recognised when goods are delivered or the title has passed to the customer.

Interest income is accrued on a time basis, by reference to the principal outstanding and at the effective interest rate applicable.

Oil and gas assets

The EPUK Group applies the successful efforts method of accounting for exploration and evaluation ("**E&E**") costs, having regard to the requirements of IFRS 6 'Exploration for and Evaluation of Mineral Resources'.

(a) Exploration and evaluation assets

Under the successful efforts method of accounting, all licence acquisition, exploration and appraisal costs are initially capitalised in well, field or specific exploration cost centres as appropriate, pending determination. Expenditure incurred during the various exploration and appraisal phases is then written off unless commercial reserves have been established or the determination process has not been completed.

Pre-licence costs

Costs incurred prior to having obtained the legal rights to explore an area are expensed directly to the income statement as they are incurred.

Exploration and evaluation costs

Costs of E&E are initially capitalised as E&E assets. Payments to acquire the legal right to explore, costs of technical services and studies, seismic acquisition, exploratory drilling and testing are capitalised as intangible E&E assets.

3. Accounting policies (Continued)

Tangible assets used in E&E activities (such as the EPUK Group's vehicles, drilling rigs, seismic equipment and other property, plant and equipment used by the exploration function) are classified as property, plant and equipment. However, to the extent that such a tangible asset is consumed in developing an intangible E&E asset, the amount reflecting that consumption is recorded as part of the cost of the intangible asset. Such intangible costs include directly attributable overhead, including the depreciation of property, plant and equipment utilised in E&E activities, together with the cost of other materials consumed during the exploration and evaluation phases.

E&E costs are not amortised prior to the conclusion of appraisal activities.

Treatment of E&E assets at conclusion of appraisal activities

Intangible E&E assets related to each exploration licence/prospect are carried forward, until the existence (or otherwise) of commercial reserves has been determined subject to certain limitations including review for indications of impairment. If commercial reserves have been discovered, the carrying value, after any impairment loss, of the relevant E&E assets, is then reclassified as development and production assets. If, however, commercial reserves have not been found, the capitalised costs are charged to expense after conclusion of appraisal activities.

(b) Development and production assets

Development and production assets are accumulated generally on a field-by-field basis and represent the cost of developing the commercial reserves discovered and bringing them into production, together with the E&E expenditures incurred in finding commercial reserves transferred from intangible E&E assets, as outlined in accounting policy (a) above.

The cost of development and production assets also includes the cost of acquisitions and purchases of such assets, directly attributable overheads, finance costs capitalised, and the cost of recognising provisions for future restoration and decommissioning.

Depreciation of producing assets

The net book values of producing assets are depreciated generally on a field-by-field basis using the unit-of-production method by reference to the ratio of production in the year and the related commercial (proved and probable) reserves of the field, taking into account future development expenditures necessary to bring those reserves into production.

Producing assets are generally grouped with other assets that are dedicated to serving the same reserves for depreciation purposes, but are depreciated separately from producing assets that serve other reserves.

Pipelines are depreciated on a straight line basis over their useful lives.

(c) Impairment of development and production assets

An impairment test is performed whenever events and circumstances arising during the development or production phase indicate that the carrying value of a development or production asset may exceed its recoverable amount.

The carrying value is compared against the expected recoverable amount of the asset, generally by reference to the present value of the future net cash flows expected to be derived from production of commercial reserves. The cash generating unit applied for impairment test purposes is generally the field, except that a number of field interests may be grouped as a single cash generating unit where the cash inflows of each field are interdependent.

Any impairment identified is charged to the income statement. Where conditions giving rise to impairment subsequently reverse, the effect of the impairment charge is also reversed as a credit to the income statement, net of any depreciation that would have been charged since the impairment.

3. Accounting policies (Continued)

(d) Acquisitions, asset purchases and disposals

Acquisitions of oil and gas properties are accounted for under the acquisition method when the assets acquired and liabilities assumed constitute a business.

Transactions involving the purchase of an individual field interest, or a group of field interests, that do not constitute a business, are treated as asset purchases irrespective of whether the specific transactions involve the transfer of the field interests directly or the transfer of an incorporated entity. Accordingly, no goodwill and no deferred tax gross up arises, and the consideration is allocated to the assets and liabilities purchased on an appropriate basis.

Proceeds on disposal are applied to the carrying amount of the specific intangible asset or development and production assets disposed of and any surplus is recorded as a gain on disposal in the income statement.

(e) Decommissioning

Provision for decommissioning is recognised in full when the related facilities are installed. The amount recognised is the present value of the estimated future expenditure. A corresponding amount equivalent to the provision is also recognised as part of the cost of the related oil and gas property. This is subsequently depreciated as part of the capital costs of the production facilities. Any change in the present value of the estimated expenditure is dealt with prospectively as an adjustment to the provision and the oil and gas property. The unwinding of the discount is included as a finance cost.

Inventories

Inventories, except for petroleum products, are valued at the lower of cost and net realisable value. Petroleum products and under and over lifts of crude oil are recorded at net realisable value, under inventories and other debtors or creditors respectively.

Tax

The tax expense/credit represents the sum of the tax currently payable/recoverable and deferred tax movements during the year.

The tax currently payable is based on taxable profit for the year. Taxable profit differs from net profit as reported in the income statement because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are never taxable or deductible. The EPUK Group's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is the tax expected to be payable or recoverable on differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit, and is accounted for using the balance sheet liability method. Deferred tax liabilities are generally recognised for all taxable temporary differences and deferred tax assets are recognised to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilised. Such assets and liabilities are not recognised if the temporary difference arises from goodwill/excess of fair value over cost or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

Deferred tax liabilities are recognised for taxable temporary differences arising on investments in subsidiaries and associates, and interests in joint ventures, except where the EPUK Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

3. Accounting policies (Continued)

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered. The EPUK Group reassesses its unrecognised deferred tax asset each year taking into account changes in oil and gas prices, the EPUK Group's proven and probable reserve profile and forecast capital and operating expenditures.

Deferred tax is calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realised based on tax laws and rates that have been enacted or substantially enacted at the balance sheet date. Deferred tax is charged or credited in the income statement, except when it relates to items charged or credited in other comprehensive income, in which case the deferred tax is also dealt with in other comprehensive income.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same tax authority and the EPUK Group intends to settle its current tax assets and liabilities on a net basis.

Translation of foreign currencies

In the accounts of individual companies, transactions denominated in foreign currencies, being currencies other than the functional currency, are recorded in the local currency at actual exchange rates as of the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies at the balance sheet date are reported at the rates of exchange prevailing at the balance sheet date. Non-monetary assets and liabilities carried at fair value that are denominated in foreign currencies are translated at the rates prevailing at the date when the fair value was determined. Any gain or loss arising from a change in exchange rate subsequent to the dates of the transactions is included as an exchange gain or loss in the income statement. Non-monetary assets held at historic cost are translated at the date of purchase and are not retranslated.

Group retirement benefits

Payments to defined contribution retirement benefit plans are charged as an expense as they fall due.

Leasing

Rentals payable for assets under operating leases are charged to the income statement on a straight-line basis over the lease term.

Financial instruments

Financial assets and financial liabilities are recognised in the EPUK Group's balance sheet when the EPUK Group becomes a party to the contractual provisions of the instrument.

Trade receivables

Trade receivables are stated at their nominal value as reduced by appropriate allowances for estimated irrecoverable amounts.

Trade payables

Trade payables are stated at their nominal value.

Derivative financial instruments

The EPUK Group uses derivative financial instruments (derivatives) to manage its exposure to changes in oil and gas price fluctuations.

All derivative financial instruments are initially recorded at cost, including transaction costs. Derivatives are subsequently carried at fair value. All changes in fair value are recorded as income or expense in the year in which they arise.

3. Accounting policies (Continued)

Derivatives embedded in other financial instruments or non-derivative host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of host contracts and the host contracts are not carried at fair value with unrealised gains or losses reported in the income statement. Embedded derivatives which are closely related to host contracts are not separated and are not carried at fair value.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It is determined by reference to quoted market prices adjusted for estimated transaction costs that would be incurred in an actual transaction, or by the use of established estimation techniques such as estimated discounted values of cash flows.

Critical accounting judgements and key sources of estimation uncertainty

Details of the EPUK Group's significant accounting judgements and critical accounting estimates are set out in these financial statements and include:

- carrying value of intangible exploration and evaluation assets (note 11);
- carrying value of property, plant and equipment (note 12);
- provision for decommissioning costs (note 18); and
- tax and recognition of deferred tax assets (note 9 and 20).

4. Operating segments

The EPUK Group is involved in offshore oil and gas exploration, development and production in the United Kingdom. This is considered to be a single group of products provided by an interdependent asset infrastructure in one geographical area. Due to these factors there are not considered to be separable identifiable operating segments for which financial information can be presented.

5. Revenue

	Note	2013	2014	2015
		£000	£000	£000
Gas sales		177,756	207,312	148,816
Crude oil sales		63,220	100,698	99,816
Tariff income		10,835	12,512	8,425
		251,811	**320,522**	**257,057**

6. Cost of sales

	Note	2013	2014	2015
		£000	£000	£000
Gas purchases		(54,234)	(52,558)	(32,210)
Operating costs		(68,662)	(109,738)	(112,718)
Inventory movement		2,661	1,755	998
Amortisation and depreciation of property, plant and equipment:				
Oil and gas assets		(53,956)	(82,815)	(61,134)
Decommissioning assets		(13,429)	(15,407)	(23,755)
Furniture, IT and office equipment		(3,448)	(2,782)	(2,700)
		(191,068)	**(261,545)**	**(231,519)**

7. Staff costs

	Note	2013	2014	2015
		£000	£000	£000
Staff costs, including directors:				
Wages and salaries		14,732	16,529	17,820
Social security costs		1,743	1,963	2,159
Pension costs		1,399	1,876	2,275
		17,874	**20,368**	**22,254**

8. Interest revenue and finance costs

	Note	2013	2014	2015
		£000	£000	£000
Interest revenue, finance and other gains:				
On cash and cash equivalents		56	163	493
Other interest receivable		516	149	464
		572	**312**	**957**
Finance costs:				
On cash and cash equivalents		(331)	(173)	—
Other interest payable		(104)	(115)	(134)
Unwinding of discount on decommissioning provision	18	(8,109)	(9,374)	(7,993)
		(8,544)	**(9,662)**	**(8,127)**

9. Tax

	Note	2013	2014	2015
		£000	£000	£000
Current tax:				
UK corporation tax on profits		1,729	5,210	5,120
Adjustments in respect of prior years		(86)	(20,182)	(3,537)
Total current tax		**1,643**	**(14,972)**	**1,583**
Deferred tax:				
UK corporation tax		(12,278)	30,792	(96,148)
Total deferred tax	20	**(12,278)**	**30,792**	**(96,148)**
Tax (credit)/charge on (loss)/profit on ordinary activities		**(10,635)**	**15,820**	**(94,565)**

The 2014 and 2015 current corporation tax credits in respect of prior years relate mainly to refunds arising from the overpayment of corporation tax in prior years.

9. Tax (Continued)

The tax charge/(credit) for the year can be reconciled to the profit/(loss) per the consolidated income statement as follows:

	2013	2014	2015
	£000	£000	£000
Group (loss) on ordinary activities before tax	(3,064)	(30,583)	(209,963)
Group (loss) on ordinary activities before tax at ring fence rate of 50% (2015) and 62% (2014 and 2013)	(1,900)	(18,962)	(104,982)
Tax effects of:			
Income/expenses that are not taxable/deductible in determining taxable profit	6,440	19,300	2,991
Tax rate differences in respect of Income not subject to ring fence taxes	(5,264)	(2,203)	(8,135)
Tax and tax credits not related to profit before tax	(7.658)	(3,010)	(3,304)
Deferred tax assets arising in year not recognised	—	7,137	49,206
Effects of tax rate changes on deferred tax	(2,153)	(259)	(31,819)
Adjustments in respect of prior years	(100)	5,200	1,478
Write down of deferred tax asset previously recognised	—	8,617	—
Tax charge/(credit) for the year	(10,635)	15,820	(94,565)

The EPUK Group's activities mainly comprise exploration and production activities in the UK sector of the North Sea which are subject to corporation tax at 30% (2013 and 2014: 30%) and a supplementary charge of 20% (2013 and 2014: 32%). The combined rate of 50% (2013 and 2014: 62%) is described in these notes as the ring fence rate.

Tax not related to profit before tax includes the impact of ring fence expenditure supplement of £nil (2014: £3.4 million; 2013: £7.7 million) and investment allowances of £3.3 million (2014: £nil; 2013: £nil).

The activities of the EPUK Group include activities that are not subject to the ring fence tax regime. Tax rate differences in respect of income not subject to ring fence taxes include the rate differential effects arising as a result. Outside ring fence activities are subject to tax at 20.25% (2014: 21.5%; 2013: 23.5%).

The tax rate changes indicated above during each of the reporting periods give rise to re-evaluation of the opening deferred tax balance in each period. These effects are separately disclosed in the above reconciliation.

10. Earnings/(Loss) per share

Basic earnings per share amounts are calculated by dividing net profit for the year attributable to ordinary equity holders of EPUK by the weighted average number of ordinary shares outstanding during the year.

Diluted earnings per share amounts are calculated by dividing the net profit attributable to ordinary equity holders of EPUK by the weighted average number of ordinary shares outstanding during the year plus the weighted average number of ordinary shares that would be issued on the conversion of any dilutive potential ordinary shares into ordinary shares.

The weighted average number of ordinary shares at each of the year ends was 21,100 shares. There are no dilutive potential ordinary shares in EPUK and hence the basic and diluted earnings per share are the same.

	2013 Profit/(Loss) after tax	2013 Per share amount pence	2014 Profit/(Loss) after tax	2014 Per share amount pence	2015 Profit/(Loss) after tax	2015 Per share amount pence
	£000		£000		£000	
Basic and diluted Earnings per share/(Loss per share)	7,571	359	(46,403)	(2,199)	(115,398)	(5,469)

11. Intangible exploration and evaluation (E&E) assets

	Total
	£000
Cost:	
At 1 January 2013	**38,035**
Additions during the year	31,182
Transfer to property, plant and equipment	—
Disposals	(450)
Exploration expense	(4,150)
At 31 December 2013	**64,617**
Additions during the year	14,865
Transfer to property, plant and equipment	—
Disposals	(3,917)
Exploration expense	(9,646)
At 31 December 2014	**65,919**
Additions during the year	39,019
Transfer to property, plant and equipment	—
Disposals	(2,186)
Exploration expense	(30,348)
At 31 December 2015	**72,404**

The amounts for intangible E&E assets represent costs incurred on active exploration projects. These amounts are written off to the income statement as exploration expense unless commercial reserves are established or the determination process is not completed and there are no indications of impairment. The outcome of on-going exploration, and therefore whether the carrying value of E&E assets will ultimately be recovered, is inherently uncertain.

12. Property, plant and equipment

	Oil and Gas assets	Decommissioning assets	Furniture, IT and office equipment	Total
	£000	£000	£000	£000
Cost:				
At 1 January 2013	**748,652**	**130,979**	**6,811**	**886,442**
Additions during the year	99,724	37,061	6,994	**143,779**
Disposals	—	—	(262)	**(262)**
Transfer from / (to) intangible E&E assets	—	—	—	**—**
At 31 December 2013	**848,376**	**168,040**	**13,543**	**1,029,959**
Additions during the year	17,800	19,152	625	**37,577**
Disposals	—	—	—	**—**
Transfer from / (to) intangible E&E assets	—	—	—	—
At 31 December 2014	**866,176**	**187,192**	**14,168**	**1,067,536**
Additions during the year	15,865	111,320	2,843	**130,028**
Disposals	—	—	—	—
Transfer from / (to) intangible E&E assets	—	—	—	**—**
At 31 December 2015	**882,041**	**298,512**	**17,011**	**1,197,564**
Depreciation and impairment:				
At 1 January 2013	360,643	27,927	2,805	**391,375**
Charge for the year	53,956	13,429	3,448	**70,833**
Impairment charge	22,500	4,857	—	**27,357**
Disposals	—	—	(118)	**(118)**
At 31 December 2013	**437,099**	**46,213**	**6,135**	**489,447**
Charge for the year	82,815	15,407	2,782	**101,004**
Impairment charge	93,229	29,478	—	**122,707**
Disposals	—	—	—	**—**
At 31 December 2014	**613,143**	**91,098**	**8,917**	**713,158**
Charge for the year	61,134	23,755	2,700	**87,589**
Impairment charge	80,618	99,406	—	**180,024**
Disposals	—	—	—	—
At 31 December 2015	**754,895**	**214,259**	**11,617**	**980,771**
Net book value:				
At 1 January 2013	388,009	103,052	4,006	**495,067**
At 31 December 2013	411,277	121,827	7,408	**540,512**
At 31 December 2014	253,033	96,094	5,251	**354,378**
At 31 December 2015	**127,146**	**84,253**	**5,394**	**216,793**

Impairment

The impairment charge in 2015 relates to Huntington (£46m), Rita (£15m), Orca (£12m), Hunter (£10m), Caister (£13m), Ravenspurn North (£16m), Babbage (£49m) and Johnston (£19m). The total impairment charge of £180m was calculated by comparing the future discounted post-tax cash flows expected to be derived from production of commercial reserves against the post-tax carrying value of the asset. The future cash flows were estimated using management best estimates of Dated Brent oil prices for 2016 to 2021 and NBP gas prices for 2016 to 2019, both inflated at approximately 5% thereafter. The future cash flows were discounted using a post-tax discount rate of 7.7%. Assumptions involved in impairment measurement include estimates of commercial reserves and production volumes, future oil and gas prices and the level and timing of expenditures, all of which are inherently uncertain. The principal cause of the impairment charge being recognised in the year is a reduction in the short to medium term oil and gas price assumptions being used when determining the future discounted cash flows for each field. In addition to the impact of the reduced oil and gas price assumptions, reviews of the expected decommissioning costs for the Johnston, Babbage, Caister, Hunter, Rita and Orca fields have also driven part of the impairment charge.

12. Property, plant and equipment (Continued)

The impairment charge in 2014 relates to Huntington (£30m), Orca (£32m), Minke (£7m), Hunter (£1m), Johnston (£35m), Babbage (£17m), Ravenspurn North (£1m). The total impairment charge of £123m was calculated using management's best estimates of Dated Brent oil prices and NBP gas prices for 2015 to 2020 inflated at approximately 2% to 3.5% thereafter. The future cash flows were discounted using a post-tax discount rate of 7.1%. The principal cause of the impairment charge being recognised in the year is a reduction in the short to medium term oil price assumptions being used when determining the future discounted cash flows for each field and also increased costs on Huntington, Babbage and Ravenspurn North fields have also driven part of the impairment charge.

The impairment charge in 2013 relates to Babbage (£14m), Johnston (£2m), Caister (£3m), Hunter (£2m), Orca (£5m) and Minke (£1m). The total impairment charge of £27m was calculated using management's best estimates of Dated Brent oil prices and NBP gas prices for 2014 to 2019 inflated at approximately 3% to 6% thereafter. The future cash flows were discounted using a post-tax discount rate of 7.4%. The principal cause of the impairment charge being recognised in the year is a reduction in the reserves profiles used to only include commercial reserves and exclude possible reserves.

13. Inventories

	1 January 2013	2013	2014	2015
	£000	£000	£000	£000
Consumables	463	3,447	3,412	580
Petroleum products	—	2,709	710	214
	463	**6,156**	**4,122**	**794**

No inventories have been pledged as collateral.

14. Trade and other receivables

	1 January 2013	2013	2014	2015
	£000	£000	£000	£000
Trade receivables	23,672	18,350	6,735	9,474
Amounts owed by E.ON Group companies	30,482	16,283	19,604	13,109
Other receivables	6,652	22,732	13,703	7,253
Prepayments	6,909	7,259	4,465	2,325
Accrued income	7,786	2,843	1,120	1,207
	75,501	**67,467**	**45,627**	**33,368**

The carrying values of the trade and other receivables are not materially different to their fair value as at the balance sheet date.

15. Cash and cash equivalents

	1 January 2013	2013	2014	2015
	£000	£000	£000	£000
Cash and cash equivalents	13,404	2	85,151	148,853
Other financial liability	—	(16,109)	—	
	13,404	**(16,107)**	**85,151**	**148,853**

The EPUK Group participates in an arrangement whereby any surplus in the EPUK Group's current accounts are transferred to E.ON UK Holding Limited, a related party, at the end of each working day. Additionally amounts are also drawn down by the EPUK Group under this arrangement for short term funding purposes. Amounts in relation to cash pooling arrangement included in cash and cash equivalent as at 31 December 2015 is £148.0 million (2014: £85.2 million, 2013: £nil, 1 January 2013: £nil). As at 31 December 2013, the Group had drawn down short term funding from E.ON UK Holding of £16.1 million which has been classified as "Other financial liability".

15. Cash and cash equivalents (Continued)

For the purpose of the consolidated cash flow statement, cash and cash equivalents consist of cash and cash equivalents stated in the table above, net of outstanding overdrawn amounts.

Amounts in relation to cash pooling arrangements are considered to be cash and cash equivalent as amounts are; held to meeting short-term commitments, readily convertible to known amounts of cash, and subject to insignificant risk of changes in value. The cash is easily accessible as there are no restrictions in place preventing the EPUK Group accessing funds.

16. Trade and other payables

	1 January 2013	2013	2014	2015
	£000	£000	£000	£000
Trade payables	(1,670)	—	(5,805)	(797)
Amounts owed to E.ON Group companies	(11,074)	(4,210)	(6,052)	(5,328)
Accrued expenses	(46,309)	(43,200)	(25,313)	(26,080)
Crude Oil overlift	(7,198)	(4,538)	(2,782)	(1,669)
Other payables	—	(6,023)	(1,001)	(3,446)
	(66,251)	**(57,971)**	**(40,953)**	**(37,320)**

The carrying values of the trade and other payables approximate to their fair value as at the balance sheet date.

17. Obligations under leases

	At 1 January 2013	2013	2014	2015
	£000	£000	£000	£000
Minimum lease payments under operating leases recognised as an expense in the year	—	7,222	13,916	13,825
Outstanding commitments for future minimum lease payments under non-cancellable operating leases, which fall due as follows:				
Within one year	12,633	14,091	14,455	21,476
In two to five years	54,760	41,517	32,610	27,713
Over five years	3,447	3,206	0	—
	70,840	**58,814**	**47,065**	**49,189**

The EPUK Group holds contracts for the fourth and sixth to eighth floors of 129 Wilton Road in London which will continue until August 2018. In addition, the EPUK Group holds the lease to the fifth floor of 129 Wilton Road in London, which will continue until June 2019.

The EPUK Group also holds a contract for the first floor of South Union Plaza in Aberdeen which will continue until February 2017.

EPUK is a lessee under the Huntington project for a floating, production, storage and offloading (FPSO) vessel. The lease term commenced in 2013 and will continue for five years until 2018.

18. Provisions

	Note	2013	2014	2015
		£000	£000	£000
Current provision:				
Total provisions at 1 January		(650)	(11,815)	(13,099)
Revision arising from:				
New provisions and changes in estimates		(19,082)	(9,935)	(593)
Payments		7,917	8,651	943
Disposals		—	—	—
Exchange differences		—	—	—
Current provisions at 31 December		(11,815)	(13,099)	(12,749)

	Note	2013	2014	2015
		£000	£000	£000
Long term provision:				
Total provisions at 1 January		(159,862)	(185,950)	(204,541)
Revision arising from:				
New provisions and changes in estimates		(17,979)	(9,217)	(110,727)
Payments		—	—	—
Disposals		—	—	—
Exchange differences		—	—	—
Unwinding of discount on decommissioning provision	8	(8,109)	(9,374)	(7,993)
Total provisions at 31 December		**(185,950)**	**(204,541)**	**(323,261)**

The above current and long term provisions relate wholly to decommissioning.

The decommissioning provision represents the present value of decommissioning costs relating to oil and gas interests in the UK North Sea which are expected to be incurred up to 2039. These provisions have been created based on the EPUK Group's internal estimates and, where available, operators estimates. Based on the current economic environment, assumptions have been made which are believed to be a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

Changes in estimates mainly relate to an increase in the estimated future costs of decommissioning for Hunter, Caister, Huntington, Orca, Johnston and Babbage fields.

19. Financial instruments

Financial risk management objectives and policies

The EPUK Group's principal financial liabilities, other than derivative financial instruments (derivatives), comprise accounts and other payables. The main purpose of the derivatives is to manage commodity price fluctuations. The EPUK Group has various financial assets such as accounts receivable and other financial assets, which arise directly from its operations.

It is the EPUK Group's policy that all transactions involving derivatives must be directly related to the underlying business of the EPUK Group. The EPUK Group does not use derivative financial instruments for speculative exposures.

The main risks that could adversely affect the EPUK Group's financial assets, liabilities or future cash flows are commodity price risk, credit risk and liquidity risk. The EPUK Group uses derivative financial instruments to hedge some of these risk exposures. The use of financial derivatives is governed by E.ON Group policies, which provide written principles on the use of financial derivatives.

19. Financial instruments (Continued)

Derivative financial instruments

The EPUK Group uses derivatives to manage its exposure to oil and gas price fluctuations. Oil and gas hedging is undertaken with swaps and forward sales contracts. Oil is hedged using Brent oil price swaps.

Fair value hierarchy

In line with IAS 39 (Financial Instruments: Recognition and Measurement), the EPUK Group uses the following hierarchy for determining the fair value of financial instruments by valuation technique:

Level 1: quoted (unadjusted) prices in active markets for identical assets or liabilities;

Level 2: other techniques for which all inputs which have a significant effect on the recorded fair value are observable, either directly or indirectly; and

Level 3: techniques which use inputs which have a significant effect on the recorded value that are not based on observable market data.

Assets and liabilities measured at fair value

The EPUK Group held the following financial instruments measured at fair value.

The carrying value of financial assets and liabilities are equal to the fair value and have been designated as level 2 as at 31 December 2015, 31 December 2014, 31 December 2013 and 1 January 2013.

	2015	2014	2013	1 January 2013
Assets measured at fair value				
Oil price swap contracts	29,726	42,856	—	—
Gas forward sale contracts	28,990	26,362	43	8
Embedded derivative contracts	2,809	1,393	10,142	11,544
Total	**61,525**	**70,611**	**10,185**	**11,552**
Current / Non-current split of financial assets measured at fair value				
Current	49,578	42,332	3,534	2,885
Non-current	11,947	28,279	6,651	8,667
Total	**61,525**	**70,611**	**10,185**	**11,552**
Liabilities measured at fair value				
Oil price swap contracts	—	—	(2,722)	(5,484)
Gas forward sale contracts	—	—	—	—
Embedded derivative contracts	(381)	(12,328)	(23,503)	(23,616)
Total	**(381)**	**(12,328)**	**(26,225)**	**(29,100)**
Current / Non-current split of financial liabilities measured at fair value				
Current	(381)	—	(4,829)	(5,930)
Non-current	—	(12,328)	(21,396)	(23,170)
Total	**(381)**	**(12,328)**	**(26,225)**	**(29,100)**
Financial asset / liabilities at fair value (net)	**61,144**	**58,283**	**(16,040)**	**(17,548)**

Commodity price risk

Oil

At 31 December 2015 the EPUK Group had 0.8 million barrels of Dated Brent oil hedged through financial swaps for 2016 at an average price of US$97/bbl. During the year, oil swaps sales contracts for 1.1 million barrels matured generating an income of £34.2m. This income is included within sales revenues.

19. Financial instruments (Continued)

At 31 December 2014 the EPUK Group had 1.9 million barrels of Dated Brent oil hedged through financial swaps for 2015 and 2016 at an average price of US$99/bbl. During the year, oil swaps sales contracts for 1.1 million barrels matured generating an income of £3.9m. This income is included within sales revenues.

At 31 December 2013 the EPUK Group had 0.4 million barrels of Dated Brent oil hedged through financial swaps for 2014 at an average price of US$97/bbl. During the year, oil swaps sales contracts for 0.6 million barrels matured, generating a loss of £5.3m. This loss is included within sales revenues.

At 31 December 2012, the EPUK Group had 1.0 million barrels of Dated Brent oil hedged through financial swaps for 2013 and 2014 at an average floor price of US$95/bbl.

Gas

At 31 December 2015, 105.1m therms of gas was subject to monthly forward sales contracts for 2016–2018 at an average price of £0.54/therm. During the year, forward contracts for 109.4m therms matured generating an income of £69.4m. This income is included within sales revenues.

At 31 December 2014, 214.5m therms of gas was subject to monthly forward sales contracts for 2015–2018 at an average price of £0.56/therm. During the year, forward contracts for 105.1m were put in place and matured generating an income of £66.1m. In addition, gas price swaps for 52.3 therms matured generating an income of £4.9m. This income is included within sales revenues.

At 31 December 2013, 52.3m therms of gas was hedged through financial swaps for 2014 at an average price of £0.67/therm. During the year, gas swap contracts for 95.6m therms matured generating a loss of £3.3m. This loss is included within sales revenues.

At 31 December 2012, 137m therms of gas was hedged through financial swaps for 2013–2014 at an average price of £0.65/therm.

Impact on income statement

Movement in the fair value of financial assets and liabilities is recorded through the income statement as set out in the table below:

	2015	2014	2013
Fair value			
As at 1 January	**58,283**	**(16,040)**	**(17,548)**
Movement recorded through the income statement	2,861	74,323	1,508
31 December	**61,144**	**58,283**	**(16,040)**

Other financial instruments

Credit risk

The EPUK Group's credit risk is attributable to its trade receivables and other financial assets. The amount of receivables presented in the balance sheet is net of allowances for doubtful receivables. The EPUK Group does not require collateral or other security to support receivables from customers or related parties. The credit risk on liquid funds and derivative financial instruments is considered limited.

19. Financial instruments (Continued)

The ageing profile of the EPUK Group's trade and other receivables and trade and other payables at the end of each period, including the related undiscounted interest amounts, is set out in the table below:

	Less than 1 month	2 to 3 months	3 months to 1 year	1 to 5 years	Over 5 years	Total
	£000s	£000s	£000s	£000s	£000s	£000s
31 December 2015:						
Trade and other receivables	31,043	—	—	—	—	**31,043**
Trade and other payables	(34,823)	—	(2,497)	—	—	**(37,320)**
Total	**(3,780)**	**—**	**(2,497)**	**—**	**—**	**(6,277)**
31 December 2014:						
Trade and other receivables	41,162	—	—	—	—	**41,162**
Trade and other payables	(38,076)	—	(2,877)	—	—	**(40,953)**
Total	**3,086**	—	**(2,877)**	—	—	**209**
31 December 2013						
Trade and other receivables	60,208	—	—	—	—	**60,208**
Trade and other payables	(56,798)	—	(1,173)	—	—	**(57,971)**
Total	**3,410**	**—**	**(1,173)**	**—**	**—**	**(2,257)**
1 January 2013						
Trade and other receivables	68,592	—	—	—	—	**68,592**
Trade and other payables	(64,578)	—	(1,673)	—	—	**(66,251)**
Total	**4,014**	**—**	**(1,673)**	**—**	**—**	**2,341**

Liquidity risk

In order to maintain liquidity to ensure that sufficient funds are available for ongoing operations and future developments, the EPUK Group uses a mixture of long-term and short-term debt finance provided by the E.ON group of companies.

The EPUK Group manages liquidity risk by maintaining adequate reserves, banking and borrowing facilities and by continuously monitoring forecast and actual cash flows and matching the maturity profiles of financial assets and liabilities and future capital and operating commitments.

20. Deferred tax

	1 January 2013	2013	2014	2015
	£000	£000	£000	£000
Deferred tax assets	159,077	203,203	36,554	76,369
Deferred tax liabilities	(257,035)	(288,883)	(153,026)	(96,693)
	(97,958)	**(85,680)**	**(116,472)**	**(20,324)**

	Consolidated balance sheet				Consolidated income statement		
	At 1 January 2013	2013	2014	2015	2013	2014	2015
	£000	£000	£000	£000	£000	£000	£000
Fixed assets and allowances	(241,884)	(274,379)	(115,369)	(70,747)	(32,495)	159,010	44,622
Decommissioning	28,731	37,971	32,830	70,519	9,240	(5,141)	37,689
Tax losses and allowances	96,653	128,368	3,723	5,849	31,715	(124,645)	2,126
Other allowance	(6,689)	(5,821)	(5,764)	(5,475)	868	57	289
Derivative financial instruments	25,231	28,181	(31,892)	(20,470)	2,950	(60,073)	11,422
Net deferred tax liability	**(97,958)**	**(85,680)**	**(116,472)**	**(20,324)**			
Deferred tax income / (expense)					**12,278**	**(30,792)**	**96,148**

20. Deferred tax (Continued)

Reconciliation of deferred tax liability

	2013	2014	2015
	£000	£000	£000
Balance as at 1 January	(97,958)	(85,680)	(116,472)
Tax income / (expense) during the period recognised in the income statement	12,278	(30,792)	96,148
Tax income/(expense) during the period recognised in other comprehensive income	—	—	—
Balance as at 31 December	**(85,680)**	**(116,472)**	**(20,324)**

The EPUK Group's unutilised tax losses and allowances are recognised at the end of each accounting period to the extent that taxable profits are expected to arise in the future against which those losses and allowances can be utilised. Based on management's evaluation of the expected future profits, deferred tax assets totalling £65 million (2014: £15.8 million; 2013: £nil) have not been recognised.

21. Share capital

	1 January 2013 £10,000 shares	1 January 2013 £	2013 £10,000 shares	2013 £	2014 £10,000 shares	2014 £	2015 £10,000 shares	2015 £
EPUK Ordinary Shares:								
Authorised, called-up, issued and fully-paid	21,100	211,000,000	21,100	211,000,000	21,100	211,000,000	21,100	211,000,000

EPUK Ordinary Shares

The rights and restrictions attached to the Ordinary Shares are as follows:

Dividend rights: The rights of the holders of Ordinary Shares shall rank pari passu in all respects with each other in relation to dividends.

Winding up or reduction of capital:

On a return of capital on a winding up or otherwise (other than on conversion, redemption or purchase of shares) the rights of the holders of Ordinary Shares to participate in the distribution of the assets of EPUK available for distribution shall rank pari passu in all respects with each other.

Voting rights:

The holders of Ordinary Shares shall be entitled to receive notice of, attend, vote and speak at any General Meeting of EPUK.

22. Notes to the cash flow statement

	2013	2014	2015
	£000	£000	£000
Loss before tax for the year	(3,064)	(30,583)	(209,963)
Adjustments for:			
Depreciation, depletion, amortisation and impairment	98,190	223,711	267,613
Exploration expense	4,600	13,563	32,534
Interest revenue and finance gains	(572)	(312)	(957)
Finance costs and other finance expenses	8,544	9,662	8,127
Gain on commodity derivative financial instruments	(1,508)	(74,322)	(2,861)
Loss on disposal of property, plant and equipment	144	—	—
Operating cash flows before movements in working capital	106,334	141,719	94,493
(Increase)/decrease in inventories	(5,693)	2,034	3,328
Decrease in receivables	11,414	34,018	24,588
Decrease in payables	(11,155)	(30,915)	(15,580)
Decrease in provision	(7,917)	(8,651)	(943)
Cash generated by operations	92,983	138,205	105,886
Income taxes paid	(2,151)	(5,636)	(5,650)
Income taxes received	(17,420)	1,955	20,370
Net cash from operating activities	**108,252**	**134,524**	**120,606**

23. Related party transactions

Transactions between EPUK and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note.

The following table provides the total amount of transactions that have been entered into with related parties for the relevant financial year and amounts outstanding at year end.

	1 January 2013	31 December 2013	31 December 2014	31 December 2015
	£000	£000	£000	£000
Sales to related parties				
Ultimate controlling party		—	—	—
Associated companies		105,131	159,743	145,981
Other related parties		—	—	—
Purchases from related parties				
Ultimate controlling party		—	—	—
Associated companies		(43,610)	(37,195)	(26,545)
Other related parties		—	—	—
Amounts due from related parties				
Ultimate controlling party	—	—	—	271
Associated companies	30,489	16,318	88,823	71,527
Other related parties	—	—	—	—
Amounts due to related parties				
Ultimate controlling party	—	—	—	—
Associated companies	(16,558)	(6,651)	(6,052)	(5,372)
Other related parties	—	—	—	—

Ultimate controlling party

The ultimate controlling party of EPUK is E.ON, a company incorporated in Germany.

23. Related party transactions (Continued)

Associated companies

All companies that are directly or indirectly controlled by E.ON, other than EPUK and its subsidiaries have been classified as associated companies.

Income and expenses from transactions with related companies is generated mainly through the purchase and sale of gas and crude oil. Receivables from related companies consist of trade receivables, receivables in relation to derivative financial instruments, and balances owed to or from associated companies.

Terms and conditions of transactions with related parties

The sales to and purchases from related parties are made at terms equivalent to those that prevail in arm's length transactions. Outstanding balances at the year-end are unsecured and interest free. There have been no guarantees provided or received for any related party receivables or payables. For the year ended 31 December 2015, the EPUK Group has not recorded any impairment of receivables relating to amounts owed by related parties (2014: £nil; 2013: £nil; 1 January 2013: £nil). This assessment is undertaken each financial year by examining the financial position of the related party and the market in which the related party operates.

Directors and executive remuneration

The remuneration of Directors and other key members of management during the year is highlighted below.

	2013	2014	2015
	£ 000	£ 000	£ 000
Short-term employee benefits	1,948	1,558	1,499
Post-employment benefits	—	—	—
Other long-term benefits: share-based payments	—	—	—
	1,948	1,558	1,499

The EPUK Group participates in a defined contribution retirement benefit plan.

24. Capital commitments and guarantees

At 31 December 2015, the EPUK Group had commitments for future capital expenditure totalling approximately £0.6 million (2014: £24.3 million; 2013: £24.9 million; 1 January 2013: £52.5 million) in relation to ongoing projects.

The EPUK Group did not have any other contingent liabilities as at 31 December 2015 (2014: £nil, 2013: £nil; 1 January 2013: £nil).

25. Dividends

A dividend of £60 million was proposed and paid for the year ended 31 December 2015 on 24 February 2016.

No dividend was paid in 2015, 2014 and 2013 for the years ended 31 December 2014, 31 December 2013 and 31 December 2012.

26. Ultimate parent undertaking

The ultimate parent company and controlling party as at 31 December 2015 was E.ON, a company incorporated in Germany.

The immediate parent company and controlling party as at 31 December 2015 was E.ON Beteiligungen GmbH, a company incorporated in Germany.

26. Ultimate parent undertaking (Continued)

The smallest and largest group in which the results of EPUK are consolidated is that headed by E.ON, whose principal place of business is Germany. The consolidated financial statements of E.ON are available to the public and may be obtained from E.ON-Platz 1, D-40479 Dusseldorf, Germany.

27. Principal subsidiaries

At 31 December 2015, EPUK had investments in the following 100 per cent owned subsidiaries which principally affected the profits or net assets of the EPUK Group.

Name of company	Principal activity	Country of incorporation and operation
E.ON E&P UK Energy Trading Limited	Natural gas trading	England
E.ON E&P UK EU Limited	Natural gas exploration, development and production	England

The registered address of EPUK and its subsidiaries is 129 Wilton Road, London, SW1V 1JZ.

Shares in all subsidiaries are held directly by EPUK.

28. Transition to IFRS

No consolidated financial statements have previously been prepared for the EPUK Group as EPUK took advantage of the exemption available under Companies Act 2006 from the preparation of consolidated financial statements, as the results of EPUK and its subsidiaries were being consolidated in the financial statements of E.ON SE. The statutory entities within the EPUK Group prepared entity financial statements under UK GAAP for the years ended 31 December 2012, 2013, 2014 and 2015.

The EPUK Group has adopted IFRS for the first time in this historical financial information for the three years ended 31 December 2015. In preparing the historical financial information, the EPUK Group's opening statement of financial position was prepared as at 1 January 2013, the EPUK Group's date of transition to IFRS.

Since EPUK did not prepare consolidated financial statements, reconciliations of previously reported amounts to those included in these financial statements have not been provided.

Exemptions applied

IFRS 1 allows first-time adopters certain exemptions from the retrospective application of certain requirements under IFRS. The EPUK Group has applied the following exemptions in preparing the opening balance sheet under IFRS:

- IFRS 3 (Business Combinations) has not been applied to acquisitions of subsidiaries or of interests in associates and joint ventures that occurred before 1 January 2013.

Estimates

The estimates at 1 January 2013 are consistent with those made as at the same date in the UK GAAP statutory entity financial statements (after adjustments to reflect any differences in accounting policies).

29. Events after the balance sheet date

On 13 January 2016, Premier announced that it had agreed to acquire the whole of EPUK and its subsidiaries for a net consideration of $120 million plus working capital adjustments.

On 19 February 2016, EPUK reduced its share capital from £211,000,000 to £50,007,000. On 24 February 2016, a dividend of £60 million was proposed and paid for the year ended 31 December 2015.

PART VI—UNAUDITED PRO FORMA FINANCIAL INFORMATION RELATING TO THE ENLARGED GROUP

Draft Report on Pro forma financial information

Deloitte.

Deloitte LLP
2 New Street Square
London
EC4A 3BZ

The Board of Directors
on behalf of Premier Oil plc
4th Floor
Saltire Court
20 Castle Terrace
Edinburgh, EH1 2EN

RBC Europe Limited
Riverbank House
2 Swan Lane
London, EC4R 3BF

7 April 2016

Dear Sirs,

Premier Oil plc ("Premier")

We report on the pro forma financial information (the "**Pro forma financial information**") set out in Part VI of the Circular, which has been prepared on the basis described in the notes for illustrative purposes only, to provide information about how the Acquisition might have affected the financial information presented on the basis of the accounting policies adopted by Premier in preparing the financial statements for the year ended 31 December 2015. This report is required by the Commission Regulation (EC) No 809/2004 (the "**Prospectus Directive Regulation**") as applied by Listing Rule 13.3.3R and is given for the purpose of complying with that requirement and for no other purpose.

Responsibilities

It is the responsibility of the Directors to prepare the Pro forma financial information in accordance with Annex II items 1 to 6 of the Prospectus Directive Regulation as applied by Listing Rule 13.3.3R.

It is our responsibility to form an opinion, as to the proper compilation of the Pro forma financial information and to report that opinion to you in accordance with Annex II item 7 of the Prospectus Directive Regulation as applied by Listing Rule 13.3.3R.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and which we may have to holders of Ordinary Shares as a result of the inclusion of this report in this Circular, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Listing Rule 13.4.1R (6), consenting to its inclusion in this Circular.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information used in the compilation of the Pro forma financial information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

Basis of Opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro forma financial information with the Directors.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro forma financial information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of Premier.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in jurisdictions outside the United Kingdom, including the United States, and accordingly should not be relied upon as if it had been carried out in accordance with those standards or practices.

Opinion

In our opinion:

(a) the Pro forma financial information has been properly compiled on the basis stated; and

(b) such basis is consistent with the accounting policies of Premier.

Yours faithfully

Deloitte LLP
Chartered Accountants

Deloitte LLP is a limited liability partnership registered in England and Wales with registered number OC303675 and its registered office at 2 New Street Square, London EC4A 3BZ, United Kingdom. Deloitte LLP is the United Kingdom member firm of Deloitte Touche Tohmatsu Limited ("DTTL"), a UK private company limited by guarantee, whose member firms are legally separate and independent entities. Please see www.deloitte.co.uk/about for a detailed description of the legal structure of DTTL and its member firms.

Unaudited pro forma statement of net assets of the Enlarged Group at 31 December 2015

The unaudited pro forma statement of net assets of the Enlarged Group in this Part VI has been prepared based on the consolidated balance sheet of Premier as at 31 December 2015 and the consolidated balance sheet of EPUK as at 31 December 2015.

The unaudited pro forma statement of net assets has been prepared to illustrate the effect of the Acquisition on the consolidated net assets of Premier as if it had been completed on 31 December 2015. The unaudited pro forma statement of net assets has been prepared for illustrative purposes only and, by its nature, addresses a hypothetical situation and, therefore, does not represent the Enlarged Group's actual financial position. This unaudited pro forma statement does not take into account trading of Premier or EPUK subsequent to 31 December 2015.

The unaudited pro forma financial information has been prepared on a consistent basis with the accounting policies and presentation adopted by Premier in relation to its consolidated financial statements for the year ended 31 December 2015, on the basis of the notes set out below and in accordance with Listing Rule 13.3.3R.

Furthermore, the unaudited pro forma financial information set out in this Part does not constitute statutory accounts within the meaning of section 434 of the Companies Act 2006.

The pro forma statement of net assets set out below is based on information which has been extracted without material adjustment from the audited consolidated balance sheet of Premier as at 31 December 2015 as incorporated by reference in Part VIII of this document and the audited consolidated balance sheet of EPUK as at 31 December 2015 as set out in Part V of this document. The EPUK consolidated balance sheet has been prepared on a basis consistent with the accounting policies of Premier for the year ended 31 December 2015. Further adjustments have been made in accordance with Listing Rule 13.3.3R.

Unaudited pro forma statement of net assets of the Enlarged Group at 31 December 2015 (continued)

	Note	Premier net assets as at 31 December 2015	EPUK net assets as at 31 December 2015	Adjustments: EPUK intercompany adjustment	Adjustments: EPUK cash dividend	Adjustments: Acquisition accounting adjustment	Pro forma
		US$ million[1]	US$ million[2]	US$ million[3]	US$ million[4]	US$ million[5]	US$ million
Non-current assets:							
Intangible exploration and evaluation assets		749.7	106.4	—	—	—	856.1
Property, plant and equipment		2,611.7	318.7				2,930.4
Goodwill		240.8	—	—	—	137.6	378.4
Investment in associate		5.3					5.3
Long-term employee benefit plan surplus		0.5	—	—	—	—	0.5
Long-term receivables		11.5	17.6	—	—	—	29.1
Deferred tax assets		871.6	—	—	—	—	871.6
		4,491.1	442.7			137.6	5,071.4
Current assets:							
Inventories		20.8	1.2	—	—	—	22.0
Trade and other receivables		240.8	49.1	(19.3)			270.6
Tax recoverable		33.6	5.4	—	—	—	39.0
Derivative financial instruments		118.3	72.9	—	—	—	191.2
Cash and cash equivalents		401.3	218.8	11.4	(213.4)	(139.9)	278.3
		814.8	347.3	(7.8)	(213.4)	(139.9)	801.0
Total assets		**5,305.9**	**790.0**	**(7.8)**	**(213.4)**	**(2.2)**	**5,872.4**
Current liabilities:							
Trade and other payables		(407.4)	(54.9)	7.8			(454.4)
Current tax payable		(64.6)	—	—	—	—	(64.6)
Provisions		(24.8)	(18.7)	—	—	—	(43.5)
Derivative financial instruments		(76.5)	(0.6)	—	—	—	(77.1)
Short-term debt		—	—	—	—	—	—
Deferred income		(20.9)	—	—	—	—	(20.9)
		(594.2)	(74.2)	7.8	—	—	(660.5)
Net current assets		**220.6**	**273.2**	—	**(213.4)**	**(139.9)**	**140.5**
Non-current liabilities:							
Convertible bonds		(232.6)	—	—	—	—	(232.6)
Other long-term debt		(2,382.5)	—	—	—	—	(2,382.5)
Deferred tax liabilities		(193.3)	(29.9)	—	—	—	(223.2)
Deferred income		(87.6)					(87.6)
Long-term provisions		(1,065.7)	(475.2)	—	—	—	(1,540.9)
Long-term employee benefit plan deficit		(15.2)	—	—	—	—	(15.2)
		(3,976.9)	(505.1)	—	—	—	(4,482.0)
Total liabilities		**(4,571.1)**	**(579.2)**	**7.8**	**—**	**—**	**(5,142.5)**
Net assets		**734.8**	**210.8**	—	**(213.4)**	**(2.2)**	**729.9**

Notes:

(1) The net assets of Premier as at 31 December 2015 have been extracted without material adjustment from the audited consolidated financial information incorporated by reference in Part VIII of this document.

(2) The net assets of EPUK as at 31 December 2015 have been extracted without material adjustment from the audited financial information of EPUK included in Part V of this document and using an exchange rate of US$1.47:£.

(3) This adjustment reflects the Completion process, which will result in the settlement of inter-company balances between EPUK and the Seller Group.

(4) By Completion a cash dividend of £145.2 million (US$213.4 million at an exchange rate of US$1.47:£) will be paid by EPUK to its parent company. The first £60.0 million of this dividend was paid on 24 February 2016. This adjustment shows the effect of this cash payment.

Unaudited pro forma statement of net assets of the Enlarged Group at 31 December 2015 (continued)

(5) The unaudited pro forma statement of net assets has been prepared on the basis that the Acquisition will be treated as a business combination in accordance with IFRS 3. However, it does not reflect any fair value adjustments to the acquired assets and liabilities as the fair value measurement of these items will only be performed as at the date of Completion. For the purposes of the pro forma statement of net assets, the excess purchase consideration over the carrying amount of the net assets of EPUK has been attributed to goodwill and no pro forma impairment charge has been applied to the goodwill balance in the period. The fair value adjustments, when finalised following Completion of the Acquisition, may be material. The preliminary goodwill arising has been calculated as follows:

	US$ million
Purchase consideration (see (5)(i) below)	135.0
Net assets of EPUK as at 31 December 2015	(210.8)
Cash dividend paid (note 4)	213.4
Purchase consideration in excess of net assets (shown as goodwill)	137.6

(5)(i) This reflects the payment of cash consideration of $135.0 million for the acquisition of EPUK. In addition, it is estimated that transaction expenses of approximately $4.9 million will be incurred, such that the total cash outflow relating to the Acquisition will be $139.9 million. These transaction expenses will be expensed.

(6) While Premier and EPUK had certain balances payable to and receivable from each other at 31 December 2015, no adjustment has been made to eliminate such balances as its impact is not considered material.

PART VII—ADDITIONAL INFORMATION

1. Director's Responsibility Statement

Premier and the Directors, whose names appear in paragraph 3 below, accept responsibility for the information contained in this document. To the best of the knowledge and belief of Premier 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.

2. Incorporation and Registered Office

Premier was incorporated and registered with the name of Dalglen (No. 836) Limited in Scotland on 31 July 2002 with registration number SC234781. The Company name was changed from Dalglen (No. 836) Limited to Premier Oil Group Limited pursuant to a written resolution passed on 13 September 2002. Premier was re-registered as a public limited company on 10 March 2003, and its name was changed from Premier Oil Group Limited to Premier Oil plc pursuant to a special resolution passed on 3 March 2003 and which became effective on 15 July 2003.

The principal legislation under which Premier operates is the Companies Act 2006 and regulations made thereunder.

Premier is domiciled in the United Kingdom and its registered office is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN. Premier's head office is 23 Lower Belgrave Street, London SW1W 0NR.

3. Directors and Service Contracts and Letters of Appointment

3.1 Directors

The names and principal functions of the Directors of Premier Oil plc are as follows:

Name	Position
Mike Welton	Non-Executive Chairman
Tony Durrant	Chief Executive Officer
Richard Rose	Finance Director
Robin Allan	Director, North Sea and Exploration
Neil Hawkings	Director, South East Asia and Falkland Islands
David Bamford	Non-Executive Director
Anne Marie Cannon	Non-Executive Director
Joe Darby	Senior Independent Non-Executive Director
David Lindsell	Non-Executive Director
Michel Romieu	Non-Executive Director
Jane Hinkley	Non-Executive Director

3.2 Directors' service contracts and letters of appointment

Details of executive Directors' service contracts and non-executive Directors' letters of appointment providing for benefits upon termination of employment are set out in the section headed "Directors' Remuneration Report" of the Premier 2015 Annual Report, which is incorporated into this document by reference.

4. Directors' interests

4.1 Directors' interests in the Ordinary Shares

As at the Latest Practicable Date, the interests of each Director and their immediate families in the Ordinary Shares, including interests arising pursuant to any transaction notified to Premier pursuant to rule 3.1.2 of the Disclosure and Transparency Rules, are as follows:

Name	Number of Ordinary Shares	Percentage of issued number of Ordinary Shares
Mike Welton	22,531	0.0044%
Tony Durrant	1,196,181	0.2342%
Richard Rose	37,378	0.0073%
Robin Allan	484,784	0.0949%
Neil Hawkings	584,609	0.1144%
David Bamford	1,514	0.0003%
Anne Marie Cannon	0	0%
Joe Darby	23,108	0.0045%
David Lindsell	17,332	0.0034%
Michel Romieu	20,000	0.0039%
Jane Hinkley	13,234	0.0026%

4.2 Share Incentive Schemes

The Directors' interests in equity pool points and share awards under the 2009 Long Term Incentive Plan, share awards under the Deferred Bonus Share Plan, share options under the SAYE Plan 2009 and share allocations under the Share Incentive Plan for the financial year ended 31 December 2015 (being the last full financial year for Premier for which an annual report has been published) are set out in the section headed "Directors' Remuneration Report" of the Premier 2015 Annual Report, which is incorporated into this document by reference.

During the period of 1 January 2016 and the Latest Practicable Date, Directors acquired the following additional interests in Ordinary Shares by virtue of their participation in the Share Incentive Plan:

Director	Partnership Shares purchased by Directors at prices between £0.3806 and £0.4740	Matching Shares awarded to Directors at prices between £0.3806 and £0.4740
Robin Allan	1,189	1,189
Tony Durrant	1,188	1,188
Neil Hawkings	1,427	1,427
Richard Rose	1,427	1,427

5. Substantial Shareholders

5.1 As at the Latest Practicable Date, Premier had received notification in accordance with Chapter 5 of the Disclosure and Transparency Rules of the following notifiable interests in the voting rights of Premier's Ordinary Shares:

Name of Shareholder	Date notified to the stock exchange	Notified number of voting rights	Notified percentage of voting rights
AXA Investment Managers SA(1)	24.10.2011	40,173,814	8.58%
Schroders plc	30.11.2015	38,338,530	7.51%
Artemis Investment Management LLP	13.05.2015	25,451,951	4.98%
Aviva plc & subsidiaries (direct interests)	27.04.2009	3,933,529	4.95%
Ameriprise Financial. Inc	20.01.2012	24,666,346	4.66%
Norges Bank	06.04.2016	17,706,338	3.47%

(1) Interests shown for Axa Investment Managers SA pre-date the EnCore transaction and related share issue in 2012; interests shown for Aviva plc and its subsidiaries pre-date the Share Split in 2011.

5.2 Save as disclosed in this paragraph 5, Premier is not aware of (i) any person who as at the Latest Practicable Date was interested directly or indirectly (within the meaning of Rule 5 of the Disclosure and Transparency Rules) in 3% or more of the Ordinary Shares.

6. Related party transactions

A description of the material provisions of agreements and other documents between the Premier Group and various individuals and entities that may be deemed to be related parties is given in note 25 in the section titled "Notes to the Consolidated Financial Statements" in the Premier 2015 Annual Report and note 24 in each of the Premier 2014 Annual Report and the Premier 2013 Annual Report, which are incorporated into this document by reference. No such related party transactions have been entered into by any member of the Premier Group during the period between 1 January 2016 and the Latest Practicable Date.

7. Material Contracts

7.1 The Premier Group

In addition to the Acquisition Agreements which have been summarised in Part III of this document, a summary of all other contracts (not being contracts entered into in the ordinary course of business) that have been entered into by any member of the Premier Group either (i) within the two years immediately preceding the date of this document which are, or may be, material or (ii) which have been entered into by any member of the Premier Group and which contain provisions under which any member of the Premier Group has an obligation or entitlement that is material as at the date of this document, is set out below:

Commercial Agreements

*Acquisition of 60% of the petroleum interests in the Falkland Islands of Rockhopper Exploration plc ("**Rockhopper**")*

Pursuant to a sale and purchase agreement dated 12 July 2012 between Rockhopper, Premier Oil Iraq (Exploration & Production) Limited (subsequently renamed as Premier Oil Exploration and Production Limited) and Premier, Premier acquired certain petroleum licence interests in the Falkland Islands of Rockhopper, including a 60% participating interest in the Sea Lion discovery situated in Falkland Islands Petroleum Licence PL032. In consideration for the acquisition of the licence interests, Premier agreed to pay Rockhopper $231 million in cash on completion of the transfer and certain contributions to Rockhopper's future expenditure. The acquisition completed on 18 October 2012 and by an amendment and restatement of the sale and purchase agreement dated 12 January 2016 it was agreed to amend Premier's contributions to Rockhopper's future expenditure as follows:

(A) Premier to pay $48 million of exploration costs incurred by Rockhopper in the Falkland Islands; forecast to be fully paid during the current exploration programme;

(B) Premier to pay $48 million of Sea Lion pre-development costs incurred by Rockhopper in the Falkland Islands; this has now been fully paid;

(C) Premier to pay Rockhopper $337 million of Sea Lion Phase 1 development costs incurred by Rockhopper after Sea Lion Phase 1 project sanction;

(D) Premier to pay Rockhopper $337 million of Sea Lion Phase 2 development costs incurred by Rockhopper after Sea Lion Phase 2 project sanction;

(E) Rockhopper to pay Premier $15.9 million per calendar quarter (subject to review prior to Phase 1 project sanction) from the date of first oil production from Sea Lion Phase 1 for 20 calendar quarters; and

(F) Premier to lend Rockhopper up to $750 million for Rockhopper's share of Sea Lion Phase 1 development costs following Sea Lion Phase 1 project sanction.

*Acquisition of 40% interest in the Solan field from Chrysaor Limited ("**Chrysaor**")*

On 29 May 2015, Premier Oil UK Limited ("**POUK**") entered into a sale and purchase agreement with Chrysaor under the terms of which POUK acquired Chrysaor's entire 40% interest in the Solan field (the "**Solan Interest**"). The consideration for this transaction was the settlement of an existing loan of $572,347,700 plus accrued interest on such sum (and future interest on such sum at a rate of 10% per annum) between Premier and Chrysaor (the "**Outstanding Loan**"), and the creation of a new 'royalty' revenue stream to be paid to Chrysaor under the terms of a Royalty and Net Production Interest Deed entered into between POUK and Chrysaor on 29 May 2015.

The royalties will be paid from a notional 40% interest in the field's net operating cash flow under three royalty streams as follows:

(A) Royalty Stream 1—an initial monthly payment based on the net production revenues from the Solan Interest each month, capped at $3 million per year from POUK to Chrysaor which will be offset against any subsequent royalty payments and net production interest;

(B) Royalty Stream 2—further monthly payments, up to $100 million in aggregate, based on the net production revenues from the Solan Interest each month, provided that such further payments will only be made (i) following repayment by Chrysaor to POUK of the Outstanding Loan, and (ii) once the cap in relation to Royalty Stream 1 has been reached in a given year; and

(C) Royalty Stream 3—calculated and operates as per Royalty Stream 1 with additional reductions for certain development capital costs, provided that payments under Royalty Stream 3 will only commence once the aggregate amount which would otherwise have been payable under Royalty Stream 3 exceeds the estimated Solan decommissioning costs.

*Agreement with FlowStream Magni Ltd. ("**FlowStream**") in relation to the transfer of a 15% production interest in the Solan field's production*

On 29 May 2015, POUK entered into an agreement with FlowStream whereby Flowstream agreed to make a payment of $100 million to Premier in consideration for the transfer of 15% of Solan field production to FlowStream (the "**Streaming Deed**"). Premier guarantees the obligations of POUK under the Streaming Deed.

The key terms of the Streaming Deed provide as follows:

(A) following each lifting of Solan hydrocarbons, POUK shall deliver the relevant share (15%) to FlowStream;

(B) FlowStream shall pay transportation costs and marketing fees to be deducted for each delivery; and

(C) the Streaming Deed shall terminate on the earlier of:

(i) the date on which the agreed return is achieved; or

(ii) the date the Solan Licence expires (currently 15 March 2018, subject to further extensions),

the result of which being that the length of the term of the Streaming Deed is dependent on the Solan field's production levels and the future oil price.

*Acquisition by POUK of interests in the Huntington field from Noreco Oil (UK) Limited ("**Noreco**") and Iona UK Huntington Limited ("**Iona**") under the Huntington Joint Operating Agreement*

On 8 January 2016 and 29 January 2016 respectively, POUK elected to acquire from Noreco and Iona a percentage of their respective equity interest shares in the Huntington field (together, the "**POUK Election Interests**") for no consideration pursuant to the default and forfeiture provisions within a joint operating agreement in relation to the Huntington field (the "**Huntington JOA**"). POUK already held a 40% equity interest in the Huntington field.

The transfers to POUK of the POUK Election Interests are being facilitated by a deed of novation and a deed of licence transfer which will provide for the simultaneous transfer of the POUK Election Interests to POUK (the "Transfer Documents"). Iona is currently in administration and Iona's administrator, FTI Consulting, Inc., is currently reviewing these documents.

As at the Latest Practicable Date, the completion of the transfer of the POUK Election Interests to POUK has not yet occurred. The transfers will be completed upon the finalisation and execution of the aforementioned documents, which are in near final form. However, pursuant to the terms of the default provisions of the Huntington JOA and following Noreco and Iona's defaults thereunder, POUK is currently entitled to 61.5% of the revenue from, and has a corresponding obligation for 61.5% of the costs associated with, the Huntington field. This represents POUK's existing 40% equity interest in the Huntington field and POUK's pro-rata beneficial interest in the POUK Election Interests (21.5%), pending completion of the transfer process.

It is expected that the transfer process will be completed in the near future. Following the completion of the transfer of the POUK Election Interests to POUK, POUK will hold a 61.5% legal and beneficial interest in the Huntington field.

7.2 The EPUK Group

Save as set out below, no contracts have been entered into (other than in the ordinary course of business) by any member of the EPUK Group, either (i) within the two years immediately preceding the date of this document which are, or may be, material; or (ii) which contain any provision under which any member of the EPUK Group has any obligations or entitlements which are or may be material as at the date of this document.

Acquisition by EPUK of interests in the Huntington field from Noreco and Iona under the Huntington JOA

On 8 January 2016 and 29 January 2016 respectively, EPUK elected to acquire from Noreco and Iona a percentage of their respective equity interest shares in the Huntington field (together, the "**EPUK Election Interests**") for no consideration pursuant to the default and forfeiture provisions within the Huntington JOA. EPUK already held a 25% equity interest in the Huntington field.

The transfers to EPUK of the EPUK Election Interests are being facilitated pursuant to the Transfer Documents. Iona is currently in administration and Iona's administrator, FTI Consulting, Inc., is currently reviewing these documents.

As at the Latest Practicable Date, the completion of the transfer of the EPUK Election Interests to EPUK has not yet occurred. The transfers will be completed upon the finalisation and execution of the aforementioned documents, which are in near final form. However, pursuant to the terms of the default provisions of the Huntington JOA and following Noreco and Iona's defaults thereunder, EPUK is currently entitled to 38.5% of the revenue from, and has a corresponding obligation for 38.5% of the costs associated with, the Huntington field. This represents EPUK's existing 25% equity interest in the Huntington field and EPUK's pro-rata beneficial interest in the EPUK Election Interests (13.5%), pending completion of the transfer process.

It is expected that the transfer process will be completed in the near future. Following the completion of the transfer of the EPUK Election Interests to EPUK, EPUK will hold a 38.5% legal and beneficial interest in the Huntington field.

8. Litigation and other proceedings

8.1 The Premier Group

Other than as set out below, there are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which Premier is aware) during the 12 months preceding the date of this document which may have, or have had in the recent past, significant effects on the financial position or profitability of the Premier Group.

Indonesian branch profits tax repayment claim

From 2011 the Indonesian Tax Authority has imposed a 20% branch profit tax rate to the Premier Group's operations in Indonesia. The Premier Group contests this imposition on the grounds that, under the Netherlands—Indonesia Tax Treaty, the Premier Group is entitled to a 10% branch profit tax rate. In accordance with due process in Indonesia, Premier has paid the additional tax of $127 million and is processing a claim for repayment using Indonesian tax dispute resolution and international tax treaty dispute procedures.

Provision of Mobile Drilling Rig Services—Eirik Raude Drilling Unit

The Premier Group and Noble Energy Falklands Limited entered into a contract dated 3 June 2014 with Ocean Rig Global Chartering Inc. (which contract was subsequently novated to OCR Falklands Drilling Inc.) for the drilling of wells offshore the Falkland Islands. The contract was terminated on 11 February 2016 and OCR Falklands Drilling Inc. has claimed a total of $62,895,562.59 from the Premier Group and Noble Energy Falklands Limited. The Premier Group and Noble Energy Falklands Limited contest this claim and intend to seek compensation from OCR Falklands Drilling Inc. for their associated losses.

8.2 The EPUK Group

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened, of which Premier is aware) during the 12 months preceding the date of this document which may have, or have had in the recent past, significant effects on the financial position or profitability of the EPUK Group.

9. Working capital statement

The Premier Group is of the opinion that it does not have sufficient working capital for its present requirements, which is, for at least the next 12 months from the date of this document ("**Working Capital Period**").

This is expected to be the case regardless of whether or not the Acquisition completes and is a result of a forecast breach of certain financial covenants in the Premier Group's principal financing arrangements based on the oil price scenarios detailed below (being the net debt to EBITDAX financial covenant in respect of the 12 month testing periods ending on 30 June 2016 and 31 December 2016 and the EBITDAX to net interest payable financial covenant in respect of the 12 month testing period ending 31 December 2016). But for such forecast covenant breach, the Premier Group would expect to have sufficient availability of liquidity throughout the Working Capital Period.

Timing

A breach of one or more financial covenant(s) would cause an event of default under the financing arrangements which contain such covenant(s), which could in turn trigger cross-defaults into the other financing arrangements of the Premier Group. This could result in the Premier Group's financing arrangements becoming repayable in October 2016 (following a covenant breach in respect of the testing period ending on 30 June 2016) or May 2017 (following a covenant breach in respect of the testing period ending on 31 December 2016) (or, in each case, on an earlier date if the relevant financial statements are available earlier).

Covenant Shortfall

As at 31 December 2015, the amount outstanding under the Premier Group's financing arrangements, which could be required to be repaid following a breach of financial covenant(s), was US$2,644 million.

In respect of the testing periods ending 30 June 2016 and 31 December 2016 respectively, the Premier Group's net debt to EBITDAX financial covenant requires that consolidated net debt must be lower than 4.75 times EBITDAX for the previous 12 months and the Premier Group's EBITDAX to net interest payable financial covenant requires that EBITDAX must be greater than 3.0 times net interest payable for the previous 12 months. Utilising an oil price of US$35 per barrel for 2016 and US$40 per barrel for 2017, adjusted for hedged oil prices where relevant (approximately 34% of 2016 liquids production and 32% of 2016 UK gas production is hedged at US$67.5 per barrel and 63p per therm respectively), and based upon the completion of the Acquisition by 30 June 2016, the Premier Group is currently forecasting a net debt to EBITDAX cover ratio of 5.4x times in respect of the financial covenant testing period ending 30 June 2016 (representing a shortfall of US$366 million) and 7.0x times in respect of the financial covenant testing period ending 31 December 2016 (representing a shortfall of US$1,074 million). In addition, the Premier Group is currently forecasting an EBITDAX to net interest payable cover ratio of 2.64x times in respect of the financial covenant testing period ending 31 December 2016 (representing a shortfall of US$67 million).

If the Acquisition does not complete the shortfall would be worse.

Action plan

The Premier Group continues to explore mitigating actions that can improve its forecast financial covenant position. The Acquisition itself, if completed, is expected to have a significant positive effect on the Premier Group's near term financial covenant calculation. However, at current oil prices, the completion of the Acquisition is unlikely, in itself, to fully mitigate any potential shortfall for the financial covenants in respect of the testing periods ending 30 June 2016 and 31 December 2016. As a result, the Premier Group's management has begun to actively explore certain mitigating actions and has entered into discussions with certain of its debt holders with a view to agreeing amendments to its financial covenants in order to give the Premier Group headroom for a further period, and financial advisers are assisting with this process. Although it is possible that the successful implementation of such mitigating actions could negate the need for a renegotiation of the financial covenants, the Premier Group's management believe that it is prudent to proceed on the basis that a combination of certain mitigating actions and a covenant renegotiation will be required and the Premier Group is therefore exploring the possible covenant renegotiation and mitigating actions in parallel.

The key mitigating actions include:

- phasing of expected capital expenditure and further savings in operating expenditure, without adverse effects to the Premier Group's ability to maintain production over the next 12 months (which may be achievable, subject to existing contractual obligations and commitments);
- entering into pre-paid oil sales agreements with third parties;
- portfolio management of non-core assets, monetising discovered resources as part of the Premier Group's existing strategy; and.
- sale and leaseback of existing facilities.

A number of these actions would need to be agreed with various debt holder groups.

The Premier Group's management reasonably expect that the covenant renegotiation with its debt holders and/or some of the other key mitigating actions above can be completed by the time the financial covenants for the testing period ending 30 June 2016 are required to be tested (when the financial statements and compliance certificate in respect of this period are delivered) or that a temporary waiver or amendment of the financial covenants would be agreed until the current renegotiation is finalised. Agreement of the terms of the renegotiation and/or a combination of some of the other mitigating actions listed above will need to occur to successfully avoid a breach of financial covenant in respect of the testing periods ending 30 June 2016 and 31 December 2016. However, all of these actions involve agreement from third parties and are therefore outside of the control of management.

Implications

If the re-negotiation with the debt holders and other key mitigation actions described above are not successful in avoiding a covenant breach in respect of either of the relevant testing periods then the Premier Group's financing arrangements could become repayable (as described above), which would be likely to result in administration or other insolvency proceedings. These could occur as early as October 2016 (following a covenant breach in respect of the testing period ending on 30 June 2016) or May 2017 (following a covenant breach in respect of the testing period ending on 31 December 2016) (or, in each case, on an earlier date if the relevant financial statements are available earlier).

As at the date of this document, approval for the Acquisition from the Premier Group's lending banks and US private placement noteholders has been received. The Directors have a reasonable expectation that the Premier Group can secure any necessary financial covenant modification or waiver and/or implement some of the mitigating actions described above so as to avoid a financial covenant breach during the Working Capital Period. If the Premier Group can achieve that, it will have sufficient working capital for its present purposes, that is, for at least the next 12 months from the date of this document.

10. Significant change

10.1 The Premier Group

There has been no significant change in the financial or trading position of the Premier Group since 31 December 2015, the date to which the last full year results of the Premier Group were prepared.

10.2 The EPUK Group

On 24 February 2016, a dividend of £60 million for the year ended 31 December 2015 was paid by EPUK to the Seller. Save for such dividend, there has been no significant change in the financial or trading position of the EPUK Group since 31 December 2015, the date to which the historical financial information set out in Part V was prepared.

11. Consents

11.1 PricewaterhouseCoopers LLP has given and not withdrawn its written consent to the inclusion in this document of its report on the historical financial information relating to the EPUK Group in the form and context in which it appears.

11.2 Deloitte LLP has given and not withdrawn its written consent to the inclusion in this document of its report on the unaudited pro forma financial information relating to the Enlarged Group in the form and context in which it appears.

11.3 DeGolyer and MacNaughton has given and not withdrawn its written consent to the inclusion in this document of its Competent Persons' Report in Part IV of this document and/or extracts therefrom and references thereto and to the inclusion of its name and references in the form and context in which they are included.

11.4 RISC (UK) Limited has given and not withdrawn its written consent to the inclusion in this document of its Competent Persons' Report in Part IV of this document and/or extracts therefrom and references thereto and to the inclusion of its name and references in the form and context in which they are included.

11.5 RBC Europe Limited has given and not withdrawn its written consent to the issue of this document and the references herein to its name in the form and context in which they appear.

12. Documents available for inspection

Copies of the following documents will be available for inspection during normal business hours on any weekday (Saturdays, Sundays and public holidays excepted) at the offices of Premier, 23 Lower Belgrave Street, London SW1 0NR up to and including the date of the General Meeting and for the duration of the General Meeting:

(A) the Articles of Association;

(B) the audited consolidated accounts of the Premier Group for each of the periods ended 31 December 2015, 31 December 2014 and 31 December 2013;

(C) the reports from PricewaterhouseCoopers LLP and Deloitte LLP set outs in Parts V and VI of this document;

(D) the Competent Persons' Reports, as set out in Part IV of this document;

(E) the written consents referred to in paragraph 11 above;

(F) the Sale and Purchase Agreement; and

(G) a copy of this document and the Form of Proxy.

PART VIII—DOCUMENTS INCORPORATED BY REFERENCE

The table below sets out the various information incorporated by reference into this document, so as to provide the information required pursuant to the Listing Rules. These documents are also available at www.premier-oil.com.

Document	Information incorporated by reference	Page number in this document
Premier 2015 Annual Report . . .	Details of executive Directors' service contracts and non-executive Directors' letters of appointment providing for benefits upon termination of employment (pages 96–98)	207
	Details of the Directors' interests in equity pool points and share awards under the LTIP Scheme, share awards under the Deferred Bonus Share Plan, share options under the SAYE Plan 2009 and share allocations under the Share Incentive Plan for the financial year ended 31 December 2015 (pages 86–114)	208
	Details of related party transactions that Premier has entered into for the financial year ended 31 December 2015 (page 162)	209
	Details of the net assets of Premier for the financial year ended 31 December 2015 (page 134)	205
Premier 2014 Annual Report . . .	Details of related party transactions that Premier has entered into for the financial year ended 31 December 2014 (page 168)	209
Premier 2013 Annual Report . . .	Details of related party transactions that Premier has entered into for the financial year ended 31 December 2013 (page 148)	209

The documents incorporated by reference in this document have been incorporated in compliance with Listing Rules 13.1.1 and 13.1.6. The information set out above is incorporated by reference in this document and forms part of this document, and is available as indicated. Information that is itself incorporated by reference or cross-referred to in these documents is not incorporated by reference into this document. Except as set out above, no other portions of these documents are incorporated by reference into this document.

PART IX—DEFINITIONS AND GLOSSARY

2009 Long Term Incentive Plan	means the 2009 Long Term Incentive Plan approved by Shareholders on 29 May 2009;
Acquisition	means the proposed acquisition of the EPUK Group, details of which are set out in Part III of this document;
Acquisition Agreements	means all agreements relating to the acquisition of the EPUK Group, including the agreements summarised in Part III of this document;
Additional Restructuring Indemnity Deed	has the meaning given to it in section 2 of Part III of this document;
Arran	means the hydrocarbon accumulation commonly known as the Arran unitised area, which underlies Blocks 23/16b, 23/11a F and 23/16c of the UKCS pursuant to Licences P359, P1051 and P1720;
Articles or Articles of Association	means the articles of association of Premier in force from time to time;
Assets	means the assets of the EPUK Group, as described in section 3 of Part I of this document;
Asset Title Warranty Claims	has the meaning given to it in section 1 of Part III of this document;
Austen	means the hydrocarbon accumulation commonly known as the Austen field which underlies Block 30/13b of the UKCS pursuant to licence P1823;
Babbage	means the hydrocarbon accumulation commonly known as the Babbage field which underlies Block 48/2a of the UKCS pursuant to licence P456;
bbl	means the unit of measurement for crude oil and petroleum products known as a barrel;
Bcf	means billion cubic feet;
Bilateral Decommissioning Security Agreement	has the meaning given to it in section 1 of Part III of this document;
boe	means barrels of oil equivalent;
bopd	means barrels of oil per day;
Board or Board of Directors	means the Directors;
Caister	means the hydrocarbon accumulation commonly known as the Caister field which underlies Block 44/23a AREAA of the UKCS pursuant to licence P452;
CMS	means the CMS facilities comprising two offshore platforms, a 16 inch nominal diameter pipeline for the transportation of natural gas between the platforms, a 26 inch nominal diameter pipeline for the transportation of natural gas off the platforms, other offshore facilities associated therewith and other property acquired or held for use in connection with the operations;
CNS	means the UK Central North Sea;
Companies Act 2006	means the Companies Act of England and Wales 2006, as amended from time to time;
Competent Persons	means DeGolyer and MacNaughton and RISC (UK) Limited;
Competent Persons' Reports	means the reports by DeGolyer and MacNaughton and RISC (UK) Limited contained in Part IV of this document;

Completion	means completion of the Acquisition;
Consideration	has the meaning given to it in section 1 of Part III of this document;
CREST	means the paperless settlement procedure operated by Euroclear enabling system securities to be evidenced otherwise than by certificates and transferred otherwise than by written instrument;
CREST Manual	means the rules governing the operation of CREST as published by Euroclear;
CREST Proxy Instruction	means a proxy appointment or instructions made via CREST, authenticated in accordance with Euroclear's specifications and containing the information set out in the CREST Manual;
D&M CPR	means the Competent Persons Report prepared by DeGolyer and MacNaughton contained in Part IV of this document;
Decommissioning Costs	has the meaning given to it in section 3 of Part III of this document;
Decommissioning Liability Agreement	has the meaning given to it in section 3 of Part III of this document;
Deferred Bonus Share Plan	means the Deferred Bonus Plan 2006 approved by the Remuneration Committee of the Board on 19 October 2006;
Deposit	has the meaning given to it in section 1 of Part III of this document;
Directors	means the directors of Premier whose names are set out on page 3 of this document;
Disclosure Rules and Transparency Rules	means the disclosure rules and transparency rules made under Part VI of FSMA (as set out in the FCA Handbook), as amended from time to time;
Dividend Condition	has the meaning given to it in section 1 of Part III of this document;
E&E	has the meaning given to it in Part V of this document;
EBITDAX	means consolidated earnings before interest, depreciation, amortisation, tax and exploration expenditure adjusted by certain items as defined in the Premier Group's financing agreements;
Elgin-Franklin	means the hydrocarbon accumulation commonly known as the Elgin-Franklin unitised area, which underlies Blocks 22/30b ELGN, 29/5b, 22/30c, 29/5c and 22/29b of the UKCS pursuant to licences P188, P362, P666 and P2068;
Enlarged Group	means the Premier Group, following Completion;
E.ON	means E.ON SE;
EPUK	means E.ON E&P UK Limited;
EPUK Company	means any member of the EPUK Group;
EPUK Group	means Newco, EPUK, E.ON E&P Energy Trading Limited and E.ON E&P UK EU Limited;
EPUK Ordinary Shares	means ordinary shares with a nominal value of £2370 each in the capital of EPUK;
ETS	means the "Esmond Transportation Pipeline" comprising the section of the 24 inch diameter pipeline extending from the Trent and Tyne fields to a gas processing terminal at Bacton in the County of Norfolk;
Euroclear	means Euroclear UK & Ireland Limited, the operator of CREST;
FCA	means the Financial Conduct Authority of the United Kingdom;

Financial Information Table . . .	has the meaning given to it in Part V of this document;
Form of Proxy	means the form of proxy for use at the General Meeting which accompanies this document;
FPS	means the "Forties Pipeline System" connecting the GAEL Northern pipeline to the shore;
FPSO	means floating production, storage and offloading vessel;
FSMA	means the Financial Services and Markets Act 2000, as amended from time to time;
Fundamental Claims	has the meaning given to it in section 1 of Part III of this document;
GAEL Northern	means the "Northern Spurline" comprising a 24 inch nominal diameter liquids pipeline connecting GAEL Southern to the FPS pipeline;
GAEL Southern	means the "Southern Spurline" comprising a 24 inch nominal diameter liquids pipeline connecting Elgin-Franklin to the GAEL Northern pipeline;
General Meeting or GM	means the general meeting of the Company to be convened pursuant to the notice set out at the end of this document (including any adjournment thereof);
General Claims	has the meaning given to it in section 1 of Part III of this document;
Glenelg	means the hydrocarbon accumulation commonly known as the Glenelg field which underlies Block 29/4d of the UKCS pursuant to licence P752;
Guarantee Warranty Claims . . .	has the meaning given to it in section 1 of Part III of this document;
Hunter	means the hydrocarbon accumulation commonly known as the Hunter field which underlies Block 44/23e D of the UKCS pursuant to licence P452;
Huntington	means the hydrocarbon accumulation commonly known as the Huntington field which underlies Block 22/14b of the UKCS pursuant to licence P1114;
Huntington Joint Operating Agreement	means the Joint Operating Agreement for Huntington dated 3 April 2006, the current parties being Premier Oil UK Limited, EPUK, Iona UK Huntington Limited and Noreco Oil (UK) Limited;
IFRS	means International Financial Reporting Standards, as adopted by the European Union;
Johnston	means the hydrocarbon accumulation commonly known as the Johnston unitised area which underlies Blocks 43/26a RESID and 43/27a of the UKCS pursuant to licences P380 and P686;
kboepd	means thousand barrels of oil equivalent per day;
Latest Practicable Date	means 6 April 2016, being the latest practicable date prior to the publication of this document;
Lender Condition	has the meaning given to it in section 1 of Part III of this document;
Licence Interest(s)	has the meaning given to it in section 1 of Part III of this document;
Listing Rules	means the Listing Rules of the UKLA;
Locked Box Claim	has the meaning given to it in section 1 of Part III of this document;
London Stock Exchange	means London Stock Exchange plc or its successor(s);

Merganser	means the hydrocarbon accumulation commonly known as the Merganser unitised area which underlies Blocks 22/25a (Merg) and 22/30a F of the UKCS pursuant to licences P111 and P012;
Minke	means the hydrocarbon accumulation commonly known as the Minke field which underlies Block 44/24a of the UKCS pursuant to licence P611;
mmboe	means million barrels of oil equivalent;
mmscfd	means million standard cubic feet per day;
Newco	means a holding company to be incorporated by the Seller, which may, by way of a share swap, be inserted between the Seller and EPUK;
OGA Condition	has the meaning given to it in section 1 of Part III of this document;
OilExco Acquisition	means Premier's acquisition of Oileco North Sea Limited that completed on 21 May 2009;
Orca	means the hydrocarbon accumulation commonly known as the Orca field of which 55% underlies Block 44/24a, 44/29b, 44/30a of the UKCS pursuant to licence P454 (the remaining 45% underlies the Dutch block D15b);
Ordinary Shares	ordinary shares with a nominal value of 12.5 pence each in the capital of Premier;
pounds sterling or £	means the lawful currency of the United Kingdom;
PRA	means the Prudential Regulation Authority of the United Kingdom;
Premier	means Premier Oil plc, a company incorporated in Scotland with registered number SC234781, whose registered office is at 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN;
Premier Group	means Premier together with its subsidiaries and subsidiary undertakings from time to time;
Premier 2013 Annual Report	means the Premier Oil plc annual report and financial statement for the year ended 31 December 2013;
Premier 2014 Annual Report	means the Premier Oil plc annual report and financial statement for the year ended 31 December 2014;
Premier 2015 Annual Report	means the Premier Oil plc annual report and financial statement for the year ended 31 December 2015;
Pro forma financial information	has the meaning given to it in Part VI of this document;
Prospectus Directive Regulation	has the meaning given to it in Part VI of this document;
Prospectus Rules	means the prospectus rules made under Part VI of the FSMA (as set out in the FCA handbook), as amended from time to time;
Purchaser	means Premier Oil Group Limited, a company incorporated in Scotland (registered number SC017829) and whose registered office is at 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh, EH1 2EN;
Ravenspurn North	means the hydrocarbon accumulation commonly known as the Ravenspurn North unitised area which underlies Blocks 42/30a, 43/26a RAVEA and 43/26a RAVEB of the UKCS pursuant to licences P001 and P380;
RBC or RBC Capital Markets	means RBC Europe Limited, of Riverbank House, 2 Swan Lance, London, EC4R 3BF;
Registrar	means Capita Asset Services, of The Registry, 34 Beckenham Road, Beckenham, Kent, BR3 4TU;

Relevant Decommissioning Relief	has the meaning given to it in section 3 of Part III of this document;
Resolution	means the resolution to be proposed at the General Meeting;
Reverse Condition	has the meaning given in section 1 of Part III of this document;
RISC CPR	means the Competent Persons Report prepared by RISC (UK) Limited contained in Part IV of this document;
Rita	means the hydrocarbon accumulation commonly known as the Rita unitised area which underlies Blocks 44/21b and 44/22c of the UKCS pursuant to licences P766 and P771;
Sale and Purchase Agreement	has the meaning given to it in section 1 of Part III of this document;
SAYE Plan 2009	means the Premier Oil plc Saving Related Share Option Scheme 2009 approved by Shareholders on 29 May 2009;
Scoter	means the hydrocarbon accumulation commonly known as the Scoter unitised area which underlies Blocks 22/30a F and 23/26d A of the UKCS pursuant to licences P012 and P264;
SEAL	means the "Shearwater Elgin Area Line" comprising a natural gas pipeline connecting Elgin-Franklin to the terminal, plant and equipment at Bacton in the County of Norfolk, England;
Seller	means E.ON Beteiligungen GmbH, a company incorporated in Germany (registered number HRB33888 in the commercial registry of the local court of Düsseldorf) and whose registered office is at E.ON-Platz 1, 40479 Düsseldorf, Germany;
Seller Group	means the Seller, Uniper AG and their affiliates from time to time, excluding the EPUK Group;
Share Incentive Plan	means the Premier Oil plc Share Incentive Plan approved by Shareholders on 2 April 2001;
Shareholder	means a holder of any Ordinary Shares;
Shareholder Condition	has the meaning given to it in section 1 of Part III of this document;
SPA Conditions	has the meaning given to it in section 1 of Part III of this document;
Tax Claims	has the meaning given to it in section 1 of Part III of this document;
Tax Deed	has the meaning given to it in section 1 of Part III of this document;
Tcf	means trillion cubic feet;
therm	means the unit of heat energy;
UKCS	UK Continental Shelf;
UK Listing Authority or UKLA	means the FCA acting in its capacity as the competent authority for the purposes of Part VI of FSMA;
United Kingdom or UK	means the United Kingdom of Great Britain and Northern Ireland;
United States or US	means the United States of America;
US$, US Dollars or $	means the lawful currency of the United States; and
Working Capital Period	has the meaning given to it in Part VII of this document.

NOTICE OF GENERAL MEETING

PREMIER OIL PLC

(Registered in Scotland with registered number SC234781)

NOTICE IS HEREBY GIVEN that a General Meeting of Premier Oil plc (the "**Company**") will be held at 157-197 Buckingham Palace Road, London SW1W 9SP on Monday 25 April 2016 at 10.00 am for the purposes of considering and, if thought fit, passing the resolution set out below which will be proposed as an ordinary resolution of the Company (meaning that for the resolution to be passed, more than half the votes cast must be in favour of it). Words and expressions defined in the circular of the Company dated 7 April 2016 (a copy of which has been produced to the meeting and initialled by the chairman of the meeting for the purpose of identification only (the "**Circular**")) shall, unless otherwise defined herein, have the same meaning in this Notice.

1. THAT the proposed acquisition by the Purchaser (or any other member of the Premier Group) of the EPUK Group on the terms and subject to the conditions of the Acquisition Agreements and all agreements and arrangements made or entered into, or which may in the future be made or entered into, by any member or members of the Premier Group in connection with, or which are ancillary to, the acquisition (the "**Acquisition**"), be and are hereby approved and that the directors (or any duly constituted committee thereof) of the Company be and are hereby authorised to:

   (A) take all such steps, execute all such agreements and make such arrangements as may seem to them necessary, desirable, expedient or appropriate for the purpose of giving effect to, or otherwise in connection with, the Acquisition; and

   (B) agree and make such modifications, variations, revisions, waivers or amendments in relation to any of the foregoing (provided that such modifications, variations, revisions, waivers or amendments are not material) as they may in their absolute discretion deem necessary, desirable, expedient or appropriate.

By order of the Board

Rachel Rickard
Company Secretary
7 April 2016

Registered Office
4th Floor, Saltire Court
20 Castle Terrace
Edinburgh EH1 2EN

Notes:

Attending the General Meeting and asking questions

To be entitled to attend and vote at the General Meeting (the "**Meeting**") (and for the purpose of the determination by the Company of the votes they may cast), shareholders must be registered in the Register of Members of the Company at close of business on Thursday 21 April 2016 (or, in the event of any adjournment, close of business on the date which is two days before the time of the adjourned Meeting). Changes to the Register of Members after the relevant deadline shall be disregarded in determining the rights of any person to attend and vote at the Meeting.

Any member attending the Meeting has the right to ask questions. The Company must cause to be answered any such question relating to the business being dealt with at the Meeting but no such answer need be given if (a) to do so would involve the disclosure of confidential information, (b) the answer has already been given on a website in the form of an answer to a question, or (c) it is undesirable in the interests of the Company or the good order of the Meeting that the question be answered.

Appointing a proxy

Shareholders are entitled to attend, speak and vote at the Meeting and may appoint a proxy to exercise all or any of their rights to attend and to speak and vote on their behalf at the Meeting. A shareholder may appoint more than one proxy in relation to the Meeting provided that each proxy is appointed to exercise the rights attached to a different share or shares held by that shareholder.

The Articles of Association provide that:

(i) if a member appoints more than one proxy and the proxy forms appointing those proxies would give those proxies the apparent right to exercise votes on behalf of the member in a general meeting over more shares than are held by the member, then each of those proxy forms will be invalid and none of the proxies so appointed will be entitled to attend, speak or vote at the relevant general meeting; and

(ii) if a member submits more than one valid proxy appointment in respect of the same share, the appointment received last (regardless of its date or the date on which it is signed) before the latest time for the receipt of proxies will take precedence. If it is not possible to determine the order of receipt, none of the forms will be treated as valid.

A proxy need not be a member of the Company. A vote withheld is not a vote in law, which means that the vote will not be counted in the proportion of votes "for" and "against" a Resolution. Where a proxy has been appointed by a member, if such member does not give any instructions in relation to that Resolution that member should note that their proxy will have authority to vote on the Resolution as he/she thinks fit.

Any power of attorney or any other authority under which the form of proxy is signed (or a duly certified copy of such power or authority) must be included with the proxy form. In the case of a member which is a company, the form of proxy should either be sealed by that company or signed by someone authorised to sign it.

A form of proxy which may be used to make such appointment and give proxy instructions accompanies this notice. If you do not have a form of proxy and believe that you should have one, or if you require additional forms, please contact Capita Asset Services on 0871 664 0300 if calling from within the UK. Calls cost 12p per minute plus your phone company's access charge. If you are outside the United Kingdom, please call +44 371 664 0300. Calls outside the United Kingdom will be charged at the applicable international rate. Lines are open between 09.00am and 5.30pm, Monday to Friday excluding public holidays in England and Wales.

To be valid, forms of proxy must be lodged by one of the following methods by 10.00 am on Thursday 21 April 2016:

- in hard copy form by post to the Company's Registrar at Capita Asset Services, PXS, 34 Beckenham Road, Beckenham, BR3 4TU; or
- in the case of CREST members or CREST Personal Members, by utilising the CREST electronic proxy appointment service in accordance with the procedures set out below; or
- by submitting your proxy appointment electronically via the internet. Instructions on how to do this can be found on the form of proxy.

The return of a completed form of proxy or any CREST Proxy Instruction (as described below) will not prevent a shareholder attending the Meeting and voting in person if he/she wishes to do so.

CREST members

CREST members who wish to appoint a proxy or proxies through the CREST electronic proxy appointment service may do so by utilising the procedures described in the CREST Manual (available to members at www.euroclear.com). CREST Personal Members or other CREST sponsored members, and those CREST members who have appointed a voting service provider(s), should refer to their CREST sponsor or voting service provider(s), who will be able to take the appropriate action on their behalf.

In order for a proxy appointment or instruction made using the CREST service to be valid, the appropriate CREST message (a "CREST Proxy Instruction") must be properly authenticated in accordance with Euroclear UK & Ireland Limited's specifications, and must contain the information required for such instruction, as described in the CREST Manual. The message, regardless of whether it constitutes the appointment of a proxy or is an amendment to the instruction given to a previously appointed proxy must, in order to be valid, be transmitted so as to be received by Capita Asset Services (ID: RA10) by 10.00 am on Thursday 21 April 2016. For this purpose, the time of receipt will be taken to be the time (as determined by the timestamp applied to the message by the CREST Application Host) from which the issuer's agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST. After this time any change of instructions to proxies appointed through CREST should be communicated to the appointee through other means.

CREST members and, where applicable, their CREST sponsors, or voting service providers should note that Euroclear UK & Ireland Limited does not make available special procedures in CREST for any particular message. Normal system timings and limitations will, therefore, apply in relation to the input of CREST Proxy Instructions. It is the responsibility of the CREST member concerned to take (or, if the CREST member is a CREST personal member, or sponsored member, or has appointed a voting service provider, to procure that their CREST sponsor or voting service provider(s) take(s)) such action as shall be necessary to ensure that a message is transmitted by means of the CREST system by any particular time. In this connection, CREST members and, where applicable, their CREST sponsors or voting system providers are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings.

The Company may treat an instruction as invalid in the circumstances set out in regulation 35(5)(a) of the Uncertificated Securities Regulations 2001.

Nominated persons and information rights

Any person to whom this notice is sent who is a person nominated under Section 146 of the Companies Act 2006 to enjoy information rights (a "**Nominated Person**") may, under an agreement between him/her and the shareholder by whom he/she was nominated, have a right to be appointed (or to have someone else appointed) as a proxy for the Meeting.

If a Nominated Person has no such proxy appointment right or does not wish to exercise it, he/she may, under any such agreement, have a right to give instructions to the shareholder as to the exercise of voting rights.

However, the statement of the rights of shareholders in relation to the appointment of proxies described above does not apply to Nominated Persons. The rights described in those paragraphs can only be exercised by shareholders of the Company.

Joint holders and corporate representatives

In the case of joint holders, where more than one of the joint holders purports to appoint a proxy, only the appointment submitted by the most senior holder will be accepted. Seniority is determined by the order in which the names of the joint holders appear in the Company's Register of Members in respect of the joint holding (the first-named being the most senior).

Any corporation which is a member can appoint one or more corporate representatives who may exercise on its behalf all of its powers as a member provided that they do not do so in relation to the same shares.

Share capital

As at 6 April 2016 (being the last business date prior to the publication of this Notice) the Company's issued Ordinary share capital consisted of 510,811,061 Ordinary Shares, carrying one vote each. Therefore the total voting rights in the Company as at 6 April 2016 were 510,811,061.

Queries and access to information

Except as provided above, members who have general queries about the Meeting should use the following means of communication (no other methods of communication will be accepted): calling Capita Asset Services' shareholder helpline on 0871 664 0300. Calls cost 12p per minute plus your phone company's access charge. If you are outside the United Kingdom, please call +44 371 664 0300. Calls outside the United Kingdom will be charged at the applicable international rate. Lines are open between 09.00am and 5.30pm, Monday to Friday excluding public holidays in England and Wales. You may not use any electronic address provided either (a) in this Notice of General Meeting, or (b) in any related documents (including the Chairman's letter and form of proxy) to communicate with the Company for any purposes other than those expressly stated.

If you would like to request a copy of this notice in an alternative format such as in large print or audio, please contact the Company's Registrar, Capita Asset Services, on 0871 664 0300. Calls cost 12p per minute plus your phone company's access charge. If you are outside the United Kingdom, please call +44 371 664 0300. Calls outside the United Kingdom will be charged at the applicable international rate. Lines are open between 9.00am to 5.30pm, Monday to Friday excluding public holidays in England and Wales.

A copy of this notice, and other information required by Section 311A of the Companies Act 2006, can be found at www.premier-oil.com.