Reject Centrica's opportunistic offer

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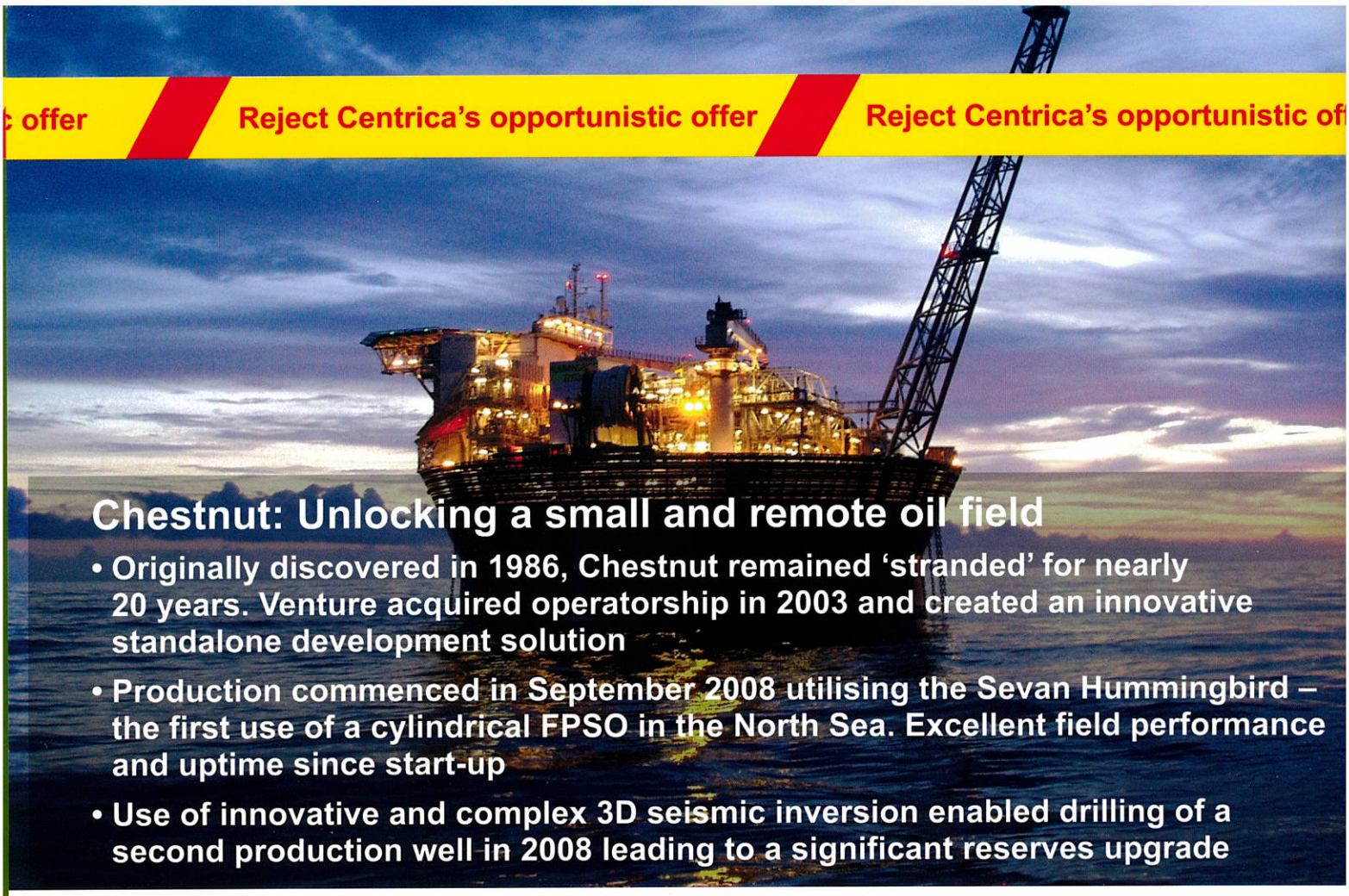
Independent valuation of Venture's assets

Venture is worth substantially more than 845p per share

VENTURE PRODUCTION plc



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Venture is worth substantially more than 845p per share

Independent RISC valuation of Venture's assets

Equivalent to between 1,066p and 1,385p per share

Even the 1,066p per share base case is more than 25% higher than Centrica's Offer

Centrica is trying to buy Venture on the cheap

Letter from your Chairman

Do not lose sight of improving fundamentals

Dear Shareholder

Centrica's Offer substantially undervalues Venture

I wrote to you on 24 July 2009 setting out the six principal reasons why you should reject Centrica's Offer. I said that Centrica is trying to buy Venture on the cheap, that Centrica's Offer substantially undervalues Venture and that Centrica should pay a higher price for control of your Company.

Resource Investment Strategy Consultants (RISC), a leading independent petroleum consultancy firm, were engaged to conduct an independent asset valuation of all of Venture's reserves and contingent and prospective resources. That valuation has now been presented to the Board. It supports clearly your Board's view that Centrica's Offer substantially undervalues Venture. The letter summarising the RISC valuation and the full report are included after this letter to you.

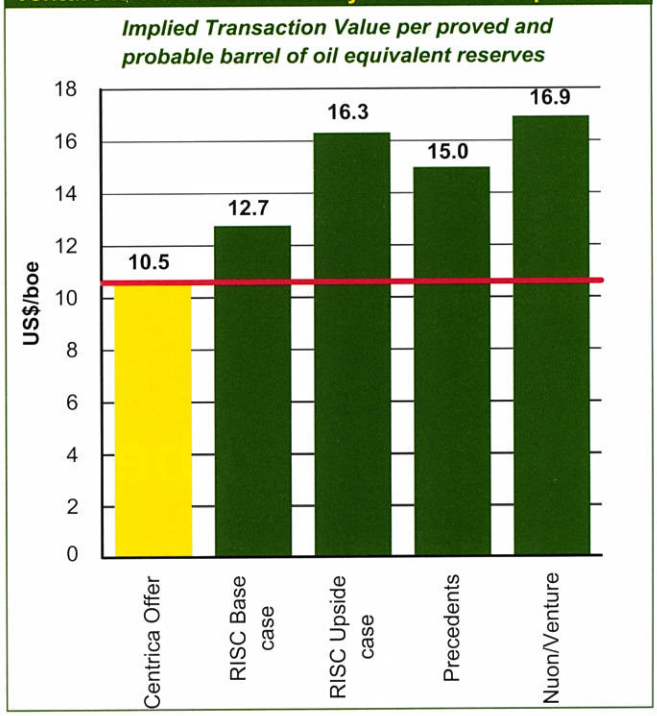
The asset valuation attributes no value for the scarcity value of Venture nor the going concern value of a proven organisational capability, nor the strategic benefits to Centrica that Venture brings.

Venture valued at up to 1,385p per share

RISC concludes that the value of Venture's assets is between £1,910 million in the base case and £2,442 million in the upside case. This is equivalent to between 1,066p per share and 1,385p per share on a fully diluted basis after adjusting for the net debt as at 30 June 2009. RISC explains their base and upside cases on page 3 of their report. RISC's range of values for Venture is equivalent to US$12.7 – 16.3/boe compared to US$10.5/boe under Centrica's Offer. **Even the 1,066p per share base case is more than 25% higher than Centrica's Offer.**

There is no reason why you should lose so much value. Venture has the critical mass, the expertise and the resources to deliver this value for you, Venture's shareholders. This is not the moment to give Venture away cheaply.

Venture is worth substantially more than 845p



Equity and energy markets have continued to strengthen

The share prices of Venture's peers have continued to rise. The document sent to you on 24 July 2009, showed that Centrica's Offer represented only a minimal premium to the price of Venture's shares adjusting for the share price performance of Venture's UK E&P peer group since the start of the Offer Period on 18 March 2009. The share prices of all Venture's peers have increased further since 10 July 2009, by an average of 17.2%. **Centrica's Offer is now at a 9% discount to Venture's share price** adjusted on the same basis.

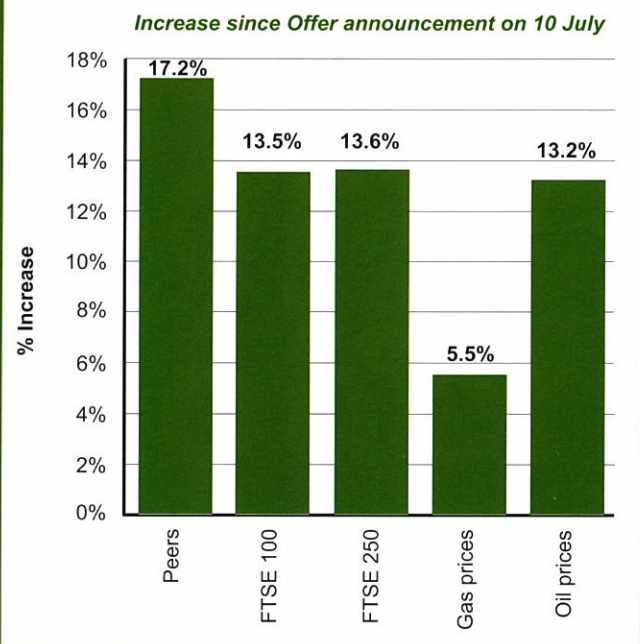
Both the FTSE 100 and FTSE 250 indices are up significantly. Since Centrica's Offer, the FTSE 100 index has increased by 13.5%, from 4,127 to 4,682. The FTSE 250 index has increased by 13.6%, from 7,184 to 8,158.

Reject Centrica's opportunistic offer

Do not lose sight of improving fundamentals

Gas prices have continued to rise. In the document sent to you on 24 July 2009, I pointed out that the average forecast gas price for 2011 was 110% higher than the spot price[1] on the date of Centrica's Offer. The 2011 price has subsequently **increased by a further 5.5%,** from 54.1p/therm to 57.0p/therm and is now **122% higher than the spot price on the date of Centrica's Offer.**

Equity and energy markets have continued to strengthen



Oil prices have continued to rise. In the document sent to you on 24 July 2009, I pointed out that forecast oil prices had strengthened appreciably between the start of the Offer Period and the date of Centrica's Offer. During this period forward prices for July 2011 had increased by 14.0% from US$62.9/bbl to US$71.7/bbl. **Forward prices for July 2011 have now increased yet further, by 13.2%, from US$71.7/bbl to US$81.2/bbl.**

With medium term rising production, Venture is ideally positioned to benefit from rising prices

(1) NBP Day Ahead price

Reject Centrica's Offer

Your Board, which has been so advised by Rothschild, Lambert Energy, Oriel and UBS Investment Bank, unanimously concluded that Centrica's Offer should be rejected. In providing advice to the Board, Rothschild, Lambert Energy, Oriel and UBS Investment Bank have each taken into account the Board's commercial assessments. Your Directors will not be accepting the Offer in respect of their own beneficial holdings.

Rothschild is acting as the independent financial adviser to Venture for the purposes of providing independent advice to the Venture Board in connection with the Offer under Rule 3 of the City Code.

Venture is worth substantially more than 845p per share

The way to reject this offer is to take no action

Do not sign any document which Centrica or its advisers send you

Yours sincerely,

John Morgan, Chairman
4 August 2009

Venture is worth substantially more than 845p per share

Independent RISC valuation of Venture's assets

Equivalent to between 1,066p and 1,385p per share

Even the 1,066p per share base case is more than 25% higher than Centrica's Offer

Centrica is trying to buy Venture on the cheap

Reject Centrica's opportunistic offer

Centrica's offer does not reflect Venture's true value

Reject the opportunistic offer

Do not complete any form of acceptance

Independent RISC valuation of Venture's assets

RISC (UK) Limited
Golden Cross House
8 Duncannon Street
London
WC2N 4JF

31st July 2009

The Directors

Venture Production plc
Kings Close
62 Huntly Street
Aberdeen
AB10 1RS

N M Rothschild & Sons Limited
New Court
St. Swithin's Lane
London
EC4P 4DU

Dear Sirs,

Venture Production plc ("Venture") appointed RISC (UK) Limited ("RISC") to act as Independent Valuer of Venture's upstream petroleum assets. In response to this appointment, RISC has prepared the attached report, "Independent Valuation of the Petroleum Assets of Venture Production plc", dated July 2009.

1. Professional Qualifications

RISC is an independent consultancy specialising in the provision of impartial advice to companies associated with the oil and gas industry. 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.

2. Valuation Approach

RISC has reviewed and valued the upstream petroleum assets of Venture predominately located in the UK and Dutch sectors of the North Sea. RISC evaluated over 80% of Venture's assets (on a 2P reserves basis) while Venture's in-house estimates were utilised for the remainder of the assets.

RISC has prepared base and upside scenarios for the purpose of this valuation. The base scenario is founded upon our review of 2P reserves and risked best estimate resources. The upside scenario comprises a number of selected credible upside opportunities that we consider represents the scope for reserves growth within the existing portfolio in the medium term and are consistent with historical reserves growth (excluding acquisitions/disposals).

For fields to which Venture assigns reserves, RISC has prepared production, cost and product price projections. The projections have been valued using a discounted cash flow analysis at a discount rate of 8% real / 10% nominal.

Volumes classified as contingent and prospective resources have been valued using unit value methods. For the Trinidadian assets, we have adopted the book valuation carried by Venture.

The following table summarises the results of our assessment.

Value of Venture's Petroleum Assets £million	**Base Scenario**	**Upside Scenario**
Reserves [1]	1,742	2,209
Contingent and Prospective Resources	160	225
Other Assets [2]	8	8
Total Asset Value	**1,910**	**2,442**

Commodity prices utilised in this valuation have been based on the following price assumptions. Our oil price assumption is based on the July 2009 forward curve in real terms to 2014, then held constant in real terms. Gas sales price assumptions (NBP for UK; TTF for The Netherlands) are based on the July 2009 forward curve, as published by Heren, in real terms to 2014, then held constant in real terms.

Commodity Prices	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Brent Oil (Real US$/bbl)	66.5	71.5	75.2	77.7	80.5	82.9	82.9	82.9
NBP Gas (Real pence/therm)	41.8	46.1	57.0	61.0	65.0	68.0	68.0	68.0

Other key economic assumptions include a constant inflation rate of 2% per annum and a constant exchange rate of US$1.60/£.

3. Valuation of Petroleum Assets

Based on the above table, RISC assesses the value of Venture's petroleum assets to be in the range of £1,900 million to £2,450 million as at 1 July 2009.

---

[1] Reserves value includes £11.7 million for Venture's 40% holding in Ten Degrees North Energy Limited ("TDN") which holds the Trinidad asset. The TDN asset value is a Venture management estimate based on current book value.

[2] Other Assets includes £14.1 million for Venture's 49.9% holding in North Sea Infrastructure Partners Limited ("NSIP"), £17.4 million for the commodity and foreign exchange hedge positions and -£23.5 million being the assessment of the net present value of Venture's corporate overhead costs. The NSIP asset is a Venture management estimate based on current book value.

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.

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, regulations that apply to these assets. 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.

4. Sensitivities to the Valuation of Petroleum Assets

Sensitivities to the base scenario reserves valuation of £1,742 million to changes in discount rate, capital costs, operating costs and commodity prices are presented in the following table.

Sensitivity Values (£million)	**Decrease**	**Base Scenario**	**Increase**
Discount rate: Low 12%, High 8%	-168	1,742	+200
Capex: Low +20%, High -20%	-107	1,742	+107
Opex: Low +20%, High -20%	-142	1,742	+142
Oil Price: Low-20%, High +20%	-151	1,742	+151
Gas Price: Low -20%, High +20%	-323	1,742	+323
Oil and Gas Price: Low -20%, High +20%	-474	1,742	+474

RISC has given its consent and has not withdrawn its consent to the publication of this report.

For and on behalf of
RISC (UK) Limited

P W Taylor

Director

Integrity Experience Advice

RISC

Independent Valuation of the Petroleum Assets of Venture Production plc

July 2009

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1 EXECUTIVE SUMMARY

1.1 ASSET OVERVIEW

Venture has an extensive portfolio comprising interests in 21 producing fields, 27 discovered fields, many of which are under appraisal/development, and exploration acreage, predominantly located in the UK and Dutch sectors of the North Sea. Venture also holds a shareholding in a company with producing interests offshore Trinidad. Total production in 1st half of 2009 averaged 52.5 Mboe/d (Venture share) excluding Trinidad.

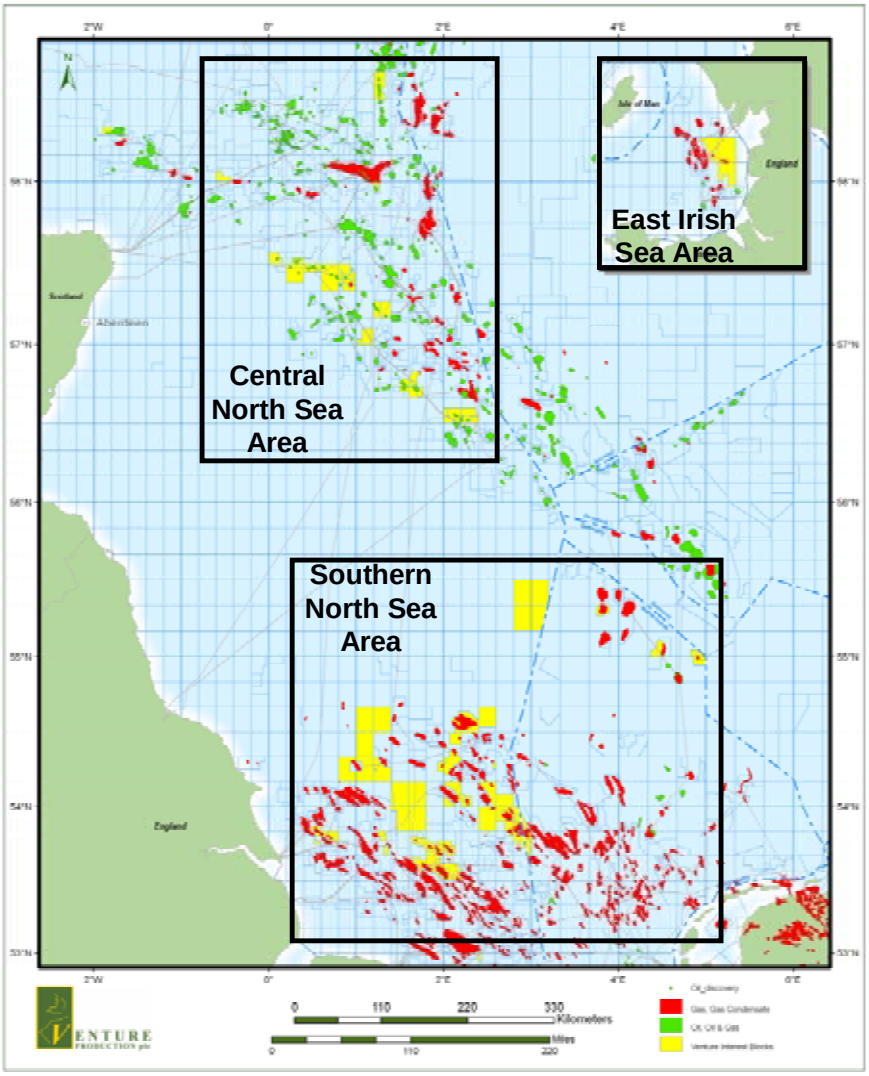

Figure 1 Asset Locations

RISC evaluated over 80% of Venture's assets (on a 2P reserves basis) while Venture's in-house estimates were utilised for the remainder of the assets. In carrying out its evaluation, RISC has reviewed and where appropriate modified the work of other evaluators, including field operators and other consultants.

1.2 RESERVES AND RESOURCES

Venture prepares its own reserves estimates at year end and periodically conducts independent assessments by other parties. The following chart shows Venture's historical reserves estimates and the increasing significance of the gas assets.

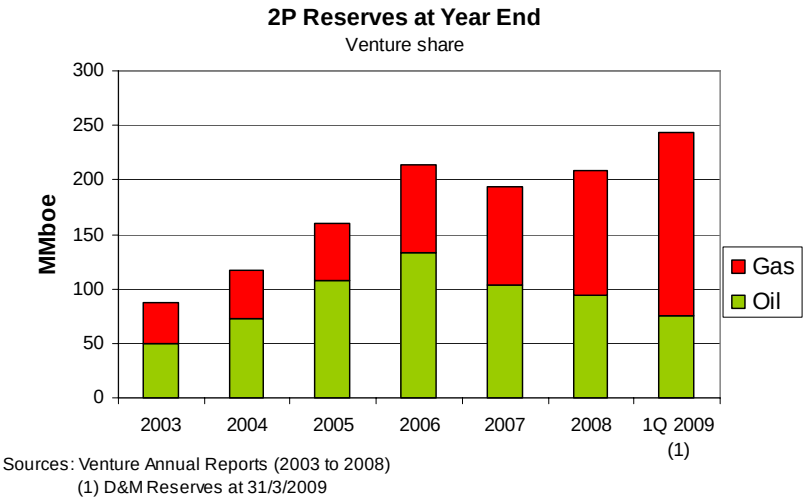

Figure 2 Historic Reserves Disclosures 2003 -2008

This reserves growth has been derived from acquisitions as well as additions and revisions. Additions are typically derived from Venture's exploration and appraisal portfolio while revisions typically reflect changes in reserve estimates as a result of new information in existing fields.

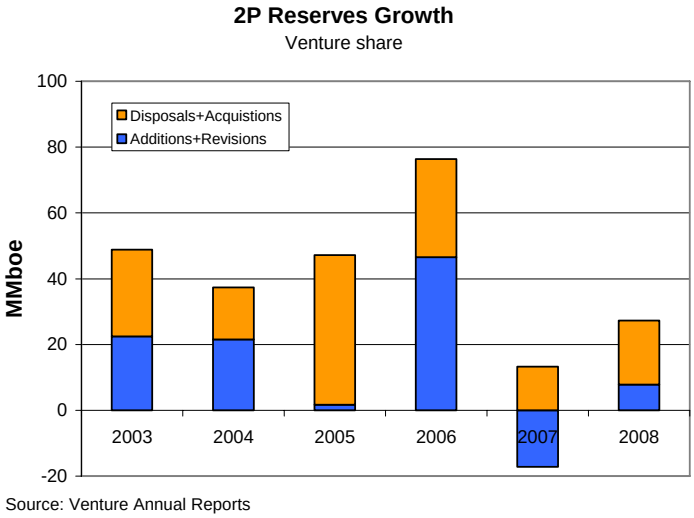

Figure 3 Historic Reserves Growth Performance 2003 – 2008[3]

[3] Year end reserves changes due to production are not shown.

RISC has prepared base and upside scenarios for the purpose of this valuation.

The base scenario comprises:-

- RISC's production and cost forecasts corresponding to volumes classified as 2P reserves for assets reviewed by RISC and Venture's production and cost forecasts corresponding to Venture's 2P reserves for assets not reviewed by RISC.
- RISC's estimates of risked contingent and prospective resources for exploration and appraisal opportunities which we expect to be evaluated in the near/medium term. (i.e. not all of Venture's exploration and appraisal assets have been included in the valuation.)

The upside scenario comprises the base scenario plus:-

- A representative sample of upside opportunities that we consider reasonably represents the scope for near/medium term reserves growth within the existing portfolio, consistent with Venture's historical reserves growth record (excluding acquisitions/disposals).
- An upside view of exploration and appraisal success in the near/medium term.

The RISC production forecasts associated with volumes classified as reserves for the two scenarios are shown below:

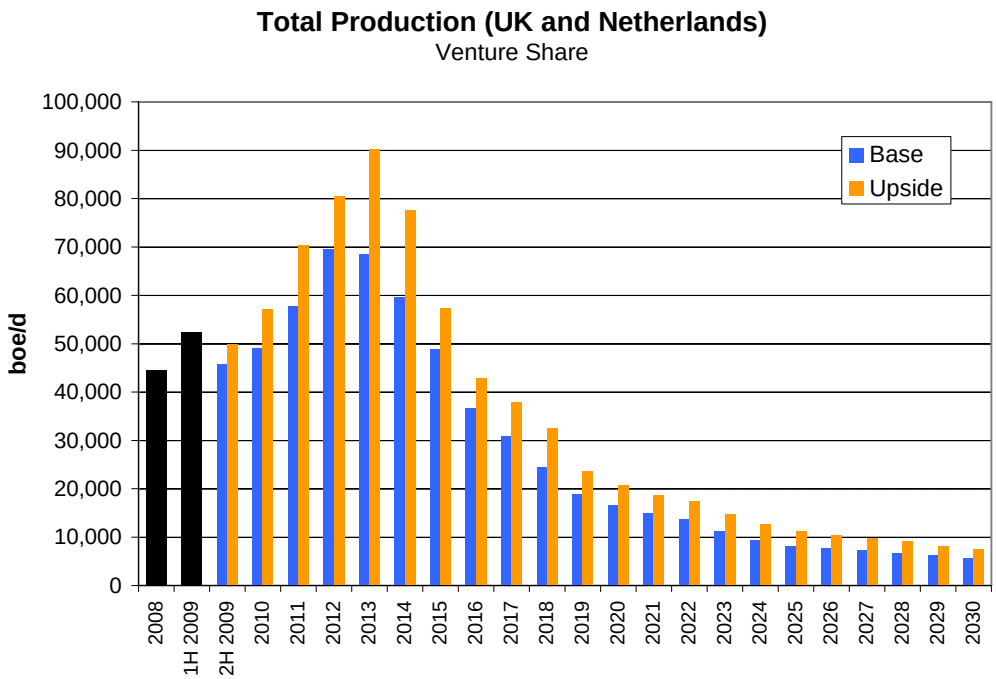

Figure 4 Total Production Forecasts

RISC has estimated base and upside scenario recoverable volumes of 218 MMboe and 269 MMboe (Venture share) respectively, for the period 1 July 2009 to the economic limit for each producing hub or year-end 2030. These estimates exclude the contingent and prospective resources related to Venture's exploration and appraisal portfolio.

By comparison, Degolyer & MacNaughton ("D&M") reported 2P oil equivalent reserves as at 31 March 2009 at 243 MMboe. This is not directly comparable to RISC's base scenario estimate due to 2Q 2009 production and forecast production beyond 2030, which are not included in the RISC estimate.

We have assessed risked contingent and prospective resources in the range 87 MMboe to 125 MMboe (Venture share) in our base and upside scenarios respectively.

1.3 COST ESTIMATION

Venture has strong project management and procurement systems in place and has historically delivered wells and installed facilities close to schedule and budget. Overall RISC considers Venture's estimates of unit costs to be reasonable. RISC has assumed somewhat higher capital costs than Venture's internal estimates, consistent with RISC's long term commodity price assumptions.

1.4 ECONOMIC EVALUATION

The production and cost projections have been valued using a discounted cash flow analysis at a discount rate of 8% real / 10% nominal. Volumes classified as contingent and prospective resources have been valued using unit value methods. For the Trinidadian assets we have adopted the book valuation carried by Venture. They are not included in the production and cost projections described.

Our oil price assumption is based on the July 2009 forward curve in real terms to 2014, then held constant in real terms. Gas sales price assumptions (NBP for UK; TTF for The Netherlands) are based on the July 2009 forward curve, as published by Heren, in real terms to 2014, then held constant in real terms. We assume that the margin between NBP and TTF (currently 4%) will reduce to zero by 2012.

Commodity Prices	2009	2010	2011	2012	2013	2014	2015	2016
Brent Oil (Real US$/bbl)	66.5	71.5	75.2	77.7	80.5	82.9	82.9	82.9
NBP Gas (Real pence/therm)	41.8	46.1	57.0	61.0	65.0	68.0	68.0	68.0

The following table summarises the results of our assessment.

Value of Venture's Petroleum Assets (£million)	Base Scenario	Upside Scenario
Reserves [4]	1,742	2,209
Contingent and Prospective Resources	160	225
Other Assets [5]	8	8
Total Asset Value	**1,910**	**2,442**

Table 1 Valuation Summary

[4] Trinidad reserves value of £11.7 million is a Venture management estimate based on current book value of Venture's 40% holding in Ten Degrees North Energy Limited ("TDN").

[5] Other Assets includes £14.1 million for Venture's 49.9% holding in North Sea Infrastructure Partners Limited ("NSIP"), £17.4 million for the commodity and foreign exchange hedge positions and -£23.5 million being the assessment of the net present value of Venture's corporate overhead costs. The NSIP asset is a Venture management estimate based on current book value.

Sensitivities to the base scenario reserves valuation of £1,742 million to changes in discount rate, capital costs, operating costs and commodity prices are presented in the following table.

Sensitivity Values (£million)	Decrease	Base Scenario	Increase
Discount rate: Low 12%, High 8%	-168	1,742	+200
Capex: Low +20%, High -20%	-107	1,742	+107
Opex: Low +20%, High -20%	-142	1,742	+142
Oil Price: Low-20%, High +20%	-151	1,742	+151
Gas Price: Low -20%, High +20%	-323	1,742	+323
Oil and Gas Price: Low -20%, High +20%	-474	1,742	+474

Table 2 Sensitivity Analysis

Graphically this is presented as follows:

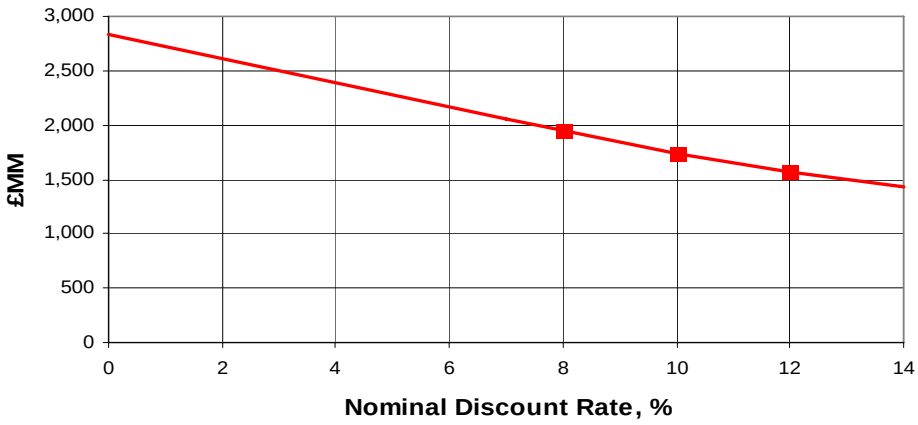

Figure 5 NPV sensitivity to Discount Rate

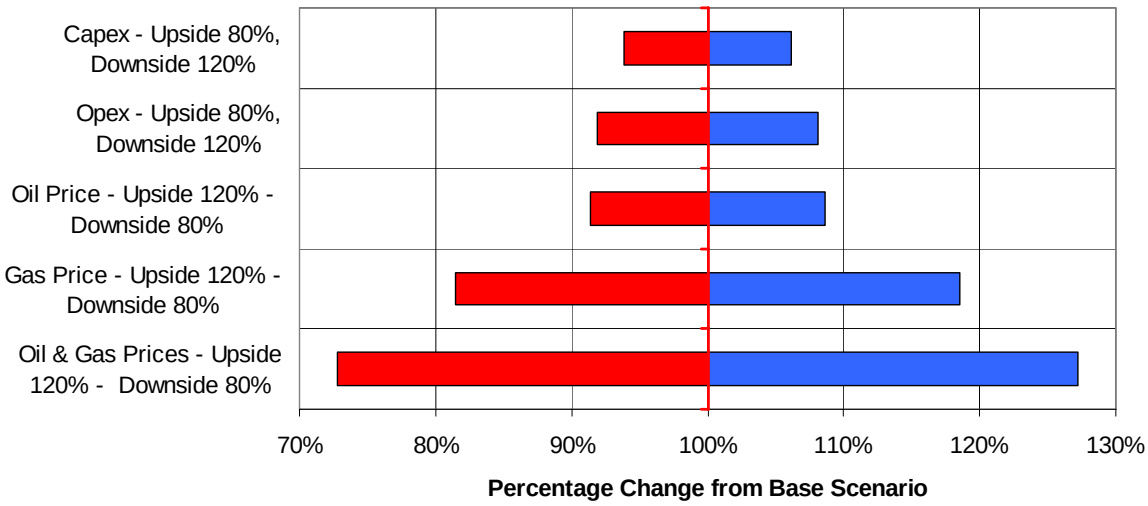

Figure 6 NPV10 sensitivities to Capex/Opex/Price

1.5 QUALIFICATIONS

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. RISC now has approximately 40 highly experienced professional staff at offices in London and Australia. We have completed over 1000 assignments in 55 countries for nearly 400 clients. Our services cover the oil and gas business lifecycle:

- 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 / Independent Expert / Expert Witness
- Strategy and corporate planning / Gas market advice

This assignment was undertaken by:

Patrick Taylor, BSc (Hons) Applied Mathematics (Queens University of Belfast, 1969), Chartered Engineer (CEng), Member of IOM3, Member SPE, Fellow of the Geological Society of London. Over 35 years experience, including over 30 years with BP.

Timothy Woodall, BEc (University of Adelaide), Fellow Australian CPA, Member AICD. Over 17 years of international M&A and finance experience predominantly within the oil and gas sector.

Geoff Salter, M.A. Engineering (Hons), Cambridge University, UK, 1979, MSc. Petroleum Engineering, Imperial College, London, UK, 1983 (with Distinction), Member SPE, Member of IOM3. Over 25 years experience with Schlumberger, ERC, Santos, Woodside Energy Ltd, and Shell (UK).

Simon Whitaker BSc Engineering Geology (University of Newcastle upon Tyne 1980), MSc Petroleum Engineering (Imperial College, 1981), MBA. Over 25 years technical and commercial experience gained with Santos, BP, Ampolex and Mobil prior to joining RISC.

Joe Salomon B App Sc (Geol) (University of Southern Queensland (1978), Member AAPG, Member PESGB, Member PESA, GAICD. Over 25 years of experience with LASMO, Ampolex and Mobil.

Mike Shaw, B Eng (Chem) Hons 1, Sydney University, Australia 1979. Member SPE 25 years, Member AIPN. Over 29 years experience, including prior experience with Exxon and Woodside in reservoir engineering, field development and business development positions.

John Wright, B Eng Mining Engineering (Leeds University, 1989), MSc Petroleum Engineering (Imperial College, 1995). 19 years experience, including prior experience with Kerr McGee (UK) Ltd., Ranger Oil (UK) Ltd., Amerada Hess (UK) Ltd, Sterling Energy plc and BG Group.

Ian Roberts, BSc Physics (Hons) (University of Nottingham, 1975), MSc Petroleum Engineering (Imperial College, 1979). Member SPE. 30 years experience, including 23 years in reservoir engineering and development team leader positions in BP.

Alan Atkinson, BSc Physics (University of Hull, 1986), MSc Geophysics (University of Newcastle, 1988), Member European Association of Geoscientists and Engineers (EAGE), Member of the Society of Exploration Geoscientists (SEG), Member PESGB, Member SPE. 20 years experience, including prior experience with Phillips Petroleum, Amerada Hess Ltd., Canadian Natural Resources International (UK) Ltd. and Cairn Energy.

Timothy Chapman, BSc Double Major, Geology and Geophysics (University of Adelaide, 1997), BSc Petroleum Geophysics (NCPGG, 1998), MSc Geophysics (University of Houston, 2007). Over 10 years experience, including with Santos and Edge Petroleum.

John Collinson, MA Geology and D Phil Geology, Oxford University. Fellow Geol. Soc. London: Member A.A.P.G. Over 35 years experience in Stratigraphy and Sedimentology; an authority on the Carboniferous of the Southern North Sea. Author and editor of numerous reports, papers and of major sedimentological text books; editor of "Sedimentology".

1.6 BASIS OF OPINION

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.

In preparing this valuation, RISC has relied on information provided by Venture as well as information from the public domain. In carrying out its evaluation, RISC has reviewed and where appropriate modified the work of other evaluators, including field operators and other consultants.

In view of the limited timeframe available for this valuation, RISC focussed on those assets considered at the outset to be most likely to impact the valuation. RISC evaluated over 80% of Venture's assets (on a 2P reserves basis) while Venture's in-house estimates were utilised for the remainder of the assets.

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, regulations that apply to these assets. 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.

RISC has given its consent and has not withdrawn its consent to the publication of this report.

1.7 INDEPENDENCE

RISC makes the following disclosures:

- RISC is independent with respect to Venture and confirms that there is no conflict of interest with any party involved in the assignment.
- Under the terms of engagement between RISC and Venture for the provision of this report, RISC will receive a fee, based on time expended at our current standard terms and conditions, payable by Venture. The payment of this fee is not contingent on the outcome of the proposed transaction.
- The Directors and staff of RISC may have from time to time owned shares in Venture. No interests are currently held by RISC Directors or by staff involved in the preparation of this report.

2 OIL FIELDS

RISC has considered the fields in geographic groupings which relate generally to the production hubs used for oil and gas processing and export.

The Oil Field areas are defined as:

- Greater Kittiwake Area
- Trees Area
- Central North Sea
  - Chestnut Area
  - 'New Oil' Area

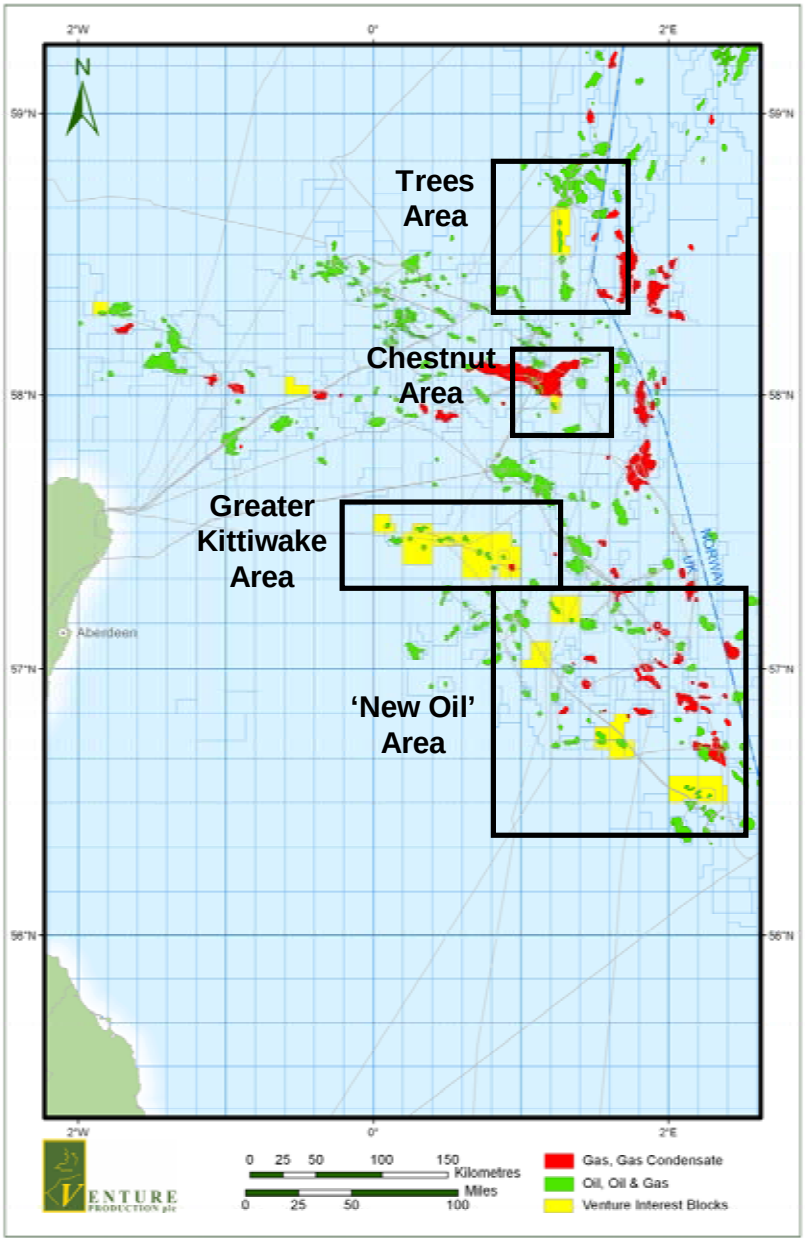

Figure 7 Oil Field Locations

2.1 GREATER KITTIWAKE AREA (GKA)

GKA covers blocks 21/12a, 17a, 18a, 19, 20b, 20c, and 20e and includes the following fields/discoveries:

- Goosander
- Mallard
- Grouse
- Kittiwake
- Gadwall
- Bligh
- Christian

2.1.1 Technical Summary

Regional Geology

The sediment record between the West Central Shelf and the West Central Graben is understood to be largely controlled by salt movement. In the Triassic, early halokinesis resulted in large-scale salt pillows upon which variable thicknesses of Smith Bank claystones were deposited. In places, the upward salt movement broached the Smith Bank skin and subjected salt cores to dissolution by ground water activity. This resulted in topographic lows which were exploited and in-filled by Triassic fluvial sands of the Skagerrak Formation. During the Jurassic, transgressive events reworked and re-deposited the valley fills as Fulmar shore face sands. A final large scale transgression culminated in deposition of widespread offshore sediments of the Kimmeridge Clay. The structurally trapped Upper Jurassic Fulmar shore face sands, sealed by Kimmeridge Clay form the primary reservoir of the GKA fields.

The **Kittiwake** field was discovered in 1981 with first production in 1990. The oil recovery factor is now approaching 60% and the field is in late life.

The **Goosander** field was discovered in 1998 with first production in 2006. The discovery well targeted a four way anticlinal feature and encountered 35° API oil in 150ft of Fulmar Sands.

The **Mallard** field was discovered in 1990 with first production in April 1998. The well targeted a faulted four way anticlinal feature and encountered 313ft of Fulmar sands. Two appraisal wells, one north and one south, encountered wet and poor quality reservoir respectively. In 1998 a horizontal producer was drilled which encountered 2,035ft of good quality sands.

The **Grouse** oil field was discovered in 1981 and is a high relief four-way dip close structure. This discovery well encountered 43ft of net pay in the Fulmar with no water contact. A pilot appraisal well and then a sidetrack producer were drilled in 2007.

Gadwall, discovered in 1996, is a four-way structurally closed Fulmar sand oil field.

Christian, discovered in 1990, is four-way structurally closed HPHT oil accumulation with an Intra Kimmeridgian sand turbidite reservoir.

Bligh is a HPHT four-way structurally closed Fulmar sand gas-condensate accumulation.

RISC has reviewed Venture's in place volume estimates for the Goosander, Mallard and Grouse Fields and considers these to be reasonable.

2.1.2 Development Status and Plans

Since acquiring the asset and assuming operatorship in 2003, Venture has carried out significant further investment, raising production from about 1 Mstb/d (Venture share) to 12.5 Mstb/d in 1H 2009.

The Kittiwake field was developed with a steel jacket platform which acts as the host platform for all production from GKA. GKA oil is exported via the Forties Pipeline. Gas production not used for fuel is delivered into the Fulmar Gas Line. Venture does not receive revenue for this gas and accordingly these volumes are not carried as reserves by Venture.

The other GKA fields currently on production are developed with subsea wells tied back to the Kittiwake platform. There are plans for an additional producer on Goosander to access attic oil volumes. An FDP for the Christian Field is in preparation with first production scheduled for 2010/11.

The Bligh wet gas accumulation requires further appraisal and may be developed in the future as part of a Joint Area development with other parties.

2.1.3 Reservoir Performance and Production Forecasts

GKA production in 1st half 2009 averaged 12.5 Mboe/d (Venture share) with the majority of production from the Goosander, Mallard and Grouse Fields.

RISC has reviewed the **Goosander**, **Mallard** and **Grouse** Fields. Recent production performance on Goosander supports the potential for an additional producer to access attic oil volumes. Grouse, since commencing production in late 2008, has exceeded expectations and our production forecasts reflect this performance.

RISC's base production forecast is shown below.

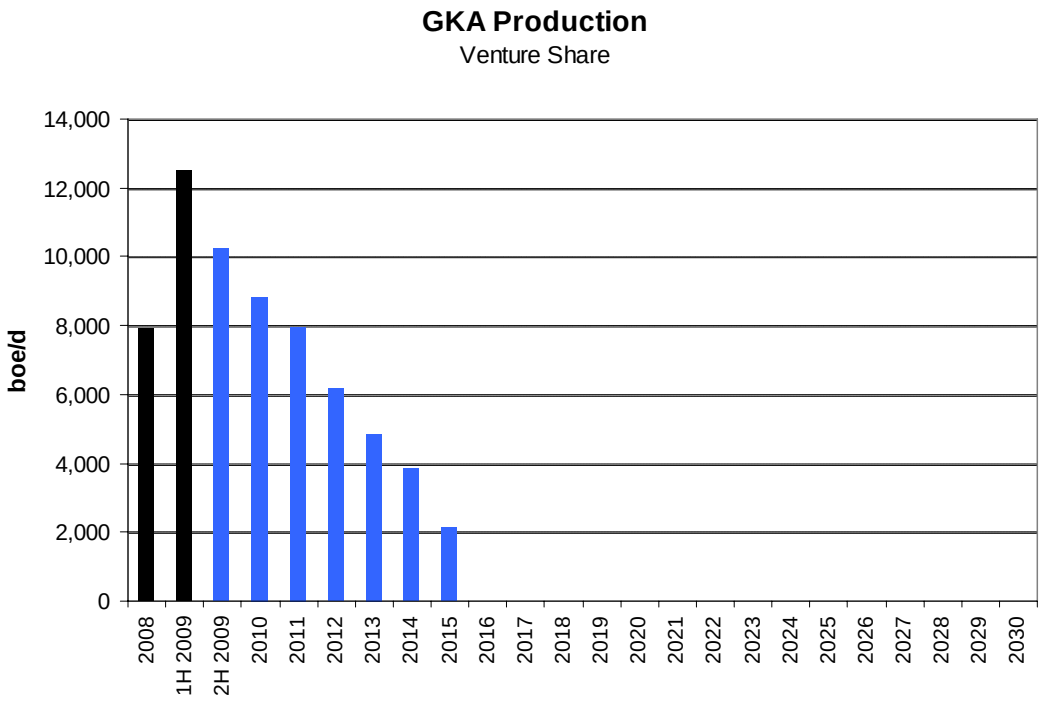

Figure 8 GKA Production Forecasts

Recoverable volumes from 1st July 2009 until the economic limit for the GKA hub are summarised below.

Venture share (MMboe)	Base Scenario
Recoverable Volumes	**15.5**

Table 3 GKA Recoverable Volumes

The **Bligh** accumulation valuation is addressed in Section 5.

2.1.4 Development Schedule and Future Costs

RISC's schedule and cost estimates are based on Operator data adjusted for the production forecasts developed by RISC.

Capital Costs

The most significant capital item is a second well in the Goosander field in 2010. Other than this the fields are fully developed so only minor ongoing capital expenditure is anticipated.

Operating Costs

RISC has reviewed operating costs budgeted for 2009 and development activities to develop forward Opex projections. RISC's estimates reflect the production forecasts discussed above. Annual operating costs for the GKA hub peak at about £38 million and decline towards the end of field life. This includes tariff payable for oil transportation through the oil export system.

A summary of our base cost projection is shown in the following table.

Venture share (£ million) 2009 RT	Base Scenario
Total Capex	**80**
Annual (2010) Opex	**39**
Field Abandonment	**31**

Table 4 GKA Cost Summary

2.1.5 Further Upside Potential

Several exploration prospects have been identified within GKA. These are mainly of modest size; however a recent reassessment has highlighted potential for a Christian Deep prospect. This prospect is planned to be tested by deepening the Christian Field development well. The valuation of the exploration potential has been addressed in Section 5.

It is understood that there is potential for future third party processing through the GKA facilities, however this has not been included in this valuation.

2.2 TREES AREA (TREES)

The Trees Area covers blocks 16/12a and includes the following fields/prospects:

- Birch
- South and Central Sycamore
- Larch

2.2.1 Technical Summary

Regional Geology

The Trees area lies in the South Viking Graben, Central North Sea. During the Upper Jurassic, a suite of conglomeritic submarine fan systems of the Brae Formation entered the basin over a major north south fault escarpment at the edge of the Fladen Ground Spur. A series of reactivated NE-SW faults influence the geometry and locations of the submarine fans. The fans sit on terraces of Devonian basement and in places extend into the basin overlying Triassic sediments. Fans are recognised on seismic by a number of direct and indirect indicators including compactional features. The major uncertainties in the Trees region are reservoir quality/distribution and accurate mapping of the fan bodies.

The **Birch** discovery well in 1985 encountered 244 ft of oil bearing Upper Jurassic Brae Formation. A test of the conglomeritic reservoir flowed 8,964 bopd.

South Sycamore has been tested by three wells which encountered a range of reservoir quality but are all oil bearing. Recent technical work indicates that a target updip area of thick good quality Brae reservoir has yet to be tested.

The **Central Sycamore** reservoir is an Upper Jurassic Brae conglomerate. The fluid properties vary across the field with GOR ranging from 922 scf/bbl to 1,393 scf/bbl.

The **Larch** reservoir is a Brae conglomerate.

RISC has reviewed Venture's in place volume estimates for the Birch and Sycamore South Fields and considers these to be reasonable.

2.2.2 Development Status and Plans

The **Birch** field was brought on stream in 1995 and has been developed with five wells - three producers and two water injectors. It is developed as a sub-sea tie back to the Brae 'A' platform, approximately eight miles away. Venture took over operatorship in 2000. Blow down of the reservoir pressure and development of a secondary gas cap is seen as a late life strategy to recover additional volumes.

The **South Sycamore** area currently has a single production well, which is an extended reach well drilled from the Tiffany platform. Production commenced in December 2005. A further production well is planned to target thickened fan sands and to be drilled utilising an existing wellbore from the Tiffany platform. If successful an additional water injector well will be evaluated.

The **Central Sycamore** area was first brought on production in March 2003 and has been developed with two wells. The field is developed as a sub-sea tie back to the Brae 'A' platform, approximately ten miles away. Water injection was initiated in 2006.

The **Larch** field was brought on production in July 1998 and has been developed as a sub-sea tie back to the Brae 'A' platform, approximately five miles away. Production is from a single horizontal production well and a single slant water injection well.

2.2.3 Reservoir Performance and Production Forecasts

Trees Area production in 1st half 2009 averaged 2.7 Mboe/d (Venture share).

Birch is currently producing from one well. Water injection has ceased in order to allow the reservoir pressure to go below the bubble point enabling recovery of attic oil and improved oil production rates (the 'blowdown' phase). RISC's base production forecast is based on Operator projections with the incremental production attributed to blowdown risked at 50% in recognition that this recovery mechanism has not yet been demonstrated. An opportunity for a sidetrack and for conversion of one well to water injection service is dependent upon blowdown performance and is captured only in RISC's upside forecast.

South Sycamore production has declined to 0.3-0.4 Mstb/d for the last 18 months. RISC's base production forecast is based on Venture's projections and assumes the drilling of a new water injection well, plus the drilling of a new producer/water injector pair into a 'sweet spot' in the reservoir north of the existing producer. RISC's upside production forecast assumes higher waterflood efficiency from the new wells.

Central Sycamore is currently producing from one well. RISC's base production forecast is based on Venture's projection of the ongoing decline. A successful completion of an injector sidetrack is included in RISC's upside production forecast.

Larch is currently producing approximately 1 Mstb/d at 50 % water cut. Limited water injection in recent years has resulted in a lowering of reservoir pressure. It is expected that more injection water will be available in the future as a result of upgrades on the Marathon-operated host facility. No further development is planned. RISC's production forecasts are based on Venture's decline analysis.

RISC's base production forecast is shown below.

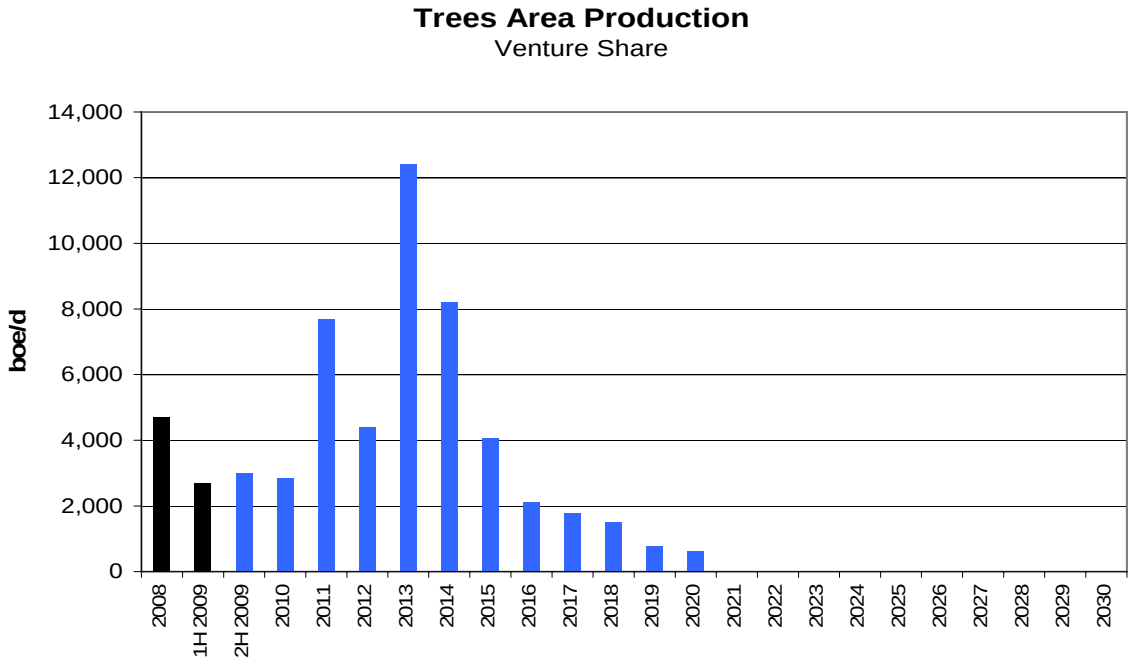

Figure 9 Trees Area Production Forecasts

Recoverable volumes from 1st July 2009 until the economic limit for the Trees hub are summarised below.

Venture share (MMboe)	Base Scenario
Recoverable Volumes	**17.5**

Table 5 Trees Area Recoverable Volumes

2.2.4 Development Schedule and Future Costs

RISC's schedule and cost estimates are based on Operator data adjusted for the production forecasts developed by RISC.

Capital Costs

The base scenario includes capital costs for further production and injection wells in the South Sycamore field. It is planned these will be drilled from and tied into the Tiffany platform. In the upside scenario we have allowed for the cost of a further production and injection well in Birch.

Operating Costs

RISC's estimates reflect the production forecasts discussed above and include a progressive decline towards the end of field life. Annual operating costs are forecast to peak at about £23 million pa, the majority of which is related to tariff for fluids processing at Brae and Tiffany and export through the Forties Pipeline System.

A summary of our base cost projection is shown in the following table.

Venture share (£ million) 2009 RT	Base Scenario
Total Capex	49
Annual (2010) Opex	10
Field Abandonment	20

Table 6 Trees Area Cost Summary

2.2.5 Further Upside Potential

No further exploration/appraisal potential has been reviewed by RISC.

2.3 CENTRAL NORTH SEA (CNS)

The Central North Sea Area covers blocks 13/21a, 22/2a, 22/22b, 22/22c, 22/26b, 29/8a, 29/8b, 29/9a, 29/9b, 29/9c, 30/11b, 30/12b and includes the following fields:

- Chestnut Area
  - Chestnut
- 'New Oil' Area
  - Halley
  - Appleton
  - Selkirk
  - Acorn
  - Beechnut
  - West Wick

2.3.1 Technical Summary

Regional Geology

The Chestnut Area is located at the south-eastern end of the Mesozoic Witch Ground Graben. In the Early to Middle Eocene, hemipelagic sedimentation dominated the area. A temporary relative lowering of the sea-level mobilized terrigenous clastic sediments on the shelf, which were transported and deposited in the Chestnut area forming the target reservoir. Sedimentation then returned to deepwater marine hemipelagics which encase the reservoir stratigraphically sealing it.

The New Oil Area is located between the West Central Graben and the Western Platform in the Central North Sea. After the withdrawal of the Zechstein Sea a continental and aeolian environment of deposition occurred. During this time the Triassic Skagerrak formation which forms one of the primary reservoirs of interest was deposited. The deposition of the Upper Jurassic Fulmar formation is attributable to a marine transgression over a Triassic sub-crop. The reservoirs are typically sealed by the Upper Jurassic shales of the Heather formation and Kimmeridge Clay.

The **Chestnut** oil field was discovered in 1986. A number of appraisal wells were drilled in the following two years, but it was not until 2001 that an extended well test helped reduce uncertainty and formed the basis of development. The Chestnut reservoir is formed by a stratigraphic trap in the Nauchlan Sandstone, which is present in the Mid-Late Eocene Lower Alba Formation.

The undeveloped high temperature **Acorn** oil field was discovered in 1983. The discovery well targeted a four-way dip closed structure broken by NW-SE trending faults and encountered oil in the Fulmar formation. An appraisal well drilled in 1985 tested the northern extension of the field and encountered 139ft of net pay in the Skagerrak formation.

The undeveloped **Beechnut** field was discovered in 1985. The field is fault bounded and the discovery well encountered 198ft of net pay in the Jurassic Heather and Fulmar formations. An appraisal well in 2001 established a stratigraphic extension to the south.

Halley – Appleton comprises a complex terrace faulted anticlinal feature, northeast of the Fulmar field. The Halley Alpha discovery well in 1980 was followed by Halley Beta in 1985 and Halley Gamma in 1993. The HPHT Appleton Alpha discovery well was drilled in 1992, followed by the Appleton Beta well in 1998. These wells targeted the same compartmentalised Fulmar formation terrace that steps downward to the north from the Fulmar field. The Halley Beta block was further appraised and brought onto production.

RISC has reviewed Venture's in place volume estimates for the above fields and considers these to be reasonable.

2.3.2 Development Status and Plans

The **Chestnut** field is developed with 2 production wells and one water injection well tied back to the 'Hummingbird' floating production unit. Produced fluids are processed and oil is stored on the Hummingbird with oil export via shuttle tankers. The field came back on production in 2008 (an Extended Well Test in 2001 produced just over 1 MMstb gross oil) with an initial gross oil rate about 15 Mstb/d. RISC's upside scenario includes additional production and injection wells and an upgrade to the water injection system.

The **Acorn** discovery is currently undeveloped. Venture plan to drill an appraisal well in late 2009. The well and planned extended production test will address the key uncertainty of connectivity and long term production rate. In the event of successful appraisal, a 2 well development of the 'core area' tied back to third party facilities is planned. RISC's upside scenario includes development of the East Area. The nearby Beechnut discovery may also be further appraised and developed depending on the results on Acorn.

The **Halley Beta** field is developed with one producer and one water injector from the Fulmar platform. No further development of this accumulation is planned.

The remainder of the **Halley/Appleton** complex is undeveloped. An appraisal well is planned on Halley in late 2009 with a sidetrack option to appraise an additional Halley fault block. A conceptual development plan for the Halley/Appleton complex has been prepared by the operator and envisages production over Fulmar via a dedicated process train. RISC has modified this plan with a later first oil date for Halley (2014), additional production wells and deferred Appleton first oil (2019) enabling utilisation of processing ullage on Fulmar.

2.3.3 Reservoir Performance and Production Forecasts

CNS production in 1st half 2009 averaged 8.0 Mboe/d (Venture share) with the majority of production from the Chestnut Field.

Chestnut early production performance has been encouraging with lateral pressure communication observed between each of the development wells. However sand production from one of the producers is currently constraining oil production and a remedial workover is planned in 2009 to address this.

Acorn production forecasts are based on Venture reservoir modelling work.

Future production from **Halley Beta** is expected to be minor although there is possible upside associated with a re-perforation workover. This potential has not been included in RISC's forecasts.

Halley/Appleton production forecasts are based on operator projections with a reduction to gas volumes to reflect our view of average reservoir fluid properties.

RISC's base production forecast is shown below.

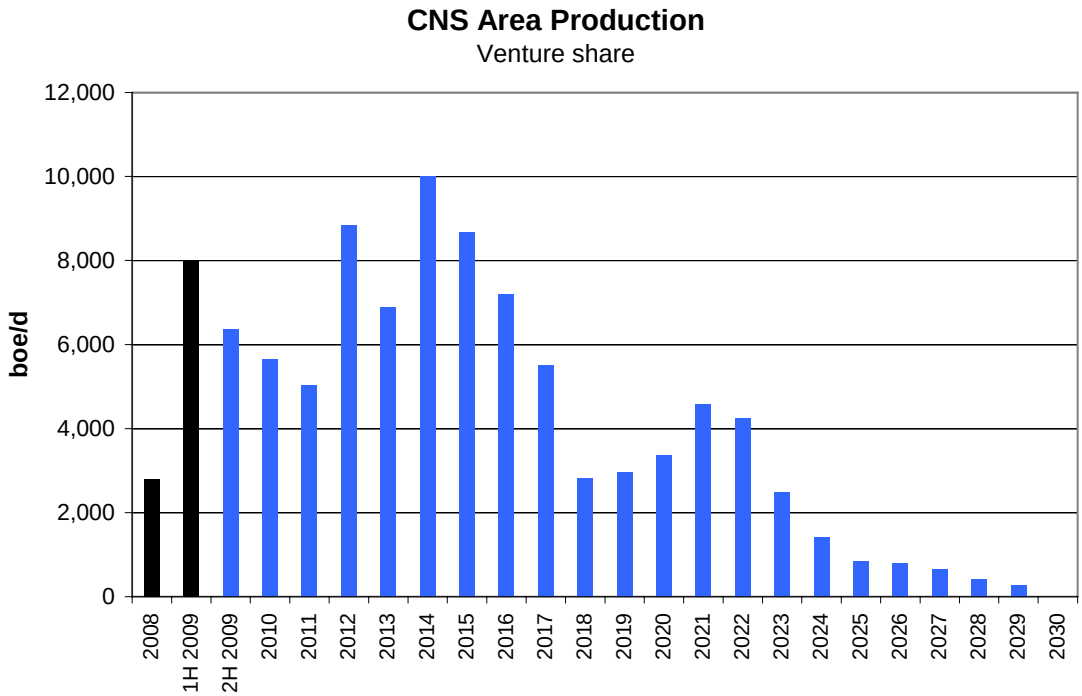

Figure 10 CNS Production Forecast

Recoverable volumes from 1st July 2009 until the economic limit for each producing hub or year end 2030 are summarised below.

Venture share (MMboe)	Base Scenario
Recoverable Volumes from 1/7/09 to 31/12/30	**31.1**

Table 7 CNS Recoverable Volumes

2.3.4 Development Schedule and Future Costs

RISC's schedule and cost estimates are based on Operator data adjusted for the production forecasts developed by RISC.

Capital Costs

The majority of capital costs are associated with development of the Halley/Appleton complex. There are also capital costs included for development of the Acorn and Selkirk fields.

Operating Costs

RISC's estimates reflect the production forecasts discussed above. Annual operating costs are forecast to peak at about £40 million pa including FPSO operating costs, fluid processing and transportation tariffs.

A summary of our base cost projection is shown in the following table.

Venture share (£ million) 2009 RT	Base Scenario
Total Capex	**331**
Annual (2010) Opex	**31**
Field Abandonment	**19**

Table 8 CNS Cost Summary

2.3.5 Further Upside Potential

The West Wick viscous oil accumulation is a potential development candidate. Timing is uncertain pending availability of ullage in the third party owned Captain Field facilities.

The Beechnut oil discovery is similar to Acorn and in the event of favourable results from Acorn could be developed in a similar manner.

In addition a number of exploration prospects (Nautilus and Cornwall) have been identified within CNS. Nautilus is a Gannet Field type analogue, Tay sandstone stratigraphic oil prospect. Cornwall is Triassic tilted fault block prospect offset from the Puffin Field.

The valuation of the exploration potential and the Beechnut and West Wick appraisal potential is addressed in Section 5.

3 GAS FIELDS

In evaluating Venture's gas assets, RISC has considered the fields in geographic groupings which relate generally to the production hubs used for gas processing and export.

The Southern North Sea gas field areas are:

- Greater Markham Area and Northern Netherlands Area
- UK Gas Area. UK Gas Area can be further subdivided as:
  - A Fields
  - Caister Murdoch System
  - Easington Catchment Area
  - Greater Carna Area

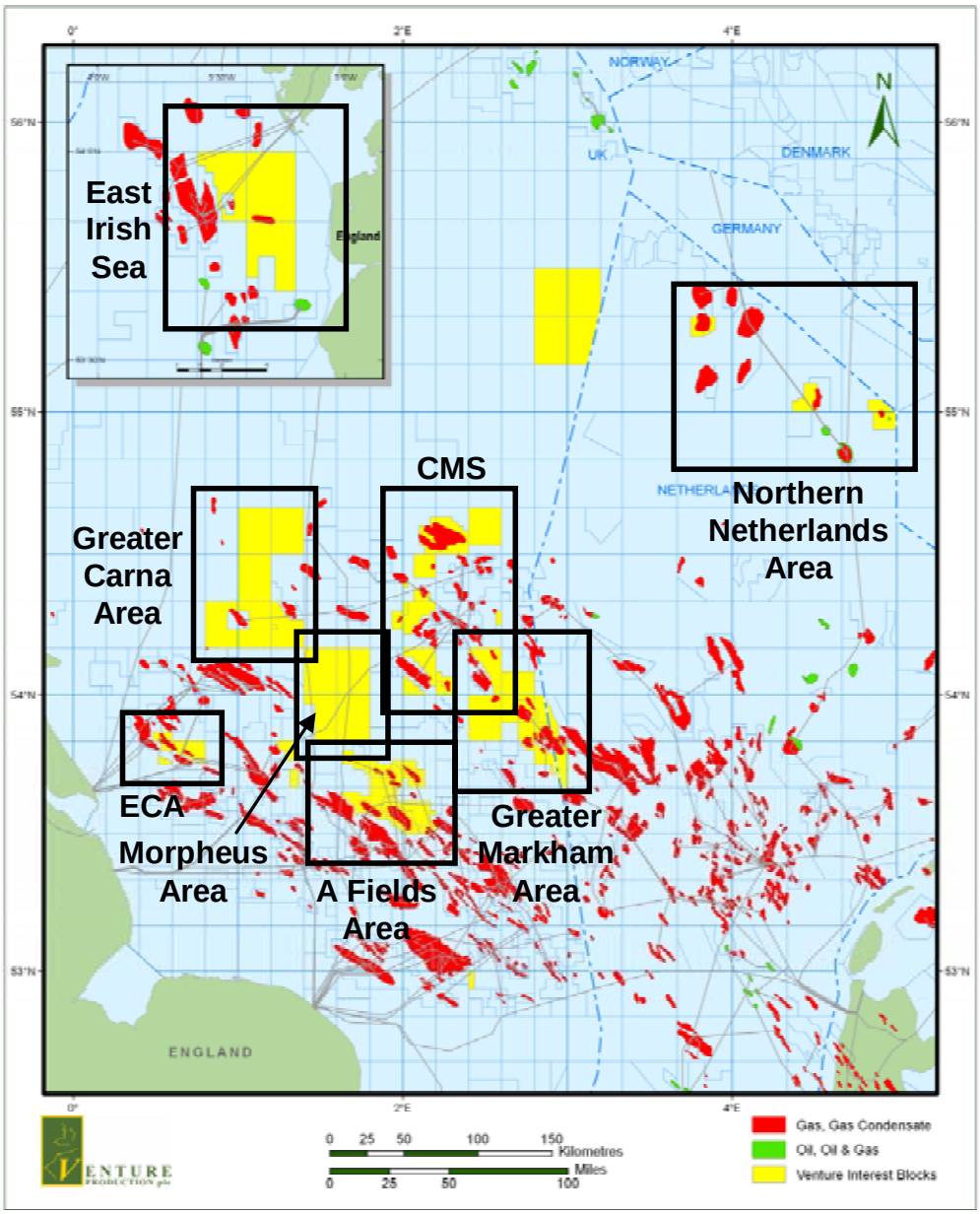

Figure 11 Southern North Sea Gas Hub Locations

3.1 GREATER MARKHAM AREA (GMA) & NORTHERN NETHERLANDS AREA (NNA)

The Greater Markham Area and Northern Netherlands Area covers blocks 44/28a, 44/29a, 49/3, 49/4a, 49/4b, 49/4c, 49/5a. 49/5b, 49/9b, 49/10c, A/15a, B/17a, B/18a, F/3a, J/3b, and J/6 and includes the following fields/discoveries:

- Markham
- Windermere
- Chiswick
- Stamford
- J3C
- Kew
- Arrol
- Ketex
- F3FA
- A15a
- B17a

3.1.1 Technical Summary

Regional Geology

The Southern North Sea area is dominated by gas reservoirs in the Permian Rotliegend and Carboniferous section. A pre-Zechstein NW-SE structural grain is visible in the subsurface with a later stage N-S extension overlain. Episodic rifting allowed for a thick Carboniferous section to be deposited which was partially eroded during the Varisican Orogeny and thereby unconformably overlain by the Permian Rotliegend section. A marine transgression resulted in the deposition of the Zechstein evaporites which provides the local seal.

The **Chiswick** field was discovered in 1984. The structure is a broad NW-SE trending faulted anticline with a Carboniferous primary reservoir. For many years the field remained one of the largest undeveloped gas fields in the UK Southern North Sea, due to uncertainty in reservoir deliverability. The discovery well encountered a 130m gas column that tested at 8.5 MMscf/d after mini-frac before being plugged and abandoned. Over the next 20 years, a further 3 appraisal wells were drilled but the field remained undeveloped because of concerns about well deliverabilty. Venture acquired an interest in 2006 and has since drilled two successful horizontal wells, encountering 2415m and 1218m of gross reservoir respectively and establishing commercial deliverability by use of massive fracture techniques.

The **Kew** discovery is located about 2km east of the Chiswick field and is a NNW-SSE tilted horst block. The discovery well penetrated the downdip flank in 1988 encountering 42m of gas-bearing Carboniferous sands. The recent Venture appraisal well tested the crest of the structure and encountered 138m gross reservoir section.

Markham and **Windermere**, discovered in 1984 and 1989 respectively, are faulted four way anticlinal structures producing gas from the Rotliegend. The J3c field, discovered in 1995 offshore Netherlands, is a horst block structure producing gas from the Rotliegend.

Stamford, discovered in 1990, is a Rotliegend gas field trapped in a faulted low-relief anticlinal structure and was brought on stream by Venture with a single development well tied back to Markham in 2008.

Arrol and **Ketex**, discovered in 1987 and 1997 respectively, are undeveloped Carboniferous gas fields trapped in a horst block structures near the existing Chiswick development.

F3FA, discovered in 1971, is an undeveloped Jurassic Scruff Green Sand gas-condensate field, trapped in a faulted rollover structure.

A15a and **B17a**, discovered in 1999 and 1997 respectively, are undeveloped shallow anticlinal Pleistocene gas fields.

3.1.2 Development Status and Plans

The **Chiswick** Field in UK Block 49/4b is developed utilising a five slot minimum facilities platform. The platform is tied back to production and compression facilities via pipeline to the Markham platform. After compression and condensate extraction at Markham, the gas is exported to the NAM operated Den Helder gas terminal in the Netherlands. Gas can then be re-exported to the UK via the Den Helder to Bacton pipeline.

Two horizontal wells are currently producing from Chiswick. The C1y well in the Alpha Block began production in September 2007 at rates up to 40 MMscf/d and has produced 18.5 Bcf to mid-2009. The C2z well in the Gamma Block began production in February 2008 at rates up to 47 MMscf/d and has produced 17.1 Bcf to mid-2009.

Wells C1y and C2z are completed with cemented liners and are stimulated with massive hydraulic fractures across the Carboniferous gas bearing sands. Well C2z is also perforated across the Silverpit Leman Sands. Production logging during completion testing of the well indicated flow from a 3m interval of the uppermost Silverpit sand

Three further long completion slant wells are planned to be drilled in 2010 and 2011 in the Alpha, Beta and Gamma Blocks. These wells will also have a series of massive hydraulic fractures across the Carboniferous gas bearing sands and any substantial Leman Sand that may be encountered.

3.1.3 Reservoir Performance and Production Forecasts

GMA and NNA production in 1st half 2009 averaged 15.9 Mboe/d (Venture share).

Venture developed a reservoir simulation model of the **Chiswick** Carboniferous and Leman Reservoirs as part of an integrated reservoir study. The simulation model was history matched to the performance of C1y and C2z from first production to end-October 2008. The model was used to predict the performance of a five well development assuming production from both the Carboniferous and Rotliegend Sands.

RISC has modified the individual simulated well forecasts to generate base and upside forecasts. RISC's base scenario assumes production from the Carboniferous sands at the same rate as Venture's forecast and minor production from the Rotliegend Sands. RISC's upside forecast addresses the potential for higher recovery from the Carboniferous sands and the same contribution from the Rotliegend Sands in the Gamma Block as modelled by Venture.

The **Kew** Field appraisal/ development well drilled in 2Q 2009 encountered Carboniferous gas bearing sands which appeared to be depleted by up to 50 psi which is attributed to communication with Chiswick. This appears to demonstrate good lateral continuity of the Carboniferous sands and the potential for good recovery.

RISC's base production forecast is shown below.

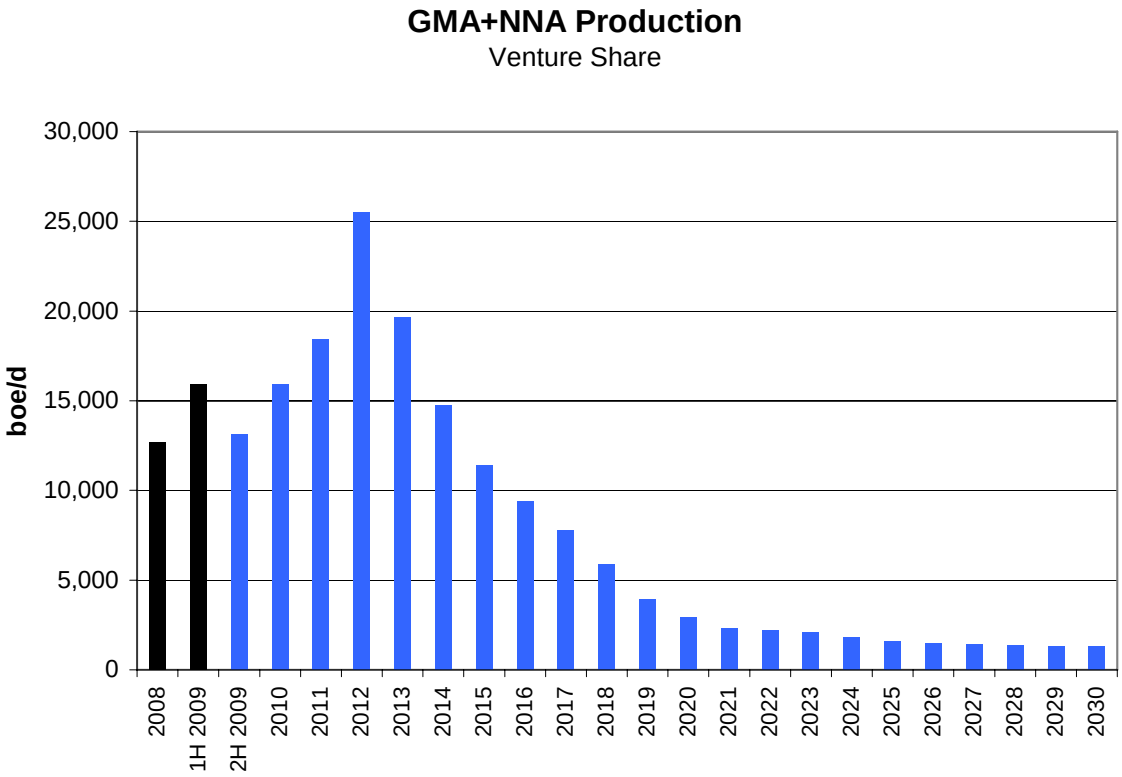

Figure 12 GMA+NNA Production Forecasts

Recoverable volumes from 1st July 2009 until the economic limit or year end 2030 are summarised below.

Venture share (MMboe)	Base Scenario
Recoverable Volumes	**58.4**

Table 9 GMA+NNA Recoverable Volumes

3.1.4 Development Schedule and Future Costs

RISC's schedule and cost estimates are based on Operator data adjusted for the production forecasts developed by RISC.

Capital Costs

Capital costs are associated with further development of the Chiswick, Kew and F3FA fields.

Operating Costs

RISC's estimates reflect the production forecasts and development activities discussed above. Annual operating costs are anticipated to peak at about £80million pa including fluid processing and transportation tariffs.

A summary of our base scenario cost projection is shown in the following table.

Venture share (£ million) 2009 RT	Base Scenario
Total Capex	**310**
Annual (2010) Opex	**40**
Field Abandonment	**16**

Table 10 GMA+NNA Cost Summary

3.1.5 Further Upside Potential

A number of prospects have been mapped close to the Chiswick Field. Arrol lies to the NW of and on structural trend with Chiswick. A discovery well, 44/28-3 flowed at 62 MMscf/d from an Upper Westphalian channel sand with gas trapped by fault seal. Further work is required to evaluate both fault and channel extents. RISC has reduced the POS from 85% to 50%. The Ketex prospect is downdip of the Ketch field and updip of a 1997 well that flowed gas at 67 MMscf/d from a thin Upper Westphalian B sandstone. This prospect also requires further definition. Other prospects on Venture's drilling schedule include Wandsworth and Battersea.

The valuation of the exploration and appraisal potential has been addressed in Section 5.

It is understood that there is potential for future additional third party processing through the GMA facilities, however this has not been included in this valuation.

3.2 UK GAS

The UK Gas Area covers blocks 38/20, 38/25, 39/16, 39/21, 42/25b, 43/11, 43/12, 43/16, 43/21b, 43/22b, 43/22c, 43/28, 43/29, 43/25a, 44/11a, 44/12a, 44/13a, 44/16a, 44/16b, 44/16c, 44/21d, 44/21e, 44/23f, 44/26b, 44/26c, 44/27a, 44/27c, 47/3h, 47/8c, 47/9c, 48/3a, 48/4, 48/7e, 48/7f, 48/9a, 48,10a, 48/14a, 48/15a, 48/15b, 49/6a, 49/11a, 53/3d and includes the following fields:

- *A Fields (A Fields)*
  - Ann
  - Alison
  - Annabel
  - Audrey
  - Saturn
  - Mimas
  - Annabel East
  - Amanda
  - Ensign
- *Caister Murdoch System (CMS)*
  - Cygnus
  - Copernicus
  - Garnet
  - Kepler
  - Opal
  - Humphrey
- *Greater Carna Area (GCA)*
  - Carna
- *Easington Catchment Area (ECA)*
  - Eris
  - Ceres

3.2.1 Technical Summary

A Fields

The A fields lie within the Sole Pit Basin which developed from mid Permian through to Triassic in response to extension and thermal subsidence. The main reservoir, the lower Permian Rotliegend sandstone, was deposited in an arid environment as aeolian, fluvial and playa lake sediments. This was followed by development of thick Zechstein evaporites in the upper Permian, which provide a regional seal. Subsidence, coupled with halokinesis, continued through to late Cretaceous times when the Rotliegend sands were most deeply buried. Traps are commonly formed by lower Permian tilted fault blocks. Mapping of these fault blocks is problematic due to complex overburden velocity variation as a result of salt movement. Reservoir quality is best in the aeolian environments and may be non-existent in the Silverpit Lake environment. Reservoir properties are impaired by deep burial in the centre of the Sole Pit.

The **Ann** Field was discovered in 1966 and first production was in 1993. The field is a northwest-southeast trending fault bounded anticline at Top Rotliegend level. Reservoir quality is moderate, with interbedded aeolian, fluvial and sabkha sands resulting in a layer-cake internal stratigraphy.

The **Alison** Field was discovered in 1987. The field is a relatively small fault-bounded structure with a large vertical relief, having a gas column of over 600ft.

The **Audrey** field was discovered in 1976 with first production in 1988 from the Audrey A platform. Production from the Audrey B platform started in late 1990. Audrey is a Rotliegend gas field where reservoir quality is moderate, with interbedded aeolian, fluvial and sabkha sands with a layer-cake internal stratigraphy.

Venture drilled the **Annabel** discovery well 48/10a-12 which tested 58 MMscf/d from the Rotliegend Upper Leman reservoir, and 44 MMscf/d from the Lower Leman. The field is a three-way dip closure bounded by a fault to the north. Rotliegend reservoir quality is good to moderate, with interbedded aeolian, fluvial and sabkha sands resulting in a layer-cake internal stratigraphy.

The ConocoPhillips operated **Saturn** development comprises the Atlas, Hyperion and Rhea gas accumulations. The first discovery well was drilled in 1986. Five further wells were drilled by 1990, and a final appraisal well drilled in 2003. The reservoir section includes both upper and lower Leman sandstones. Test rates for single zones in four wells ranged from 13 to 49 MMscf/d. The fields lie below the salt wall providing many issues in imaging the structures, and drilling surprises. First production was from Atlas South in September 2005 with subsequent development wells added at Atlas North, Hyperion and Rhea. The fields produce from the Rotliegend sandstones.

The ConocoPhillips operated **Mimas** field was discovered in 1989 with first production in June 2007. The field comprises a WNW-ESE trending rhombic-shaped fault block with gas located in the Leman sandstone reservoir of moderate to good quality.

The **Ensign** field is an elongate fault bounded horst situated to the west of the Audrey Gas Field. The reservoir is characterised by extensive illite cementation of the pore throats reducing reservoir permeability resulting from deeper burial than the other fields in the hub. The 1986 discovery well intersected a 543 ft gross gas bearing Leman Sandstone reservoir which flowed at ~15 MMscf/d after fracture stimulation. An appraisal well to the SE in 1988 intersected the reservoir in the water leg proximal to cross cutting “dekeyser” lineaments. In 2006 Venture drilled a further appraisal well, which flowed 14 MMscf/d after fracture stimulation. It encountered some open fractures not seen in previous wells. This was followed in 2007 by a long horizontal well drilled close to the discovery well. This well targeted the Upper Leman Sandstone and drilled through a number of “dekeyser” separated compartments. It is still not known whether the dekeyser lineaments act as baffles/barriers or not. Five intervals were fracture stimulated resulting in a maximum test rate of 44 MMscf/d. The well has since been suspended pending re-use as a development well.

Caister Murdoch System

The Gaz de France (“GdF”) operated **Cygnus** field, discovered in 1988, is one of the most northerly gas discoveries in Southern gas Basin. It has excellent quality Carboniferous reservoir sands in structurally high “pods” which generally inhibit development of Leman sands. Good reservoir quality in the Permian Leman sandstone also occurs in this area. The Cygnus Field is a large composite structure made up of 5 main fault blocks. The discovery well found gas in the Leman reservoir within a fault bound compartment in the centre of the field. A 1989 appraisal well in block 5a found gas in both Leman and Carboniferous reservoirs. GdF further appraised fault block 1 in 2006, finding gas in both reservoirs. The

Leman interval was tested at 3 MMscf/d. GdF drilled appraisal wells in fault blocks 2b and 3 in late 2008 and early 2009. A thinner than expected Leman interval but a much thicker and better quality Carboniferous interval were intersected in block 2b. The Carboniferous interval tested at a facility constrained rate of 32 MMscf/d. The Leman interval flowed negligible gas to surface. In block 3 the Leman reservoir was tested at a facility constrained rate of 32 MMscf /d. The wells proved a common gas contact for the larger eastern part of the field and demonstrated that Cygnus has significant potential in both the Carboniferous and the Rotliegend sandstones.

Greater Carna Area

Fields in the Carna area, on the north-western side of the Sole Pit Basin, produce gas from both the Permian Rotliegend and Carboniferous section. The area is dominated by an underlying NW-SE trending structural grain which faulted and folded the Carboniferous section during the Variscan Orogeny. This topography was peneplained into the Permian, leading to a subcrop of Carboniferous of varying ages upon which the Rotliegend section was deposited. A widespread transgression resulted in deposition of a thick Zechstein evaporitic sealing succession.

The **Carna** field was discovered by Venture in 2009 and encountered a 180ft gross (130ft net) Carboniferous section. The undeveloped gas field is trapped in a high relief 'pop-up' horst block formed as a result of structural inversion and was flow tested at 8.8 MMscf/d.

Easington Catchment Area

The Easington Catchment Area (ECA) is located on the western margin of the Sole Pit Basin along the Dowsing Fault Zone, a major Variscan trend fault zone with throws in the order of 700 ft to 2000 ft. It is surrounded on all sides by gas production. The basin has undergone a number of key structural and depositional events which provide robust structures, large volumes of generated gas and regionally extensive reservoirs and seals. The reservoir is the Rotliegend Leman sands comprising a sequence of aeolian dune, fluvial channels, fans and playa lake sandstones. In many instances regionally, gas water contacts are not seen in wells, and most fields are filled to spill.

The **Eris** field was discovered in 2007 by Venture and proved a gas column of 215 feet in Lower Permian Rotliegend Leman Sandstone in the Main Block. The well tested at a stabilised, constrained rate of 55 MMscf/d. The well proved gas in two separate fault blocks, the Main and North blocks. A West fault block appears to be a part of the aggregate structure, commonly sealed by a main western fault. This is supported by a fault seal study. A GWC was not encountered.

The **Ceres** field (formerly called Barbarossa) was discovered in 1982 and proved 113 gross ft of gas bearing Leman Rotliegend sands. The discovery well tested at a very low rate, likely related to drilling damage by overbalanced drilling muds. In 2008 Venture drilled a pilot production/appraisal well which was sidetracked. It drilled the Lower Rotliegend sands, entered the non-reservoir Carboniferous before again drilling the Lower Rotliegend in a 5659 ft long section crossing two fault blocks. The well tested at 40 MMscf/d. Additional gas resources are possible in the southern fault block immediately adjacent to the south of the proven area, but further appraisal is required.

RISC has reviewed Venture's in place volume estimates for the fields and apart from the Ensign and Ceres Field considers these to be reasonable. RISC considers that a higher

volume than Venture currently carries on Ensign is reasonable, following seismic reprocessing and a revised structural model which supports a higher pick over parts of the field. On Ceres, RISC mapped the northeastern flank of the field higher than Venture, leading to an approximate 10% increase in the in place volumes.

3.2.2 Development Status and Plans

A Fields

The **Ann** field is currently developed by three horizontal wells, A2, A3 and A4Z. The A3 is a replacement for the A1 well that had started to produce water and was sidetracked in 1995. First production from Ann was in 1993 from two subsea horizontal wells. Wet gas is transported from Ann via a 40km, twelve inch pipeline to the LOGGS complex located in block 49/16. Compression is provided at this complex, which will allow a low abandonment pressure. The A4z infill well was completed in January 2007.

First production from **Alison** was in 1995 from a single subsea tri lateral well tied into the Ann pipeline. The well failed in June 1996 due to formation collapse around the trilateral junction which resulted in sand production and a blockage in the subsea tree. The well was worked over to restore production in January 1997 and again in May 2000 in an attempt to try to understand the declining production rate before the decision was taken to sidetrack the well. The B3 well was successfully drilled and was tested at 29 MMscf/d and was placed on production in September 2000.

The **Audrey** field has been produced from a total of 13 wells via natural depletion. Eight wells are located on the Audrey 'A', twelve slot unmanned wellhead platform located in block 49/11a. Four wells are located on the satellite Audrey B, six slot unmanned wellhead platform in block 48/15a, tied back to the A platform. There is also a subsea well 49/11a-7x drilled to the northwest of the A platform. First production from Audrey was in late September 1988 from the Audrey A platform. Production from the Audrey B platform started in late 1990.

Wet gas is transported from Audrey 'A' to the LOGGS complex located in block 49/16. Compression is provided at this complex, which will allow a low abandonment pressure at Audrey. Other processing is limited. Water handling facilities were installed on the 'A' and 'B' platforms in 1995 and 1996 respectively.

The **Annabel** field has been developed using a near vertical fracture-stimulated subsea well (AB-1) completed in September 2005 and a horizontal subsea well (AB-2) that was brought on stream in December 2005. Peak production rates from these wells were over 100 MMscf/d and 50 MMscf/d respectively.

Wet gas is transported from Annabel to the Audrey A platform, where it is co-mingled with Audrey production and exported to the Lincolnshire Offshore Gas Gathering System (LOGGS) complex located in block 49/16. Compression is provided at this complex, which will allow a low abandonment pressure at Annabel.

The **Saturn** field has been developed by a minimum facilities wellhead platform, with wet gas being transported to the LOGGS complex. Production from Saturn commenced in 2005 from a single horizontal well in the Atlas structure, with a second Atlas well drilled in 2006. The Hyperion horst and dome structures were developed via a dual lateral well. This and the Rhea horizontal development well were drilled in 2006.

The **Mimas** field is developed by a minimum facilities wellhead platform, with wet gas being transported to the Saturn Platform and thence on to the LOGGS complex located in block 49/16. First production in June 2007 was from a single deviated well (48/9-4) that twins the 48/9-2 discovery well.

The **Ensign** field is currently undeveloped. Development has been stalled by the lack of capacity in LOGGS, the closest available export infrastructure. Discussions are on-going with regard to a number of other potential export options.

Caister Murdoch System

Cygnus is planned to be developed in up to five phases, the number and scope depending on the success of appraisal drilling and field performance. An FDP has been submitted for the planned Phase 1 development which involves a near-horizontal fracture-stimulated Leman well in fault block 1, a high angle horizontal Carboniferous well in fault block 2, and one normally unmanned platform. Gas export options are still being considered including a tie back of 27 km to the McAdam sub-sea template. McAdam is tied back to the Murdoch platform which will provide separation and compression for export to the Theddlethorpe gas terminal if this alternative is adopted.

RISC's base scenario assumes five platforms and thirteen development wells and the upside scenario assumes six platforms and sixteen development wells.

Greater Carna Area

The **Carna** discovery is currently undeveloped. Venture is currently working on a development plan likely to involve a 2 well development to nearby third party infrastructure.

Easington Catchment Area

Ceres and **Eris** are both single well developments utilising near-horizontal subsea development wells. Ceres and Eris will be tied back subsea 6 km and 8.5 km respectively to the Mercury manifold and from there to the Neptune platform then on to the Cleeton Platform for compression prior to export to the Dimlington onshore terminal.

First gas from Ceres and Eris is scheduled for November 2009. Production is expected to back-out some production from the Mercury and Neptune Fields due to higher well head pressure. Owners of Ceres and Eris will be required to compensate existing ECA owners. The ECA owners will repay the gas over agreed timescales.

In RISC's upside scenario a second Eris development well would be required.

3.2.3 Reservoir Performance and Production Forecasts

UK Gas Area production in 1st half 2009 averaged 13.4 Mboe/d (Venture share).

A Fields

The **Annabel** field has produced almost 100 Bcf to date, and current production rate is around 33 MMscf/d. RISC's base scenario production forecast is based on exponential decline of existing production together with an improvement due to low pressure compression, and supports Venture's estimate. No further development activity is planned. RISC's upside forecast is based on a more optimistic harmonic decline rate.

On **Saturn** RISC has reviewed and supports Venture's estimate of ultimate recovery from the four producing wells of 306 Bcf, which is based on an updated performance forecast following the acquisition of downhole pressure data in all wells in late 2008. RISC's base scenario production forecast is based on exponential decline of existing production together with an increase in production rates due to low pressure compression. RISC's upside scenario production forecast is based on a more optimistic forecast of decline rate.

The **Ensign** field is currently undeveloped. During 2009, Venture has undertaken a detailed geological remodelling of the field, resulting in a significant increase in GIIP (from 330 Bcf to 475 Bcf at the P50 level).

Venture has simulated development using three horizontal wells, with the preliminary conclusion that ultimate recovery will be 135 Bcf. As this work is still in progress, RISC has assigned a more conservative ultimate recovery of 125 Bcf. RISC's upside scenario is based on a high case GIIP and more optimistic recovery factor, which will require a fourth development well.

Caister Murdoch System

Cygnus is a significant gas discovery which is expected to make a material contribution to Venture's gas production capacity. The recent appraisal successes have facilitated reservoir evaluation and development planning studies.

GdF has developed a reservoir simulation model of the Carboniferous and Leman Sands. RISC has modified the individual simulated well forecasts to generate base and upside forecasts based on our view of the gas volume and deliverability in the individual fault blocks.

For the base scenario RISC supports the operator's most likely recovery estimates associated with the fault blocks in the east of the field (1, 2a, 2b and 3). RISC has downgraded the recovery in western Block 5 to 80% of the operator's value and, as the operator has done, we have excluded the untested western Block 4 from the base scenario.

RISC's upside scenario assumes no increase in Block 1 which we believe has limited upside potential, a 25% increase in Blocks 2 and 3 and the operator's simulated recovery in the western blocks 4 and 5.

Greater Carna Area

Carna field production forecasts are based on preliminary estimates by Venture for first gas in 2011.

Easington Catchment Area

Venture has developed production profiles for **Ceres and Eris** field using material balance, well inflow and an inter-field pipeline models. RISC has modified the Venture well forecasts to represent RISC's view of base and upside performance.

The **Ceres** base scenario assumes well 47/9c-11x contacts around 44 Bcf within a single fault block. The upside scenario assumes pressure communication across a possible east-west fault thereby contacting up to 73 Bcf.

The **Eris** development well, 47/8c-4 was completed within two fault blocks – the Main and the North (toe of well). There was only a trace of flow indicated by the PLT from the North block. This was attributed to intersection of poorer reservoir stratigraphically higher in the section. RISC therefore has no recovery from the North Block in the base scenario.

The Eris upside scenario assumes pressure communication across the North and Western Blocks can be achieved utilising a second development well.

RISC's base production forecast is shown below.

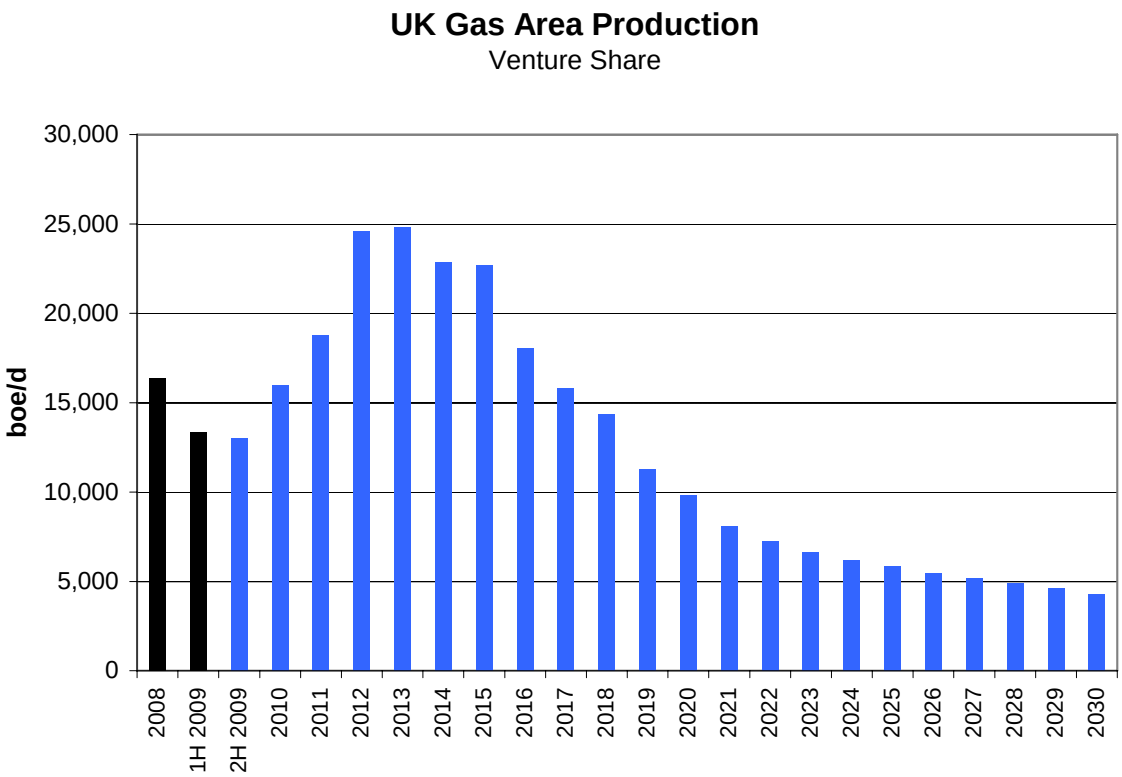

Figure 13 UK Gas Area Production Forecasts

Recoverable volumes from 1st July 2009 until the economic limit for each producing hub or year end 2030 are summarised below.

Venture share (MMboe)	Base Scenario
Recoverable Volumes	**95.4**

Table 11 UK Gas Area Recoverable Volumes

3.2.4 Development Schedule and Future Costs

RISC's schedule and cost estimates are based on Operator data adjusted for the production forecasts developed by RISC.

Capital Costs

The largest component of future capital costs is associated with development of Cygnus. Other significant capital cost drivers are future development of Ensign and of Carna.

Operating Costs

RISC's estimates reflect the production forecasts and development activities discussed above. Annual operating costs are anticipated to peak at about £70million pa including gas processing and transportation tariffs.

A summary of our base cost projection is shown in the following table.

Venture share (£million) 2009 RT	Base Scenario
Total Capex	**528**
Annual (2010) Opex	**32**
Field Abandonment	**81**

Table 12 UK Gas Area Cost Summary

3.2.5 Further Upside Potential

Several exploration prospects close to existing infrastructure have been identified within UK Gas. In the A Fields area these include Annabel East, SE Adele/Agatha and Adele.

A Fields

The **Annabel East Extension** is a North South trending tilted fault block structure on the eastern edge of the salt wall that overlies Annabel, with a narrow pop-up horst extension to the south, which has increased top-seal risk. Significant uncertainty is associated with the depth of the western side of the structure close to the salt wall. RISC has proposed an alternative lower range for GIIP to Venture based on a shallower independent closure of the main tilted fault block under the salt wall. The well is currently drilling.

The **SE Adele/Agatha** and **Adele** prospects have been recently remapped by Venture following the acquisition of full 3D seismic coverage. RISC has reviewed Venture's updated mapping and work in progress and agrees with the Venture position on in place volumes and risk.

CMS

RISC's base and upside production forecasts for **Cygnus** do not include the undrilled Fault Block 4.

The valuation of the exploration and appraisal potential is addressed in Section 5.

4 OTHER AREAS

East Irish Sea

Venture has interests in 3 blocks in this area which includes the Marram gas discovery and the Whitbeck prospect which is currently drilling. The Marram discovery well indicated potentially significant inerts content and an appraisal well is planned during 2009 to assess gas composition and determine if a development is viable.

Trinidad

For the Trinidadian assets we have adopted the book valuation carried by Venture for its 40% interest in Ten Degrees North Energy Limited. These assets are not addressed further in this report and are not included in the production and cost projections described.

5 EXPLORATION AND APPRAISAL PORTFOLIO

Venture's exploration and appraisal portfolio comprises in excess of 50 opportunities classified as appraisal, exploration near existing Venture operated facilities, or exploration. RISC selected 20 opportunities for review on the basis of materiality and likelihood of drilling by 2012.

RISC reviewed these selected opportunities and where appropriate made adjustments to Venture's resources and risk assessment. Where opportunities were reviewed in detail, an upside volume was also assessed and utilised in the upside scenario. For opportunities not reviewed in detail, the base scenario volumes were carried across to the upside scenario.

A review of recent comparative transactions from public domain information between 2006 and 2009 provides a range of £0.80 to £6.75/boe for portfolios comprising undeveloped discoveries or exploration prospects only. From this analysis, RISC assigned unit values of £1, £1.50 and £3/boe for exploration, near-field exploration and undeveloped discoveries respectively to the risked volumes for the 20 selected opportunities. The estimated risked contingent and prospective resources for the base scenario are 87 MMboe (Venture share) and for the upside scenario 125 MMboe (Venture share). This resulted in a base scenario value of £160 million and an upside scenario value of £225 million.

While the valuation of these opportunities was primarily determined from comparative transaction values, EMVs (based on discounted cash flow analysis for selected prospects) and a review of indicative work programs both bracket the value range indicated above, providing general support to this methodology.

A short description of 3 key prospects follows.

Morpheus is a large undrilled Rotliegend fault block with a potential high estimate prospective resource of 1 Tcf). The structure sits under an unusual detached salt canopy which provides significant challenges to seismic imaging of the structure and depth conversion. The Carboniferous is a secondary target. RISC views Venture's range of prospective resources as too narrow given the high uncertainty associated with the prospect and our own estimates result in a reduction in the best estimate volume to 400 Bcf. RISC supports Venture's estimated Probability of Success of 15%.

The Andromeda prospect is to the north of the Carna discovery with reservoirs in Carboniferous channel sands. The structure is faulted and carries reservoir risk. Additional seismic has been acquired by Venture and will be incorporated into a broader interpretation. RISC supports Venture's best estimate prospective resource of 274 Bcf and Probability of Success of 17%.

South Copernicus is a Carboniferous discovery to the south of the Cygnus field. The discovery well tested up to 30 MMscf/d. A large robust structure is developed to the south of the discovery well and an appraisal well is required to test the extent of the reservoir. We estimate best estimate resources of 60 Bcf (Venture share) and Probability of Success of 50%. A CO2 content of up to 10% is expected which will impact development costs.

Venture's full exploration license interests are shown in Appendix A.

6 ECONOMICS

6.1 FISCAL TERMS AND KEY ASSUMPTIONS

RISC has audited a consolidated discounted cash flow model provided by Venture. The model and data input have been based on 100% field cash flows. Venture's share of value is calculated at the hub level, applying their working interest. Ventures opening tax balances have been added at a consolidated level.

A summary description of the relevant terms and assumptions used in the models follows.

UK Terms

- All fields pay no UK Government Royalties.
- All values are presented post Corporation Tax (CT) at 30% and Supplementary Corporation Tax (SCT) at 20%.
- Two fields qualify for Petroleum Revenue Tax (PRT), Markham, Audrey and Kittiwake. Audrey and Kittiwake never reach a PRT payable position, remaining within its petroleum allowances. Markham is expected to start paying PRT in 2010 (Ventures supplied calculation) when oil allowances come to an end – such that PRT at 50% is applied to the Markham revenue stream.
- Small Field Allowance – Qualifying fields (less than 26.3 MMboe) have additional offset allowances for tax. In the upside scenario total value of this allowance reduces as reserve size increases and excludes fields.

Netherlands Terms

Companies engaged in the production of hydrocarbons in the Netherlands pay an additional Production Profit Tax (50%) as well as the normal Corporate Income Tax (30%). The taxes are mutually interactive, and thus the effective tax rate payable is 50%.

Effective Date

The effective date of our valuation is 1st July 2009.

Opening Position

Tax losses are assumed to be applied at the consolidated level, with the majority offset over the first two years of cash flow. The opening balance of £153 million (supplied by Venture) is based on audited end 2008 accounts. RISC has not audited the past costs.

Oil Price

A base scenario forecast of Brent oil price was assumed to be the current (July '09) forward curve in real terms to 2014, then constant in real terms thereafter. Sensitivities to value of 80% and 120% were evaluated.

Brent	2009	2010	2011	2012	2013	2014	2015	2016
Real US$/bbl	66.5	71.5	75.2	77.7	80.5	82.9	82.9	82.9

Gas Price

A base scenario forecast of National Balancing Point (NBP) gas sales price was assumed to be the current (July '09) forward curve as published by Heren, in real terms to 2014, then held constant in real terms thereafter. For the UK this was a NBP price and for the Dutch gas, a Title Transfer Facility (TTF) price – both prices are flat real. Sensitivities to value of 80% and 120%, equating for all prices to 54p/therm and 82p/therm in 2014 respectively, were also evaluated.

NBP	2009	2010	2011	2012	2013	2014	2015	2016
Real pence/therm	41.8	46.1	57.0	61.0	65.0	68.0	68.0	68.0

It is assumed that the margin between NBP and TTF (currently 4%) will reduce to zero by 2012, and then follow the same price thereafter.

Inflation

2.0% per annum.

Discount Rate

Project NPVs are reported at 8% real / 10% nominal discount rates, with effective end year discounting.

Exchange rate

US$ per GBP = 1.60 based on a rolling average over the past 10 years.

6.2 THIRD PARTY INCOME

Markham field attracts third party tariffing, however due to the asset paying PRT from 2010 the value of the income stream is modest.

6.3 BASE AND UPSIDE SCENARIOS

RISC has prepared base and upside scenarios for the purpose of this valuation.

The base scenario comprises:-

- RISC's production and cost forecasts corresponding to volumes classified as 2P reserves for assets reviewed by RISC and Venture's production and cost forecasts corresponding to Venture's 2P reserves for assets not reviewed by RISC.
- RISC's estimates of risked contingent and prospective resources for exploration and appraisal opportunities which we expect to be evaluated in the near/medium term.

The upside scenario comprises the base scenario plus:-

- A representative sample of upside opportunities that we consider reasonably represents the scope for near/medium term reserves growth within the existing portfolio, consistent with Venture's historical reserves growth record (excluding acquisitions/disposals).
- An upside view of exploration and appraisal success in the near/medium term.

6.4 ECONOMIC RESULTS

Net present values have been calculated for the production, cost and product price forecasts for volumes classified as 2P reserves. All values are post tax.

In addition, $/boe values have been applied to select assets that are in the appraisal phase, and also exploration risked reserves. The $/boe metrics employed are based on discounted cash flow analysis of generic analogous fields and RISC's global assumptions.

The tables below summarises value for both the base and upside scenarios.

Value of Venture's Petroleum Assets £million	**Base Scenario**	**Upside Scenario**
Reserves	1,742	2,209
Contingent and Prospective Resources	160	225
Other Assets	8	8
Total Asset Value	**1,910**	**2,442**

Table 13 Valuation Summary

Reserves value includes UK and Dutch assets (North Sea) plus Trinidad acreage and brought forward tax losses. Trinidad reserves value of £11.7 million is a Venture management estimate based on current book value of Venture's 40% holding in Ten Degrees North Energy Limited ("TDN") and has not been audited by RISC.

Contingent and Prospective Resources value is more fully described in Section 5.0 above.

Other Assets value includes £14.1 million for Venture's 49.9% holding in North Sea Infrastructure Partners Limited ("NSIP"), £17.4 million for the commodity and foreign exchange hedge positions and -£23.5 million being the assessment of the net present value of Venture's corporate overhead costs (at £5.1 million per annum per the 2008 accounts). The NSIP asset is a Venture management estimate based on current book value.

The above estimates have not been adjusted for other factors that a buyer or seller may consider in any transaction concerning these assets.

6.5 SENSITIVITY ANALYSES

Sensitivities to the base scenario reserves valuation of £1,742 million to changes in discount rate, capital costs, operating costs and commodity prices are presented in the following table and figures:

Sensitivity Values (£million)	Decrease	Base Scenario	Increase
Discount rate: Low 12%, High 8%	-168	1742	+200
Capex: Low +20%, High -20%	-107	1742	+107
Opex: Low +20%, High -20%	-142	1742	+142
Oil Price: Low-20%, High +20%	-151	1742	+151
Gas Price: Low -20%, High +20%	-323	1742	+323
Oil and Gas Price: Low -20%, High +20%	-474	1742	+474

Table 14 Sensitivity Analysis

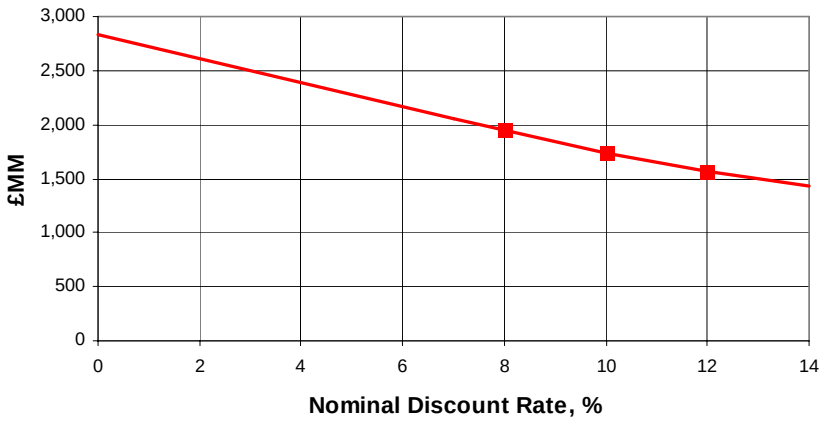

Figure 14 NPV Sensitivity to Discount Rate

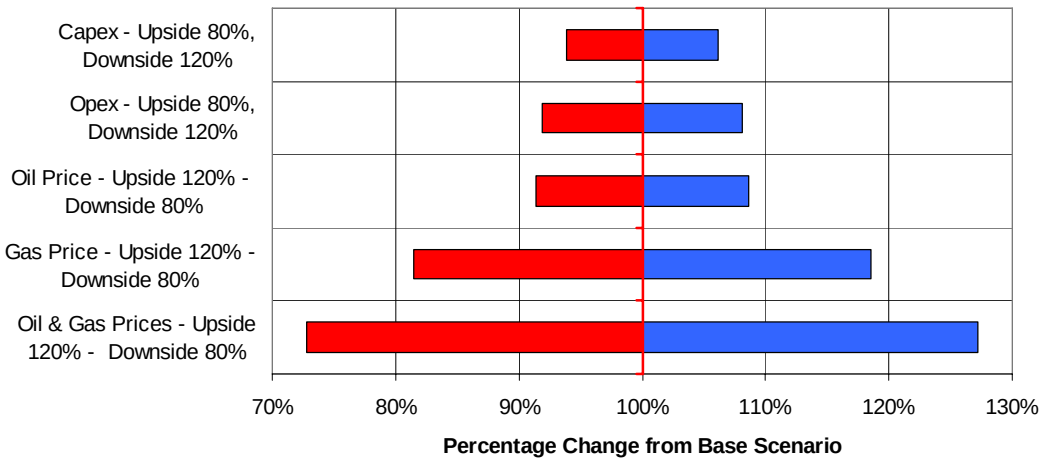

Figure 15 NPV10 sensitivities to Capex/Opex/Price

APPENDIX A

Area/Hub	Field	Blocks	Working Interest	Operator
Greater Kittiwake				
	Goosander	21/12a	50%	Venture
	Mallard	21/19	50%	Venture
	Grouse	21/19	50%	Venture
	Kittiwake	21/18a	50%	Venture
	Gadwall	21/19	50%	Venture
Trees				
	Birch	16/12a	100%	Venture
	Larch	16/12a	100%	Venture
	Sycamore	16/12a	100%	Venture
Central N Sea				
	Chestnut	22/2a	69.8%	Venture
	Halley Beta	30/12b	40%	Talisman
Greater Markham				
	Markham	49/5a	37.5%	Venture
	Windermere	49/4b	20%	RWE-DEA
	Chiswick	49/4a	100%	Venture
	Stamford	49/10c	100%	Venture
	J3C	J/3b, J6	4%	Total
UK Gas				
	Ann	49/6a	100%	Venture
	Alison	49/11a	100%	Venture
	Annabel	48/10a	100%	Venture
	Audrey	48/15a	100%	Venture
	Saturn	48/10b	22%	Conoco Phillips
	Mimas	48/9a	15%	Conoco Phillips

Table 15 Venture's Producing Field Interests (excluding Trinidad)

Area/Hub	Field	Blocks	Working Interest	Operator
Greater Kittiwake				
	Christian	21/20b	50%	Venture
	Bligh	21/20c	30.5%	Venture
Central N Sea				
	Halley	30/12b	40%	Talisman
	Appleton	30/11b	100%	Venture
	Acorn	29/8a(S), 29/8b	100%	Venture
	Beechnut	29/9b	100%	Venture
	Selkirk	22/22b	31.5%	
	West Wick	13/21a	58.73	Venture
Greater Markham				
	Kew	49/4c	100%	Venture
	Arrol	44/28a	90%	Venture
	Ketex	49/3	90%	Venture
Northern Netherlands				
	F3FA	F/3a, B/18a	58%	Venture
	A15a	A/15a	27%	Venture
	B17a	B/17a	23.5%	Venture
UK Gas				
CMS	Cygnus	44/11a, 44/12a	48.8%	GdF
	Copernicus	44/16b	48.75	GdF
	Garnet	44/27a	26.5	GdF
	Kepler	44/16c	20.475	GdF
	Opal	43/25a	32.3	GdF
	Humphrey	44/16a	24.375	GdF
A Fields	Annabel East	48/10a	100%	Venture
	Amanda	49/11a	100%	Venture
	Ensign	48/14a, 48/15a	100%	Venture
ECA	Ceres	47/9c	90%	Venture
	Eris	47/3h	54%	Venture
GCA	Carna	43/21b, 43/22c	56%	Venture
East Irish Sea				
	Marram	110/4, 110/9b	70%	Venture

Table 16 Venture's Discovered Non-Producing Field Interests

Block	License Round	Expiry Date	Commitments	Key Prospects
16/12A	UK 4th	2018	None	Cedar
21/17A	UK 24th	2033	Firm well	Whitethroat, Warbler
21/19	UK 4th	2018	None	Gadwall South, Godwit, Greylag, Mallard South, Shark, Nora
21/20B	UK 8th	2019	None	Christian Deep
21/20C	UK 25th	2034	Contingent Well	Bligh Extension
21/20D	UK 4th	2018	None	Bligh (A)
21/20E	UK 25th	2034	None	Bligh Extension
22/26B	UK 25th	2034	Drill-or-drop	Nautilus
29/9E	UK 25th	2034	Contingent Well	Cornwall
38/25	UK 24th	2015	Drill-or-drop	Cheddar & other leads
42/25B	UK 22nd	2012	None	Ptelea, Garrow SE
43/11	UK 23rd	2013	Contingent well (in 43/11 or 12)	Carboniferous Leads
43/12	UK 23rd	2013	Contingent well (in 43/11 or 12)	Andromeda, Carboniferous Leads
43/16	UK 22nd	2012	None	West Harmonia, Carya
43/21B	UK 22nd	2012	None	Thetis, Morea
43/22B	UK 25th	2034	Drill-or-drop	Carna Extension
43/25A	UK 8th	2019	None	Opal (A)
43/28	UK 25th	2034	Drill-or-drop	Morpheus extension, Hypnos extension
43/29	UK 25th	2034	Drill-or-drop	Hypnos extension, Lead
44/16A	UK 20th	2010	None	NW Humphrey, Humphrey (A)
44/16B	UK 20th	2010	None	Copernicus (A)
44/16C	UK 20th	2010	None	Kepler (A)
44/21E	UK 24th	2033	Drill-or-drop	Boulton X & Y
44/26B	UK 25th	2034	Drill-or-drop	Schooner SE extension, lead
44/26C	UK 25th	2034	Drill-or-drop	Lead
44/27A	UK 9th	2021	None	Garnet (A)
44/27C	UK 24th	2015	Drill-or-drop	Schooner SE
44/28A	UK 25th	2034	Drill-or-drop	Arrol (A), SE

				Corner, Carboniferous leads
44/29A	UK 22nd	2030	None	Carboniferous leads
48/3A	UK 22nd	2012	Firm well (in 48/3a or 4)	Morpheus, Endymion, Updip 48/3-4
48/4	UK 22nd	2012	Firm well (in 48/3a or 4)	Hypnos, Morpheus Extension
48/7E	UK 25th	2034	Drill-or-drop	Lead
48/7F	UK 25th	2034	Drill-or-drop	Lead
48/10A	UK 1st	2010	First round well	Annabel East
48/15A (Ensign)	UK 4th	2018	None	Ensign SE (A)
48/15B	UK 22nd	2012	First round well – well drilled	Andrea (drilled)
49/3	UK 25th	2034	Drill-or-drop	Ketex (A), Carboniferous leads
49/4A	UK 8th	2019	None	Battersea
49/5A	UK 8th	2019	None	Battersea Extension
49/5B	UK 22nd	2030	None	Wandsworth
49/11A	UK 1st	2010	First round well	Adele, Agatha/Adele SE
53/3D	UK 23rd	2013	Firm well	Alcyone, Lead
110/3B	UK 24th	2015	Firm well (currently drilling)	Whitbeck

Table 17 Venture's Exploration Licenses and Commitments

APPENDIX B

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.

Abbreviation	Definition
boe	US barrels of oil equivalent
bbl	US barrel
bbl/d	US barrels per day
Bcf	Billion (109) cubic feet
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
BTU	British Thermal Units
BWPD	Barrels of water per day
C	Celsius
Capex	Capital expenditure
CNS	Central North Sea
CGR	Condensate Gas Ratio – usually expressed as bbl/MMscf
Contingent Resources	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable according to the definitions of the Society of Petroleum Engineers, World Petroleum Congresses and American Association of Petroleum Geologists.
CT	Corporation Tax
deg	Degrees
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
EIA	US Energy Information Administration
EMV	Expected Monetary Value
EUR	Economic ultimate recovery
F	Degrees Fahrenheit
FC	Forward Curve
FDP	Field Development Plan
Fm	Formation
FPSO	Floating offshore production and storage unit
ft	Feet

Abbreviation	Definition
GIIP	Gas Initially In Place
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GWC	Gas water contact
HPHT	High Pressure High Temperature
JV(P)	Joint Venture (Partners)
Kh	Horizontal permeability
km2	Square kilometers
Kv	Vertical permeability
LOGGS	Lincolnshire Offshore Gas Gathering System
Mstb/d	Thousand US barrels per day
m	Metres
mD	Millidarcies (permeability)
MMbbl	Million US barrels
MMscf(d)	Million standard cubic feet (per day)
MMstb	Million US stock tank barrels
Mscf	Thousands standard cubic feet
Mstb	Thousand US stock tank barrels
mss	Metres subsea
MSV	Mean Success Volume
mTVDss	Metres true vertical depth subsea
NBP	National Balancing Point
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

Abbreviation	Definition
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.
POS	Probability of Success
Prospective Resources	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations according to the definitions of the Society of Petroleum Engineers, World Petroleum Congresses and American Association of Petroleum Geologists.
PRT	Petroleum Revenue Tax
Psia	Pounds per square inch pressure absolute
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 hydrocarbons which are anticipated to be commercially recovered from known accumulations from a given date forward according to the definitions of the Society of Petroleum Engineers and World Petroleum Congresses.
RISC	RISC (UK) Limited (authors of this report)
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
SCT	Supplementary Corporation Tax
Sg	Gas saturation
SPE	Society of Petroleum Engineers
ss	Subsea
stb	Stock tank barrels
SNS	Southern North Sea
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
Tcf	Trillion (10^{12}) cubic feet
TTF	Title Transfer Facility
TVD	True vertical depth
US$	United States dollar
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 Congresses
WP&B	Work Programme and Budget

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Additional information

1. Responsibility

The Company and the Directors accept responsibility for the information contained in this document and confirm that to the best of their knowledge and belief (having 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. Directors

The Directors and their functions are set out below:

Name	*Function*
Rod Begbie	Corporate Development Director
Tom Blades	Non-Executive Director
Andrew Carr- Locke	Non-Executive Director
Tom Ehret	Non-Executive Director
Alan Jones	Non-Executive Director
Larry Kinch	Non-Executive Director
John Morgan	Chairman and Non-Executive Director
Mark Nicholls	Non-Executive Deputy Chairman and Non-Executive Senior Independent Director
Jonathan Roger	Chief Operating Officer
Peter Turner	Finance Director
Robb Turner	Non-Executive Director
Mike Wagstaff	Chief Executive

The business address of each of the Directors is Kings Close, 62 Huntly Street, Aberdeen AB10 1RS.

3. Disclosure of interest and dealings

3.1 Since the publication by the Company of the Defence Circular there have been the following material changes in the interests and dealings of Directors in Ordinary Shares.

(a) *Dealings in Ordinary Shares by Directors*

The following Ordinary Shares were purchased under the Share Incentive Plan on 29 July 2009 on the London Stock Exchange. Partnership Shares (as defined in the Share Incentive Plan) were purchased by the following Directors at 834.95 pence per Ordinary Share, Matching Shares (as defined in the Share Incentive Plan) were transferred at nil cost pursuant to the Share Incentive Plan and all such Ordinary Shares will be held on trust by Share Nominees Limited as trustee under the Share Incentive Plan.

Name	*Date*	*Transaction*	*Number*	*Price*
Mike Wagstaff	29 July 2009	Purchase	15	834.95 p
		Purchase	30	Nil
Jonathan Roger	29 July 2009	Purchase	15	834.95 p
		Purchase	30	Nil
Rod Begbie	29 July 2009	Purchase	15	834.95 p
		Purchase	30	Nil
Peter Turner	29 July 2009	Purchase	15	834.95 p
		Purchase	30	Nil

(b) *Interests of Directors in Ordinary Shares*

As at close of business on 3 August 2009 (the latest practicable date prior to publication of this document), the following Ordinary Shares were held on trust for the Directors by Share Nominees Limited as trustee under the Share Incentive Plan:

Director	*Number of Ordinary Shares*
Mike Wagstaff	9,272
Jonathan Roger	7,958
Rod Begbie	9,272
Peter Turner	1,155

4. Other information

4.1 Save as disclosed in this document there have been no material changes to the information contained in the Defence Circular.

4.2 RISC has given and not withdrawn its written consent to the issue of this document, with the inclusion of its report entitled "Independent Valuation of the Petroleum Assets of Venture Production plc" (the **RISC Report**) and the inclusion herein of the references to its name in the form and context in which they appear. RISC has consented to the public display of the RISC Report in accordance with the City Code and to the inclusion of the RISC Report on the Company's website.

4.3 Rothschild has given and not withdrawn its written consent to the issue of this document with the inclusion herein of the references to its name in the form and context in which they appear.

4.4 Lambert Energy has given and not withdrawn its written consent to the issue of this document with the inclusion herein of the references to its name in the form and context in which they appear.

4.5 Oriel has given and not withdrawn its written consent to the issue of this document with the inclusion herein of the references to its name in the form and context in which they appear.

4.6 UBS has given and not withdrawn its written consent to the issue of this document with the inclusion herein of the references to its name in the form and context in which they appear.

4.7 A copy of this document (which includes the RISC Report) and the letters of consent referred to in paragraphs 4.2 to 4.6 will be available for inspection at the offices of Orrick, Herrington & Sutcliffe, Tower 42, Level 35, 25 Old Broad Street, London EC2N 1HQ during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) up to and including the end of the Offer Period.

4 August 2009

Bases of calculation and sources of information

1. General

1.1 Unless otherwise stated in this document:

1.1.1 the financial information relating to Venture has been extracted or derived (without any adjustments) from annual reports and accounts of Venture for the relevant periods and other information made publicly available by Venture; and

1.1.2 information regarding the Offer is sourced from the Offer Document and other material made publicly available by Centrica.

1.2 Values stated throughout the document have been subjected to rounding and are given to the stated number of decimal places.

Page references

The relevant bases of calculation and sources of information are provided below in the order in which such information appears in this document and by reference to page numbers of this document. Where such information is repeated in this document, the underlying sources and bases are not repeated.

Page 2

1) The reference that RISC's value range for Venture's assets is equivalent to between 1,066p per share and 1,385p per share on a fully diluted basis after adjusting for net debt as at 30 June 2009 is calculated as follows

$$\frac{\text{RISC total asset value} - \text{Venture net debt as at 30 June 2009 (excluding convertible bonds)}}{\text{Fully diluted number of shares (including convertible bonds)}}$$

2) The reference that RISC's range of values for Venture is equivalent to US$12.7 – 16.3/boe is calculated as follows

i. The enterprise value in US dollars is calculated based on RISC's total asset value in pounds sterling, converted to US dollars at a £:US$ exchange rate of 1:1.60. The exchange rate is as per page 36 of the RISC Report

ii.

$$\text{Implied value per barrel} = \frac{\text{Enterprise value}}{\text{Venture's proved and probable reserves as of 31 March 2009}}$$

3) The reference that the value under Centrica's offer is US$10.5/boe is calculated as follows

i. The equity value is calculated based on the Offer Price of 845p per share and number of shares in issue of 149,769,828

ii. The enterprise value is calculated based on Venture's net debt of £286 million as of 30 June 2009 (including £151 million of convertible bonds). £:US$ exchange rate of 1:1.6211 is used in converting the enterprise value from pounds sterling to US dollars. The exchange rate is sourced from Bloomberg (as of market close on 10 July 2009)

iii.

$$\text{Implied value per barrel} = \frac{\text{Enterprise value}}{\text{Venture's proved and probable reserves as of 31 March 2009}}$$

Note: The implied value under Centrica's offer of US$10.3/boe quoted in the Defence Circular, dated 24 July 2009, has been calculated using the same methodology as shown above but using a net debt figure for Venture as of 31 December 2008.

4) The reference that the 1,066p per share base case is more than 25% higher than Centrica's Offer is calculated as follows

$$\frac{\text{Per share base case}}{\text{Offer Price of 845p per share}} - 1$$

5) The 'Precedents' column in the chart 'Venture is worth substantially more than 845p' represents the mean value per barrel of proved and probable reserves implied in comparable transactions involving gas-weighted asset portfolios with existing production in the UK and Dutch sectors of the North Sea, announced from 2004 to 2009 year to date. The selection of comparable transactions and the data is sourced from an independent analysis undertaken by IHS Herold on behalf of Venture and dated 22 July 2009. The report can be viewed at www.venture-production.com.

6) The 'Nuon/Venture' column in the chart 'Venture is worth substantially more than 845p' represents the value per barrel of proved and probable reserves implied in Venture's recently announced proposed sale and farm out of 9.3MMboe proved and probable reserves in the southern North Sea to N.V. Nuon Energy for £96.5 million (US$158 million). The data is sourced from an independent analysis undertaken by IHS Herold on behalf of Venture and dated 22 July 2009. The report can be viewed at www.venture-production.com.

7) The reference that the share prices of all Venture's peers have increased further since 10 July 2009 by an average of 17.2% is calculated by taking the mean for Tullow Oil plc, Dana Petroleum plc, Premier Oil plc and Valiant Petroleum plc of the following calculation

$$\frac{\text{Peer share price at market close on 3 August 2009}}{\text{Peer share price at market close on 10 July 2009}} - 1$$

where for each of the peers the result of the above calculation was greater than zero. All share price data is sourced from Exshares (Note: Exshares adjusts historical data, including share prices, for the effects of corporate actions such as rights issues and stock splits)

8) The reference that Centrica's Offer is now at a 9% discount to Venture's share price adjusted for the share price performance of its UK E&P peer group since the start of the Offer Period on 18 March 2009 is calculated as follows

$$\frac{\text{Offer Price of 845p per share}}{\text{Venture's adjusted share price}} - 1$$

Where Venture's adjusted share price is calculated as follows

Venture closing price on 17 March 2009 x
(1+peers' average share price increase since 17 March 2009)

Where the peers' average share price increase is calculated by taking the mean increase in share price for Tullow Oil plc, Dana Petroleum plc, Premier Oil plc and Valiant Petroleum plc since 17 March 2009, being the last trading day prior to the commencement of the Offer Period, using the following calculation

$$\frac{\text{Peer share price at market close on 3 August 2009}}{\text{Peer share price at market close on 17 March 2009}} - 1$$

All share price data is sourced from Exshares (Note: Exshares adjusts historical data, including share prices, for the effects of corporate actions such as rights issues and stock splits)

9) The reference to the FTSE 100 index having increased by 13.5% and the FTSE 250 having increased by 13.6% is calculated as follows

$$\frac{\text{Index at market close on 3 August 2009}}{\text{Index at market close on 10 July 2009}} - 1$$

All FTSE index data is sourced from Exshares

Page 3

1) The reference that the average forecast gas price for 2011 has increased by a further 5.5% is calculated as follows

$$\frac{\text{Average forecast gas price for 2011 at market close on 3 August 2009}}{\text{Average forecast gas price for 2011 at market close on 10 July 2009}} - 1$$

where the average forecast gas price for 2011 is calculated as follows

$$\frac{\text{Sum of NBP Natural Gas quarterly contracts prices for the 2011 calendar year}}{4}$$

All prices are sourced from the ICE (as at market close on the respective dates)

2) The reference that the average gas forecast for 2011 is now 122% higher than the spot price on the date of Centrica's offer is calculated as follows

$$\frac{\text{Average forecast gas price for 2011 at market close on 3 August 2009}}{\text{NBP Day Ahead price at market close on 10 July 2009}} - 1$$

All prices are sourced from the ICE (as at market close on the respective dates)

3) The reference that the forward oil prices for July 2011 have increased yet further, by 13.2% is calculated as follows

$$\frac{\text{Forward Brent oil price for 1 July 2011 at market close on 3 August 2009}}{\text{Forward Brent oil price for 1 July 2011 at market close on 10 July 2009}} - 1$$

All prices are sourced from the ICE (as at market close on the respective dates)

Definitions

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

3D Seismic	a set of numerous closely-spaced seismic lines that provide a high spatially sampled measure of subsurface reflectivity. In a properly migrated 3D seismic data set, events are placed in their proper vertical and horizontal positions, providing more accurate subsurface maps than can be constructed on the basis of more widely spaced 2D seismic lines
bbl	a barrel (a barrel which is equivalent to 42 US gallons)
Board or **Directors**	the board of directors of the Company, whose names appear on page 7 of this document
boe	barrel of oil equivalent
Brent	a benchmark crude oil, the most commonly traded North Sea crude oil
Centrica	Centrica plc and its wholly owned subsidiary, Centrica Resources (UK) Limited (as offeror)
City Code	The City Code on Takeovers and Mergers published by the Panel on Takeovers and Mergers from time to time
Company or **Venture**	Venture Production plc and, where the context permits, its subsidiary undertakings
Contingent Resources	those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable
Defence Circular	the circular to shareholders published by the Company on 24 July 2009 in response to Centrica's Offer
Development	the phase of petroleum operations that occurs after exploration has proven successful, and before full scale production
E&P	Exploration and Production
Exploration	the initial phase in petroleum operations that includes generation of a prospect or play or both, and drilling of an exploration well
FPSO	Floating Production, Storage and Off-loading vessel
FTSE 100	an index of the share prices of the UK's 100 largest companies (by market capitalisation)
FTSE MID 250 Index (FTSE 250)	Financial Times Stock Exchange Mid 250 Index comprises the share prices of the 250 companies that follow the top 100 (comprising the FTSE 100)
Group	Venture and each of its subsidiary undertakings
ICE	IntercontinentalExchange Inc
IHS Herold	IHS Herold Inc
Lambert Energy	Lambert Energy Advisory Limited, financial adviser to Venture

MMboe	million barrels of oil equivalent
Natural gas	a naturally occurring mixture of hydrocarbon gases that is highly compressible and expansible
NBP Natural Gas quarterly	NBP Natural Gas Futures contracts traded on ICE for delivery of gas over the one calendar quarter stated in the specific futures contract (For example a quarterly contract for Q1 2011 would be for gas delivery from 1st January 2011 to 31st March 2011)
NBP	National Balancing Point, a virtual trading location for the sale and purchase of UK natural gas
NBP Day Ahead	NBP Natural Gas Futures contract traded on ICE for delivery of gas the calendar day immediately following the day on which the trade occurred
Offer or **Centrica's Offer**	the final offer made by Centrica pursuant to the terms set out in the Offer Document to acquire Ordinary Shares not already owned by Centrica at the Offer Price
Offer Document	the offer document published by Centrica on 16 July 2009 setting out the terms of the Offer
Offer Period	the period commencing on (and including) 18 March 2009 and ending on the date on which the Offer becomes or is declared unconditional as to acceptances or lapses
Offer Price	845 pence per Ordinary Share
Ordinary Shares or **shares**	ordinary shares of 0.4 pence each in the capital of the Company and references to an **Ordinary Share** or a **share** shall be construed accordingly
Oriel	Oriel Securities Limited, financial adviser and corporate broker to Venture
per share base case	1,066p per share which is equivalent to RISC base case total asset valuation on a fully diluted basis after adjusting for net debt as at 30 June 2009. See Page 9 of this document for the bases of calculation
Petroleum	oil or gas or condensate
pounds sterling, "£", pence or **"p"**	the lawful currency of the United Kingdom
probable reserves	those reserves which are not yet proven but which, on the available evidence and taking into account technical and economic factors, have a better than 50 per cent. chance of being produced
prospective resources	those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations according to the definitions of the Society of Petroleum Engineers, World Petroleum Congresses and American Association of Petroleum Geologists
proved reserves	those reserves which, on the available evidence and taking into account technical and economic factors, have a better than 90 per cent. chance of being produced
Rothschild	N M Rothschild & Sons Limited, financial adviser to Venture
Share Incentive Plan	the share incentive plan of the Company established on 12 September 2003

Shareholder	a holder of Ordinary Shares and **Shareholders** shall be construed accordingly
therm	a non-SI unit of heat equal to 100,000 Btu
UBS or **UBS Investment Bank**	UBS Limited, financial adviser and corporate broker to Venture

For the purposes of this document, **subsidiary**, **subsidiary undertaking** and **undertaking** have the meanings given by the Act and **associated undertaking** has the meaning given by paragraph 19 of Schedule 6 to the Large and Medium-sized Companies and Groups (Accounts and Reports) Regulations 2008 other than paragraph 19(1)(b) of Schedule 6 to those regulations.

Certain other capitalised terms not otherwise defined above are defined and used elsewhere in this document.

All times referred to in this document are London times unless otherwise stated

Reject Centrica's opportunistic offer

Centrica's offer does not reflect Venture's true value

Reject the opportunistic offer

Do not complete any form of acceptance