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Project No. ECV1655

February 2011

Gentlemen,

**EVALUATION OF LANSDOWNE OIL & GAS PLC'S CELTIC SEA ASSETS**

In response to your request, and the subsequent Letter of Engagement dated 15th September 2010 RPS Energy ("RPS") has completed an independent evaluation of certain oil and gas properties in the Celtic Sea, offshore Ireland in which Lansdowne Oil & Gas plc ("Lansdowne") has an interest ("the Properties"). This report on the interests of Lansdowne has been prepared to update the work carried out in February 2009. The update reflects revisions to the economics in light of current oil and gas prices, together with prevailing costs for drilling rigs and associated equipment. No new geological or geophysical data or reports are available since our report dated February 2009. Conceptual development scenarios presented in the report of February 2009 also remain unchanged.

We have estimated a range of reserves and resources as at 1st January 2011 based on data and information available up to 31st December 2010.

In estimating resources we have used standard petroleum engineering techniques, which combine geological and production data with information concerning fluid characteristics and reservoir pressure, where available. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of reserves and resources and risk factors in accordance with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System (See Section 1).

We have taken the working interest that Lansdowne has in the Properties, as presented by Lansdowne, and we have not investigated nor do we make any warranty as to Lansdowne's interest in the Properties.

The data set included geological, geophysical and engineering data, together with reports and presentations pertaining to the contractual and fiscal terms applicable to the assets. In carrying out this review RPS has relied solely upon this information.

**Qualifications**

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. Except for the provision of professional services on a fee basis, RPS does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report.

Mr Gordon Taylor, Director, Geoscience for RPS Energy, has supervised the evaluation. Mr Taylor is a Chartered Geologist and Chartered Engineer with over 30 years experience in upstream oil and gas. Other RPS Energy employees involved in this work hold at least a Masters degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

**Basis of Opinion**

The evaluation presented herein reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the properties. Our estimates of resources and value are based on the data set available to, and provided by, Lansdowne. We have accepted, without independent verification, the accuracy and completeness of these data.

The report represents RPS' best professional judgement and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The report, of which this letter forms part, must therefore be read in its entirety. Except with permission from RPS, this report may not be reproduced or redistributed, in whole or in part, to any other person or published, in whole or in part, for any purpose without the express written consent of RPS. However in instances where excerpts only are to be reproduced or published, this cannot be done without the express permission of RPS. The report was provided for the sole use of Lansdowne and its advisors on a fee basis,

RPS accepts responsibility for the information contained in the RPS report set out in this part of this document and to the best knowledge and belief of RPS, having taken all reasonable care to ensure that such is the case, the information contained herein is in accordance with the facts and does not omit anything likely to affect the import of such information.

Yours faithfully,

RPS Energy

**Gordon R Taylor, CEng, CGeol**
**Director, Geoscience**

# A Valuation of the Celtic Sea Assets, Offshore Ireland

# for

# Lansdowne Oil & Gas plc

Date: February 2011

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# A Valuation of the Celtic Sea Assets of Lansdowne Oil & Gas plc

## Prepared for Lansdowne Oil & Gas plc

**DISCLAIMER**

The opinions and interpretations presented in this report represent our best technical interpretation of the data made available to us. However, due to the uncertainty inherent in the estimation of all sub-surface parameters, we cannot and do not guarantee the accuracy or correctness of any interpretation and we shall not, except in the case of gross or wilful negligence on our part, be liable or responsible for any loss, cost damages or expenses incurred or sustained by anyone resulting from any interpretation made by any of our officers, agents or employees.

Except for the provision of professional services on a fee basis, RPS Energy does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report.



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## Table of Contents


**1. EXECUTIVE SUMMARY ........................................................................................1**

**2. INTRODUCTION ..........................................................................................10**

2.1 Valuation Methodology ........................................................................ 12

2.2 Cashflow Modelling ........................................................................ 13

2.2.1 Oil and Gas Price Assumptions ........................................................................ 13

2.2.2 Currency and Inflation Assumptions ........................................................................ 14

2.2.3 License Block Rentals ........................................................................ 14

2.2.4 Depreciation ........................................................................ 15

2.2.5 Taxation ........................................................................ 15

2.2.6 Economic Limit and Abandonment ........................................................................ 15

2.2.7 Operating Costs of the Kinsale Head Platform ........................................................................ 16

2.3 Previous Exploration in the Celtic Sea Basin ........................................................................ 16

**3. OIL DISCOVERIES AND OIL EXPLORATION LICENSE ......................................19**

3.1 Licensing Option 08/1 (Barryroe Oil Discovery) ........................................................................ 19

3.1.1 Barryroe Oil Discovery ........................................................................ 19

3.1.2 Conceptual Development Plan ........................................................................ 20

3.1.3 Economics ........................................................................ 21

3.1.4 Contingent Resources ........................................................................ 21

3.2 West Barryroe Gas Prospect ........................................................................ 22

3.3 License 2/07 (Helvick Oil Discovery) ........................................................................ 22

3.3.1 Geophysics and Geology ........................................................................ 22

3.3.2 Petrophysics ........................................................................ 26

3.3.3 Volumetrics ........................................................................ 30

3.3.4 Reservoir Engineering ........................................................................ 33

3.3.5 Development Plan ........................................................................ 33

3.3.6 Economics and Contingent Resources ........................................................................ 33

3.4 License 5/08 (Amergin) ........................................................................ 34

3.4.1 Amergin Prospect Upper / Middle Jurassic ........................................................................ 35

3.4.2 Amergin Prospect Upper / Middle Jurassic Conceptual Development Plan . 35

3.4.3 Amergin Prospect Upper / Middle Jurassic Economics ........................................................................ 36

3.4.4 Amergin Prospect Base Wealden ........ 37
3.4.5 Amergin Prospect Basal Wealden Development Plan ........ 37
3.4.6 Amergin Prospect Basal Wealden Economics ........ 37
**4. GAS EXPLORATION LICENSES ........ 39**
4.1.1 Midleton Prospect ........ 40
4.1.2 Midleton Prospect Reservoir Engineering ........ 40
4.1.3 Midleton Prospect Economics ........ 41
4.1.4 East Kinsale Prospect ........ 41
4.1.5 East Kinsale Prospect Reservoir Engineering ........ 42
4.1.6 East Kinsale Prospect Economics ........ 42
4.1.7 East Kinsale 'A' Sand Prospect ........ 43
4.1.8 Northern Old Head of Kinsale Prospect ........ 43
4.1.9 Northern Horst Prospect ........ 44
4.1.10 North Eastern Horst Prospect ........ 44
4.2 License 5/07 (Rosscarbery) ........ 44
4.2.1 Galley Head Discovery ........ 45
4.2.2 Western Upside Prospect ........ 46
4.2.3 Carrigaline Discovery ........ 46
4.2.4 Rosscarbery Prospect ........ 47
4.2.5 Rosscarbery Gas Prospects Reservoir Engineering ........ 47
4.2.6 Rosscarbery Prospect Gas Economics ........ 48
4.2.7 Rosscarbery Prospect Basal Wealden Oil ........ 49
4.2.8 Rosscarbery Prospect Basal Wealden Oil Development Plan ........ 49
4.2.9 Rosscarbery Prospect Basal Wealden Oil Economics ........ 50
4.2.10 West Rosscarbery Prospect ........ 50
4.2.11 South South East Rosscarbery Prospect ........ 51
**APPENDIX A: GLOSSARY OF TERMS AND ABBREVIATIONS ........ 53**
**APPENDIX B: SPE/WPC/AAPG/SPEE RESERVE/RESOURCE DEFINITIONS ........ 56**
**APPENDIX C: CASHFLOW MODELS ........ 60**

## List of Figures


Figure 1: Location of Lansdowne's Celtic Sea licenses and licensing options ........................ 10

Figure 2: Illustration of the use of three points (P90, P50 and P10) to represent a hypothetical resources distribution, as employed in this study ................................ 12

Figure 3: Example of the modelled outcomes for each prospect ............................................ 13

Figure 4: Variation of the real Brent oil price .......................................................................... 14

Figure 5: Production profiles for the Kinsale Head, Seven Heads and Old Head of Kinsale Fields ........................................................................................................ 16

Figure 6: Stratigraphy of the Celtic Sea Basin.......................................................................... 17

Figure 7: Licensing option 08/1 illustrating the division of subsurface rights .......................... 19

Figure 8: Top Bathonian two-way time structure, Helvick discovery........................................ 23

Figure 9: Average velocity to Top Bathonian Limestone, Helvick oil discovery ....................... 24

Figure 10: Depth of Top Main Sand, Helvick oil discovery........................................................ 24

Figure 11: Correlation of the Upper Sands, Helvick oil discovery ............................................. 25

Figure 12: Correlation of the Main Sands, Helvick oil discovery ............................................... 26

Figure 13: RPS Petrophysical analyses of wells 49/9-2, 49/9-3st2 and 49/9-6 ........................ 29

Figure 14: Top Middle / Upper Jurassic (Bathonian) depth structure showing the Amergin Prospect ........................................................................................................ 35

Figure 15: Prospects and leads to the north east of the Ballycotton Field ................................ 39

Figure 16: Prospects and leads in the East Kinsale area.......................................................... 40

Figure 17: Location of discoveries and prospects in the 5/07 license area................................ 45


## List of Tables


Table 1: Base case oil price forecast for Brent crude ............................................................... 2

Table 2: Indicative net present values from the Barryroe Oil Discovery (net to Lansdowne 20% working interest) ............................................................................... 2

Table 3: Contingent Resources from the Barryroe License Option (net to Lansdowne 20% working interest) ................................................................................................ 2

Table 4: Summary of Prospective Gas Resources from the Barryroe License Option .............. 2

Table 5: Summary of oil in place in the 49/9-2 fault block of the Helvick discovery (full field interest) ........................................................................................................ 3

Table 6: Indicative net present value for the Helvick oil discovery (net to Lansdowne 10% working interest) ................................................................................................ 3

Table 7: Contingent oil resources for the Helvick oil discovery (net to Lansdowne 10% working interest) ........................................................................................................ 3

Table 8: Indicative net present values for the Upper / Middle Jurassic target in the Amergin Prospect (net to Landsdowne 100% working interest) .................................. 4

Table 9: Indicative net present values for the Basal Wealden target in the Amergin Prospect (Net to Landsdowne 100% working interest) ............................................... 4

Table 10: Summary of Prospective Resources from Exploration License 5/08 .......................... 5

Table 11: Summary of Prospective Resources from Exploration License 4/07 .......................... 6

Table 12: Indicative, success case net present values for the Midleton and East Kinsale Prospects (net to Landsdowne 100% working interest) .............................................. 6

Table 13: Summary of Contingent Gas Resources in Exploration License 5/07 ......................... 7

Table 14: Summary of Prospective Gas Resources in Exploration License 5/07 ........................ 7

Table 15: Summary of Prospective Oil Resources in Exploration License 5/07 .......................... 8

Table 16: Indicative net present values for the 'A' Sand and Wealden Reservoirs of the Rosscarbery Prospect (net to Landsdowne 99% working interest) ............................ 8

Table 17: Indicative, success case net present values and expected monetary value for the Rosscarbery Basal Wealden oil prospect (net to Landsdowne 99% working interest) ......................................................................................................... 9

Table 18: Summary of interests held by Lansdowne ................................................................ 11

Table 19: Summary of blocks within licenses held by Lansdowne ........................................... 11

Table 20: Variation of PRRT rate with R factor .......................................................................... 15

Table 21: Calculation of STOIIP, technically recoverable oil and associated gas from the Middle Wealden of the Barryroe Discovery (full field interest) .................................. 20

Table 22: Calculation of STOIIP, technically recoverable oil and associated gas from the Lower Wealden of the Barryroe Discovery (full field interest) ................................... 20

Table 23: Indicative net present value from the Barryroe License Option (on the basis of a 20% Lansdowne working interest) ............................................................................. 21

Table 24: Summary of Contingent Resources for the Barryroe License Option (on the basis of a 20% Lansdowne working interest) ........................................................... 21

Table 25: GIIP and technically recoverable gas from the West Barryroe Prospect (full field interest) ....................................................................................................... 22

Table 26: Summary of RPS and Jenner Associates petrophysical analyses of wells 49/9-2, 49/9-3st2 and 49/9-6 ............................................................................................ 30

Table 27: Calculation of STOIIP for the Helvick oil discovery (full field interest) ....................... 32

Table 28: Consolidation of STOIIP for the Helvick discovery (full field interest) ........................ 32

Table 29: Indicative net present value for the Helvick oil discovery (net to Lansdowne 10% working interest) ........................................................................................... 34

Table 30: Contingent oil resources for the Helvick oil discovery (net to Lansdowne 10% working interest) ........................................................................................................ 34

Table 31: STOIIP, technically recoverable oil and technically recoverable associated gas from the Upper / Middle Jurassic of the Amergin Prospect....................................... 35

Table 32: Indicative net present values for the Upper / Middle Jurassic target in the Amergin Prospect (net to Lansdowne 100% working interest) .................................. 36

Table 33: Prospective Resources from the Upper / Middle Jurassic target in the Amergin Prospect (net to Lansdowne 100% working interest) ................................................ 36

Table 34: STOIIP, technically recoverable oil and technically recoverable associated gas from the Basal Wealden of the Amergin Prospect ..................................................... 37

Table 35: Indicative net present value from the Basal Wealden target in the Amergin Prospect ........................................................................................................................ 38

Table 36: Summary of Prospective Resources from the Basal Wealden target in the Amergin Prospect .......................................................................................................... 38

Table 37: Calculation of GIIP and technically recoverable gas for the Midleton Prospect......... 40

Table 38: Indicative net present values of the Midleton Prospect............................................. 41

Table 39: Prospective Resources of the Midleton Prospect ... 41
Table 40: Calculation of GIIP and technically recoverable gas for the Upper Wealden reservoir of the East Kinsale Prospect ... 42
Table 41: Indicative net present values for the East Kinsale Prospect ... 42
Table 42: Prospective Resources of the East Kinsale Prospect ... 43
Table 43: Calculation of GIIP and technically recoverable gas for the 'A' Sand reservoir of the East Kinsale Prospect ... 43
Table 44: Calculation of GIIP and technically recoverable gas for the Northern Old Head of Kinsale Prospect ... 43
Table 45: Calculation of GIIP and technically recoverable gas for the Northern Horst Prospect ... 44
Table 46: Calculation of GIIP and technically recoverable gas for the North Eastern Horst Prospect ... 44
Table 47: Calculation of GIIP and technically recoverable gas from the Galley Head Discovery (full field interest) ... 46
Table 48: Calculation of GIIP and technically recoverable gas from the Western Upside Prospect (full field interest) ... 46
Table 49: Summary of GIIP from the Carrigaline Discovery ... 46
Table 50: Calculation of GIIP and technically recoverable gas from the 'A' Sand of the Rosscarbery Prospect (full field interest) ... 47
Table 51: Calculation of GIIP and technically recoverable gas from the Mid Wealden of the Rosscarbery Prospect (full field interest) ... 47
Table 52: Indicative net present values from the 'A' Sand of the Rosscarbery Prospect (net to Lansdowne 99% working interest) ... 48
Table 53: Indicative net present values from the Wealden of the Rosscarbery Prospect (net to Lansdowne 99% working interest) ... 48
Table 54: Prospective Resources of the 'A' Sand of the Rosscarbery Prospect (net to Lansdowne 99% working interest) ... 49
Table 55: Prospective Resources of the Wealden of the Rosscarbery Prospect (net to Lansdowne, on the basis of a 99% working interest) ... 49
Table 56: STOIIP and technically recoverable oil from the Basal Wealden of the Rosscarbery Prospect (full field interest) ... 49
Table 57: Indicative net present values from the Basal Wealden of the Rosscarbery Prospect net to Lansdowne 99% working interest) ... 50
Table 58: Prospective Resources from the Basal Wealden of the Rosscarbery Prospect (net to Lansdowne 99% working interest) ... 50
Table 59: Calculation of GIIP and technically recoverable gas from the 'A' Sand of the West Rosscarbery Prospect ... 51
Table 60: Calculation of GIIP and technically recoverable gas from the Wealden of the West Rosscarbery Prospect (full field interest) ... 51
Table 61: Calculation of GIIP and technically recoverable gas from the 'A' Sand of the South South East Rosscarbery Prospect (full field interest) ... 52
Table 62: Calculation of GIIP and technically recoverable gas from the Wealden of the South South East Rosscarbery Prospect (full field interest) ... 52

# 1. EXECUTIVE SUMMARY

This report presents an update of the Competent Persons Report *A Valuation of the Celtic Sea Assets of Lansdowne Oil & Gas plc* dated February 2009. No new geological or geophysical data has become available since February 2009. However, during December 2010 Lansdowne undertook an asset swap with Providence Resources plc, acquiring a 10% working interest in the portion of Standard Exploration License 02/7 containing the Helvick oil discovery.

As part of the previous evaluation of Lansdowne's Celtic Sea assets dated February 2009, RPS has reviewed the technical data from Standard Exploration Licenses 4/07, 5/07 5/08 and 08/1 and has assessed the range of Contingent Resources or Prospective Resources and the Chance of Discovery (Geological Probability of Success) for each of the prospects. RPS selected the prospects it thinks are likely to be developed and devised a conceptual development scenario for each prospect, estimated production profiles and calculated success case values using a variety of assumptions with regards to variations of gas and oil prices, together with capital and operating costs. No new technical data is available from the Lansdowne licenses. Consequently, this study presents an updated evaluation of the same discovery (Barryroe) and prospects based on current oil and gas price scenarios, together with capital and operating costs. In addition, Lansdowne conducted an asset swap with Providence Resources plc during December 2010, reducing their interest in Licensing Option 08/1 to 20%, whilst acquiring 10% of Standard Exploration License 02/7 containing the Helvick oil discovery and an evaluation of the Helvick discovery is included within this report.

The Barryroe oil discovery is classed as Contingent Resources, of the Development Pending sub-class, as no development plan has yet been submitted to the Petroleum Development Authority (PDA) for approval. The two main problems with the Barryroe conceptual development are the reservoir continuity risk and the high pour point of the oil. The development plan aims to alleviate the reservoir continuity risk through the development of the field in two phases:

Phase 1 involves the drilling of an appraisal well, followed by the pre-drilling of between one (low case) and twenty two (high case) high angle producers into the Middle Wealden in the area around and between wells 48/24-1 and 48/28-1. These wells will be tied back to a well head production platform (WHPP) with minimum facilities and the oil transferred to a leased floating storage, off-take and production vessel (FPSO), with heated storage tanks. The decision on how many producers are required will be based primarily on the results of the appraisal well, but also on the results of early producers.

Phase 2 is assumed to be initiated after fourteen (mid case) or eighteen (high case) years of production and involves the drilling of a further two (mid case) or six (high case) wells through another drilling template in the eastern part of the field. The two Lower Wealden producers will be drilled in the area of wells 48/24-2 and 48/24-3. A second WHPP will be installed and the FPSO moved to that area.

Major items of capital cost are the WHPP and the drilling of wells. It is estimated by RPS that the WHPP will cost US$150MM and that the cost of an appraisal well is US$ 35MM, while the cost of a production well is US$28MM. The main operating cost is associated with the lease of the FPSO and is US$90,000 per day for the first five years, falling to US$75,000 per day thereafter, with an additional variable cost of US$6.5/bbl. Other major operating costs largely result from operating the FPSO, which is estimated as US$7.5MM per annum, together with workovers on the wells. In this evaluation we have used the RPS base case oil price forecast for Brent crude outlined in Table 1.

| Year | Oil price (real) (US$/bbl) |
|---|---|
| 2011 | 85.00 |
| 2012 | 87.00 |
| 2013 | 88.00 |
| 2014 | 90.65 |
| 2015 | 92.47 |
| 2016 | 94.32 |
| 2017 | 96.20 |
| 2018 onwards | + 2% p.a. |

**Table 1: Base case oil price forecast for Brent crude**

The net present value (NPV), in money of the day, of the Lansdowne working interest (20%), in the Barryroe Licensing Option, is summarised in Table 2.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| 1C | 4.4 |
| 2C | 227.3 |
| 3C | 634.4 |

**Table 2: Indicative net present values from the Barryroe Oil Discovery (net to Lansdowne 20% working interest)**

Indicative net present values on Table 6 are based on a total capital investment ranging from US$207 - 1243MM (Lansdowne Share US$43-249MM). Contingent Resources from the Barryroe License Option are summarised in Table 3.

| Case | Contingent Resources (MMstb) |
|---|---|
| 1C | 1.6 |
| 2C | 10.0 |
| 3C | 30.5 |

**Table 3: Contingent Resources from the Barryroe License Option (net to Lansdowne 20% working interest)**

The West Barryroe Gas Prospect has been mapped at Upper Wealden level in License Option 08/1. A summary of technically recoverable Prospective Resources derived by volumetric analysis is given in Table 4.

| | Gross Attributable | | | Net Attributable to Lansdowne 20% Working Interest | | | | |
|---|---|---|---|---|---|---|---|---|
| **Prospect** | **Low (Bscf)** | **Best (Bscf** | **High (Bscf)** | **Low (Bscf)** | **Best (Bscf)** | **High (Bscf)** | **Risk Factor (%)** | **Operator** |
| West Barryroe | 13.9 | 23.9 | 39.8 | 2.8 | 4.8 | 8.0 | 17.6 | Providence Resources |

**Table 4: Summary of Prospective Gas Resources from the Barryroe License Option**

The Helvick oil discovery, in Standard Exploration License 02/7, is classed as Contingent Resources, Development Pending, as Providence (the operator) acknowledge that further subsurface technical studies are required before a development plan can be submitted to the Petroleum Development Authority (PDA). RPS has reviewed the Providence seismic interpretation and mapping and found it to be a reasonable basis for volumetric calculations and has undertaken its own petrophysical analyses. The range of oil in place in the Upper sands, Main Sands and Bathonian Limestone reservoirs has been determined by Monte Carlo simulation and is summarised on Table 5 for the 49/9-2 fault block.

| STOIIP | P90 (MMstb) | P50 (MMstb) | P10 (MMstb) |
|---|---|---|---|
| 49/9-2 Fault Block | 6.6 | 8.0 | 9.8 |

**Table 5: Summary of oil in place in the 49/9-2 fault block of the Helvick discovery (full field interest)**

Production profiles have been calculated using a material balance approach, assuming 100% voidage replacement during water injection. A development plan involving a single producer and injector, together with a Seahorse well head platform and oil off take using an FSO has been proposed by Providence. The cost of the development well is estimated as US$26.8MM and the cost of the injector US$20.0MM by RPS, whilst well head platform has been estimated as US$37.5MM and the cost of converting a tanker to an FSO as US$5.0MM. Oil production is assumed to commence in July 2012. The principal operating cost is that of hire and operation of the FSO, which is estimated as US$17.8/bbl/day. Indicative net present values, in money of the day at a discount rate of 10%, for the 1C, 2C and 3C Contingent Resources, are summarised on Table 6. The indicative net present values are based on a capital outlay of US$ 111.0MM, Lansdowne share US$11.0MM.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| 1C | 1.5 |
| 2C | 3.0 |
| 3C | 12.8 |

**Table 6: Indicative net present value for the Helvick oil discovery (net to Lansdowne 10% working interest)**

Contingent Resources that may be economically recovered from the Helvick oil discovery are summarised on Table 7. Only oil is considered to be contingent resources, as there are currently no plans for gas sales.

| Case | Contingent Resources (MMstb) |
|---|---|
| .1C | 0.2 |
| 2C | 0.3 |
| 3C | 0.6 |

**Table 7: Contingent oil resources for the Helvick oil discovery (net to Lansdowne 10% working interest)**

In the area of Exploration License 5/08 the Amergin Prospect has been mapped. The Amergin Prospect contains both Upper / Middle Jurassic (Bathonian) and Basal Wealden targets. Indicative, success case net present values for the Upper / Middle Jurassic (Bathonian) and Basal Wealden targets have been modelled on a stand-alone basis. A conceptual development plan has been devised by RPS. It is assumed that both of the targets will be developed using a leased FPSO which is estimated by RPS to cost US$90,000 per day for the first five years, subsequently dropping to US$75,000 per day, with a variable cost of US$6.5/bbl. The principal capital costs are the sub-sea jackets and other facilities which are estimated to cost US$29 - 234MM, together with well costs which are estimated as US$31MM for an exploration well, US$25 - 36MM for an appraisal well and US$25 – 32MM for a development well. The annual operating cost of the FPSO is estimated as US$7.5MM. Indicative net present values, in money of the day and at a discount rate of 10%, for the low, best and high case Prospective Resources from the Upper / Middle Jurassic of the Amergin Prospect are summarised in Table 8.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| Cost of failure | -30.1 |
| Low estimate | 226.0 |
| Best estimate | 757.6 |
| High estimate | 2,336.5 |

**Table 8: Indicative net present values for the Upper / Middle Jurassic target in the Amergin Prospect (net to Landsdowne 100% working interest)**

An expected monetary value (EMV) is computed for the Upper / Middle Jurassic target of the Amergin Prospect of US$172.0MM at a discount rate of 10% applying Swanson's rule to the net present values on Table 7 and a chance of discovery of 16.1%. Indicative net present values, in money of the day and at a discount rate of 10%, for the low, best and high case Prospective Resources from the Basal Wealden of the Amergin Prospect are summarised in Table 9.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| Cost of failure | -30.1 |
| Low estimate | -15.1 |
| Best estimate | 484.5 |
| High estimate | 1,583.1 |

**Table 9: Indicative net present values for the Basal Wealden target in the Amergin Prospect (Net to Landsdowne 100% working interest)**

An expected monetary value (EMV) is computed for the Wealden target of the Amergin Prospect of US$146.1MM at a discount rate of 10% applying Swanson's rule to the net present values in Table 9 and a chance of discovery of 22.0%. The total Prospective resources for the Amergin Prospect are summarised in Table 10 and are the volumes recoverable economically from the conceptual development plan.

| | Gross Attributable | | | Net Attributable to Lansdowne 100% Working Interest | | | | |
|---|---|---|---|---|---|---|---|---|
| **Prospect** | **Low (MMstb)** | **Best (MMstb)** | **High (MMstb)** | **Low (MMstb)** | **Best (MMstb)** | **High (MMstb)** | **Risk Factor[1] (%)** | **Operator** |
| Amergin (Upper / Middle Jurassic)[3] | 12.3 | 27.0 | 72.1 | 12.3 | 27.0 | 72.1 | 16 | Lansdowne |
| Amergin (Basal Wealden)[3] | 4.7 | 21.0 | 55.3 | 4.7 | 21.0 | 55.3 | 22 | Lansdowne |
| Consolidated Total[2] | 17.0 | 28.0 | 127.4 | 17.0 | 28.0 | 127.4 | 35 | Lansdowne |

Notes
1 Risk factor means geological chance of discovery
2 The consolidated total is the probabilistic addition of volumes and risk[1]
3 Prospective Resources are economically recoverable with the conceptual development plan

**Table 10: Summary of Prospective Resources from Exploration License 5/08**

Prospects in Standard Exploration License 4/07 occur on two structural trends. Three prospects have been identified on the northern trend with the Midleton Prospect the largest and most mature. Two prospects are identified in the southern trend of which the largest is the East Kinsale Prospect. The East Kinsale prospect contains 'A' Sand (Lower Cretaceous Greensand) and Wealden targets. Two wells have been drilled within the area of the exploration license, but neither tested a valid closure. However, the Old Head of Kinsale gas discovery, just to the south of the license area, confirms the presence of effective reservoirs and moveable hydrocarbons. A summary of Prospective Resources in Exploration License 4/07 is given in Table 11. The Prospective Resources for the Midleton and East Kinsale (Wealden) prospects are those recoverable economically from the conceptual development plan, whereas those from the East Kinsale ('A' Sand) the Northern Horst, the North Eastern Horst and the Old Head of Kinsale are technically recoverable Prospective Resources determined volumetrically using a recovery factor.

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[1] The consolidated total represents the stastically rigorous addition of risked volumes, such that the consolidated total is the P90, P50 and P10 of the risked distribution of the total volume. Consolidation requires the recognition of common chance, those elements that are common to every prospect in a play and termed play risk. The play risk needs to be distinguished from those risk factors specific to individual prospects. In the absence of common chance, distributions are simply summed, after adjustment for the overall chance of each input.

| | Gross Attributable | | | Net Attributable to Lansdowne 100% Working Interest | | | | |
|---|---|---|---|---|---|---|---|---|
| **Prospect** | **Low (Bscf)** | **Best (Bscf)** | **High (Bscf)** | **Low (Bscf)** | **Best (Bscf)** | **High (Bscf)** | **Risk Factor[1] (%)** | **Operator** |
| Midleton* | 40.8 | 44.5 | 45.4 | 40.0 | 44.5 | 45.4 | 26 | Lansdowne |
| East Kinsale (Wealden)* | 26.0 | 54.0 | 114.1 | 26.0 | 54.0 | 114.1 | 24 | Lansdowne |
| East Kinsale ('A' Sand) | 20.3 | 42.1 | 87.5 | 20.3 | 42.1 | 87.5 | 9 | Lansdowne |
| Northern Horst | 23.5 | 36.0 | 54.4 | 23.5 | 36.0 | 54.4 | 13 | Lansdowne |
| North Eastern Horst | 13.7 | 30.0 | 65.3 | 13.7 | 30.0 | 65.3 | 13 | Lansdowne |
| Northern Old Head of Kinsale | 7.7 | 14.3 | 24.2 | 7.7 | 14.3 | 24.2 | 24 | Lansdowne |
| Consolidated Total | 19.9 | 61.9 | 135 | 19.9 | 61.9 | 135 | 64 | |

Notes 1 Risk factor means geological chance of discovery
2 The consolidated total is the probabilistic addition of volumes and risk[2]
3 * Prospective Resources are economically recoverable with the conceptual development plan

**Table 11: Summary of Prospective Resources from Exploration License 4/07**

Indicative success case net present values, in money of the day, for the Midleton prospect and the Wealden reservoir of the East Kinsale Prospect are given in Table 12. The major capital costs are the drilling of wells, estimated by RPS as US$17-25MM, together with the cost of flowlines and umbilicals (US$50MM). The major operating cost is the share of the Kinsale Head platform operating costs, which were allocated on a pro-rata basis according to production and which have been estimated at US$25MM during 2008. A flat real gas price of UK£5.0/Mcf was used in the evaluation.

| **Case** | **NPV @ 10% discount (US$MM)** |
|---|---|
| Midleton | |
| Low Estimate | 36.8 |
| Best Estimate | 42.5 |
| High Estimate | 57.5 |
| East Kinsale (Wealden) | |
| Low Estimate | -22.4 |
| Best Estimate | 44.1 |
| High Estimate | 215.1 |

**Table 12: Indicative, success case net present values for the Midleton and East Kinsale Prospects (net to Landsdowne 100% working interest)**

An expected monetary value for the Midleton Prospect (EMV) of US$-9.5MM, at 10% discount, is calculated from the NPVs in Table 12, together with the chance of discovery of 26.0%. An EMV of US$18.1MM is calculated for the Wealden of the East Kinsale Prospect from the NPVs in, Table together with the chance of discovery of 24.3%.

Standard Exploration License 5/07 contains the Galley Head and Carrigaline discoveries, which are classified as Contingent Resources as there are no plans to develop the discoveries. The small size of the Galley Head discovery means that it belongs to the Development Not Viable sub-class of Contingent Resources whilst the Carrigaline discovery belongs to the Development on Hold sub-class. The existence of these discoveries confirms the presence of effective reservoirs and moveable hydrocarbons. A total of six other principal prospects have been identified in the exploration license. However, prospect size and risk vary quite widely. The Rosscarbery Prospect is the largest and most mature prospect in the licence option, whilst the Wealden reservoir of the Rosscarbery prospect also has the lowest risk. A summary of Contingent Resources in Licence Option 5/07 is given in Table 13 whilst a summary of Prospective Resources in the licence option is given in Table 14. Prospective Resources for the 'A' Sand, Wealden and Basal Wealden oil reservoirs are economically recoverable volumes derived from the conceptual development plan. However, Prospective Resources for the West Rosscarbery 'A' Sand, West Rosscarbery Wealden, SSE Rosscarbery 'A' Sand and SSE Rosscabery Wealden reservoirs are technically recoverable Prospective Resources determined volumetrically using a recovery factor.

| | Gross Attributable | | | Net Attributable to Lansdowne (99%) | | | |
|---|---|---|---|---|---|---|---|
| **Discovery** | **1C (Bscf)** | **2C (Bscf)** | **3C (Bscf)** | **1C (Bscf)** | **2C (Bscf)** | **3C (Bscf)** | **Operator** |
| Galley Head | 4.0 | 5.3 | 7.0 | 4.0 | 5.2 | 6.9 | Lansdowne |
| Carrigaline | 41.6 | 60.8 | 85.5 | 41.2 | 60.2 | 84.6 | Lansdowne |
| Total | 45.6 | 66.1 | 92.5 | 45.2 | 65.4 | 91.5 | |

**Table 13: Summary of Contingent Gas Resources in Exploration License 5/07**

| | Gross Attributable | | | Net Attributable to Lansdowne (99% Working Interest) | | | | |
|---|---|---|---|---|---|---|---|---|
| **Prospect** | **Low (Bscf))** | **Best (Bscf)** | **High (Bscf)** | **Low (Bscf))** | **Best (Bscf)** | **High (Bscf)** | **Risk Factor[1] (%)** | **Operator** |
| Rosscarbery 'A' Sand* | 26.0 | 83.8 | 143.5 | 25.7 | 83.0 | 142.1 | 29.0 | Lansdowne |
| Rosscarbery Wealden* | 26.0 | 54.0 | 107.3 | 25.7 | 53.5 | 106.2 | 36.4 | Lansdowne |
| West Rosscarbery 'A' Sand | 19.4 | 46.2 | 111.0 | 19.2 | 45.7 | 110.0 | 14.7 | Lansdowne |
| West Rosscarbery Wealden | 2.6 | 8.3 | 26.9 | 2.6 | 8.2 | 26.6 | 11.8 | Lansdowne |
| SSE Rosscarbery 'A' sand | 14.2 | 30.2 | 65.0 | 14.1 | 30.0 | 64.4 | 23.3 | Lansdowne |
| SSE Rosscarbery Wealden | 38.1 | 64.1 | 106.0 | 37.7 | 63.5 | 105.0 | 19.1 | Lansdowne |
| Consolidated Total | 27.1 | 81.7 | 185.0 | 26.8 | 80.9 | 183.0 | 78.0 | |

Notes
1 Risk factor means geological chance of discovery
2 The consolidated total is the probabilistic addition of volumes and risk
3 * Prospective Resources are economically recoverable with the conceptual development plan

**Table 14: Summary of Prospective Gas Resources in Exploration License 5/07**

The Base Wealden of the Rosscarbery Prospect is analogous to the Barryroe oil discovery and constitutes an oil play. A summary of the technically recoverable Prospective Oil Resources in the Base Wealden reservoir is given on Table 15. The Prospective Resources are economically recoverable volumes derived from the conceptual development plan.

| | Gross Attributable | | | Net Attributable to Lansdowne (99% Working Interest) | | | | |
|---|---|---|---|---|---|---|---|---|
| **Prospect** | **Low (MMstb)** | **Best (MMstb)** | **High (MMstb)** | **Low (MMstb)** | **Best (MMstb)** | **High (MMstb)** | **Risk Factor (%)** | **Operator** |
| Rosscarbery Basal Wealden | 4.0 | 19.0 | 33.2 | 4.0 | 18.8 | 32.9 | 13.5 | Lansdowne |

**Table 15: Summary of Prospective Oil Resources in Exploration License 5/07**

Indicative net present values, net to Lansdowne, in money of the day, for the 'A' Sand and Wealden reservoirs of the Rosscarbery Prospect are given on Table 16. The major capital costs are the drilling of wells, estimated by RPS as US$17-25MM, together with the cost of flowlines and umbilicals (US$50MM). The major operating cost is the share of the Kinsale Head platform operating costs, which were allocated on a pro-rata basis according to production and which have been estimated at US$29MM during 2009. A flat real gas price of UK£5.0/Mcf was used in the evaluation.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| Rosscarbery 'A' Sand | |
| Low Estimate | -38.3 |
| Best Estimate | 124.5 |
| High Estimate | 329.2 |
| Rosscarbery Wealden | |
| Low Estimate | -38.3 |
| Best Estimate | 35.6 |
| High Estimate | 175.5 |

**Table 16: Indicative net present values for the 'A' Sand and Wealden Reservoirs of the Rosscarbery Prospect (net to Landsdowne 99% working interest)**

An expected monetary value (EMV) for the 'A' Sand reservoir of the Rosscarbery Prospect of US$39.8MM, at 10% discount, net to Lansdowne, is calculated from the NPVs in Table 16, together with the chance of discovery of 29.0%. Similarly, an EMV of US$3.6MM net to Lansdowne is calculated for the Wealden of the Rosscarbery Prospect from the NPVs in Table 16, together with the chance of discovery of 36.4%.

An indicative net present value has also been determined for the Basal Wealden oil play of the Rosscarbery Prospect and the indicative net present value, net to Lansdowne, in money of the day, is given on Table 17. It is assumed that the Basal Wealden will be developed using a leased FPSO which is estimated by RPS to cost US$90,000 per day for the first five years, falling to US$75,000 thereafter, plus a variable US$6.5/bbl. The principal capital costs are the sub-sea jackets and other facilities which are estimated to cost US$72-105MM, together with well costs which are estimated as US$25MM for an exploration well, US$22MM for an appraisal well and US$17MM for a development well. The annual operating cost of the FPSO is estimated as US$18.25MM.

| Prospect | Low case $NPV_{10}$ (US$MM) | Best case $NPV_{10}$ (US$MM) | High case $NPV_{10}$ (US$MM) | Chance of Discovery (%) | $EMV_{10}$ (US$MM) |
|---|---|---|---|---|---|
| Rosscarbery Basal Wealden | -57.3 | 446.3 | 916.1 | 13.5 | 58.9 |
| (net to Lansdowne on the basis of a 99% working interest) | | | | | |

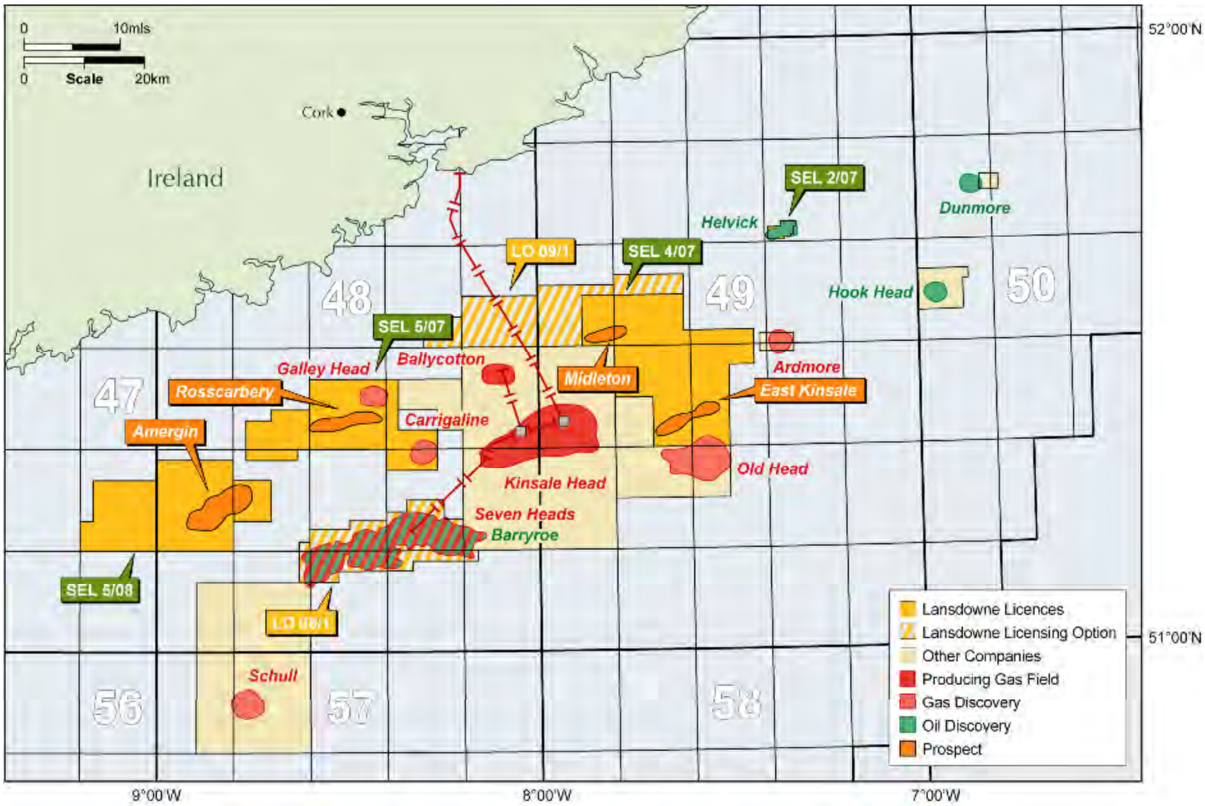
**Table 17: Indicative, success case net present values and expected monetary value for the Rosscarbery Basal Wealden oil prospect (net to Landsdowne 99% working interest)**

The sum of EMVs from the 'A' Sand, Wealden and the Basal Wealden reservoirs of the Rosscarbery prospect is US$103MM net to Lansdowne.

## 2. INTRODUCTION

This report presents an update of the Competent Persons Report *A Valuation of the Celtic Sea Assets of Lansdowne Oil & Gas plc* dated February 2009. No new geological or geophysical data has become available since February 2009. However, during December 2010 Lansdowne undertook an asset swap with Providence Resources plc, Lansdowne reducing their share of Licensing Option 08/1 to 20%, whilst acquiring a 10% interest in Licensing Option 2/07, operated by Providence Resources containing, the Helvick oil discovery. In the case of the discoveries and prospects described in the February 2009 report, Contingent or Prospective resources from each structure are summarized, then the updated evaluations presented. License Option 08/1 (Barryroe) is described first, followed by License Option 2/07 (described in full) and then by standard exploration license 5/07, as these are prospective for oil. Standard exploration licenses 4/07 (Midleton / East Kinsale) and 5/07 (Rosscarbery) are then discussed, which are largely prospective for gas. For each exploration license, the main prospects are summarized. Conceptual development scenarios were formulated for the main prospects and production and cost profiles computed. Economic analyses were preformed on the basis of the production and cost profiles. No prospects are currently identified in License Option 09/1 (Lee).

The location of the Lansdowne's Celtic Sea Licences and Licensing Option are shown on Figure 1 and summarised on Table 18.




*Source: Lansdowne*

**Figure 1: Location of Lansdowne's Celtic Sea licenses and licensing options**

| Licence | Operator | Lansdowne WI (%) | Status | License Expiry | License Area (sq km) | Comments |
|---|---|---|---|---|---|---|
| 4/07 | Lansdowne | 100 | Exploration | 31/7/2015 | 542 | Standard Exploration Licence - 1st phase ends 31st July 2012 |
| 5/07 | Lansdowne | 99 | Exploration | 31/7/2015 | 366 | Standard Exploration Licence - 1st phase ends 31st July 2012 |
| 5/08 | Lansdowne | 100 | Exploration | 31/3/2015 | 449 | Standard Exploration Licence - 1st phase ends 31st July 2012, when 50% will be relinquished |
| 08/1 | Providence Resources plc | 20 | Appraisal | 13/7/2011 | 291 | Licensing Option - 1st phase ends 13th July 2011 |
| 09/1 | Lansdowne | 100 | Exploration | 1/3/2012 | 315 | Licensing Option |
| 02/7 | Providence Resources plc | 10 | Appraisal | 31/1/2013 | 12 | Standard Exploration Licence |

**Table 18: Summary of interests held by Lansdowne**

Standard Exploration Licenses 4/07, 5/07 and 5/08 permit the licensee (Lansdowne) to conduct seismic surveys, conduct technical studies and to drill wells. By contrast, licensing options 08/1 and 09/1 only entitle the license holders to conduct seismic surveys and perform technical studies. Providence Resources plc has become operator of Licensing Option 08/1 and will acquire 3D seismic in 2011, following which it is expected that the Group will apply for a Standard Exploration Licence. It is worthy of note that Lansdowne License Option 08/1 is subdivided into two parts. One part of License Option 08/1 covers the entire subsurface and this covers an area of 122km$^2$, but in the remaining 166km$^2$ the licensing option only extends below 4000ft subsea. The area above 4000ft sub-sea contains part of the producing Seven Heads Gas Field, operated by Star Energy (86.5%). During December 2010 Lansdowne undertook an asset swap with Providence Resources plc, reducing their share of Licensing Option 08/1 to 20%, whilst acquiring 10% of the portion Standard Exploration License 02/7 containing the Helvick oil discovery.

The blocks covered by the standard exploration licenses (4/07, 5/07, 5/08 and 2/07) and licensing option 08/1 are listed on Table 19.

| License | Name | Blocks |
|---|---|---|
| 4/07 | Midleton / East Kinsale | 49/11 (part), 49/12 (part), 49/13 (part), 49/17 (part), 49/18 (part) |
| 5/07 | Rosscarbery | 48/17 (part), 48/18 (part), 48/19 (part), 48/22 (part), 48/24 (part) |
| 5/08 | Amergin | 47/25 (part), 48/21 (part), 48/22 (part) |
| 08/1 | Barryroe | 48/22 (part), 48/23 (part), 48/24 (part), 48/27 (part), 48/28 (part), 48/29 (part), 48/30 (part) |
| 09/1 | Lee | 48/14 (part), 48/15 (part), 49/11 (part) |
| 2/07 | Helvick | 49/9a |

**Table 19: Summary of blocks within licenses held by Lansdowne**

## 2.1 Valuation Methodology

Volumetric results, together with assessments of geological risk, were obtained from the February 2009 study and production profiles were also largely obtained from the February 2009 study, but with new production profiles generated for the Midleton Prospect. Conceptual development scenarios were also taken from the February 2009 study which exploit the hydrocarbons with minimal technical risk whilst at the same time are economically attractive. However, the Helvick oil discovery was not discussed in the February 2009 report and is therefore extensively discussed here. The valuation presented in this report adopts an expected monetary value (EMV) approach using probability tree methodology to compute the range of possible outcomes for the assumed developments from net present value (NPV) and the Chance of Discovery. Each prospect is evaluated in a stand-alone manner, to allow direct comparison with previous evaluations of the Lansdowne Celtic Sea assets.

The technical evaluation of each prospect, results in success case resources for each prospect, expressed as a continuous distribution produced using a Monte Carlo simulation methodology. To this distribution is applied an overall geological chance of success (termed "Chance of Discovery" in the PRMS resources definitions used in this study) derived from an analysis of all the risks involved in the chance of finding hydrocarbons within the prospect under consideration.

A complete valuation of this success case resources distribution is not usually attempted due to the difficulty of generating production and cost profiles for the entire range of resources. Instead, it is normal industry practice to extract one value, or a number of values, from the distribution and generate discrete deterministic cases which can then be valued to provide an indication of value, given success. The simple approach would be to extract one representative value from the distribution and, if this were to be done, the value to extract would be the mean of the success case resources distribution. However, where the success case resources distribution is wide, as is the case for the Lansdowne prospects, and no commercial threshold has been applied to the success case resource distributions, then a single point valuation using the mean is not representative of the whole distribution. The valuation in this report is based on the statistically valid assumption (Swanson's Rule) that the distribution can properly be represented by the P90, P50 and P10 values, weighted 30%, 40% and 30% respectively, provided the distribution is not highly skewed (e.g. Hurst *et al*. 2000[3]). Figure 2 demonstrates the three point (Swanson's rule) methodology for a hypothetical resources distribution.

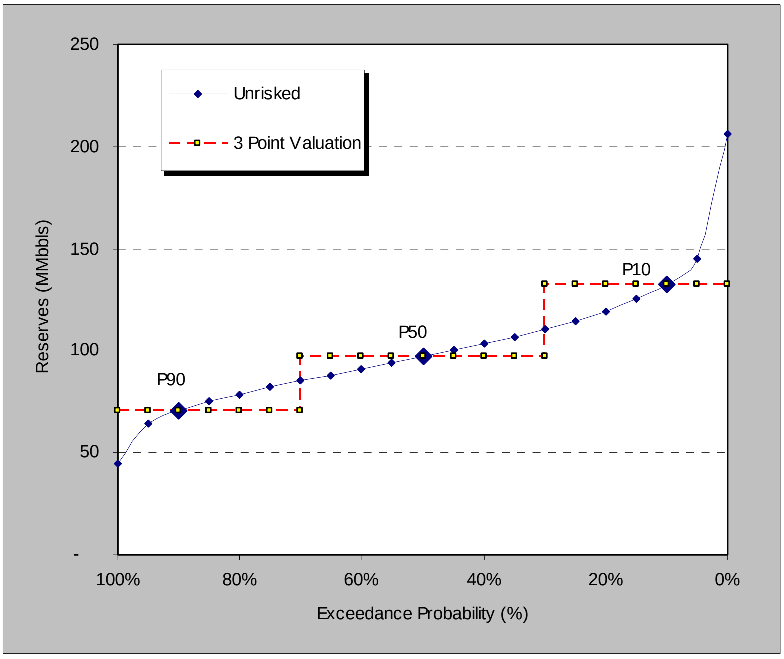



**Figure 2: Illustration of the use of three points (P90, P50 and P10) to represent a hypothetical resources distribution, as employed in this study**

[3] Hurst A., Brown G.C. & Swanson R.I. 2000 Swanson's 30-40-30 rule. *AAPG Bull.* **84**, pp. 1883 – 1891

Discrete production profiles were generated for the P90, P50 and P10 success case resources with corresponding profiles of capital costs constructed for each of the prospects. Each well drilled has two initial possible outcomes, success or failure. The probability of success is equal to the geological probability of success (GPoS) as defined in the technical evaluation process. The chance of failure (dry hole) is therefore always equal to (1 – GPoS). In the event of success, the full, continuous range of possible volumes is simplified to three representative values, the P90, P50 and P10 volumes. The relative probability of each outcome is 30%, 40% and 30% respectively, according to Swanson's rule. Figure 3 illustrates the outcome for each prospect.

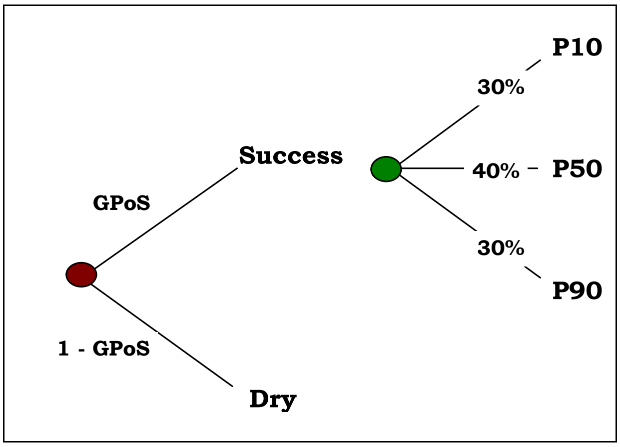



**Figure 3: Example of the modelled outcomes for each prospect**

GPoS = Geological Probability of Success. Termed chance of discovery in the PRMS guidelines

The possible outcomes for each prospect were combined in a probability, or value, tree (Figure 3) to capture all possible combinations of success and failure. The cost for any failure modelled was taken to be the total exploration costs from the beginning of 2011, up to, and including, the drilling of the dry exploration wells. No testing costs were included in the failure branch.

## 2.2 Cashflow Modelling

The discoveries and prospects evaluated in this study have been valued based on the net present value (NPV) of future cashflows using a valuation date of 1$^{st}$ January 2011 and a discount rate of 10%. NPVs under other discount rates have been calculated for reference. Details of the cashflow models are given in Appendix C.

### 2.2.1 Oil and Gas Price Assumptions

The RPS base-case price forecast for Brent crude has been employed in this evaluation. Variation of the real oil price with time is shown in Figure 4

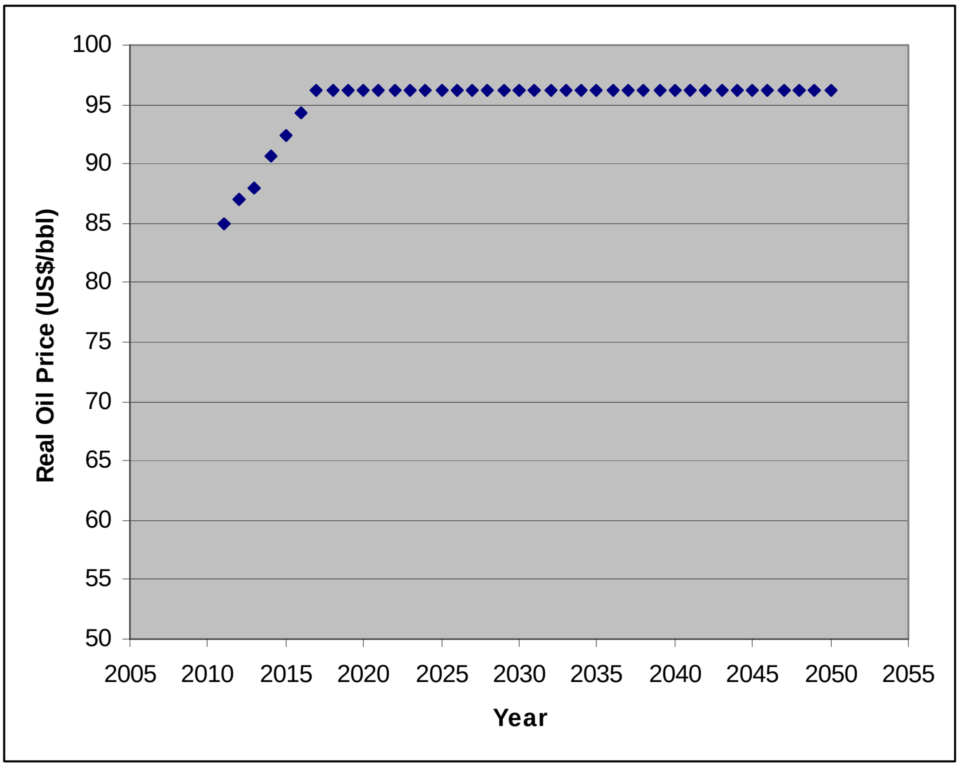



**Figure 4: Variation of the real Brent oil price**

The real gas is assumed to be a flat UK£5.00/Mcf.

### 2.2.2 Currency and Inflation Assumptions

A flat exchange rate of US$1.60 per UK£1 (in real, 2010 terms) has been applied to forecast gas price realisations (in real, 2010 terms) and used to compute sunk costs. A flat exchange rate of US$1.38 per 1 Euro (in real, 2010 terms) has also been assumed.

All prices and costs which have been forecast in real 2010 monetary units have been escalated at an annual inflation rate of 2%.

### 2.2.3 License Block Rentals

RPS has modelled rental payments on license blocks as follows:

50% of the surface area of a given block is relinquished after the first three years of the exploration period

- RPS assumed different proportions of the original exploration licenses are retained after the declaration of commerciality. It was assumed that 60% of the current area of Standard Exploration License 4/07 would be relinquished if either the Midleton or East Kinsale Prospects were successful. If the Rosscarbery Prospect is successful it has been assumed that 60% of the current area of Standard Exploration License 5/07 would be relinquished. By contrast, if the Amergin Prospect were successful it is assumed that 70% of the current area of Standard Exploration License 5/08 would be relinquished.
- Rental rates, in real 2010 terms, applied to retained areas, are as follows:
  - From Years 1 through 3 of the exploration period, Euro 175 per sq km
  - From Years 4 through 6 of the exploration period, Euro 351 per sq km
  - From the declaration of commerciality until first commercial production, Euro 2,539 per km

- From first commercial production, Euro 3,970 per sq km

- Rental payments are escalated according to annual inflation and assumed to be tax deductable.

Some miscellaneous fees are also payable. Obtaining Exploration Licenses and Petroleum Leases (i.e. commercial development licenses) for a given block requires the payment of one-time fees (in real 2010 terms) of Euro 8,763 each. The fees are escalated according to annual inflation and assumed to be tax deductable.

### 2.2.4 Depreciation

All capital expenditure, including that for intangibles, are depreciated for tax purposes at the rate of 100% per annum in the year of expenditure. This includes a total of approximately UK£7.57MM in "sunk costs" expended on all the blocks before the valuation date of 1st January 2011. Any tax losses resulting from this policy are carried forward until amortised.

### 2.2.5 Taxation

Profits are subject to a Corporate Income Tax rate of 25%. Any tax losses not arising from abandonment costs are carried forward until amortised. By contrast, tax losses arising from abandonment costs are carried back three years.

A Petroleum Resource Rent Tax (PRRT) is also applicable. PRRT is based on an R Factor which is calculated by division of cumulative post corporate tax profits, by cumulative exploration, appraisal and development expenditure.

In all years when there is a PRRT liability, the PRRT rate is calculated as shown on Table 20.

| R Factor | | PRRT Rate (%) |
|---|---|---|
| - | <1.5 | 0 |
| ≥1.5 | <3.0 | 5 |
| ≥3.0 | <4.5 | 10 |
| ≥4.5 | No limit | 15 |

**Table 20: Variation of PRRT rate with R factor**

In the first year when there is a PRRT liability, the PRRT tax base is calculated using the relation

$$PRRT = CATP - ( CFE \times 1.5 ) \times [100 / (100 - R) ]$$

in which CATP is cumulative after-tax profits and CFE is cumulative field expenditure.

Following Lansdowne guidance, we have assumed that cash payments of both Corporate Tax and PRRT liabilities are paid as follows:

- 90% of the liability in the year in which it is incurred

- 10% of the liability in the year after it is incurred

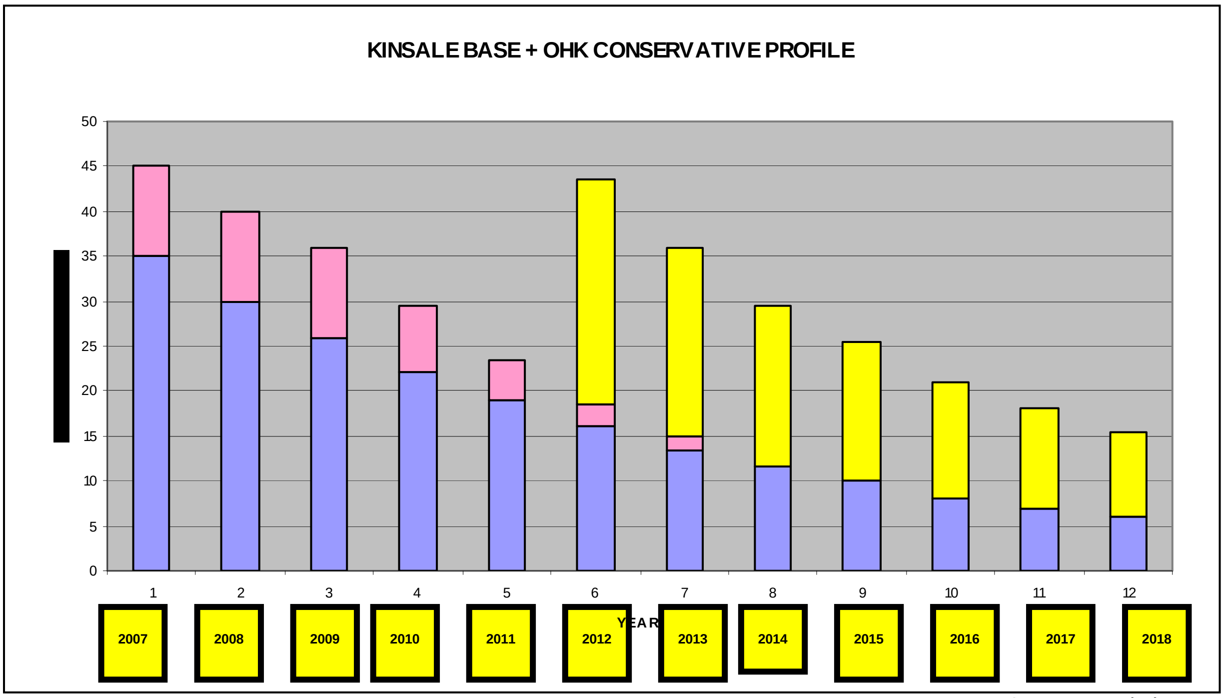
We note that Irish legislation calls for consolidation for tax purposes at the country level. At Lansdowne's request, to facilitate comparisons of prospects on a stand-alone basis, we have modelled each prospect on an individual tax "ring-fence" basis.

### 2.2.6 Economic Limit and Abandonment

We have assumed that once commercial production has started, the economic life of a prospect ends (i.e. it is permanently shut-in) in the first year during which gross operating cashflow is negative. Gross operating cashflow is defined as gross revenue less cash operating costs. Abandonment (decommissioning) costs are assumed to be paid the following year. We have assumed there are no abandonment liabilities in the dry hole cases. Abandonment costs for facilities and infrastructure were assumed to be 5% of the capital costs and we estimate that US$750,000 is required to abandon each development well. It has been assumed that Lansdowne are not liable for any platform abandonment costs. Star Energy plan to use the SW part of the Kinsale Field, together with the Ballycotton Field, for gas storage and will therefore probably be liable for all of the Kinsale Head platform abandonment costs. Also, satellite producers using the Seven Heads gas platforms are only liable for the abandonment costs for the satellite infrastructure (flow lines etc.) (information supplied by Lansdowne).

### 2.2.7 Operating Costs of the Kinsale Head Platform

Development of the gas prospects described in Section 4 involves the use of the Kinsale Head platform. Currently production from the Kinsale Head and Seven Heads Fields involves the platform and production data from the two fields has been provided by Lansdowne and is shown in Figure 5. In addition, San Leon Energy have proposed to develop the Old Head of Kinsale discovery through the platform and production profiles for the Old Head of Kinsale Field have also been provided by Lansdowne, with the base case profile shown in Figure 5. The Schull discovery has not been included in this analysis and production will probably not commence until after 2016. San Leon plan to produce the Schull discovery through the Seven Heads manifold and this requires production from Seven Heads to have ceased. (The Schull gas is at a higher pressure than Seven Heads, and if production from Schull were to commence too early the backing out of the production at Seven Heads is likely).



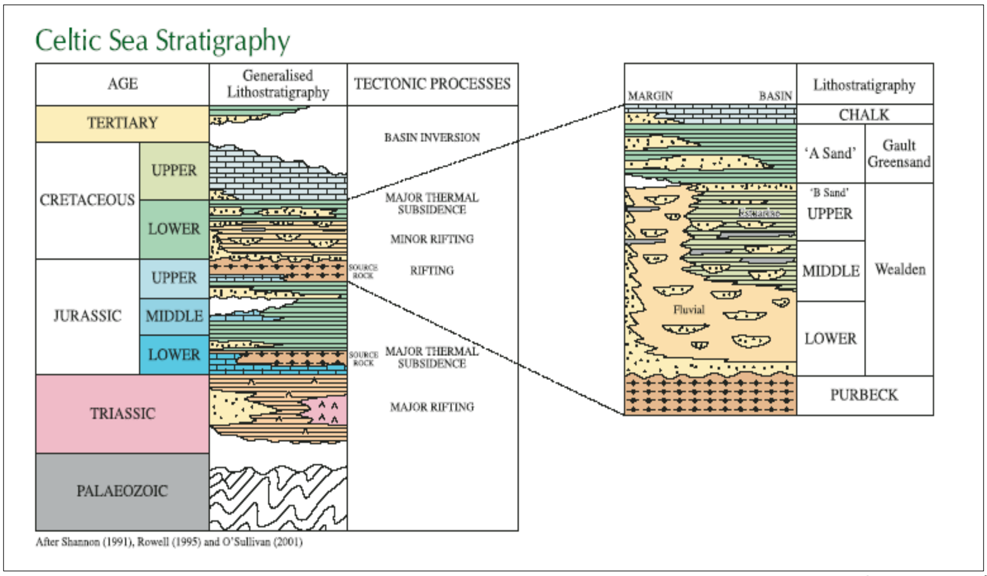

*Source: Landsdowne*

**Figure 5: Production profiles for the Kinsale Head, Seven Heads and Old Head of Kinsale Fields**

The cost of operating the Kinsale Head Platform was Euro 20-21MM during 2009 (as supplied by Lansdowne) and this is essentially a fixed cost. Production profiles for each prospect were used, in conjunction with the above information, to derive each prospect's share of Kinsale Head platform operating costs, on a pro-rata basis. The operating costs thus derived must therefore be regarded as conservative, as they take no account of any contribution to the operating costs from gas storage projects or the potential contribution from the Schull discovery.

## 2.3 Previous Exploration in the Celtic Sea Basin

The Celtic Sea Basin is one of a system of Mesozoic rift basins south of Ireland. A stratigraphic column for the Celtic Sea Basin is shown in Figure 6.




*Source: Landsdowne*

**Figure 6: Stratigraphy of the Celtic Sea Basin**

A total of 89 wells were drilled in the North Celtic Sea Basin between 1970 and 2010, 55 of which targeted the Cretaceous and the remaining 34 targeted Jurassic and Triassic prospects. Of the 55 wells targeting the Cretaceous, 26 have been drilled on the producing fields (Kinsale Head, Ballycotton and Seven Heads) and potentially commercial discoveries (Old Head of Kinsale and Schull). A further 9 wells lie on structures that contain hydrocarbons, but which are not currently considered commercial (Hook Head, Ardmore, Galley Head, Carrigaline, etc.). Some 20 wells were drilled on Cretaceous structures are dry, although this includes wells that found biodegraded oil.

Marathon were originally awarded all of the Celtic Sea acreage in the late 1960s and discovered the Kinsale Head Field in 1971 with 48/25-2, which flowed gas at 26.5MMscf/d. Esso farmed into the southwest portion of the Marathon concession and discovered the Seven Heads Field with well 48/24-1, which flowed 780bbl/d oil and 10MMscf/d gas from Wealden reservoirs. Production from the Kinsale Head Field commenced in 1978, saturating the Irish gas market until 1995. During the 1980s exploration focused on oil in older, pre-inversion structures with reservoirs of Triassic or Jurassic age. Such older structures have been successful in the Wessex Basin (Wytch Farm) and the Paris Basin (Villeperdue and Chanouy). During the 1990s and 2000s, exploration has focused on Cretaceous reservoired gas.

The drilling of wells has led to the discovery of gas and oil at a variety of stratigraphic levels. The discoveries hosted by the oldest reservoirs are the Helvick and Dunmore oil discoveries hosted predominantly by sandstones of Upper / Middle Jurassic (Bathonian to Callovian) age. Oil in the Helvick and Dunmore discoveries is sourced from marine shales of Toarcian age. Flow rates of >6,600bbl/d were tested from the Helvick discovery (49/9-2).The Hook Head oil discovery is hosted by Middle Wealden sandstones whilst the Barryroe (Seven Heads) discovery consists of an oil rim and overlying gas cap, the oil hosted by sandstones of Lower and Middle Wealden age. There is also a heavy-oil rim (Nemo) to the Ardmore gas discovery (approx. 230MMstb in-place of 16˚API oil, from the Providence Resources website) and a heavy-oil discovery, Baltimore, (approx. 300MMstb in-place and 30-100MMstb recoverable, of 11˚API oil, from the Providence Resources website) about 10km to the east of the Carrigaline gas discovery.

The Greensand ('A' Sand) and Upper Wealden ('B' Sand) reservoirs tend to host gas. The Kinsale Head Field, with reserves of approximately 1.7Tcf, is hosted by the 'A' and 'B' Sand reservoirs. The 'A' Sand forms a laterally continuous sheet sand whereas the 'B' Sand consists of a series of sands 5-10ft thick in a 60ft section. Other fields and discoveries hosted by Greensand ('A' Sand) and Upper Wealden ('B' Sand) reservoirs are Ballycotton (recoverable gas approx. 64 Bscf, estimated by RPS from production data), Seven Heads (recoverable gas approx. 25 Bscf) Old Head of Kinsale (recoverable gas approx. 45 Bscf), Schull (recoverable gas approx. 30 Bscf), Galley Head (in License Option 5/07), Carrigaline (in License Option 5/07) and Ardmore (volumes of recoverable gas were supplied by Lansdowne). There are thick, mature source rocks of Lower Jurassic age throughout the

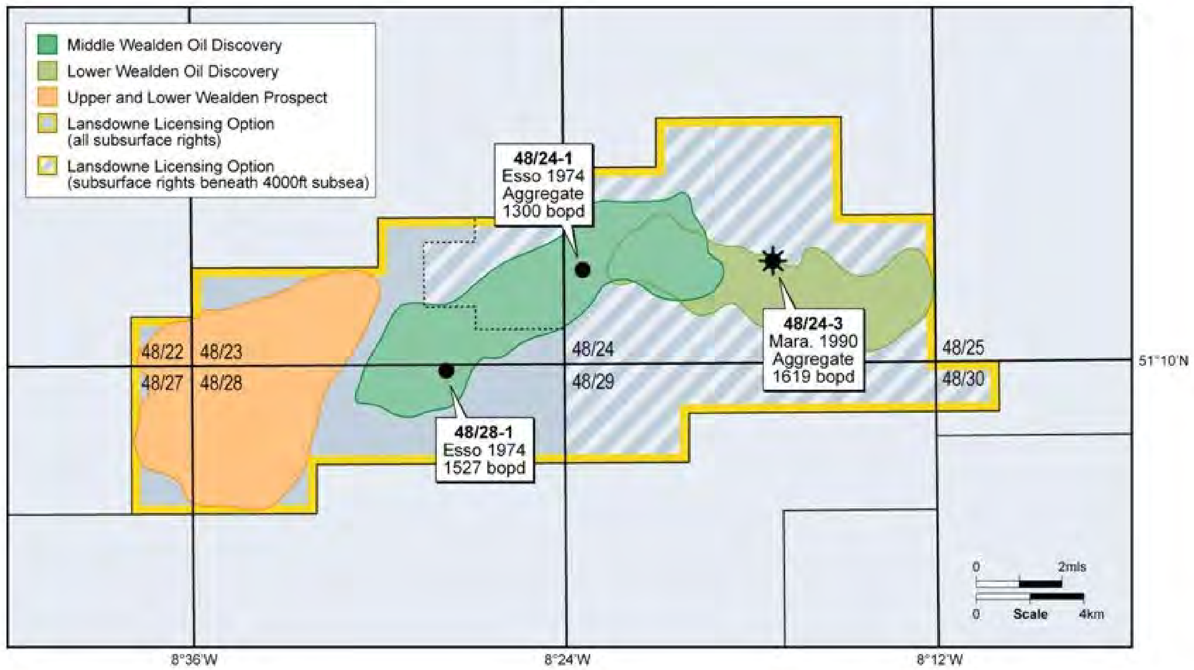
Celtic Sea Basin.  Gas generation is likely to have started in the Late Cretaceous and peaked prior to Miocene inversion.  Significant re-migration of gas has subsequently taken place and there is also evidence from the very dry nature of the gas, and other geochemical data, of recent biogenic gas generation, which may come form coaly sequences within the Wealden.  Failure of wells targeting the Greensand or Wealden reservoirs has resulted from early wells being drilled off structure, wells being outside the play fairway, or an early oil charge not being displaced by later gas migration.  There is little evidence of failure caused by leaking faults.

Three distinct plays are therefore recognised, a Jurassic reservoired oil play, a Cretaceous (Middle to Lower Wealden) reservoired oil play and a Cretaceous gas play, where both 'A' and 'B' sand reservoirs may provide multiple targets in parts of the basin.

## 3. OIL DISCOVERIES AND OIL EXPLORATION LICENSE

### 3.1 Licensing Option 08/1 (Barryroe Oil Discovery)

Licensing option 08/1 contains the Barryroe oil discovery (formerly termed Seven Heads Oil) and the West Barryroe gas prospect. The licensing option covers part of blocks 48/22, 48/23, 48/24, 48/27, 48/28, 48/29 & 48/30 and lies 32.5 km to the west-southwest of the Kinsale Head gas field (Figure 1). The Lansdowne working interest in licensing option 08/1 is currently 20%, with Providence Resources, the operator, holding 50% and San Leon Energy the other 30%. License Option 08/1 is subdivided into two parts. One part of Licence Option 08/1 covers the entire subsurface and this covers an area of 122km$^2$, but in the remaining 166km$^2$ the licensing option only extends below 4000ft subsea (Figure 7).




*Source: Landsdowne*

**Figure 7: Licensing option 08/1 illustrating the division of subsurface rights**

The Barryroe oil discovery and the Seven Heads Gas Field are hosted by a 4500ft thick sequence of thin sandstones, interbedded with claystones, of Lower Cretaceous (Wealden) age, subdivided into Upper, Middle and Lower Wealden. The upper limit of the eastern part of the Barryroe Licensing Option at 4000ft subsea is near the top of the Middle Wealden. Sandstones of the Middle and Lower Wealden contain both oil and associated gas volumes. However, the Upper Wealden sands are gas bearing.

#### 3.1.1 Barryroe Oil Discovery

The Barryroe oil discovery was described in detail in the February 2009 report. Volumetrics presented in the February 2009 study are summarised on Table 21 and Table 22. The Barryroe oil discovery is classed as Contingent Resources, Development Pending, as partners in the 08/1 License Option have no firm development plan. Consequently, RPS has devised has devised a conceptual development plan.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 57.1 | 756 | 1872 | Lognormal |
| Porosity (%) | 18.4 | 18.8 | 19.3 | Normal |
| Oil Saturation (%) | 59 | 61 | 63 | Normal |
| FVF | 1.18 | 1.20 | 1.22 | Normal |
| **STOIIP (MMstb)** | **31.0** | **287** | **706** | |
| Recovery Factor (%) | 12 | 16 | 20 | Normal |
| **Technically Recoverable Oil (MMstb)** | **4.3** | **45.1** | **113** | |
| **Technically Recoverable Associated Gas (Bscf)** | **1.9** | **20.5** | **51.6** | |

**Table 21: Calculation of STOIIP, technically recoverable oil and associated gas from the Middle Wealden of the Barryroe Discovery (full field interest)**

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 31.2 | 175 | 382 | Lognormal |
| Porosity (%) | 18.2 | 18.6 | 19.0 | Normal |
| Oil Saturation (%) | 64.0 | 65.5 | 67.0 | Normal |
| FVF | 1.55 | 1.57 | 1.59 | Normal |
| **STOIIP (MMstb)** | **15.2** | **86** | **187** | |
| Recovery Factor (%) | 12 | 16 | 20 | Normal |
| **Technically Recoverable Oil (MMstb)** | **2.4** | **13.5** | **30.6** | |
| **Technically Recoverable Associated Gas (Bscf)** | **5.6** | **31.6** | **71.8** | |

**Table 22: Calculation of STOIIP, technically recoverable oil and associated gas from the Lower Wealden of the Barryroe Discovery (full field interest)**

### 3.1.2 Conceptual Development Plan

The two main risks associated with the Barryroe oil discovery are reservoir continuity and the high pour point of the oil. The selected development option aims to alleviate the reservoir continuity risk, and allow for the most likely resources to be depleted effectively with a relatively low CAPEX exposure.

A conceptual development plan devised by RPS envisages the development of the field in two phases:

Phase 1: Commences with the acquisition of a 3D seismic survey, which has been estimated by Lansdowne to cost US$4.5MM. This will be followed by the drilling a high angle appraisal well (at a cost of US$32MM), followed in-turn by pre-drilling high angle producers (at a cost of US$35MM per well) into the Middle Wealden through a drilling template in the area around and in between wells 48/24-1 and 48/28-1, which were both tested with good results. One development well was assumed in the 1C case, nine wells in the 2C case and twenty two wells in the 3C case. It is assumed that the appraisal well will be drilled in 2012 with first oil on 1st January 2014. A well head jacket will be placed over the template and the completions raised to the surface. This will enable the wells to be completed with dry trees, which have lower capital and operating costs than sub-sea completed wells. These wells will be tied back to a well head production platform (WHPP) with minimum facilities, and the oil will be transferred through a heated coflexip hose, to a leased FPSO, moored adjacent to the platform, with heated storage tanks. RPS estimates the cost of the WHPP to vary from US$ 79MM in the 1C case to US$123MM in the 3C case and the cost of FPSO rental to be US$90,000 per day, falling to US$75,000 per day after 5 years, plus a variable US$6.5/bbl, based on rates supplied by Petrojarl.

Phase 2: After some ten years of production more development wells will be drilled in the eastern area to develop the Lower Wealden in the 2C and 3C cases. Two wells are required to develop the mid case and six for the high case at a cost of US$35MM per well. The Lower Wealden wells will penetrate the area around 48/24-3 and 48/24-2, which tested oil and had good indication of hydrocarbon, respectively. The first of the phase 2 wells will be an appraisal well, which will be converted into a producer if successful. A second WHPP at accost of US$79-97MM will be installed and the FPSO will be moved to that area. Phase 2 is uneconomic in the 1C case.

There are no provisions for any pressure support measures in the conceptual plan, rather a simple natural depletion model is assumed. The key factor affecting commerciality is the likely production potential per well, which in turn is related to sand connectivity.

### 3.1.3 Economics

A Brent price has been assumed for the Barryroe crude in the cashflow modelling, despite the high wax content. A waxy crude with an API similar to Brent would not trade at a discount to Brent, as in many instances, refiners are happy to process high wax crudes, particularly for producing base oils and for waxy cat cracker feedstocks, which result in higher yield conversions of refined crude. The net present value, in money of the day, of the Lansdowne working interest (20%), in the Barryroe Licensing Option, is summarised on Table 23.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| 1C | 4.4 |
| 2C | 227.3 |
| 3C | 634.4 |

**Table 23: Indicative net present value from the Barryroe License Option (on the basis of a 20% Lansdowne working interest)**

### 3.1.4 Contingent Resources

Contingent oil and gas resources for the Barryroe discovery are summarised in Table 24. The Contingent Resources are volumes of oil which can be recovered economically by the conceptual development plan. As there are no gas sales in the conceptual development plan, the associated gas is not included within the Contingent Resources.

| Case | Contingent Resources (MMstb) |
|---|---|
| .1C | 1.6 |
| 2C | 10.0 |
| 3C | 30.5 |

**Table 24: Summary of Contingent Resources for the Barryroe License Option (on the basis of a 20% Lansdowne working interest)**

The 1C Contingent Resources are currently calculated to be marginally economic. However, future appraisal drilling and technical studies may allow the range of uncertainty of sand connectivity to be reduced, ultimately resulting in a higher estimate of 1C resources. The 2C case represents the most realistic expectation of recoverable volumes based on our current knowledge, and the 3C case can be considered, in our opinion, the most optimistic outcome of an appraisal and development programme. It must be emphasised that both the 2C and 3C cases require the reservoir units to be laterally continuous, and in the high case some thickening of these units is assumed, based on the regional geological model for the Middle and Lower Wealden.

## 3.2 West Barryroe Gas Prospect

The West Barryroe Gas Prospect is located in the western portion of License Option 08/1, covering part of blocks 48/22, 48/23, 48/27 and 48/28. Volumetrics presented in the February 2009 report are summarised in Table 25.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 169 | 239 | 338 | Lognormal |
| Net to Gross (%) | 20 | 25 | 30 | Normal |
| Porosity (%) | 15 | 20 | 25 | Normal |
| Gas Saturation (%) | 60 | 70 | 80 | Normal |
| 1/Bg | 110 | 120 | 130 | Normal |
| **GIIP (Bscf)** | **20.5** | **34.4** | **56.0** | |
| Recovery Factor (%) | 60 | 70 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **13.9** | **23.9** | **39.8** | |

**Table 25: GIIP and technically recoverable gas from the West Barryroe Prospect (full field interest)**

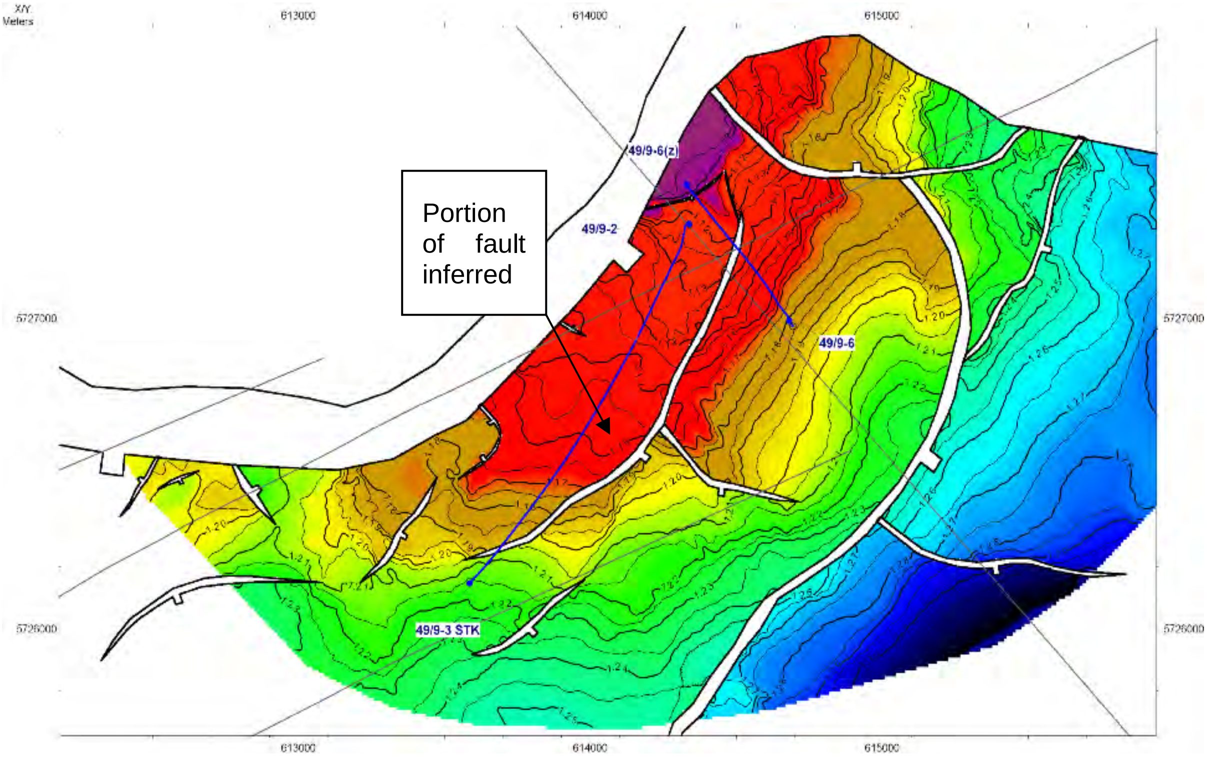
RPS estimate the play risk to be 80% with an overall GPoS of 18%.

## 3.3 License 2/07 (Helvick Oil Discovery)

The part of Standard Exploration License 2/07 which contains the Helvick oil discovery lies about 50km northeast of the Kinsale Head gas field and covers part of blocks 49/8, 49/9, 49/13 and 49/15 (Figure 1). As Lansdowne farmed into Standard Exploration License 2/07 in December 2010, the Helvick oil discovery was not discussed in the February 2009 report. The Helvick Field was discovered by Gulf in 1983 with well 49/9-2, which tested four intervals of intervals of Middle-Upper Jurassic age, and flowed at a cumulative rate of 9,901 bopd with 7.44 MMscfg/d. High-angle appraisal well 49/9-3st2 was drilled in 1984. Subsequently, in 2000, two further appraisal wells, 49/9-6 and 49/9-6z, were drilled by Providence to test the fault block to the east of that previously drilled. The Helvick oil discovery is classified as Contingent Resources, of the Development Pending sub-class, as Providence Resources (the operator) acknowledge that further subsurface technical study is necessary before a development plan can be submitted to the Petroleum Development Authority (PDA).

### 3.3.1 Geophysics and Geology

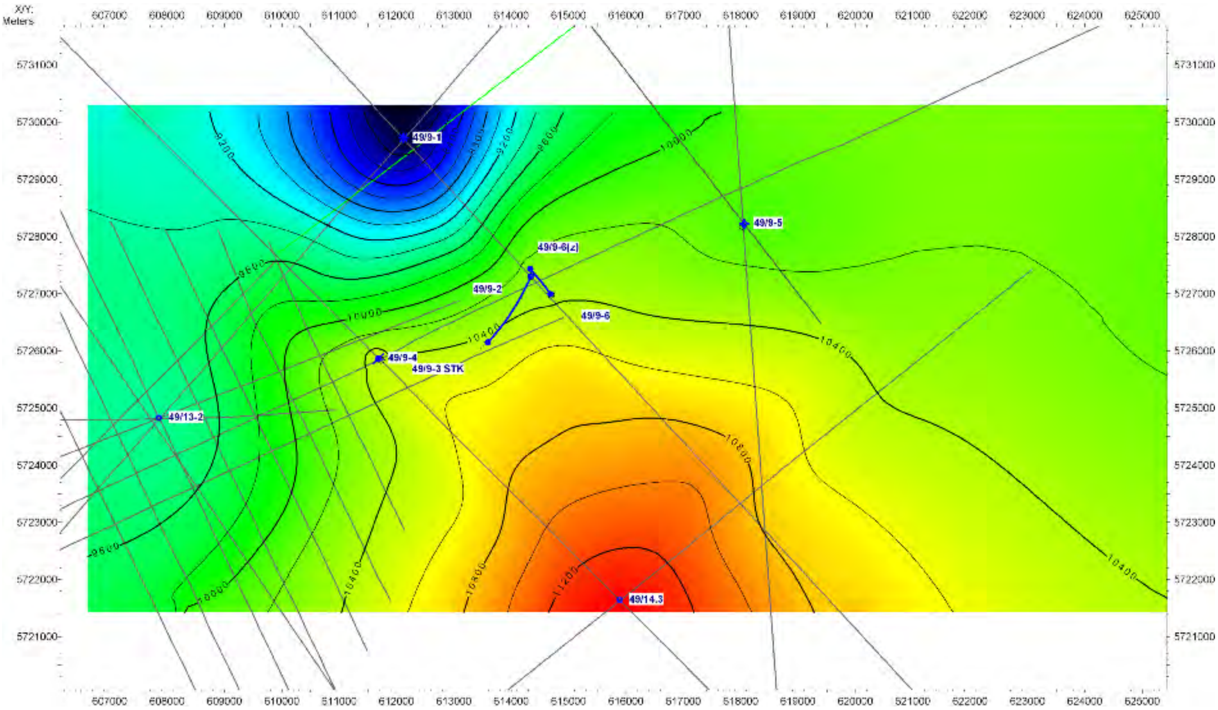
A 3D seismic survey was acquired by Providence in 1998 and reprocessed by pre-stack time migration in 2005 (Choice Geophysical). This dataset appears to be of good quality and exhibits a coherent set of mappable reflectors from the Sea Bed to the Middle Jurassic (Bathonian Limestone). The only strong reflector which forms a mappable horizon near the reservoir interval is the Bathonian Limestone. RPS interrogated the Providence seismic interpretation and the Bathonian Limestone pick appears robust and the fault interpretation reasonable. Inferences were made connecting a number of faults, in particular the fault that runs NNE-SSW from the crestal area down towards the toe of the 49/9-3st2 (also referred to as 49/9-3STK) well (Figure 8). As vertical resolution of the seismic at reservoir depth is about 50ft, fault throws smaller than this are not detectable and therefore it is realistic to assume the throw observable on the seismic on the northern and southern portions of this NNE-SSW fault connect. Evidence that this fault is sealing is provided by MDT data from well 49/9-6 which shows that the hydrocarbon bearing Upper Sands are not in communication with the water bearing Main Sand.




*Source: Providence*

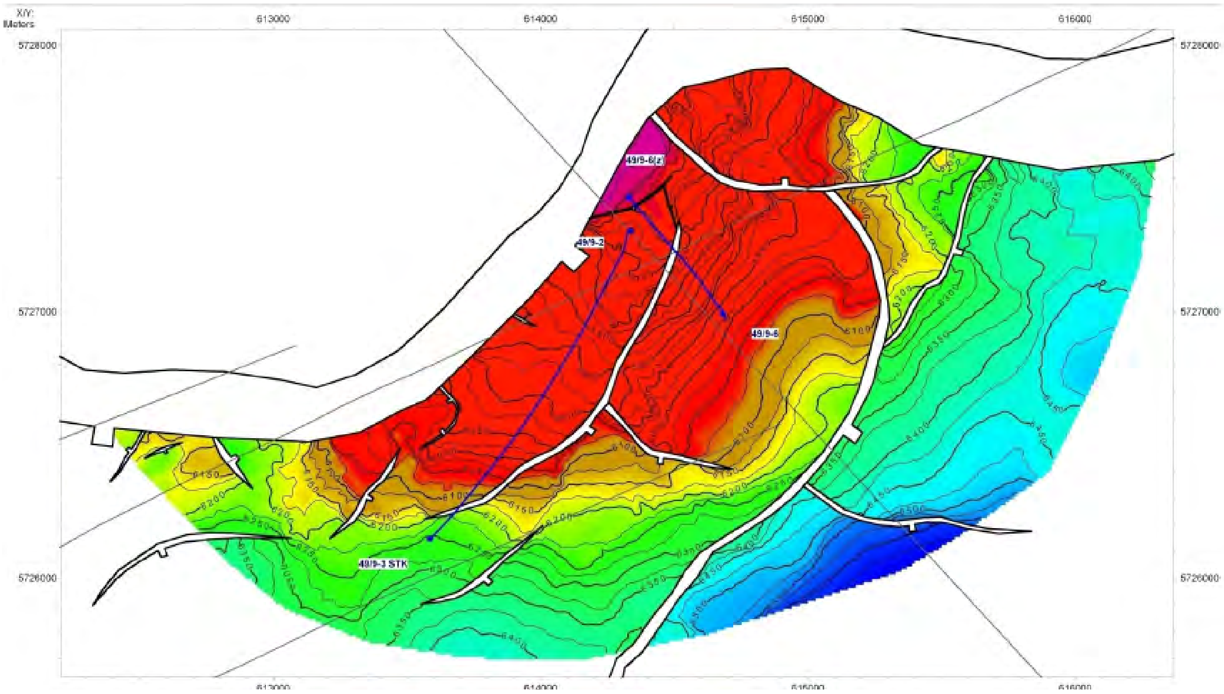
**Figure 8: Top Bathonian two-way time structure, Helvick discovery**

Depth conversion was undertaken using check-shot data, as no stacking velocity information was available. The check-shot data was used by providence to derive an average velocity map for the Bathonian Limestone (Figure 9), which was used to convert the two-way time surface to depth. This approach to depth conversion seemed reasonable to RPS. Depth maps for the Top Main Sands and Top Upper sands were constructed from the Top Bathonian Limestone depth map using well-based isochors and this approach seemed practical to RPS. The resulting top Main Sands depth map is shown on Figure 10.




*Source: Providence*

**Figure 9: Average velocity to Top Bathonian Limestone, Helvick oil discovery**



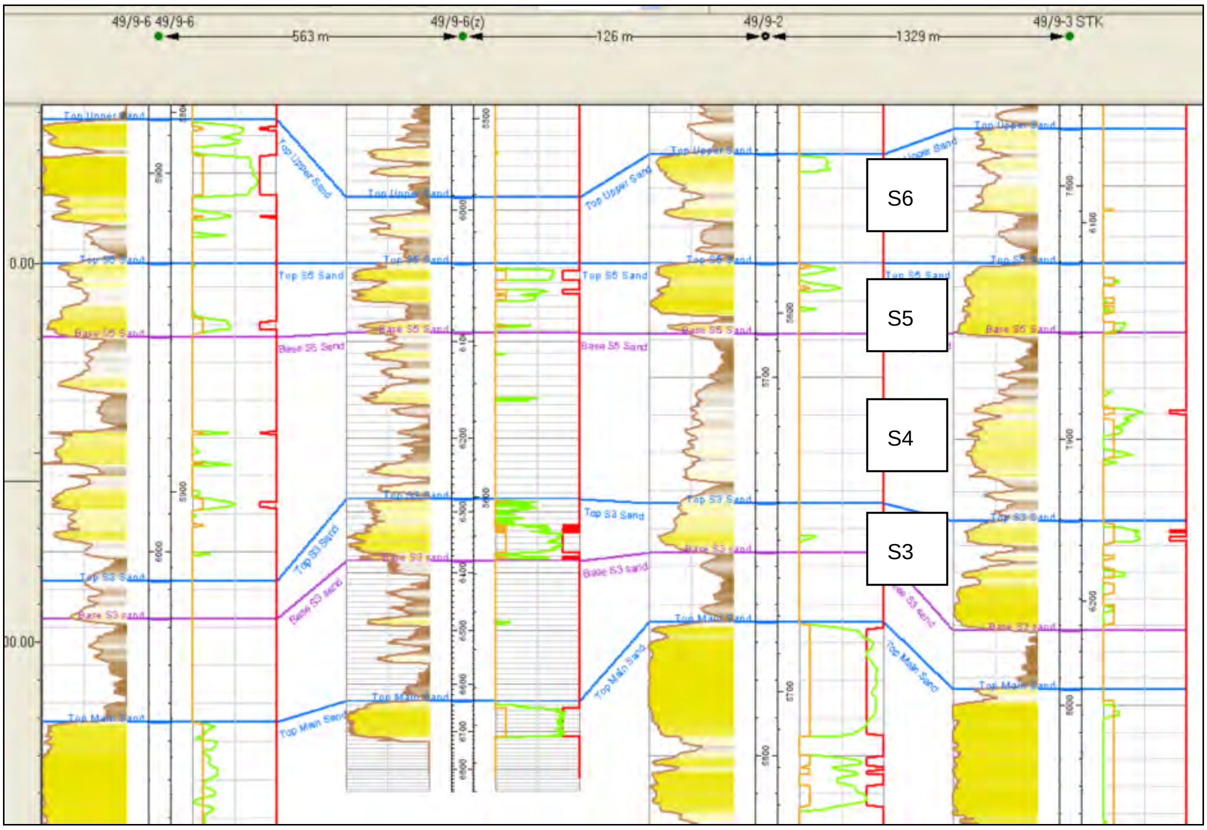

*Source: Providence*

Depth in feet

**Figure 10: Depth of Top Main Sand, Helvick oil discovery**

The reservoir in the Helvick Field is subdivided into three main sequences, the Upper Sands (Calovian to Oxfordian age), Main Sands and the Bathonian Limestone. The Upper sands were deposited in a coastal delta plain environment and consist of fluvial channel, abandoned channel, levee and mouth-bar sands, with fluvial channel sands being of the best reservoir quality. The Upper

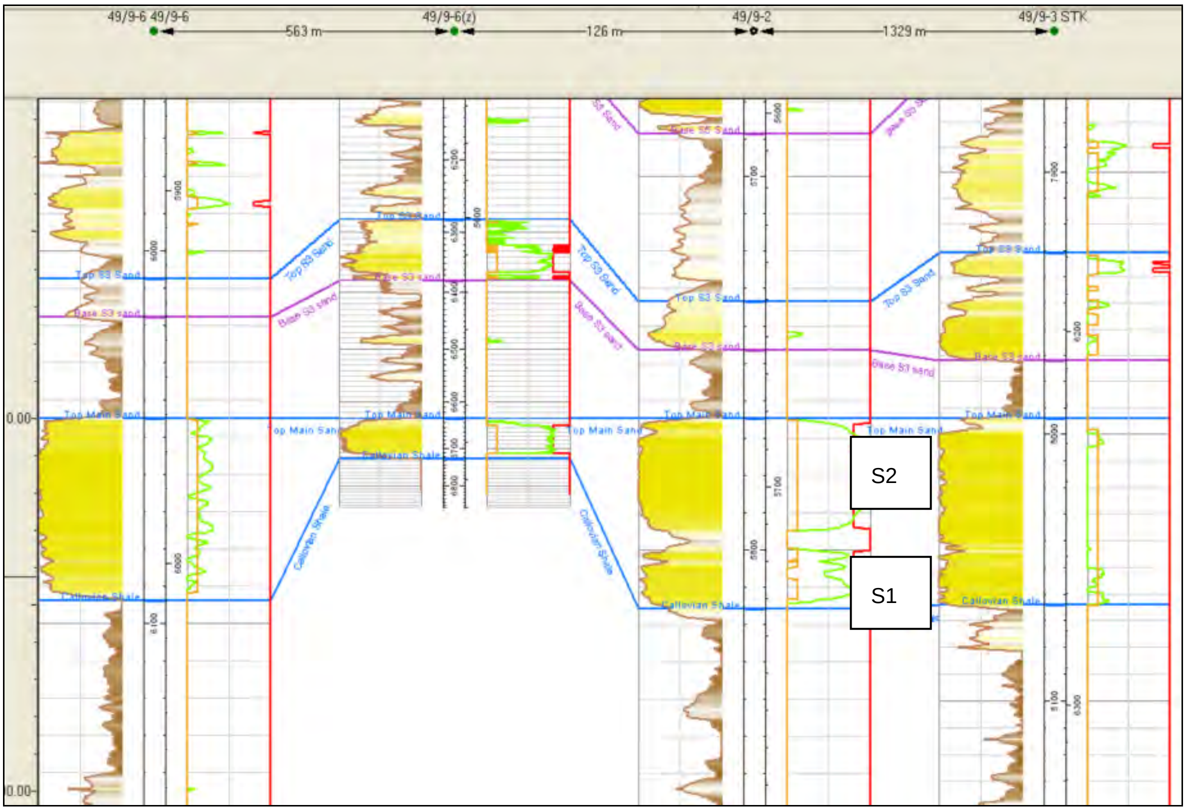
Sands are further subdivided by Providence into four zones (S3, S4, S5 and S6). The S3 and S5 sands in 49/9-2 and 49/9-3st2 appear to correlate well, suggesting good reservoir continuity in the 49/9-2 fault block. By contrast, the S4 and S6 sands are more shale-prone and less correlative. This subdivision and correlation of the Upper Sands appeared reasonable to RPS and is shown on Figure 11.




*Source: Providence*

**Figure 11: Correlation of the Upper Sands, Helvick oil discovery**

The Main Sands were deposited as stacked, braided channel sequences. Subdivision of the Main Sands into two zones, S1 and S2, has been proposed by Providence. The S1 and S2 sands are separated by a shale about 1m thick in the 49/9-2 fault block, which may be a barrier to flow. Subdivision of the Main Sand into two zones appears reasonable to RPS and is shown on Figure 12.




*Source: Providence*

**Figure 12: Correlation of the Main Sands, Helvick oil discovery**

The Bathonian Limestone is an oolitic limestone deposited in a shallow marine environment and is present in all the wells that penetrated to the appropriate depth (49/9-3st2, 49/9-2 and 49/9-6). In 49-3st2 and 49/9-6 the limestone is of similar thickness, but the Calovian and Bathonian section in 49/9-2 is condensed due to faulting.

### 3.3.2 Petrophysics

RPS has conducted petrophysical analysis on the Upper Sands, Main Sands and Bathonian Limestone and the results compared with previous work by RML (1999[4]) and Jenner Associates (2000[5]). Wells 49/9-2, 49/9-3, 49/9-3st2, 49/9-6 had a full suite of wireline logs (comprising calliper, gamma ray, spontaneous potential, sonic, density, neutron and resistivity) and were included in the RPS evaluation. However, 49/9-6z had only LWD gamma ray and resistivity logs and was excluded from the analysis.

The clay volume (Vshale) was estimated by RPS using a level-by-level linear transform of the gamma ray based on sand and shale baseline readings, and also by crossplotting density and neutron logs. The linear transform method lead to a lower Vshale.

Porosity was derived from the density-neutron crossplot in a similar manner to Jenner Associates and RML. Jenner Associates employed a sandstone matrix density of 2.66g/cc, derived from the 49/9-3 core, whereas RPS used an average sandstone matrix density of 2.65g/cc. However, porosities computed by RPS were similar to those derived by Jenner Associates and RML.

---

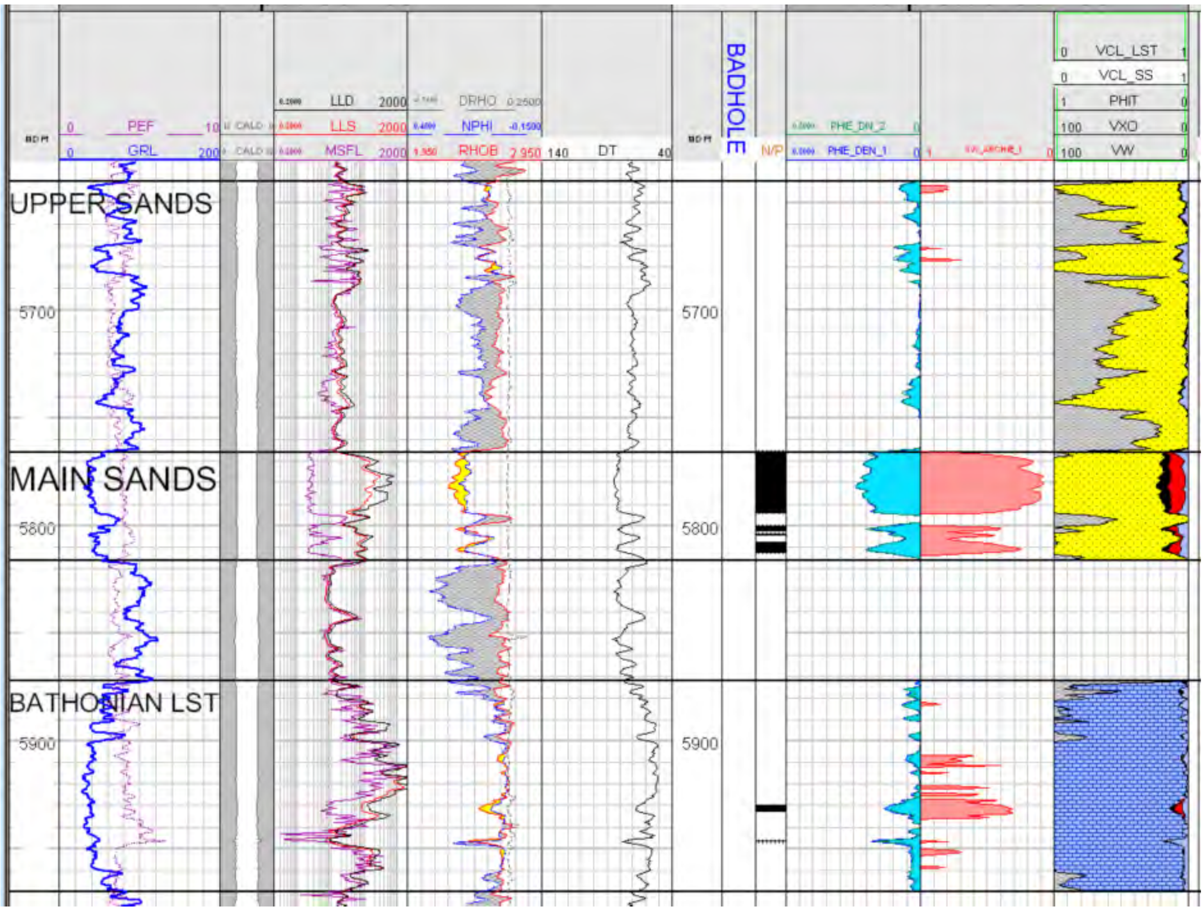
[4] Reservoir Management Ltd 2000 Helvick Field Reservoir Evaluation & Field Development Studies. Proprietary report prepared for Providence Resources plc

[5] Jenner Associates 2000 Petrophysical Evaluation of the Helvick Field (Block 49/9), offshore Ireland. Proprietary report prepared for Providence Resources plc

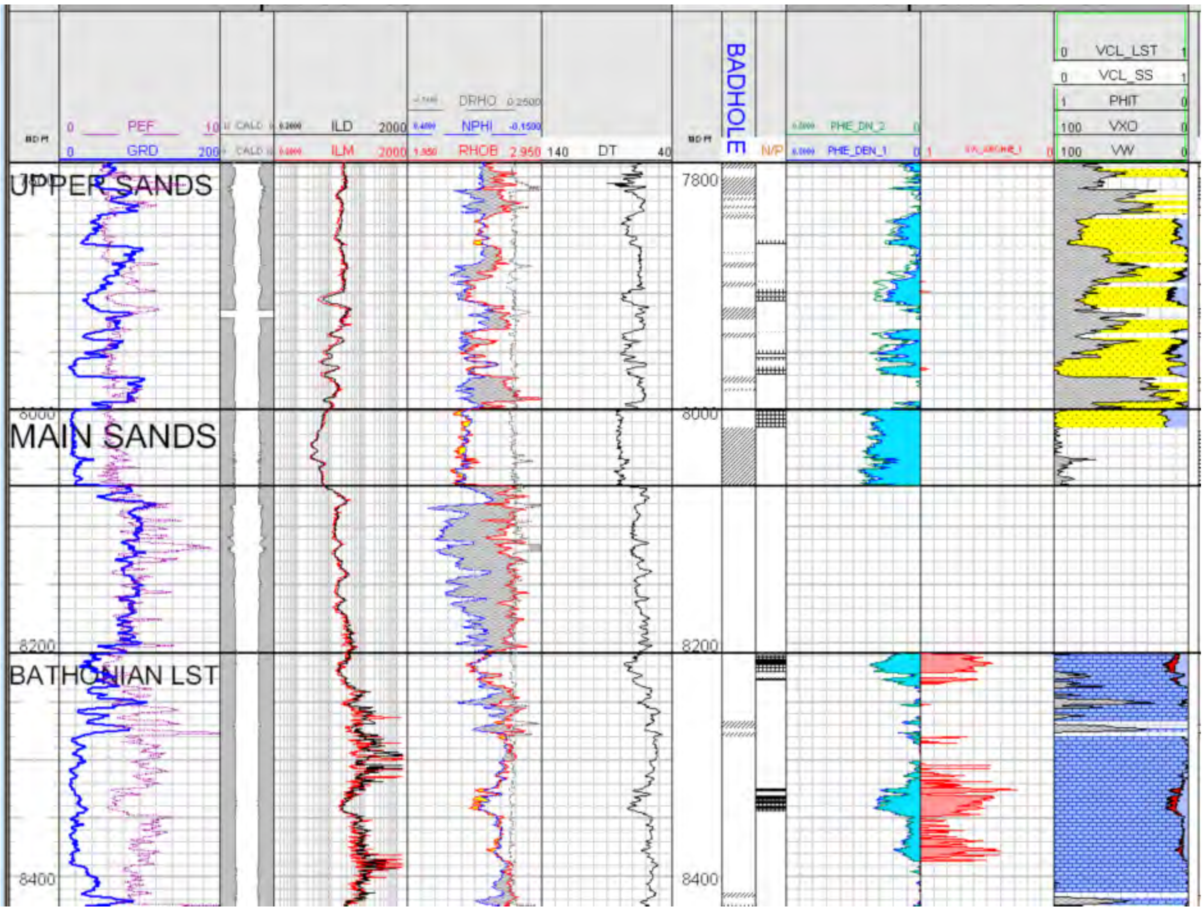
RPS have calculated water saturation using the Archie equation whereas both RML and Jenner and Associates used the Indonesia equation. RPS did not regard the reservoirs as particularly shaly and therefore used a “clean-sand” methodology to compute Sw. Both the Jenner Associates and RML studies employed a common Rw in each reservoir sequence (Main Sand, Upper Sand and Bathonian Limestone) whereas RPS used a separate pickett plot for each reservoir sequence in each well. Also, all three studies use differing values of the electrical parameters a, m and n, with RPS using a combination of a = 1, m = 2 and n =2. However, the Sw determined in all three studies are similar, despite contrasting methodolgies.

Reservoir cut-offs were the same for all three studies, with Vshale < 40%, porosity > 10% and Sw < 60% used to define pay. Results of the petrophyscial analysis of 49/9-2, 49/9-3st2 and 49/9-6 are shown as CPI plots on Figure 13 and summarised on Table 26. The Jenner and Associates and RML petrophysical properties are reasonable and can be utilised in volumetric calculations.

**49/9-2**



**49/9-3st2**



PEF
GRD
CALD
ILD
ILM
DRHO
NPHI
RHOB
DT
BADHOLE
N/P
PHIE_DN_2
PHIE_DEN_1
VCL_LST
VCL_SS
PHIT
VXO
VW
UPPER SANDS
MAIN SANDS
BATHONIAN LST
7800
8000
8200
8400

## 49/9-6

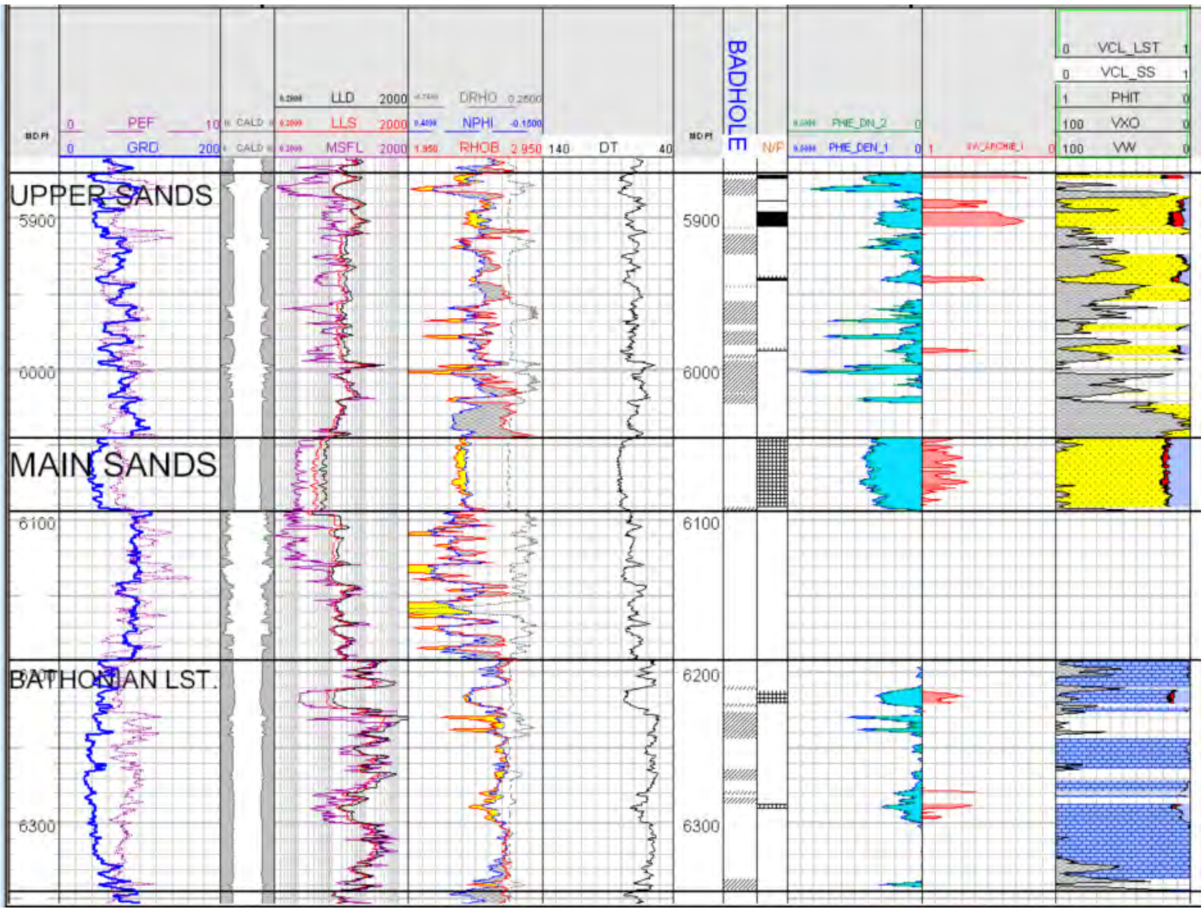



**Figure 13: RPS Petrophysical analyses of wells 49/9-2, 49/9-3st2 and 49/9-6**

### 49/9-2: Sums and Averages

| | | | | | | | | RPS | Jenner | RPS | Jenner |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Zone | Top | Base | Gross | Net | N/G | Pay | VCL [Net] | PHIE [Net] | *PHIE [Net]* | SW [Pay] | *SW [Pay]* |
| | ft | ft | ft | ft | fr | ft | % | % | | % | |
| Upper Sands | 5640.00 | 5766.00 | 126.00 | 0.50 | 0.00 | 0.00 | 17.59 | 13.05 | *11.20* | - | *-* |
| Main Sands | 5766.00 | 5816.00 | 50.00 | 39.00 | 0.77 | 35.50 | 1.48 | 18.43 | *19.60* | 21.91 | *18.90* |
| Bathonian Lst. | 5872.00 | 5970.00 | 98.00 | 5.50 | 0.06 | 3.50 | 0.00 | 13.05 | *12.80* | 34.01 | *39.20* |

*Cut-offs: VCL =< 40%, PHIE =>10% [Net]; SW =< 60% [Pay]*

### 49/9-3st2: Sums and Averages

| | | | | | | | | RPS | Jenner | RPS | Jenner |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Zone | Top | Base | Gross | Net | N/G | Pay | VCL [Net] | PHIE [Net] | *PHIE [Net]* | SW [Pay] | *SW [Pay]* |
| | ft | ft | ft | ft | fr | ft | % | % | | % | |
| Upper Sands | 7788.00 | 7999.00 | 211.00 | 28.50 | 0.16 | 0.00 | 15.37 | 12.35 | *13.90* | - | *57.20* |
| Main Sands | 7999.00 | 8065.00 | 66.00 | 16.00 | 0.24 | 0.00 | 2.18 | 17.19 | *19.00* | - | *-* |
| Bathonian Lst. | 8208.00 | 8428.00 | 220.00 | 35.00 | 0.16 | 35.00 | 0.35 | 14.14 | *13.60* | 51.89 | *54.90* |

*Cut-offs: VCL =< 40%, PHIE =>10% [Net]; SW =< 60% [Pay]*

| 49/9-6: Sums and Averages | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | RPS | Jenner | RPS | Jenner |
| Zone | Top | Base | Gross | Net | N/G | Pay | VCL [Net] | PHIE [Net] | PHIE [Net] | SW [Pay] | SW [Pay] |
| | ft | ft | ft | ft | fr | ft | % | % | | % | |
| | | | | | | | | | | | |
| Upper Sands | 5870.00 | 6045.00 | 175.00 | 19.00 | 0.12 | 16.00 | 2.23 | 15.22 | 14.30 | 36.39 | 33.60 |
| Main Sands | 6045.00 | 6094.00 | 49.00 | 45.50 | 0.92 | 0.00 | 2.85 | 18.84 | 20.10 | - | - |
| Bathonian Lst. | 6192.00 | 6345.00 | 153.00 | 11.50 | 0.08 | 0.00 | 6.12 | 14.25 | 13.60 | - | - |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| *Cut-offs: VCL =< 40%, PHIE =>10% [Net]; SW =< 60% [Pay]* | | | | | | | | | | | |

**Table 26: Summary of RPS and Jenner Associates petrophysical analyses of wells 49/9-2, 49/9-3st2 and 49/9-6**

### 3.3.3 Volumetrics

Volumetric calculations were undertaken separately on each reservoir zone by RPS. Only the 49/9-2 fault block is proposed for development in the Providence draft report[6] and therefore volumetric calculations were confined to this area. Depth maps from the Providence report form the basis of the volumetric calculations. However, Providence did not include depth maps in their report for the top S3 and top S1 zones, so these were calculated from the top S4 and top S1 maps respectively, using an average well thickness. Base depth surfaces for each reservoir zone were obtained from the top thickness by using the average thickness for the zone derived from wells. Area-depth pairs were generated for the top and base surfaces of each reservoir and were used to determine GRVs within the REP™ software.

In the Upper Sands, in the 49/9-2 fault block, only the S5 and S3 zones appear to be laterally continuous and were therefore considered in volumetric calculations. Reservoir properties were derived from averages from wells 49/9-2, 49/9-3st2 and 49/9-6z. Uncertainty in the OWC has also been modelled, with the most likely OWC at 6015ft is based on RFT pressure data, but the possibility that the reservoirs are full to the mapped spill point at 6075ft was also considered. A triangular distribution of OWC was incorporated into the volumetric calculations.

Both the S2 and S1 reservoirs of the Main Sands contain oil in the 49/9-2 fault block. Reservoir properties were derived from averages from wells 49/9-2, 49/9-3st2 and 49/9-6z. However, there appears to be an increase in reservoir quality downdip from 49/9-2 towards 49/9-3st2. The most likely OWC is at 6135ft, based on RFT data, but the possibility of a common contact with the Upper Sands at 6015ft cannot be ignored. Uncertainty in the OWC was modelled as a triangular distribution of spill point in the volumetric calculations.

A summary of the parameters used in volumetric calculations is given on Table 27.

[6] Providence Resources plc 2010 Review of the Helvick oil accumulation. Draft Report

**Upper Sands S5**

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 2.0 | 2.3 | 2.7 | Area –depth pairs |
| Spill Point (TVDSS m) | 1837 | 1843 | 1848 | Triangular |
| Area uncertainty (%) | 85 | 100 | 115 | Normal |
| Net to Gross (%) | 60 | 70 | 80 | Normal |
| Porosity (%) | 8 | 10 | 12 | Normal |
| Oil Saturation (%) | 40 | 50 | 60 | Normal |
| FVF | 1.40 | 1.42 | 1.44 | Normal |
| **STOIIP (MMstb)** | **0.2** | **0.4** | **0.5** | |

**Upper Sands S3**

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 17.6 | 20.8 | 24.0 | Area –depth pairs |
| Spill Point (TVDSS m) | 1837 | 1843 | 1848 | Triangular |
| Area uncertainty (%) | 85 | 100 | 115 | Normal |
| Net to Gross (%) | 40 | 50 | 60 | Normal |
| Porosity (%) | 6 | 9 | 12 | Normal |
| Oil Saturation (%) | 40 | 60 | 80 | Normal |
| FVF | 1.40 | 1.42 | 1.44 | Normal |
| **STOIIP (MMstb)** | **1.3** | **2.3** | **3.9** | |

**Main Sands S2**

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 4.3 | 5.1 | 5.9 | Area –depth pairs |
| Spill Point (TVDSS m) | 1841 | 1852 | 1862 | Triangular |
| Area uncertainty (%) | 85 | 100 | 115 | Normal |
| Net to Gross (%) | 84 | 90 | 96 | Normal |
| Porosity (%) | 18.3 | 20.0 | 21.7 | Normal |
| Oil Saturation (%) | 77.0 | 81.5 | 86.0 | Normal |
| FVF | 1.40 | 1.42 | 1.44 | Normal |
| **STOIIP (MMstb)** | **2.7** | **3.3** | **3.9** | |

**Main Sands S1**

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 2.7 | 3.2 | 3.7 | Area –depth pairs |
| Spill Point (TVDSS m) | 1841 | 1852 | 1862 | Triangular |
| Area uncertainty (%) | 85 | 100 | 115 | Normal |
| Net to Gross (%) | 81 | 91 | 100 | Normal |
| Porosity (%) | 14 | 17 | 20 | Normal |
| Oil Saturation (%) | 57 | 67 | 77 | Normal |
| FVF | 1.40 | 1.42 | 1.44 | Normal |
| **STOIIP (MMstb)** | **1.0** | **1.4** | **1.9** | |

**Bathonian Limestone**

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 10.8 | 13.3 | 15.9 | Area –depth pairs |
| Spill Point (TVDSS m) | 1841 | 1852 | 1862 | Triangular |
| Area uncertainty (%) | 85 | 100 | 115 | Normal |
| Net to Gross (%) | 7 | 15 | 23 | Normal |
| Porosity (%) | 9 | 11 | 13 | Normal |
| Oil Saturation (%) | 45 | 58 | 71 | Normal |
| FVF | 1.40 | 1.42 | 1.44 | Normal |
| **STOIIP (MMstb)** | **0.2** | **0.5** | **0.9** | |

**Table 27: Calculation of STOIIP for the Helvick oil discovery (full field interest)**

Consolidated STOIIP in the Helvick Field is summarised on Table 28 for the Upper Sands (S3 and S5), the Main Sands (S1 and S2), together with the whole of the 49/9-2 fault block (Upper Sands, Main Sands and Bathonian Limestone).

| STOIIP | P90 (MMstb) | P50 (MMstb) | P10 (MMstb) |
|---|---|---|---|
| Upper Sands | 1.6 | 2.7 | 4.3 |

| STOIIP | P90 (MMstb) | P50 (MMstb) | P10 (MMstb) |
|---|---|---|---|
| Main Sands | 3.9 | 4.7 | 5.5 |

| STOIIP | P90 (MMstb) | P50 (MMstb) | P10 (MMstb) |
|---|---|---|---|
| 49/9-2 Fault Block | 6.6 | 8.0 | 9.8 |

**Table 28: Consolidation of STOIIP for the Helvick discovery (full field interest)**

### 3.3.4 Reservoir Engineering

The development plan in the Providence review of the Helvick accumulation only involved producing the Main Sands. Production profiles determined by RPS were therefore confined to the Main Sands in the low and mid cases, based on the P90 and P50 Main Sand STOIIPs respectively, whereas the high case considered production from all three reservoirs. Production profiles were calculated by material balance using the MBAL™ software. The Main Sands, Upper sands and Bathonian Limestone were modelled as separate reservoirs in the high case. Volumes of oil in place used in the construction of the production profiles were:

| | | | | | |
|---|---|---|---|---|---|
| Low | 3.9 MMstb | Mid | 4.7 MMstb | High | 10.7 MMstb |

Different porosities were used in the three reservoir layers, with a porosity of 10% used in the Upper Sands, 14% in the Main Sands and 11% in the Bathonian Limestone. By contrast, a single permeability was assumed in the three reservoirs, with a horizontal permeability of 300mD and a vertical permeability of 30mD, following the assumptions made by Providence. A residual oil saturation of 0.3 was assumed, together with a connate (irreducible) water saturation of 0.1 and the water-oil relative permeability curves presented in the “BP case” in the RML (1999) report. The bubble point of the solution gas was calculated from measurements of GOR and FVF using the relationship proposed by Beggs and Robinson (1975[7]), whilst oil viscosity was determined using the method proposed by Standing (1981[8]). It was further assumed that water injection resulted in 100% voidage replacement. Also, a flowing bottom hole pressure of 1500 psi was assumed in the production well. The RPS production profiles are characterised by lower deliverability than the profile presented by Providence, which is largely a result of assumptions concerning water-oil relative permeability.

### 3.3.5 Development Plan

Providence have outlined several alternative development scenarios for the Helvick Field in the draft 2010 report “*Review of the Helvick accumulation*”. The most cost effective of these schemes, which minimises concept risk and could be procured and installed rapidly, involves using a Seahorse III wellhead platform in conjunction with a Kunsten floating storage and offtake vessel (FSO), and this development plan was reviewed by RPS.

All three production cases calculated require a single production well, together with a single water injector. RPS has estimated the cost of drilling a newly drilled producer to be US$26.8MM and the cost of a newly drilled injector to be US$20.0MM, and these estimates are broadly similar to those provided by Providence. An estimate of the cost of a Seahorse well head platform, including topside processing equipment, transportation and instillation, has been provided by Upstream Engineering LLC to Providence of US$37.5MM (excluding contingency) and this seems reasonable to RPS. The cost of converting a Kunsten tanker to an FSO is estimated as US$6.0MM for the FSO conversion and necessary oil export lines. First oil was assumed in July 2012, following the Providence draft development plan. Operating and hire costs for the FSO have been estimated by Providence as US$62MM over the lifetime of the field for their best case, or US$17.74/bbl/day. These operating and hire costs for the FSO have been used by RPS. Additional G&A costs, estimated as US$1.0MM per annum, together with the costs of workovers, have also been incorporated into the cashflow models. Providence have assumed flaring of the associated gas in their draft development plan.

### 3.3.6 Economics and Contingent Resources

A cashflow model has been constructed using the production and cost profiles. Indicative net present values, in money of the day at a discount rate of 10%, for the 1C, 2C and 3C Contingent Resources, are summarised on Table 29.

---

[7] Beggs H.D. & Robinson J.R. 1975 Estimating the viscosity of crude oil systems *Journal of Petroleum Technology*, **September 1975**, pp.1140-1141.

[8] Standing M.B. 1981 Volumetric and phase behaviour of oilfield hydrocarbon systems *Society of Petroleum Engineers of AIME*, Dallas.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| 1C | 1.5 |
| 2C | 3.0 |
| 3C | 12.8 |

**Table 29: Indicative net present value for the Helvick oil discovery (net to Lansdowne 10% working interest)**

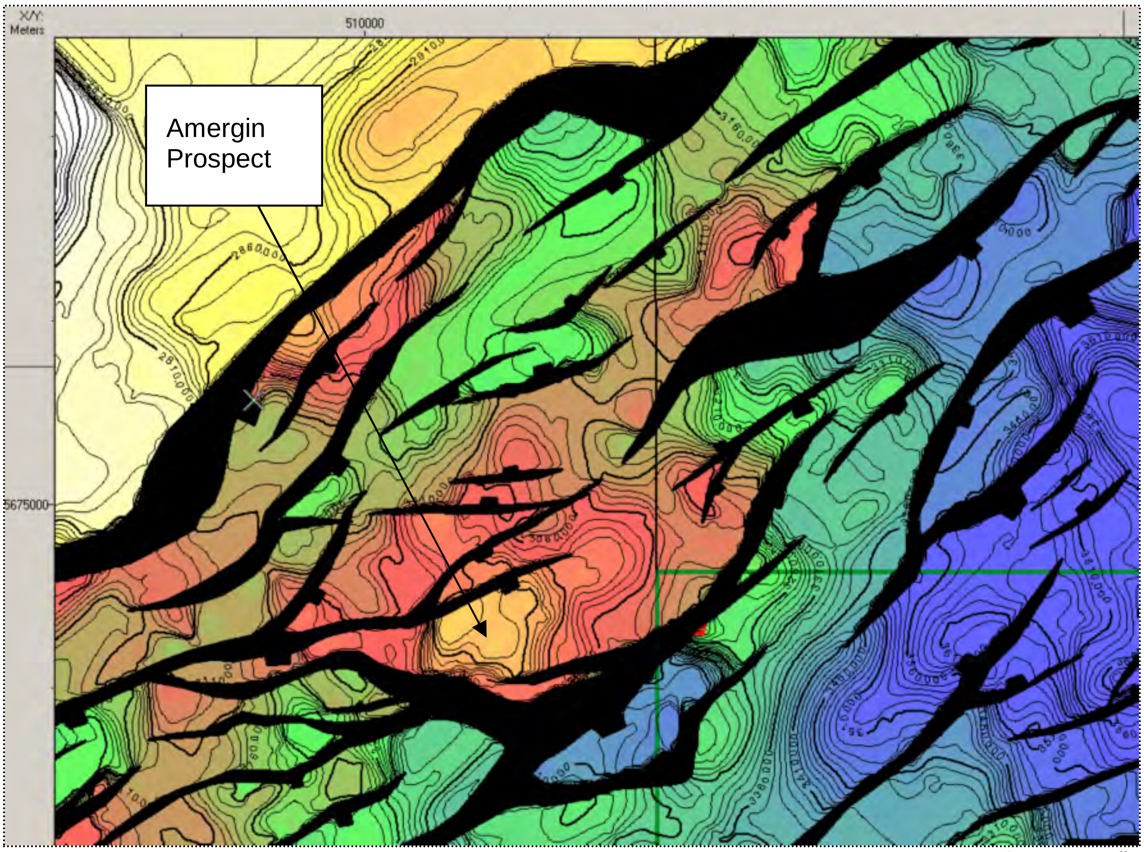
Contingent Resources that may be economically recovered from the Helvick oil discovery are summarised on Table 30. Only oil is considered to be contingent resources, as there are currently no plans for gas sales.

| Case | Contingent Resources (MMstb) |
|---|---|
| .1C | 0.2 |
| 2C | 0.3 |
| 3C | 0.6 |

**Table 30: Contingent oil resources for the Helvick oil discovery (net to Lansdowne 10% working interest)**

## 3.4 License 5/08 (Amergin)

Standard Exploration License 5/08 lies about 25km from the Barryroe oil discovery and covers part of blocks 47/25, 48/21 and 48/22. The Amergin Prospect lies within Standard Exploration 5/08 which contains two targets, at Middle / Upper Jurassic (Bathonian) and Basal Wealden levels. The Upper / Middle Jurassic target of the Amergin Prospect is shown on Figure 14.




*Source: Merlin*

**Figure 14: Top Middle / Upper Jurassic (Bathonian) depth structure showing the Amergin Prospect**

### 3.4.1 Amergin Prospect Upper / Middle Jurassic

Volumetric analysis for the Upper / Middle Jurassic reservoir, discussed fully in the February 2009 report, is summarised in Table 31.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV (MMm$^3$) | 209 | 370 | 655 | Lognormal |
| Net to Gross (%) | 30 | 50 | 70 | Normal |
| Porosity (%) | 16 | 18 | 20 | Normal |
| Oil Saturation (%) | 65 | 75 | 85 | Normal |
| FVF | 1.38 | 1.40 | 1.42 | Normal |
| **STOIIP (MMstb)** | **49.4** | **107** | **219** | |
| Recovery Factor (%) | 25 | 35 | 45 | Normal |
| **Technically Recoverable Oil (MMstb)** | **15.8** | **36.9** | **79.2** | |
| **Technically Recoverable Associated Gas (Bscf)** | **1.17** | **2.72** | **5.84** | |

**Table 31: STOIIP, technically recoverable oil and technically recoverable associated gas from the Upper / Middle Jurassic of the Amergin Prospect**

RPS estimate the play risk to be 73% with an overall GPoS of 16%.

### 3.4.2 Amergin Prospect Upper / Middle Jurassic Conceptual Development Plan

Conceptual development plans have been devised by RPS for the Low, Best and High cases. All of the cases (including failure) involve acquiring 3D seismic over the Amergin Prospect during 2011, which has been estimated to cost US$1.5MM by Lansdowne. The low case involves one vertical well without any pressure support for which an initial flow rate of 6,600bbl/d and a decline rate of 20% has been assumed, from the 49/9-2 test results. By contrast, the best and high cases assume production from high angle wells with an initial flow rate of 19,800bbl/d and pressure support by water injection, together with a decline rate of 20%. The flow rate of 19,800bbl/d is derived from extrapolation of the 49/9-2 test results to a horizontal well. The best case assumes one producer and one water injector while the high case assumed two producers and a water injector. The cost of a vertical exploration well is estimated to be US$31MM, whereas the cost of a high angle appraisal well is estimated as US$36MM and the cost of a development well as US$32MM.

Development of the Amergin Prospect involves a leased FPSO which is estimated by RPS to cost US$90,000 per day for the vessel, reducing to US$75,000 after five years, plus a variable cost of US$6.5/bbl, based on rates supplied by Petrojarl. Consequently, the principal capital costs were the costs of the sub-sea jackets and other facilities which are estimated by RPS as US$29MM in the Low case, US$59MM in the Best case and US$88MM in the High case. The annual operating cost of the FPSO is estimated at US$5.0MM to US$5.5MM. Included within that is the cost of offloading the oil through a CALM buoy to shuttle tanker and transportation to the shore base. Other operating costs are workovers, which are assumed to be required every four years and are estimated to cost US$2-4MM, together with general management and administrative costs, which are estimated as US$1.0-1.5MM per annum. The associated gas will be used for power generation on the FPSO.

### 3.4.3 Amergin Prospect Upper / Middle Jurassic Economics

A cashflow model has been constructed using the production and cost profiles for the Upper / Middle Jurassic target of the Amergin Prospect. Indicative, success case net present values, in money of the day and at a discount rate of 10%, for the Low, Best and High case Prospective Resources are summarised on Table 32.

An expected monetary value (EMV) of **US$144.3MM**, at 10% discount, is calculated using Swanson's 30-40-30 rule from the NPVs in Table 32.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| Cost of failure | -30.1 |
| Low estimate | 226.0 |
| Best estimate | 757.6 |
| High estimate | 2,336.5 |

**Table 32: Indicative net present values for the Upper / Middle Jurassic target in the Amergin Prospect (net to Lansdowne 100% working interest)**

Prospective Resources for the Upper / Middle Jurassic reservoir corresponding to the values given on Table are summarised in Table 33. The associated gas is not included within volumes of Prospective Resources as there no gas sales included within the conceptual development plan.

| Case | Prospective Resources (MMstb) |
|---|---|
| Low estimate | 12.3 |
| Best estimate | 27.0 |
| High estimate | 71.5 |

**Table 33: Prospective Resources from the Upper / Middle Jurassic target in the Amergin Prospect (net to Lansdowne 100% working interest)**

### 3.4.4 Amergin Prospect Base Wealden

Volumetric parameters and results for the Base Wealden target of the Amergin Prospect presented in the February 2009 study are summarised in Table 34.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 144 | 296 | 608 | Lognormal |
| Net to Gross (%) | 40 | 50 | 60 | Normal |
| Porosity (%) | 17 | 20 | 23 | Normal |
| Oil Saturation (%) | 65 | 75 | 85 | Normal |
| FVF | 1.26 | 1.30 | 1.34 | Normal |
| **STOIIP (MMstb)** | **48.3** | **105** | **228** | |
| Recovery Factor (%) | 15 | 25 | 35 | Normal |
| **Technically Recoverable Oil (MMstb)** | **10.0** | **25.2** | **60.3** | |
| **Technically Recoverable Associated Gas (Bscf)** | **4.5** | **11.3** | **27.1** | |

**Table 34: STOIIP, technically recoverable oil and technically recoverable associated gas from the Basal Wealden of the Amergin Prospect**

RPS estimate the play risk to be 95% with an overall GPoS of 22%.

### 3.4.5 Amergin Prospect Basal Wealden Development Plan

Conceptual development plans have been devised for the Low, Best and High case Prospective Resources. All of the cases involved acquiring a 3D seismic survey over the Amergin Prospect during 2011, which was estimated by Lansdowne to cost US$1.5MM, and utilise high angle development wells. The low case involves one development well without any pressure support for which an initial flow rate of 4,800bbl/d and a decline rate of 20% has been assumed. This flow rate was derived from vertical well 48/24-3 on the Barryroe Field which flowed at 1,600bbl/d, with the flow rate extrapolated to a high angle well. The best case was developed with three high angle wells whereas the high case employed eight producers. The cost of a vertical exploration well is estimated by RPS to be US$22MM, whereas the cost of an appraisal well is estimated as US$25MM and the cost of a development well as US$25MM.

Development of the Amergin Prospect involves a leased FPSO which is estimated by RPS to cost US$90,000 per day for rental of the vessel, together with a variable cost of US$6.5/bbl. Consequently, the principal capital costs were the costs of the sub-sea jackets and other facilities which are estimated by RPS as US$20MM in the low case, US$40MM in the best case and US$60MM in the high case. The annual operating cost of the FPSO is estimated by RPS at US$5.0MM to US$7.5MM Other operating costs are workovers, which are assumed to be required every four years and are estimated to cost US$2-4MM, together with general management and administrative costs, which are estimated as US$1.0-1.5MM per annum. The associated gas will be used for power generation on the FPSO.

### 3.4.6 Amergin Prospect Basal Wealden Economics

A cashflow model has been constructed using the production and cost profiles for the Basal Wealden target of the Amergin Prospect. Net present values, in money of the day and at a discount rate of 10%, for the Low, Best and High case Prospective Resources are summarised in Table 35.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| Cost of failure | -30.1 |
| Low estimate | -15.1 |
| Best estimate | 484.5 |
| High estimate | 1,583.1 |

**Table 35: Indicative net present value from the Basal Wealden target in the Amergin Prospect**

An expected monetary value (EMV) of **US$117.4MM**, at 10% discount, is calculated using Swanson's 30-40-30 rule from the NPVs in Table 30, together with the risking on Table 35. Details of the cashflow model are given in Appendix C.

Prospective Resources for the Basal Wealden target, corresponding to the values given on Table 35, are summarised on Table 36. The associated gas is not included within volumes of Prospective Resources as there is no sales gas in the conceptual development plan.

| Case | Prospective Resources (MMstb) |
|---|---|
| Low estimate | 4.1 |
| Best estimate | 20.4 |
| High estimate | 54.7 |

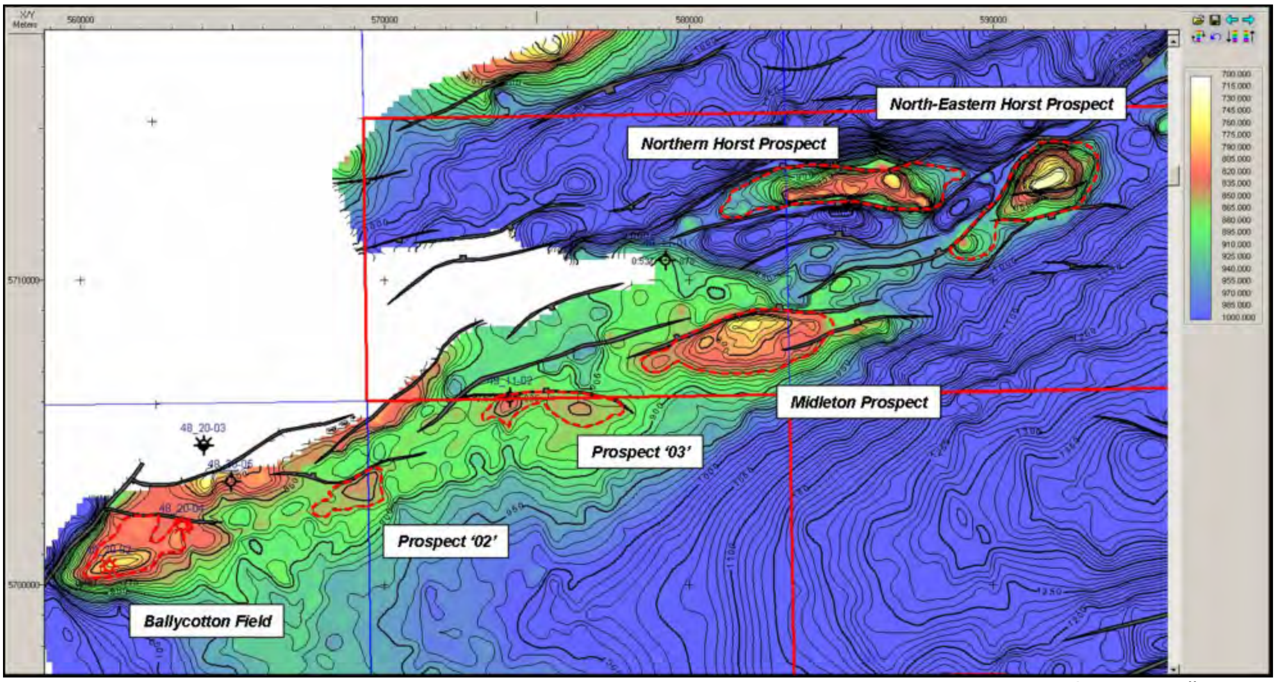
**Table 36: Summary of Prospective Resources from the Basal Wealden target in the Amergin Prospect**

A more realistic EMV for the Amergin Prospect can be obtained by combining the Upper / Middle Jurassic and Basal Wealden targets using a simple probability tree methodology involving 16 branches. The branch of the probability tree involving failure of both targets includes the cost of a single exploration well. The EMV thus obtained is **US$265MM** (at 10% discount rate, in money of the day) and this can be considered as the EMV for Standard Exploration License 5/08.

## 4. GAS EXPLORATION LICENSES

Standard Exploration License 4/07 lies some 20km northeast of the Kinsale Head and Ballycotton gas fields and approximately 60-75km to the southeast of Cork on the southern Irish coast (Figure 1). Water depths across the area of the exploration license vary from about 75m to 90m. The Midleton area in the north of the exploration license (blocks 49/11 and 49/12) is covered by a reasonably dense grid of 2D seismic data largely acquired by Marathon between 1998 and 1994, some 388km of which has been reprocessed by Fugro, Two wells have been drilled within the area of the exploration license, 49/11-1 drilled in 1972 and 49/17-1 drilled in 1979, both of which were dry. However, two wells on the Old Head of Kinsale discovery, 49/23-1 and 49/23-2Z, lie to the south of exploration license 4/07 (Figure 15). The wells were drilled by Island Oil and Gas in 2006 (49/23-1) and 2007 (49/23-2Z). Well 49/23-2Z tested gas at a rate of 18MMscf/d through a 56/64" choke from Upper Wealden sands. The Old Head of Kinsale discovery has been estimated by San Leon to contain Contingent Resources of 45 Bscf gas in Exploration License 4/05.

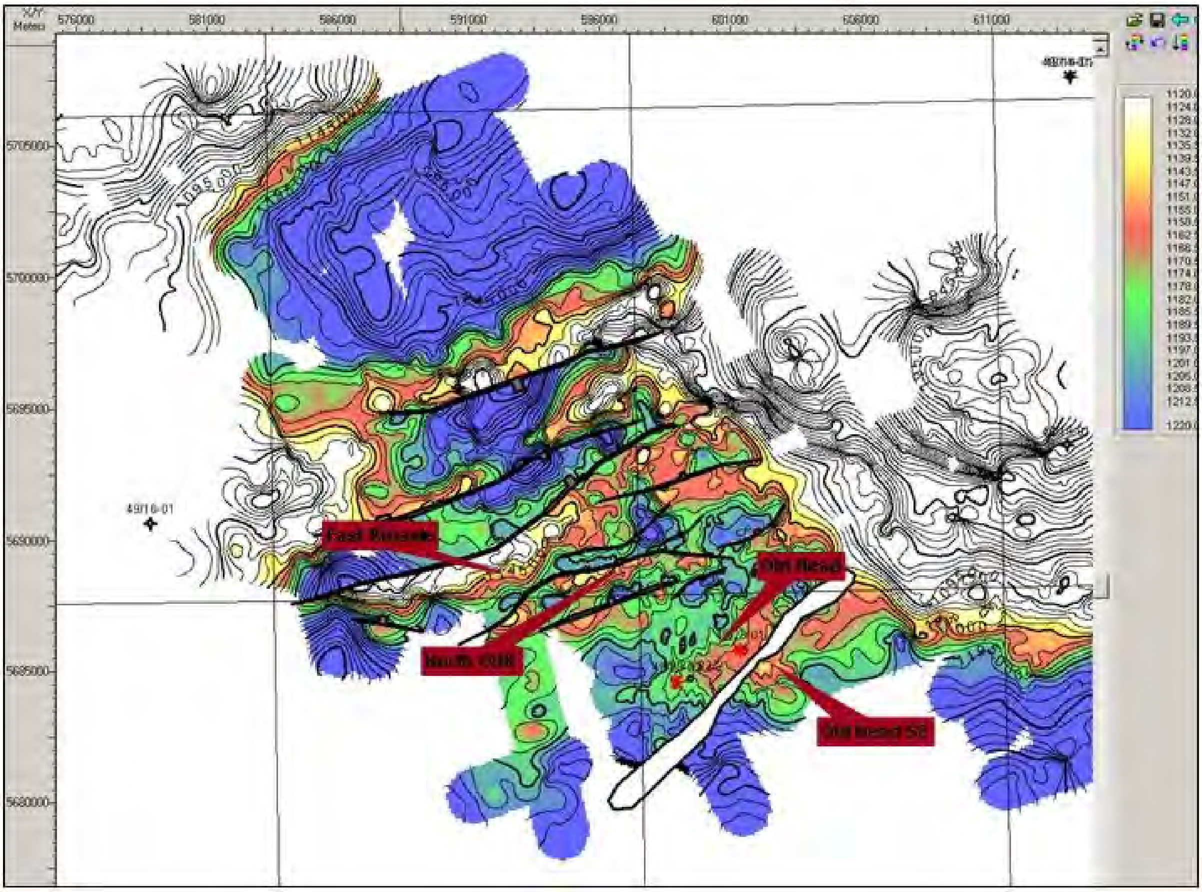
An important structural trend has been identified to the north east of the Ballycotton Field (recoverable gas of approx. 64 Bscf estimated by RPS from production data) in which a number of prospects and leads are developed (Figure 15). The most attractive prospect was originally identified by Marathon, and is now named Midleton. A number of other prospects and leads have been identified along the Ballycotton to Midleton trend, but these are all smaller than Midleton and some of them lie outside of the current Licence Option and will not be considered in any detail in this evaluation (see Figure 15). Two further prospects are recognised in the northern part of the 03/02 Licence Option named the Northern Horst Prospect and the North-Eastern Horst Prospect.




*Source: Merlin*

**Figure 15: Prospects and leads to the north east of the Ballycotton Field**

A depth map from the East Kinsale area showing the East Kinsale and Northern Old Head of Kinsale prospects is shown on Figure 16.



*Source: Merlin*

**Figure 16: Prospects and leads in the East Kinsale area**

### 4.1.1 Midleton Prospect

The Midleton Prospect has been described fully in the February 2009 study and volumetric estimates are summarised in Table 37.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV (MMm$^3$) | 127.5 | 160.8 | 200.8 | Lognormal |
| Net to Gross (%) | 60 | 70 | 80 | Normal |
| Porosity (%) | 20 | 22 | 24 | Normal |
| Gas Saturation (%) | 70 | 75 | 80 | Normal |
| 1/Bg | 110 | 115 | 120 | Normal |
| **GIIP (Bscf)** | **55.3** | **74.3** | **99.5** | |
| Recovery Factor (%) | 65 | 75 | 85 | Normal |
| **Technically Recoverable Gas (Bscf)** | **40.0** | **55.6** | **76.2** | |

**Table 37: Calculation of GIIP and technically recoverable gas for the Midleton Prospect**

RPS estimate the play risk to be 80% with an overall GPoS of 26%.

### 4.1.2 Midleton Prospect Reservoir Engineering

The proposed development strategy is to have a single vertical sub-sea producer tied back to the Ballycotton Field in all three cases (P90, P50 and P10). From Ballycotton the gas will be piped the 15km to the Kinsale Head Field which has compression facilities. It has been assumed that the exploration well and appraisal well are drilled during 2012, and that the appraisal well is subsequently converted to a producer. This development schedule is implied in information received from Lansdowne, whose production profile for Midleton has peak gas production during 2013. Production data for the Ballycotton Field has been made available by Lansdowne and this has been used to construct a production profile for the high case. The Ballycotton Field has analogous structure and reservoir the Midleton Prospect. The initial well production potential is 35MMscf/d and declines at 25% per annum. By contrast, the low case profile is based on that presented by RPS in the February 2009 study, with a plateau rate of 20MMscf/d and a decline rate of 20% per annum, based on test data from the 'A' Sand.

### 4.1.3 Midleton Prospect Economics

All of the cases evaluated include the cost of acquiring a 3D seismic survey over the Midleton Prospect during 2011, which has been estimated to cost US$0.975MM by Lansdowne. The principal capital costs are the costs of flowlines and risers, which are estimated by RPS as US$50MM. Other major capital costs are well costs, with the cost of an exploration well estimated by RPS as US$25MM. The cost of an appraisal well is estimated as US$22MM, and it is assumed that this well is subsequently converted to a producer. The major operating cost is that of the Kinsale Head Platform, which cost US$28.6MM during 2010 (cost obtained from Lansdowne) and is essentially a fixed cost. Operating costs for the Kinsale Head Platform were assumed to be allocated on a pro-rata basis with production. Indicative net present values for the Midleton Prospect are given in Table 38.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| Cost of failure | -25.1 |
| Low case | 36.8 |
| Best case | 42.5 |
| High case | 57.5 |

**Table 38: Indicative net present values of the Midleton Prospect**

An expected monetary value (EMV) of **US$-6.8MM**, at 10% discount, is calculated using Swanson's 30-40-30 rule from the NPVs in Table 38, together with the GPoS of 26%. Details of the cashflow models are given in Appendix C.

Prospective Resources, which constitute economically recoverable volumes of gas, are summarised in Table 39.

| Case | Prospective Resources (Bscf) |
|---|---|
| Low | 40.8 |
| Best | 44.5 |
| High | 45.4 |

**Table 39: Prospective Resources of the Midleton Prospect**

### 4.1.4 East Kinsale Prospect

The East Kinsale Prospect is mapped at Wealden level which constitutes the primary target, but there is also prospectivity at 'A' sand level, as described in the February 2009 study. Volumetrics for the Wealden reservoir are summarised in Table 40.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 413 | 574 | 798 | Lognormal |
| Net to Gross (%) | 14 | 22 | 30 | Normal |
| Porosity (%) | 17 | 22 | 27 | Normal |
| Gas Saturation (%) | 70 | 75 | 80 | Normal |
| 1/Bg | 130 | 140 | 150 | Normal |
| **GIIP (Bscf)** | **53.6** | **99.3** | **168** | |
| Recovery Factor (%) | 65 | 75 | 85 | Normal |
| **Technically Recoverable Gas (Bscf)** | **39.4** | **73.9** | **127** | |

**Table 40: Calculation of GIIP and technically recoverable gas for the Upper Wealden reservoir of the East Kinsale Prospect**

RPS estimate the play risk to be 80% with an overall GPoS of 24%.

### 4.1.5 East Kinsale Prospect Reservoir Engineering

Production profiles were constructed for the Wealden reservoir and are based on the assumption that the field will be produced by depletion drive. The development strategy proposed is to have one vertical producer, converted from an appraisal well, in the low case and two vertical producers in the best and high cases (one converted from an appraisal well). The wells will be tied back to the Kinsale Head field a distance of around 20km. The field will utilise the Seven Heads gas processing facilities at Kinsale Head and compression will be applied from field start-up. It has been assumed that the exploration well will be drilled in 2012 and that first gas will be 1st October 2013. The initial well production potential is estimated at 18-20MMscf/d and a decline rate of 20% per annum has been assigned to calculate the production profile. The initial flow rate and decline rate are obtained from test data on the Wealden reservoir The production profiles also assume 5% average downtime due to facilities maintenance or for well intervention/workovers.

### 4.1.6 East Kinsale Prospect Economics

The cost of acquiring 3D seismic over the East Kinsale prospect during 2011 has been estimated as US$1.13MM by Lansdowne and is included in all the modelled cases. The principal capital costs for developing the Wealden reservoir are the costs of flowlines and risers, which are estimated by RPS as US$50MM. Other major capital costs are well costs, with the cost of an exploration well estimated as US$25MM. The cost of an appraisal well as US$22MM and the cost of a producer is US$17MM. The major operating cost is that of the Kinsale Head Platform, which cost US$28.6MM (Euro 21MM) during 2010 and is essentially a fixed cost. Operating costs for the Kinsale Head Platform were assumed to be allocated on a pro-rata basis with production. Indicative net present values for the East Kinsale Prospect are given in Table 41.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| Cost of failure | -25.2 |
| Low case | -22.4 |
| Best case | 44.1 |
| High case | 215.1 |

**Table 41: Indicative net present values for the East Kinsale Prospect**

An expected monetary value (EMV) of **US$18.1MM**, at 10% discount, is calculated using Swanson's 30-40-30 rule from the NPVs in Table 42, together with the associated risk. Details of the cashflow models are given in Appendix C.

Prospective Resources corresponding to the values presented on Table 41 are summarised on Table 42.

| Case | Prospective Resources (Bscf) |
|---|---|
| Low | 26.0 |
| Best | 54.0 |
| High | 114.1 |

**Table 42: Prospective Resources of the East Kinsale Prospect**

### 4.1.7 East Kinsale 'A' Sand Prospect

Prospectivity of the 'A' sand reservoir at the East Kinsale structure has been discussed in the February 2009 study and volumetrics are given in Table 43.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 140 | 280 | 559 | Lognormal |
| Net to Gross (%) | 20 | 25 | 30 | Normal |
| Porosity (%) | 20 | 22 | 24 | Normal |
| Gas Saturation (%) | 70 | 75 | 80 | Normal |
| 1/Bg | 130 | 140 | 150 | Normal |
| **GIIP (Bscf)** | **27.0** | **56.0** | **117** | |
| Recovery Factor (%) | 70 | 75 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **20.3** | **42.1** | **87.5** | |

**Table 43: Calculation of GIIP and technically recoverable gas for the 'A' Sand reservoir of the East Kinsale Prospect**

RPS estimate the play risk to be 80% with an overall GPoS of 8%.

### 4.1.8 Northern Old Head of Kinsale Prospect

The Northern Old Head of Kinsale prospect has been mapped at top Wealden level and discussed in the February 2009 study. Volumetrics are summarised in Table 44.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 82.5 | 111 | 149 | Lognormal |
| Net to Gross (%) | 14 | 22 | 30 | Normal |
| Porosity (%) | 17 | 22 | 27 | Normal |
| Gas Saturation (%) | 70 | 75 | 80 | Normal |
| 1/Bg | 130 | 140 | 150 | Normal |
| **GIIP (Bscf)** | **10.5** | **19.2** | **31.8** | |
| Recovery Factor (%) | 65 | 75 | 85 | Normal |
| **Technically Recoverable Gas (Bscf)** | **7.7** | **14.3** | **24.2** | |

**Table 44: Calculation of GIIP and technically recoverable gas for the Northern Old Head of Kinsale Prospect**

RPS estimate the play risk to be 80% with an overall GPoS of 24%.

### 4.1.9 Northern Horst Prospect

The Northern Horst Prospect is located within the "northern trend" immediately to the north of the Midleton prospect discussed fully in the February 2009 report and volumetrics are summarised Table 45.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV (MMm$^3$) | 94.5 | 133 | 186 | Lognormal |
| Net to Gross (%) | 60 | 70 | 80 | Normal |
| Porosity (%) | 20 | 22 | 24 | Normal |
| Gas Saturation (%) | 70 | 75 | 80 | Normal |
| 1/Bg | 80 | 90 | 100 | Normal |
| **GIIP (Bscf)** | **32.3** | **48.1** | **71.4** | |
| Recovery Factor (%) | 65 | 75 | 85 | Normal |
| **Technically Recoverable Gas (Bscf)** | **23.5** | **36.0** | **54.4** | |

**Table 45: Calculation of GIIP and technically recoverable gas for the Northern Horst Prospect**

RPS estimate the play risk to be 80% with an overall GPoS of 13%.

### 4.1.10 North Eastern Horst Prospect

The North Eastern Horst Prospect is described in the February 2009 report and volumetrics are summarised in Table 46.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV (MMm$^3$) | 52.5 | 110 | 232 | Lognormal |
| Net to Gross (%) | 60 | 70 | 80 | Normal |
| Porosity (%) | 20 | 22 | 24 | Normal |
| Gas Saturation (%) | 70 | 75 | 80 | Normal |
| 1/Bg | 80 | 90 | 100 | Normal |
| **GIIP (Bscf)** | **18.7** | **40.1** | **86.8** | |
| Recovery Factor (%) | 65 | 75 | 85 | Normal |
| **Technically Recoverable Gas (Bscf)** | **13.7** | **30.0** | **65.3** | |

**Table 46: Calculation of GIIP and technically recoverable gas for the North Eastern Horst Prospect**

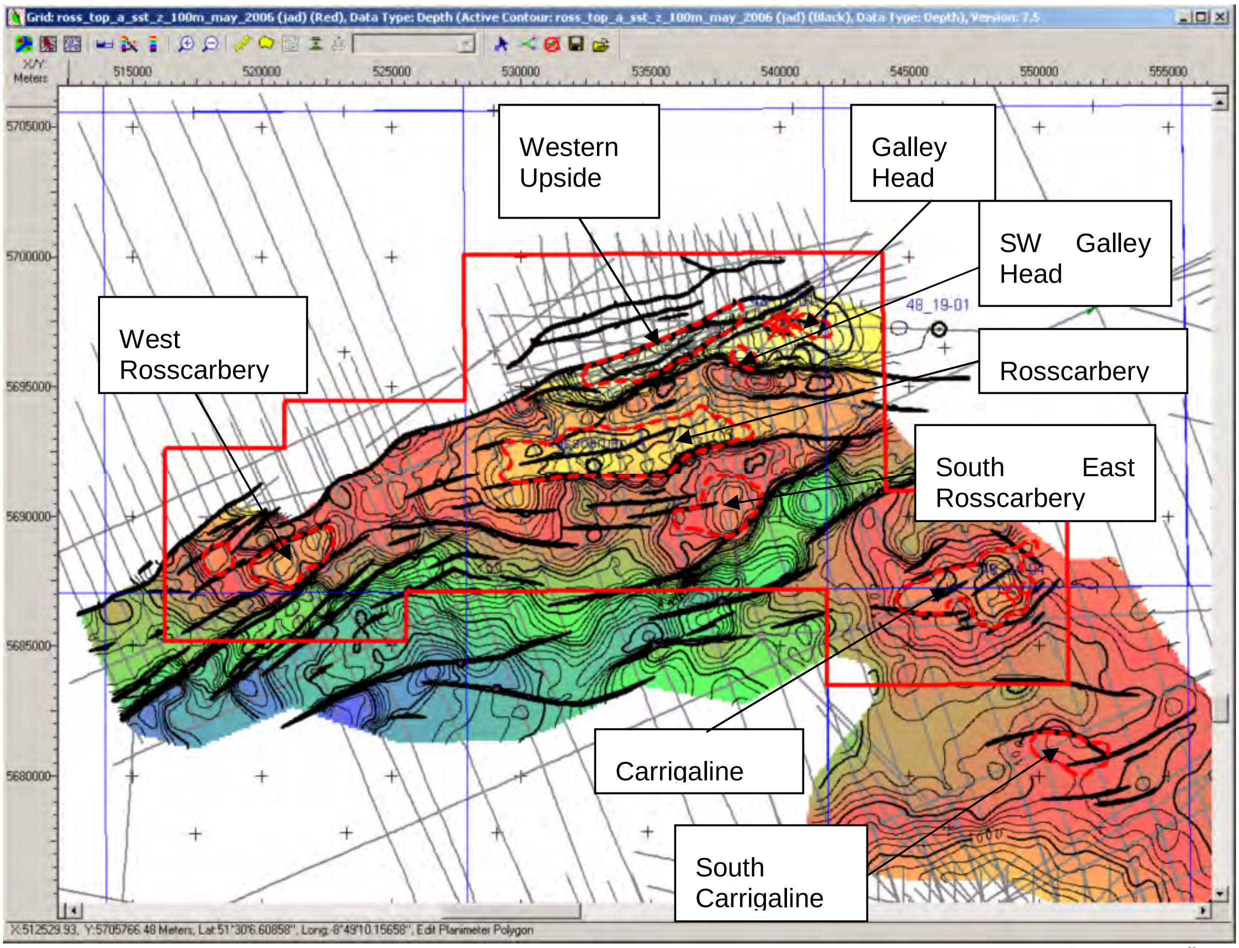
RPS estimate the play risk to be 80% with an overall GPoS of 13%.

## 4.2 License 5/07 (Rosscarbery)

Standard Exploration License 5/07 (Lansdowne 99%) lies some 30km west of the Kinsale Head and Ballycotton gas fields and approximately 70km to the south of Cork on the southern Irish coast. Water depths across the Licence Option area are less than 100m.

The license is covered by 2D seismic data of various vintages. A sparse grid of seismic data was acquired by BP and Marathon in 1990 and this has been supplemented subsequently from various sources. Lansdowne (Ramco) have reprocessed all of the BP data and in 2000 acquired approximately 200km of new data to infill the existing grid. In addition, some 560km of the Fugro/TGS non-exclusive seismic data together with newly released data has been purchased and incorporated into the mapping. The seismic interpretation and mapping undertaken by Merlin was reviewed during the February 2009 and May 2007 studies and found to be robust. There are three wells within the Licence Option area. Well 48/18-1 was drilled by BP in 1985 and tested gas at 13.7MMscf/d from the 'A' Sand. Well 48/19-1 was drilled in 1984 and recorded good shows from Lower Cretaceous reservoirs but was not tested. Well 48/24-4 was drilled by Marathon in 1990 and found some gas in the 'A' Sands and Upper Wealden, but was not tested.

The 48/18-1 discovery is called Galley Head, and was originally thought to be a large, elongate closure against the Basin Shoulder Fault. However, current mapping, reveals that the 48/18-1 well was drilled on a small independent closure separated from the main body of the structure by previously unrecognised faulting. This un-drilled area is now referred to as the Western Upside prospect. The 48/24-4 structure was named Carrigaline. One additional prospect was also recognised on the earlier mapping and this was named Sneem. This prospect has subsequently been remapped and renamed Rosscarbery, with additional prospectivity now also recognised at West Rosscarbery and South South East Rosscarbery (see Figure 17).




*Source: Merlin*

**Figure 17: Location of discoveries and prospects in the 5/07 license area**

### 4.2.1 Galley Head Discovery

The Galley Head discovery was described in the February 2009 report, with volumetrics summarised in Table 47. The Galley Head Discovery is classed as Contingent Resources. Due to the low volumes of technically recoverable gas, the Galley Head Discovery belongs to the Development Not Viable sub-class.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 18.2 | 18.2 | 18.2 | Uniform |
| Net to Gross (%) | 80 | 85 | 90 | Normal |
| Porosity (%) | 24 | 26 | 28 | Normal |
| Gas Saturation (%) | 55 | 60 | 65 | Normal |
| 1/Bg | 83 | 83 | 83 | Uniform |
| **GIIP (Bscf)** | **5.7** | **7.1** | **8.8** | |
| Recovery Factor (%) | 70 | 75 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **4.0** | **5.3** | **7.0** | |

**Table 47: Calculation of GIIP and technically recoverable gas from the Galley Head Discovery (full field interest)**

### 4.2.2 Western Upside Prospect

Current Lansdowne mapping has the Galley Head discovery separated from the main body of the old closure, which is now called the Western Upside Prospect. The Western Upside Prospect was discussed in the February 2009 study and volumetrics are presented in Table 48.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 262.6 | 262.6 | 262.6 | Uniform |
| Net to Gross (%) | 80 | 85 | 90 | Normal |
| Porosity (%) | 24 | 26 | 28 | Normal |
| Gas Saturation (%) | 55 | 60 | 65 | Normal |
| 1/Bg | 83 | 83 | 83 | Normal |
| **GIIP (Bscf)** | **81.7** | **103** | **127** | |
| Recovery Factor (%) | 70 | 75 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **57.2** | **77.3** | **102** | |

**Table 48: Calculation of GIIP and technically recoverable gas from the Western Upside Prospect (full field interest)**

RPS estimate the play risk to be 80% with an overall GPoS of 18%.

### 4.2.3 Carrigaline Discovery

The Carrigaline Discovery was made by Marathon in 1990 with well 48/24-4 and it is described in the May 2007 and February 2009 reports. Volumetric results from the Carrigaline Discovery are shown in Table 49. There is currently no plan to develop the Carrigaline Discovery and consequently it is classed as Contingent Resources, Development on Hold, using the PRMS guidelines.

| Reservoir | P90 | P50 | P10 |
|---|---|---|---|
| 'A' Sand | 46 | 63.5 | 83 |
| 'B' Sand equivalent | 14 | 18.3 | 25 |
| Total GIIP (Bscf) | **60** | **81.8** | **108** |
| GIIP Net to Lansdowne (99%) | **59.4** | **81.0** | **106.9** |

**Table 49: Summary of GIIP from the Carrigaline Discovery**

### 4.2.4 Rosscarbery Prospect

The Rosscarbery Prospect has been fully described in the February 2009 report. As well 48/24-1, the Carrigaline discovery well, recovered gas from ‘A’ Sand and Wealden reservoirs, Rosscarbery is considered to be prospective for gas at both horizons. Volumetrics for the ‘A’ Sand reservoir are presented in Table 50.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 173.0 | 295.5 | 504.7 | Lognormal |
| Net to Gross (%) | 70 | 80 | 90 | Normal |
| Porosity (%) | 21 | 23 | 25 | Normal |
| Gas Saturation (%) | 55 | 60 | 65 | Normal |
| 1/Bg | 110 | 115 | 120 | Normal |
| **GIIP (Bscf)** | **75.0** | **131.0** | **231.0** | |
| Recovery Factor (%) | 70 | 75 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **56.0** | **98.4** | **173.0** | |

**Table 50: Calculation of GIIP and technically recoverable gas from the ‘A’ Sand of the Rosscarbery Prospect (full field interest)**

RPS estimate the play risk to be 80% with an overall GPoS of 29%.

Volumetrics for the Wealden reservoir, from the February 2009 study, are presented in Table 51.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 219 | 377 | 647 | Lognormal |
| Net to Gross (%) | 40 | 50 | 60 | Normal |
| Porosity (%) | 18 | 20 | 22 | Normal |
| Gas Saturation (%) | 55 | 60 | 65 | Normal |
| 1/Bg | 110 | 115 | 120 | Normal |
| **GIIP (Bscf)** | **50.0** | **90.0** | **163** | |
| Recovery Factor (%) | 60 | 70 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **34.1** | **63.0** | **115** | |

**Table 51: Calculation of GIIP and technically recoverable gas from the Mid Wealden of the Rosscarbery Prospect (full field interest)**

RPS estimate the play risk to be 80% with an overall GPoS of 36%.

### 4.2.5 Rosscarbery Gas Prospects Reservoir Engineering

Conceptual development plans have been made for the Low, Best and High cases from the ‘A’ Sand and Wealden reservoirs. The development strategy proposed for the ‘A’ Sand is to have vertical wells with an initial production potential of 20-30MMscf/d, declining at 20% per annum. The initial flow rate and decline rate were obtained from test data for the ‘A’ Sand reservoirs. One development well is required for the low case, with two in the best case and three in the high case. In each of the cases it is assumed that the appraisal well is converted to a producer. It is assumed that production is by depletion drive and that a theoretical recovery factor of 70% may be achieved. However, the tail of the production profile will be curtailed due to economic criteria and the actual recovery factor achieved will be less than 70%. The production profiles also assume 5% average downtime due to facilities maintenance or for well intervention/workovers. All the producers will be tied back to the Seven Heads field, a distance of around 25km. From Seven Heads the gas will be piped to the Kinsale Head field which has compression facilities. It has been assumed that the discovery well will be drilled in 2012 and the appraisal well in 2013, together with the required producers. First gas is projected to be 1st October 2013. Prior to the drilling of the discovery well, all cases assume the shooting of 3D seismic at a cost of US$1.8MM during 2011.

The development strategy proposed for the Wealden reservoir is to have vertical development wells with an initial production potential of 20MMscf/d declining at 20% per annum. This initial flow rate and decline rate were obtained from test data on Wealden reservoirs. One development well is required for the low case, with two in the best case and three in the high case.

### 4.2.6 Rosscarbery Prospect Gas Economics

The cost of a 3D seismic survey of the Rosscabery Prospect has been estimate as US$1.8MM and this has been included in all of the modelled cases. The principal capital costs are estimated by RPS to be the costs of flowlines and risers, which are estimated as US$50MM. Other major capital costs are well costs, with the cost of an exploration well estimated as US$25MM, the cost of an appraisal well as US$22MM and the cost of a producer is US$17MM. The major operating cost is that of the Kinsale Head Platform, which cost Euro 21MM during 2010 and is essentially a fixed cost. Operating costs for the Kinsale Head Platform were assumed to be allocated on a pro-rata basis with production. Indicative net present values for the Lansdowne working interest of 99%, for Rosscarbery Prospect are given for the 'A' Sand on Table 52 and the Wealden on Table 53.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| Cost of failure | -25.6 |
| Low case | -38.3 |
| Best case | 124.5 |
| High case | 329.2 |

**Table 52: Indicative net present values from the 'A' Sand of the Rosscarbery Prospect (net to Lansdowne 99% working interest)**

An expected monetary value (EMV) of **US$ 39.8MM**, at 10% discount, is calculated for the 'A' Sand, using Swanson's 30-40-30 rule from the NPVs in Table 52 and the associated risks. Details of the cashflow models are given in Appendix C.

| Case | NPV @ 10% discount (US$MM) |
|---|---|
| Cost of failure | -25.6 |
| Low case | -38.3 |
| Best case | 35.6 |
| High case | 175.5 |

**Table 53: Indicative net present values from the Wealden of the Rosscarbery Prospect (net to Lansdowne 99% working interest)**

An expected monetary value (EMV) of **US$ 3.6MM**, at 10% discount, is calculated for the Wealden, using Swanson's 30-40-30 rule from the NPVs in Table 53 and the associated risks. Details of the cashflow models are given in Appendix C.

Prospective Resources for the 'A' Sand, consisting of economically recoverable gas volumes corresponding to the values shown in Table 53, are summarised in Table 54.

| Case | Prospective Resources (Bscf) |
|---|---|
| Low | 25.7 |
| Best | 83.0 |
| High | 152.0 |

**Table 54: Prospective Resources of the 'A' Sand of the Rosscarbery Prospect (net to Lansdowne 99% working interest)**

Prospective Resources for the Wealden, consisting of economically recoverable gas volumes corresponding to the values shown in Table 53, are summarised in Table 55.

| Case | Prospective Resources (Bscf) |
|---|---|
| Low | 25.7 |
| Best | 53.5 |
| High | 106.2 |

**Table 55: Prospective Resources of the Wealden of the Rosscarbery Prospect (net to Lansdowne, on the basis of a 99% working interest)**

### 4.2.7 Rosscarbery Prospect Basal Wealden Oil

Basal Wealden sands have a widespread distribution in the Celtic Sea Basin. Oil was tested from Basal Wealden sandstones at a flow rate of approximately 1,600bbl/d well 48/24-3 on the Barryroe discovery, which is 25km to the southeast of the Rosscarbery Prospect. A heavy oil discovery was also made about 10km to the east by well 48/19-2 in 1992 called Baltimore. The Baltimore discovery consists of very-heavy 11˚API oil, but with a STOIIP of approx. 300 MMstb and technically recoverable oil approx 30-100 MMstb (from the Providence Resources website). It is therefore possible that oil is developed in the Basal Wealden interval at Rosscarbery. The Basal Wealden of the Rosscarbery Prospect has been described in the February 2009 report and volumetrics are summarised in Table 56**Error! Reference source not found.**.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 139 | 236 | 398 | Lognormal |
| Porosity (%) | 40 | 50 | 60 | Normal |
| Oil Saturation (%) | 55 | 60 | 65 | Normal |
| FVF | 1.20 | 1.30 | 1.40 | Normal |
| **STOIIP (MMstb)** | **36.0** | **65.2** | **119** | |
| Recovery Factor (%) | 20 | 30 | 40 | Normal |
| **Technically Recoverable Oil (MMstb)** | **9.3** | **19.2** | **37.6** | |

**Table 56: STOIIP and technically recoverable oil from the Basal Wealden of the Rosscarbery Prospect (full field interest)**

RPS estimate the play risk to be 50% with an overall GPoS of 14%.

### 4.2.8 Rosscarbery Prospect Basal Wealden Oil Development Plan

Conceptual development plans have been made for the Low, Best and High cases, with the cost of a 3D seismic survey of US$1.8MM included in all of the cases, this cost was provided by Lansdowne. The Low case involves development one high angle producer, which was assumed to flow at an initial rate of 4,800bbl/d and a decline rate of 20% per annum. Three such vertical wells are required in the Best case and five in the High case. One of the producers is assumed to be converted from an appraisal well. The cost of a vertical exploration well is estimated to be US$22MM, whereas the cost of an appraisal well is estimated as US$25MM and the cost of a development well as US$25MM.

Development of the Basal Wealden of the Rosscarbery Prospect involves a leased FPSO which is estimated by RPS to cost US$90,000 per day for the first five years, falling to US$75,000 per day subsequently, with an additional cost of US$6.5/bbl. Consequently, the principal capital costs were the costs of the sub-sea jackets and other facilities which are estimated by RPS as US$29MM in the low case, US$88MM in the best case and US$146MM in the high case. The annual operating cost of the FPSO is estimated at US$5.0MM to US$7.5MM. Included within that is the cost of offloading the oil through a CALM buoy to shuttle tanker and transportation to the shore base. Other operating costs are workovers, which are assumed to be required every four years and are estimated by RPS to cost US$2-4MM, together with general management and administrative costs, which are estimated as US$1.0-1.5MM per annum. The associated gas will be used for power generation on the FPSO.

### 4.2.9 Rosscarbery Prospect Basal Wealden Oil Economics

A cashflow model has been constructed based on the production and cost profiles for the Upper / Middle Jurassic target of the Amergin Prospect. Indicative net present values, in money of the day and at a discount rate of 10%, for the low, best and high case Prospective Resources for the Lansdowne 99% working interest, are summarised in Table 57.

| Case | NPV (@ 10% discount) (US$MM) |
|---|---|
| Cost of failure | -28.2 |
| Low case | -57.3 |
| Best case | 446.3 |
| High case | 916.1 |

**Table 57: Indicative net present values from the Basal Wealden of the Rosscarbery Prospect net to Lansdowne 99% working interest)**

An expected monetary value (EMV) of **US$43.7MM**, at 10% discount, is calculated using Swanson's 30-40-30 rule from the NPVs in Table 57.

Prospective Resources for the Basal Wealden, consisting of economically recoverable volumes of oil corresponding to the values on Table 57, are summarised on Table 58.

| Case | Prospective Resources (MMstb) |
|---|---|
| Low case | 5.1 |
| Best case | 19.3 |
| High case | 33.5 |

**Table 58: Prospective Resources from the Basal Wealden of the Rosscarbery Prospect (net to Lansdowne 99% working interest)**

### 4.2.10 West Rosscarbery Prospect

The West Rosscabery Prospect is a target for gas at both the 'A' Sand and Wealden levels, as described in the February 2009 report. Volumetrics for the 'A' Sand reservoir are summarised in Table 59.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 139 | 327 | 1033 | Lognormal |
| Net to Gross (%) | 70 | 80 | 90 | Normal |
| Porosity (%) | 21 | 23 | 25 | Normal |
| Gas Saturation (%) | 55 | 60 | 65 | Normal |
| 1/Bg | 110 | 115 | 120 | Normal |
| **GIIP (Bscf)** | **26.0** | **61.7** | **148** | |
| Recovery Factor (%) | 70 | 75 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **19.4** | **46.2** | **111** | |

**Table 59: Calculation of GIIP and technically recoverable gas from the ‘A’ Sand of the West Rosscarbery Prospect**

RPS estimate the play risk to be 80% with an overall GPoS of 15%.

Volumetrics and risking were also undertaken for the Wealden reservoir during the course of the February 2009 study and these are summarised in Table 60.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 16.0 | 50.0 | 156 | Lognormal |
| Net to Gross (%) | 40 | 50 | 60 | Normal |
| Porosity (%) | 17 | 20 | 23 | Normal |
| Gas Saturation (%) | 55 | 60 | 65 | Normal |
| 1/Bg | 110 | 115 | 120 | Normal |
| **GIIP (Bscf)** | **3.7** | **11.9** | **38.4** | |
| Recovery Factor (%) | 60 | 70 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **2.6** | **8.3** | **26.9** | |

**Table 60: Calculation of GIIP and technically recoverable gas from the Wealden of the West Rosscarbery Prospect (full field interest)**

RPS estimate the play risk to be 80% with an overall GPoS of 12%.

### 4.2.11 South South East Rosscarbery Prospect

The South South East Rosscarbery Prospect also has target reservoirs in the ‘A’ Sand and the Wealden, as discussed in the February 2009 report and volumetrics are summarised in Table 61 and Table 62.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 43.3 | 90.9 | 191 | Lognormal |
| Net to Gross (%) | 70 | 80 | 90 | Normal |
| Porosity (%) | 21 | 23 | 25 | Normal |
| Gas Saturation (%) | 55 | 60 | 65 | Normal |
| 1/Bg | 110 | 115 | 120 | Normal |
| **GIIP (Bscf)** | **19.0** | **40.3** | **86.5** | |
| Recovery Factor (%) | 70 | 75 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **14.2** | **30.2** | **65.0** | |

**Table 61: Calculation of GIIP and technically recoverable gas from the 'A' Sand of the South South East Rosscarbery Prospect (full field interest)**

RPS estimate the play risk to be 80% with an overall GPoS of 23%.

| Parameter | P90 | P50 | P10 | Distribution |
|---|---|---|---|---|
| GRV ($MMm^3$) | 250 | 383 | 589 | Lognormal |
| Net to Gross (%) | 40 | 50 | 60 | Normal |
| Porosity (%) | 18 | 20 | 22 | Normal |
| Gas Saturation (%) | 55 | 60 | 65 | Normal |
| 1/Bg | 110 | 115 | 120 | Normal |
| **GIIP (Bscf)** | **56.2** | **91.6** | **150** | |
| Recovery Factor (%) | 60 | 70 | 80 | Normal |
| **Technically Recoverable Gas (Bscf)** | **38.1** | **64.1** | **106** | |

**Table 62: Calculation of GIIP and technically recoverable gas from the Wealden of the South South East Rosscarbery Prospect (full field interest)**

RPS estimate the play risk to be 80% with an overall GPoS of 19%.

# APPENDIX A: GLOSSARY OF TERMS AND ABBREVIATIONS

| | |
|---|---|
| API | American Petroleum Institute |
| asl | above sea level |
| B | Billion |
| bbl(s) | Barrels |
| bbls/d | barrels per day |
| Bcm | billion cubic metres |
| $B_g$ | gas formation volume factor |
| $B_{gi}$ | gas formation volume factor (initial) |
| $B_o$ | oil formation volume factor |
| $B_{oi}$ | oil formation volume factor (initial) |
| $B_w$ | water volume factor |
| stb/d | barrels of oil per day |
| BTU | British Thermal Unit |
| Bscf | billions of standard cubic feet |
| bwpd | barrels of water per day |
| $CO_2$ | Carbon dioxide |
| condensate | liquid hydrocarbons which are sometimes produced with natural gas and liquids derived from natural gas |
| cP | centipoise |
| CROCK | rock compressibility |
| $C_w$ | water compressibility |
| DBA | decibels |
| $E_a$ | areal sweep efficiency |
| EMV | Expected Monetary Value |
| EPSA | Exploration and Production Sharing Agreement |
| ESD | emergency shut down |
| $E_{vert}$ | vertical sweep efficiency |
| FBHP | flowing bottom hole pressure |
| FTHP | flowing tubing head pressure |
| ft | feet |
| ftSS | depth in feet below sea level |
| GDT | Gas Down To |
| GIP | Gas in Place |
| GIIP | Gas Initially in Place |
| GOR | gas/oil ratio |
| GRV | gross rock volume |
| GWC | gas water contact |
| $H_2S$ | Hydrogen sulphide |
| HIC | hydrogen induced cracking |
| IRR | internal rate of return |
| KB | Kelly Bushing |
| $k_a$ | absolute permeability |
| $k_h$ | horizontal permeability |

| | |
|---|---|
| km | kilometres |
| $km^2$ | square kilometres |
| kPa | kilopascals |
| $k_r$ | relative permeability |
| $k_{rg}$ | relative permeability of gas |
| $k_{rgcl}$ | relative permeability of gas @ connate liquid saturation |
| $k_{rog}$ | relative permeability of oil-gas |
| $k_{roso}$ | relative permeability at residual oil saturation |
| $k_{roswi}$ | relative permeability to oil @ connate water saturation |
| $k_v$ | vertical permeability |
| LNG | Liquefied Natural Gases |
| LPG | Liquefied Petroleum Gases |
| M | thousand |
| MM | million |
| M$ | thousand US dollars |
| US$ MM | million US dollars |
| MD | measured depth |
| mD | permeability in millidarcies |
| $m^3$ | cubic metres |
| $m^3/d$ | cubic metres per day |
| MMscf/d | millions of standard cubic feet per day |
| m/s | metres per second |
| msec | milliseconds |
| mV | millivolts |
| Mt | thousands of tonnes |
| MMt | millions of tonnes |
| MPa | mega pascals |
| N:G | net to gross ratio |
| NGL | Natural Gas Liquids |
| NPV | Net Present Value |
| OWC | oil water contact |
| $P_b$ | bubble point pressure |
| $P_c$ | capillary pressure |
| petroleum | deposits of oil and/or gas |
| phi | porosity fraction |
| pi | initial reservoir pressure |
| PI | productivity index |
| ppm | parts per million |
| psi | pounds per square inch |
| psia | pounds per square inch absolute |
| psig | pounds per square inch gauge |
| $p_{wf}$ | flowing bottom hole pressure |
| PVT | pressure volume temperature |
| rb | barrel(s) of oil at reservoir conditions |

| | |
|---|---|
| rcf | reservoir cubic feet |
| RFT | repeat formation tester |
| RKB | relative to kelly bushing |
| $rm^3$ | reservoir cubic metres |
| SCADA | supervisory control and data acquisition |
| SCAL | Special Core Analysis |
| scf | standard cubic feet measured at 14.7 pounds per square inch and 60°F |
| scf/d | standard cubic feet per day |
| scf/stb | standard cubic feet per stock tank barrel |
| SGS | Sequential Gaussion Simulation |
| SIS | Sequential Indicator Simulation |
| $sm^3$ | standard cubic metres |
| $S_o$ | oil saturation |
| $S_{or}$ | residual oil saturation |
| $S_{orw}$ | residual oil saturation (waterflood) |
| $S_{wc}$ | connate water saturation |
| $S_{oi}$ | irreducible oil saturation |
| SSCC | sulphur stress corrosion cracking |
| stb | stock tank barrels measured at 14.7 pounds per square inch and 60°F |
| stb/d | stock tank barrels per day |
| STOIIP | stock tank oil initially in place |
| $S_w$ | water saturation |
| $ | United States Dollars |
| t | tonnes |
| THP | tubing head pressure |
| Tscf | trillion standard cubic feet |
| TVDSS | true vertical depth (sub-sea) |
| TVT | true vertical thickness |
| TWT | two-way time |
| US$ | United States Dollar |
| $V_{sh}$ | shale volume |
| W/m/K | watts/metre/° K |
| WC | water cut |
| WUT | Water Up To |
| $\phi$ | porosity |
| $\mu$ | viscosity |
| $\mu_{gb}$ | viscosity of gas |
| $\mu_{ob}$ | viscosity of oil |
| $\mu_w$ | viscosity of water |

## APPENDIX B: SPE/WPC/AAPG/SPEE RESERVE/RESOURCE DEFINITIONS

The following is extracted from the SPE/WPC/AAPG/SPEE PRMS 2007 using the section numbering and spelling from PRMS.

### 1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

### 1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

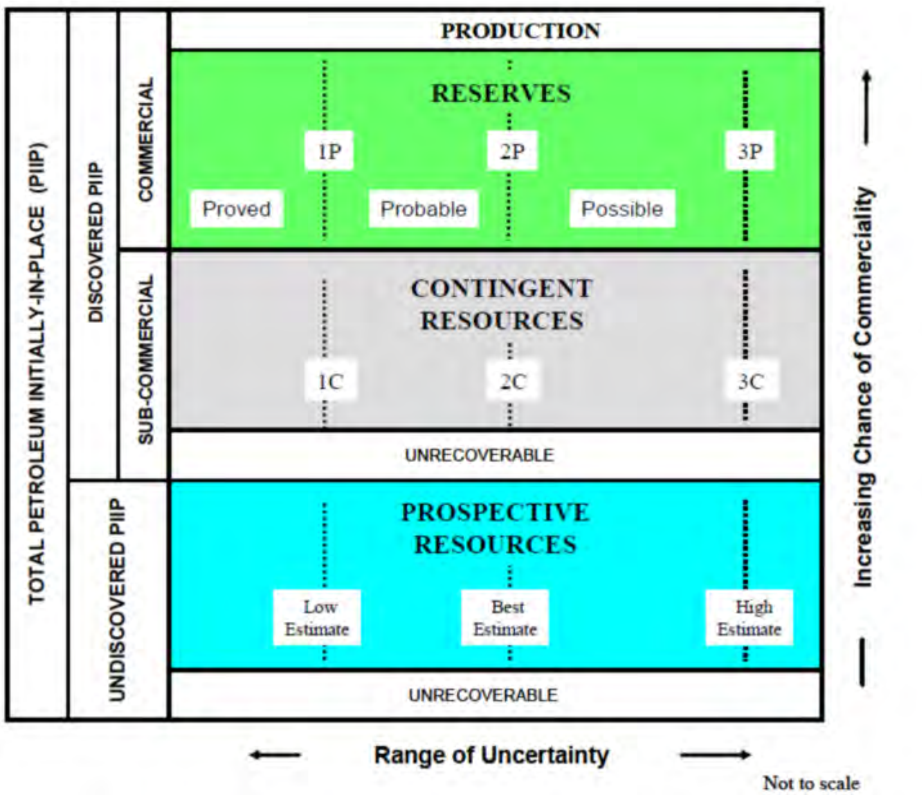



**Figure 1-1 Resources Classification Framework.**

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

**TOTAL PETROLEUM INITIALLY-IN-PLACE** is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

**DISCOVERED PETROLEUM INITIALLY-IN-PLACE** is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

**PRODUCTION** is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage.

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

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

**CONTINGENT RESOURCES** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

**UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

**PROSPECTIVE RESOURCES** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

**UNRECOVERABLE** is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

## 1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

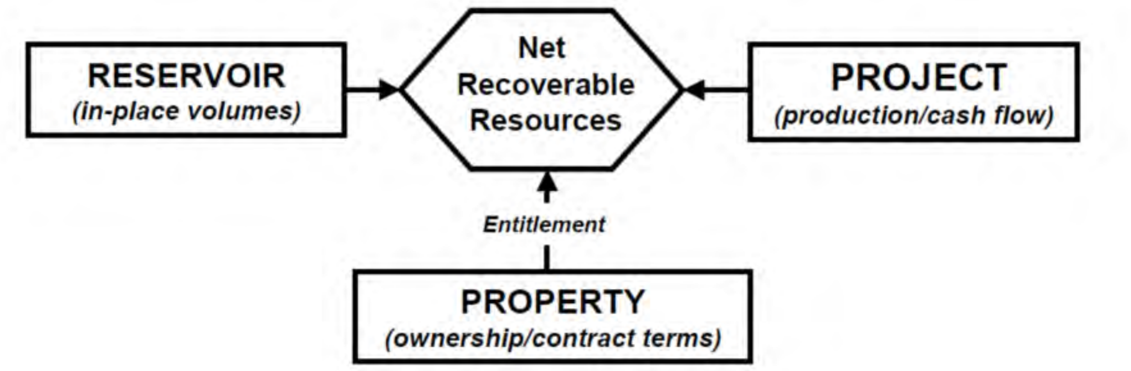



**Figure 1-2: Resources Evaluation Data Sources**

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.
- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.
- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities. "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer. The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project.

# APPENDIX C: CASHFLOW MODELS

## Barryroe P90 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 20%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | - | - | - | 6.12 | - | - | 0.29 | - | - | (6.41) | (1.28) |
| 2012 | - | - | - | 38.49 | - | - | 0.29 | - | - | (38.79) | (7.76) |
| 2013 | - | - | - | 2.12 | - | - | 0.30 | - | - | (2.42) | (0.48) |
| 2014 | 2.02 | 98.12 | 197.75 | 159.83 | 70.57 | - | 1.88 | - | - | (34.53) | (6.91) |
| 2015 | 1.61 | 102.09 | 164.77 | - | 69.10 | - | 1.91 | - | - | 93.75 | 18.75 |
| 2016 | 1.29 | 106.22 | 137.24 | - | 68.13 | - | 1.95 | 11.96 | - | 55.19 | 11.04 |
| 2017 | 1.04 | 110.50 | 114.37 | - | 67.57 | - | 1.99 | 11.41 | - | 33.40 | 6.68 |
| 2018 | 0.83 | 112.71 | 93.50 | - | 68.53 | - | 2.03 | 6.28 | - | 16.66 | 3.33 |
| 2019 | 0.66 | 114.97 | 76.43 | - | 55.74 | - | 2.07 | 4.76 | - | 13.85 | 2.77 |
| 2020 | 0.53 | 117.27 | 62.51 | - | 56.85 | - | 2.11 | 1.26 | - | 2.28 | 0.46 |
| 2021 | - | - | - | - | - | 2.98 | - | (0.58) | - | (2.40) | (0.48) |
| 2022 | - | - | - | - | - | - | - | (0.07) | - | 0.07 | 0.01 |
| **Total (from 2011)** | **7.98** | | **846.56** | **206.56** | **456.51** | **2.98** | **14.82** | **35.02** | - | **130.66** | **26.13** |

| | Gross Cashflow | Lansdowne Share |
|---|---|---|
| **NPV @ 5%** | **91.18** | **18.24** |
| **NPV @ 10%** | **62.62** | **12.52** |
| **NPV @ 20%** | **26.12** | **5.22** |
| **IRR** | **34.07%** | **34.07%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2016** | **2016** |

## Barryroe P50 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 20%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | - | - | - | 6.12 | - | - | 0.29 | - | - | (6.41) | (1.28) |
| 2012 | - | - | - | 38.49 | 0.20 | - | 0.29 | - | - | (38.99) | (7.80) |
| 2013 | - | - | - | 2.12 | 0.20 | - | 0.30 | - | - | (2.62) | (0.52) |
| 2014 | 5.47 | 98.12 | 536.91 | 389.24 | 95.43 | - | 1.88 | - | - | 50.36 | 10.07 |
| 2015 | 7.43 | 102.09 | 758.92 | 123.66 | 111.42 | - | 1.91 | 117.15 | - | 404.77 | 80.95 |
| 2016 | 5.95 | 106.22 | 632.31 | - | 102.81 | - | 1.95 | 131.72 | - | 395.83 | 79.17 |
| 2017 | 4.77 | 110.50 | 526.62 | - | 96.00 | - | 1.99 | 109.63 | 12.00 | 307.00 | 61.40 |
| 2018 | 3.82 | 112.71 | 430.30 | - | 94.22 | - | 2.03 | 85.88 | 5.09 | 243.08 | 48.62 |
| 2019 | 3.06 | 114.97 | 351.77 | - | 80.09 | - | 2.07 | 69.01 | 3.45 | 197.15 | 39.43 |
| 2020 | 2.45 | 117.27 | 287.54 | - | 76.87 | - | 2.11 | 53.67 | 5.03 | 149.86 | 29.97 |
| 2021 | 1.97 | 119.61 | 235.20 | - | 74.49 | - | 2.16 | 40.89 | 4.09 | 113.58 | 22.72 |
| 2022 | 1.58 | 122.00 | 192.38 | - | 72.76 | - | 2.20 | 30.38 | 3.04 | 83.99 | 16.80 |
| 2023 | 1.30 | 124.44 | 161.48 | - | 75.75 | - | 2.24 | 21.72 | 2.17 | 59.59 | 11.92 |
| 2024 | 1.10 | 126.93 | 139.69 | - | 71.62 | - | 2.29 | 16.89 | 1.69 | 47.21 | 9.44 |
| 2025 | 1.30 | 129.47 | 168.00 | - | 74.78 | - | 2.33 | 22.10 | 2.21 | 66.59 | 13.32 |
| 2026 | 1.10 | 132.06 | 145.33 | - | 74.51 | - | 2.38 | 17.67 | 1.77 | 49.00 | 9.80 |
| 2027 | 0.93 | 134.70 | 125.80 | - | 74.49 | - | 2.43 | 12.71 | 1.27 | 34.90 | 6.98 |
| 2028 | 0.79 | 137.40 | 108.97 | 171.60 | 78.95 | - | 2.48 | 7.42 | 0.74 | (152.22) | (30.44) |
| 2029 | 1.87 | 140.15 | 261.90 | - | 86.35 | - | 2.53 | 39.62 | 3.96 | 129.45 | 25.89 |
| 2030 | 1.50 | 142.95 | 214.44 | - | 84.51 | - | 2.58 | 32.98 | 3.30 | 91.08 | 18.22 |
| 2031 | 1.21 | 145.81 | 176.16 | - | 83.33 | - | 2.63 | 23.48 | 2.35 | 64.37 | 12.87 |
| 2032 | 0.97 | 148.72 | 144.40 | - | 82.61 | - | 2.68 | 15.55 | 2.22 | 41.33 | 8.27 |
| 2033 | 0.78 | 151.70 | 119.04 | - | 87.09 | - | 2.73 | 8.05 | 1.21 | 19.96 | 3.99 |
| 2034 | 0.64 | 154.73 | 98.27 | - | 82.44 | - | 2.79 | 3.67 | 0.55 | 8.83 | 1.77 |
| 2035 | - | - | - | - | - | 32.81 | - | (7.06) | 0.05 | (25.80) | (5.16) |
| 2036 | - | - | - | - | - | - | - | (0.82) | - | 0.82 | 0.16 |
| **Total (from 2011)** | **49.99** | | **5,815.42** | **731.24** | **1,760.93** | **32.81** | **49.25** | **852.30** | **56.18** | **2,332.72** | **466.54** |

| | Gross Cashflow | Lansdowne Share |
|---|---|---|
| **NPV @ 5%** | **1,587.32** | **317.46** |
| **NPV @ 10%** | **1,136.48** | **227.30** |
| **NPV @ 20%** | **642.86** | **128.57** |
| **IRR** | **140.31%** | **140.31%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2014** | **2014** |

## Barryroe P10 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 20%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2011** | - | - | - | 6.12 | - | - | 0.29 | - | - | (6.41) | (1.28) |
| **2012** | - | - | - | 38.49 | 0.20 | - | 0.29 | - | - | (38.99) | (7.80) |
| **2013** | - | - | - | 2.65 | 0.20 | - | 0.30 | - | - | (3.15) | (0.63) |
| **2014** | 13.35 | 98.12 | 1,310.07 | 601.40 | 150.87 | - | 1.88 | 113.35 | - | 442.57 | 88.51 |
| **2015** | 18.14 | 102.09 | 1,851.76 | 309.14 | 188.24 | - | 1.91 | 316.90 | - | 1,035.56 | 207.11 |
| **2016** | 14.53 | 106.22 | 1,542.85 | - | 165.56 | - | 1.95 | 343.26 | 44.42 | 987.65 | 197.53 |
| **2017** | 11.63 | 110.50 | 1,284.94 | - | 147.24 | - | 1.99 | 289.92 | 30.49 | 815.30 | 163.06 |
| **2018** | 9.32 | 112.71 | 1,049.93 | - | 137.26 | - | 2.03 | 233.29 | 23.33 | 654.03 | 130.81 |
| **2019** | 7.47 | 114.97 | 858.32 | - | 114.31 | - | 2.07 | 189.70 | 27.32 | 524.92 | 104.98 |
| **2020** | 5.98 | 117.27 | 701.60 | - | 104.85 | - | 2.11 | 152.34 | 22.85 | 419.44 | 83.89 |
| **2021** | 4.80 | 119.61 | 573.88 | - | 97.37 | - | 2.16 | 121.60 | 18.24 | 334.52 | 66.90 |
| **2022** | 3.85 | 122.00 | 469.40 | - | 91.48 | - | 2.20 | 96.40 | 14.46 | 264.86 | 52.97 |
| **2023** | 3.17 | 124.44 | 394.00 | - | 92.76 | - | 2.24 | 76.67 | 11.50 | 210.83 | 42.17 |
| **2024** | 2.69 | 126.93 | 340.84 | - | 85.21 | - | 2.29 | 64.48 | 9.67 | 179.19 | 35.84 |
| **2025** | 2.28 | 129.47 | 295.02 | - | 83.36 | - | 2.33 | 53.43 | 8.02 | 147.88 | 29.58 |
| **2026** | 1.94 | 132.06 | 255.56 | - | 81.96 | - | 2.38 | 43.76 | 6.56 | 120.90 | 24.18 |
| **2027** | 1.64 | 134.70 | 221.34 | - | 80.94 | - | 2.43 | 35.32 | 5.30 | 97.35 | 19.47 |
| **2028** | 1.40 | 137.40 | 191.94 | - | 85.99 | - | 2.48 | 26.73 | 4.01 | 72.74 | 14.55 |
| **2029** | 1.19 | 140.15 | 166.89 | - | 79.93 | - | 2.53 | 21.59 | 3.24 | 59.62 | 11.92 |
| **2030** | 1.01 | 142.95 | 144.86 | - | 79.81 | - | 2.58 | 16.17 | 2.43 | 43.88 | 8.78 |
| **2031** | 0.86 | 145.81 | 126.05 | - | 79.94 | - | 2.63 | 11.35 | 1.70 | 30.44 | 6.09 |
| **2032** | 0.74 | 148.72 | 110.69 | 258.60 | 80.33 | - | 2.68 | 7.32 | 1.10 | (239.33) | (47.87) |
| **2033** | 9.85 | 151.70 | 1,494.78 | - | 175.31 | - | 2.73 | 296.96 | 44.54 | 975.24 | 195.05 |
| **2034** | 7.91 | 154.73 | 1,223.91 | - | 158.49 | - | 2.79 | 272.01 | 40.80 | 749.82 | 149.96 |
| **2035** | 6.37 | 157.83 | 1,005.39 | - | 145.25 | - | 2.84 | 219.46 | 32.92 | 604.93 | 120.99 |
| **2036** | 5.12 | 160.98 | 824.12 | - | 112.37 | - | 2.90 | 180.92 | 27.14 | 500.79 | 100.16 |
| **2037** | 4.14 | 164.20 | 679.43 | - | 108.85 | - | 2.96 | 145.44 | 21.82 | 400.37 | 80.07 |
| **2038** | 3.35 | 167.49 | 560.86 | - | 96.87 | - | 3.02 | 117.91 | 17.69 | 325.38 | 65.08 |
| **2039** | 2.52 | 170.84 | 430.70 | - | 89.26 | - | 3.08 | 87.66 | 13.15 | 237.56 | 47.51 |
| **2040** | 2.02 | 174.25 | 352.13 | - | 85.15 | - | 3.14 | 67.82 | 10.17 | 185.84 | 37.17 |
| **2041** | 1.62 | 177.74 | 287.33 | - | 82.00 | - | 3.20 | 52.08 | 7.81 | 142.24 | 28.45 |
| **2042** | 1.35 | 181.29 | 244.23 | - | 85.99 | - | 3.27 | 39.92 | 5.99 | 109.06 | 21.81 |
| **2043** | 1.15 | 184.92 | 213.53 | - | 79.54 | - | 3.33 | 33.27 | 4.99 | 92.39 | 18.48 |
| **2044** | 1.02 | 188.62 | 192.39 | - | 79.42 | - | 3.40 | 27.92 | 4.19 | 77.47 | 15.49 |
| **2045** | - | - | - | - | - | 64.00 | - | (11.66) | 0.41 | (52.75) | (10.55) |
| **2046** | - | - | - | - | - | - | - | (1.60) | - | 1.60 | 0.32 |
| **Total (from 2011)** | **152.39** | | **19,398.77** | **1,216.41** | **3,326.34** | **64.00** | **80.38** | **3,741.66** | **466.24** | **10,503.73** | **2,100.75** |

| | Gross Cashflow | Lansdowne Share |
|---|---|---|
| **NPV @ 5%** | **5,710.64** | **1,142.13** |
| **NPV @ 10%** | **3,678.96** | **735.79** |
| **NPV @ 20%** | **1,978.90** | **395.78** |
| **IRR** | **261.99%** | **261.99%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2014** | **2014** |

## Helvick P90 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 10%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc. US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.14 | - | - | (0.14) | (0.01) |
| **2011** | - | - | - | - | - | - | 0.20 | - | - | (0.20) | (0.02) |
| **2012** | 0.78 | 90.51 | 71.03 | 110.86 | 15.52 | - | 0.21 | - | - | (55.56) | (5.56) |
| **2013** | 0.56 | 93.39 | 52.20 | - | 11.58 | - | 0.22 | - | - | 40.40 | 4.04 |
| **2014** | 0.27 | 98.12 | 26.49 | - | 6.27 | - | 0.22 | - | - | 20.00 | 2.00 |
| **2015** | 0.16 | 102.09 | 16.23 | - | 5.32 | - | 0.23 | - | - | 10.68 | 1.07 |
| **2016** | 0.12 | 106.22 | 12.64 | - | 3.50 | - | 0.23 | - | - | 8.91 | 0.89 |
| **2017** | 0.09 | 110.50 | 10.17 | - | 3.02 | - | 0.24 | 1.35 | - | 5.56 | 0.56 |
| **2018** | 0.07 | 112.71 | 8.23 | - | 3.86 | - | 0.24 | 1.08 | - | 3.05 | 0.30 |
| **2019** | 0.06 | 114.97 | 7.01 | - | 2.49 | - | 0.24 | 1.07 | - | 3.21 | 0.32 |
| **2020** | - | - | - | - | - | 4.14 | - | (0.83) | - | (3.32) | (0.33) |
| **2021** | - | - | - | - | - | - | - | (0.10) | - | 0.10 | 0.01 |
| **Total (from 2011)** | **2.12** | | **204.01** | **110.86** | **51.57** | **4.14** | **2.03** | **2.56** | - | **32.84** | **3.28** |

| | Gross Cashflow | Lansdowne Share |
|---|---|---|
| **NPV @ 5%** | **23.00** | **2.30** |
| **NPV @ 10%** | **15.37** | **1.54** |
| **NPV @ 20%** | **4.70** | **0.47** |
| **IRR** | **26.46%** | **26.46%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2016** | **2016** |

### Helvick P50 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 10%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc. US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.14 | - | - | (0.14) | (0.01) |
| **2011** | - | - | - | - | - | - | 0.20 | - | - | (0.20) | (0.02) |
| **2012** | 0.86 | 90.51 | 77.74 | 110.86 | 16.89 | - | 0.21 | - | - | (50.23) | (5.02) |
| **2013** | 0.64 | 93.39 | 59.95 | - | 13.15 | - | 0.22 | - | - | 46.59 | 4.66 |
| **2014** | 0.34 | 98.12 | 32.87 | - | 7.52 | - | 0.22 | 4.08 | - | 21.05 | 2.11 |
| **2015** | 0.20 | 102.09 | 20.01 | - | 6.05 | - | 0.23 | 3.54 | - | 10.19 | 1.02 |
| **2016** | 0.14 | 106.22 | 15.08 | - | 3.96 | - | 0.23 | 2.79 | - | 8.10 | 0.81 |
| **2017** | 0.11 | 110.50 | 12.49 | - | 3.45 | - | 0.24 | 2.25 | - | 6.55 | 0.65 |
| **2018** | 0.09 | 112.71 | 10.46 | - | 3.10 | - | 0.24 | 1.83 | - | 5.31 | 0.53 |
| **2019** | 0.08 | 114.97 | 8.74 | - | 4.00 | - | 0.24 | 1.19 | - | 3.30 | 0.33 |
| **2020** | 0.06 | 117.27 | 7.62 | - | 2.62 | - | 0.25 | 1.18 | - | 3.57 | 0.36 |
| **2021** | 0.06 | 119.61 | 6.68 | - | 2.48 | - | 0.25 | 1.01 | - | 2.94 | 0.29 |
| **2022** | - | - | - | - | - | 4.31 | - | (0.87) | - | (3.44) | (0.34) |
| **2023** | - | - | - | - | - | - | - | (0.11) | - | 0.11 | 0.01 |
| **Total (from 2011)** | **2.58** | | **251.67** | **110.86** | **63.22** | **4.31** | **2.53** | **16.90** | - | **53.85** | **5.38** |
| | | | | | | | | | **NPV @ 5%** | **40.19** | **4.02** |
| | | | | | | | | | **NPV @ 10%** | **29.89** | **2.99** |
| | | | | | | | | | **NPV @ 20%** | **15.81** | **1.58** |
| | | | | | | | | | **IRR** | **43.01%** | **43.01%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **2014** **2014**

### Helvick P10 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 10%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc. US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.14 | - | - | (0.14) | (0.01) |
| **2011** | - | - | - | - | - | - | 0.20 | - | - | (0.20) | (0.02) |
| **2012** | 1.35 | 90.51 | 122.10 | 111.01 | 25.10 | - | 0.21 | - | - | (14.22) | (1.42) |
| **2013** | 1.07 | 93.39 | 99.83 | - | 23.17 | - | 0.22 | 13.24 | - | 63.20 | 6.32 |
| **2014** | 0.53 | 98.12 | 51.81 | - | 13.25 | - | 0.22 | 10.10 | - | 28.24 | 2.82 |
| **2015** | 0.37 | 102.09 | 37.37 | - | 11.44 | - | 0.23 | 6.74 | - | 18.96 | 1.90 |
| **2016** | 0.28 | 106.22 | 29.95 | - | 8.87 | - | 0.23 | 5.34 | - | 15.52 | 1.55 |
| **2017** | 0.22 | 110.50 | 24.09 | - | 7.74 | - | 0.24 | 4.15 | - | 11.97 | 1.20 |
| **2018** | 0.21 | 112.71 | 23.44 | - | 7.69 | - | 0.24 | 3.89 | - | 11.62 | 1.16 |
| **2019** | 0.18 | 114.97 | 20.35 | - | 8.38 | - | 0.24 | 3.03 | - | 8.70 | 0.87 |
| **2020** | 0.16 | 117.27 | 19.11 | - | 4.74 | - | 0.25 | 3.47 | - | 10.65 | 1.07 |
| **2021** | 0.15 | 119.61 | 17.94 | - | 4.55 | - | 0.25 | 3.31 | - | 9.83 | 0.98 |
| **2022** | 0.14 | 122.00 | 16.47 | - | 4.31 | - | 0.26 | 3.01 | 0.04 | 8.86 | 0.89 |
| **2023** | 0.13 | 124.44 | 15.56 | - | 5.46 | - | 0.26 | 2.51 | 0.12 | 7.21 | 0.72 |
| **2024** | 0.12 | 126.93 | 14.85 | - | 4.06 | - | 0.27 | 2.61 | 0.13 | 7.78 | 0.78 |
| **2025** | 0.11 | 129.47 | 13.85 | - | 3.90 | - | 0.28 | 2.44 | 0.12 | 7.11 | 0.71 |
| **2026** | 0.10 | 132.06 | 13.07 | - | 3.78 | - | 0.28 | 2.27 | 0.11 | 6.63 | 0.66 |
| **2027** | 0.09 | 134.70 | 12.53 | - | 5.11 | - | 0.29 | 1.83 | 0.09 | 5.21 | 0.52 |
| **2028** | 0.09 | 137.40 | 12.23 | - | 3.68 | - | 0.29 | 2.04 | 0.10 | 6.12 | 0.61 |
| **2029** | 0.08 | 140.15 | 11.63 | - | 3.60 | - | 0.30 | 1.95 | 0.10 | 5.69 | 0.57 |
| **2030** | 0.08 | 142.95 | 11.29 | - | 3.57 | - | 0.30 | 1.86 | 0.09 | 5.46 | 0.55 |
| **2031** | 0.07 | 145.81 | 10.79 | - | 5.02 | - | 0.31 | 1.41 | 0.07 | 3.97 | 0.40 |
| **2032** | 0.07 | 148.72 | 10.41 | - | 3.47 | - | 0.32 | 1.63 | 0.08 | 4.92 | 0.49 |
| **2033** | 0.07 | 151.70 | 10.16 | - | 3.45 | - | 0.32 | 1.60 | 0.08 | 4.71 | 0.47 |
| **2034** | 0.06 | 154.73 | 9.75 | - | 3.41 | - | 0.33 | 1.51 | 0.08 | 4.42 | 0.44 |
| **2035** | 0.06 | 157.83 | 9.62 | - | 3.41 | - | 0.34 | 1.47 | 0.07 | 4.33 | 0.43 |
| **2036** | 0.06 | 160.98 | 9.40 | - | 3.41 | - | 0.34 | 1.42 | 0.07 | 4.16 | 0.42 |
| **2037** | 0.06 | 164.20 | 9.09 | - | 3.38 | - | 0.35 | 1.35 | 0.07 | 3.95 | 0.39 |
| **2038** | 0.05 | 167.49 | 8.81 | - | 3.37 | - | 0.36 | 1.28 | 0.06 | 3.74 | 0.37 |
| **2039** | 0.05 | 170.84 | 8.51 | - | 3.34 | - | 0.36 | 1.21 | 0.06 | 3.53 | 0.35 |
| **2040** | 0.05 | 174.25 | 8.19 | - | 3.32 | - | 0.37 | 1.13 | 0.06 | 3.31 | 0.33 |
| **2041** | 0.04 | 177.74 | 7.86 | - | 3.30 | - | 0.38 | 1.05 | 0.05 | 3.06 | 0.31 |
| **2042** | 0.04 | 181.29 | 7.52 | - | 3.27 | - | 0.39 | 0.97 | 0.05 | 2.84 | 0.28 |
| **2043** | 0.04 | 184.92 | 7.15 | - | 3.24 | - | 0.39 | 0.89 | 0.04 | 2.58 | 0.26 |
| **2044** | 0.04 | 188.62 | 6.77 | - | 3.21 | - | 0.40 | 0.80 | 0.04 | 2.32 | 0.23 |
| **2045** | - | - | - | - | - | 6.80 | - | (1.42) | 0.00 | (5.38) | (0.54) |
| **2046** | - | - | - | - | - | - | - | (0.17) | - | 0.17 | 0.02 |
| **Total (from 2011)** | **6.20** | | **691.53** | **111.01** | **200.99** | **6.80** | **10.02** | **89.92** | **1.80** | **270.99** | **27.10** |
| | | | | | | | | | **NPV @ 5%** | **175.45** | **17.55** |
| | | | | | | | | | **NPV @ 10%** | **127.94** | **12.79** |
| | | | | | | | | | **NPV @ 20%** | **81.73** | **8.17** |
| | | | | | | | | | **IRR** | **364.81%** | **364.81%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **2013** **2013**

### Amergin Jurassic P90 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2009

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.25 | - | - | (0.25) | (0.25) |
| **2011** | - | - | - | 1.50 | 0.20 | - | (0.09) | - | - | (1.61) | (1.61) |
| **2012** | - | - | - | 31.00 | 0.20 | - | (0.09) | - | - | (31.11) | (31.11) |
| **2013** | - | - | - | 69.28 | 0.20 | - | 0.83 | - | - | (70.31) | (70.31) |
| **2014** | 2.29 | 98.12 | 224.88 | 34.64 | 75.81 | - | 1.22 | - | - | 113.21 | 113.21 |
| **2015** | 2.52 | 102.09 | 257.48 | - | 78.93 | - | 1.24 | 27.56 | - | 149.75 | 149.75 |
| **2016** | 2.02 | 106.22 | 214.89 | - | 79.22 | - | 1.26 | 33.30 | - | 101.10 | 101.10 |
| **2017** | 1.62 | 110.50 | 179.34 | - | 75.61 | - | 1.29 | 26.41 | - | 76.03 | 76.03 |
| **2018** | 1.30 | 112.71 | 146.74 | - | 74.75 | - | 1.32 | 18.46 | 1.32 | 50.89 | 50.89 |
| **2019** | 1.04 | 114.97 | 120.07 | - | 70.16 | - | 1.34 | 12.69 | 0.69 | 35.18 | 35.18 |
| **2020** | 0.84 | 117.27 | 98.24 | - | 67.54 | - | 1.37 | 7.82 | 0.39 | 21.13 | 21.13 |
| **2021** | 0.67 | 119.61 | 80.39 | - | 67.59 | - | 1.40 | 3.30 | 0.16 | 7.94 | 7.94 |
| **2022** | - | - | - | - | - | 21.56 | - | (4.57) | 0.01 | (17.01) | (17.01) |
| **2023** | - | - | - | - | - | - | - | (0.54) | - | 0.54 | 0.54 |
| **Total** | **12.32** | | **1,322.02** | **136.41** | **590.21** | **21.56** | **11.08** | **124.44** | **2.58** | **435.74** | **435.74** |
| | | | | | | | | | **NPV @ 5%** | **330.77** | **330.77** |
| | | | | | | | | | **NPV @ 10%** | **253.79** | **253.79** |
| | | | | | | | | | **NPV @ 20%** | **153.00** | **153.00** |
| | | | | | | | | | **IRR** | **83.55%** | **83.55%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **2015** **2015**

### Amergin Jurassic P50 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2009

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.25 | - | - | (0.25) | (0.25) |
| **2011** | - | - | - | 1.50 | 0.20 | - | (0.09) | - | - | (1.61) | (1.61) |
| **2012** | - | - | - | 31.00 | 0.20 | - | (0.09) | - | - | (31.11) | (31.11) |
| **2013** | - | - | - | 38.20 | 0.20 | - | 0.83 | - | - | (39.24) | (39.24) |
| **2014** | 4.54 | 98.12 | 445.26 | 132.66 | 91.67 | - | 1.22 | 25.96 | - | 193.74 | 193.74 |
| **2015** | 4.99 | 102.09 | 509.81 | - | 96.67 | - | 1.24 | 95.56 | 2.29 | 314.05 | 314.05 |
| **2016** | 4.01 | 106.22 | 425.49 | - | 94.98 | - | 1.26 | 84.38 | 3.96 | 240.91 | 240.91 |
| **2017** | 3.21 | 110.50 | 355.09 | - | 87.70 | - | 1.29 | 68.10 | 6.40 | 191.60 | 191.60 |
| **2018** | 2.58 | 112.71 | 290.54 | - | 84.76 | - | 1.32 | 52.66 | 5.27 | 146.55 | 146.55 |
| **2019** | 2.07 | 114.97 | 237.73 | - | 79.66 | - | 1.34 | 40.38 | 5.80 | 110.56 | 110.56 |
| **2020** | 1.66 | 117.27 | 194.52 | - | 74.45 | - | 1.37 | 30.63 | 4.59 | 83.48 | 83.48 |
| **2021** | 1.33 | 119.61 | 159.16 | - | 73.37 | - | 1.40 | 21.96 | 3.29 | 59.15 | 59.15 |
| **2022** | 1.07 | 122.00 | 130.23 | - | 76.54 | - | 1.42 | 13.87 | 2.08 | 36.32 | 36.32 |
| **2023** | 0.86 | 124.44 | 106.56 | - | 72.47 | - | 1.45 | 8.65 | 1.30 | 22.69 | 22.69 |
| **2024** | 0.69 | 126.93 | 87.19 | - | 72.51 | - | 1.48 | 3.79 | 0.57 | 8.85 | 8.85 |
| **2025** | - | - | - | - | - | 26.92 | - | (5.73) | 0.05 | (21.24) | (21.24) |
| **2026** | - | - | - | - | - | - | - | (0.67) | - | 0.67 | 0.67 |
| **Total** | **27.00** | | **2,941.59** | **203.37** | **905.36** | **26.92** | **15.44** | **439.54** | **35.59** | **1,315.37** | **1,315.37** |
| | | | | | | | | | **NPV @ 5%** | **987.90** | **987.90** |
| | | | | | | | | | **NPV @ 10%** | **757.56** | **757.56** |
| | | | | | | | | | **NPV @ 20%** | **468.77** | **468.77** |
| | | | | | | | | | **IRR** | **167.64%** | **167.64%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **2014** **2014**

## Amergin Jurassic P10 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2009

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.25 | - | - | (0.25) | (0.25) |
| **2011** | - | - | - | 1.50 | 0.20 | - | (0.09) | - | - | (1.61) | (1.61) |
| **2012** | - | - | - | 31.00 | 0.20 | - | (0.09) | - | - | (31.11) | (31.11) |
| **2013** | - | - | - | 76.41 | 0.20 | - | 0.83 | - | - | (77.44) | (77.44) |
| **2014** | 9.56 | 98.12 | 937.74 | 198.99 | 126.44 | - | 1.22 | 105.31 | - | 505.78 | 505.78 |
| **2015** | 12.84 | 102.09 | 1,310.63 | - | 151.78 | - | 1.24 | 272.16 | 64.68 | 820.76 | 820.76 |
| **2016** | 10.30 | 106.22 | 1,093.85 | - | 141.31 | - | 1.26 | 242.98 | 39.29 | 669.01 | 669.01 |
| **2017** | 8.26 | 110.50 | 912.86 | - | 124.80 | - | 1.29 | 200.81 | 30.12 | 555.85 | 555.85 |
| **2018** | 6.63 | 112.71 | 746.94 | - | 115.23 | - | 1.32 | 161.51 | 24.23 | 444.66 | 444.66 |
| **2019** | 5.32 | 114.97 | 611.17 | - | 105.90 | - | 1.34 | 129.14 | 19.37 | 355.41 | 355.41 |
| **2020** | 4.26 | 117.27 | 500.08 | - | 95.07 | - | 1.37 | 103.42 | 15.51 | 284.71 | 284.71 |
| **2021** | 3.42 | 119.61 | 409.18 | - | 90.36 | - | 1.40 | 81.51 | 12.23 | 223.68 | 223.68 |
| **2022** | 2.74 | 122.00 | 334.80 | - | 91.84 | - | 1.42 | 62.28 | 9.34 | 169.92 | 169.92 |
| **2023** | 2.20 | 124.44 | 275.95 | - | 84.08 | - | 1.45 | 48.43 | 7.26 | 132.72 | 132.72 |
| **2024** | 1.77 | 126.93 | 224.15 | - | 82.14 | - | 1.48 | 36.33 | 5.45 | 98.75 | 98.75 |
| **2025** | 1.42 | 129.47 | 183.41 | - | 86.20 | - | 1.51 | 25.04 | 3.76 | 66.89 | 66.89 |
| **2026** | 1.14 | 132.06 | 150.07 | - | 80.01 | - | 1.54 | 17.81 | 2.67 | 48.04 | 48.04 |
| **2027** | 0.91 | 134.70 | 122.79 | - | 79.63 | - | 1.57 | 11.07 | 1.66 | 28.86 | 28.86 |
| **2028** | 0.73 | 137.40 | 100.47 | - | 85.31 | - | 1.60 | 4.09 | 0.61 | 8.85 | 8.85 |
| **2029** | 0.59 | 140.15 | 82.21 | - | 79.86 | - | 1.64 | 0.50 | 0.07 | 0.14 | 0.14 |
| **2030** | - | - | - | - | - | 52.01 | - | (3.19) | 0.00 | (48.82) | (48.82) |
| **2031** | - | - | - | - | - | - | - | (0.36) | - | 0.36 | 0.36 |
| **Total** | **72.08** | | **7,994.30** | **307.90** | **1,620.57** | **52.01** | **23.31** | **1,498.84** | **236.27** | **4,255.40** | **4,255.40** |
| | | | | | | | | | **NPV @ 5%** | **3,107.52** | **3,107.52** |
| | | | | | | | | | **NPV @ 10%** | **2,336.52** | **2,336.52** |
| | | | | | | | | | **NPV @ 20%** | **1,416.03** | **1,416.03** |
| | | | | | | | | | **IRR** | **269.28%** | **269.28%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **2014** **2014**

## Amergin Wealden P90 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.25 | - | - | (0.25) | (0.25) |
| **2011** | - | - | - | 1.53 | - | - | 0.25 | - | - | (1.78) | (1.78) |
| **2012** | - | - | - | 24.97 | 0.20 | - | 0.26 | - | - | (25.43) | (25.43) |
| **2013** | - | - | - | 95.81 | 0.20 | - | 0.83 | - | - | (96.84) | (96.84) |
| **2014** | 1.10 | 98.12 | 107.94 | - | 65.52 | - | 1.22 | - | - | 41.21 | 41.21 |
| **2015** | 1.21 | 102.09 | 123.59 | - | 67.60 | - | 1.24 | - | - | 54.75 | 54.75 |
| **2016** | 0.97 | 106.22 | 103.15 | - | 69.50 | - | 1.26 | - | - | 32.38 | 32.38 |
| **2017** | 0.78 | 110.50 | 86.08 | - | 67.21 | - | 1.29 | - | - | 17.59 | 17.59 |
| **2018** | 0.62 | 112.71 | 70.44 | - | 67.41 | - | 1.32 | - | - | 1.71 | 1.71 |
| **2019** | - | - | - | - | - | 20.32 | - | - | - | (20.32) | (20.32) |
| **Total (from 2011)** | **4.69** | | **491.20** | **122.31** | **337.65** | **20.32** | **7.66** | - | | **3.26** | **3.26** |
| | | | | | | | | | **NPV @ 5%** | **(7.24)** | **(7.24)** |
| | | | | | | | | | **NPV @ 10%** | **(15.15)** | **(15.15)** |
| | | | | | | | | | **NPV @ 20%** | **(25.32)** | **(25.32)** |
| | | | | | | | | | **IRR** | **1.41%** | **1.41%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **0** **0**

### Amergin Wealden P50 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise

NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc. US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.25 | - | - | (0.25) | (0.25) |
| **2011** | - | - | - | 1.53 | - | - | 0.25 | - | - | (1.78) | (1.78) |
| **2012** | - | - | - | 24.97 | 0.20 | - | 0.26 | - | - | (25.43) | (25.43) |
| **2013** | - | - | - | 38.20 | 0.20 | - | 0.83 | - | - | (39.24) | (39.24) |
| **2014** | 2.37 | 98.12 | 232.28 | 176.26 | 74.70 | - | 1.22 | - | - | (19.90) | (19.90) |
| **2015** | 4.13 | 102.09 | 422.01 | - | 88.46 | - | 1.24 | 46.86 | - | 285.43 | 285.43 |
| **2016** | 3.32 | 106.22 | 352.21 | - | 87.83 | - | 1.26 | 64.41 | - | 198.71 | 198.71 |
| **2017** | 2.68 | 110.50 | 293.94 | - | 81.39 | - | 1.29 | 54.11 | 4.59 | 152.55 | 152.55 |
| **2018** | 2.13 | 112.71 | 240.51 | - | 79.14 | - | 1.32 | 41.29 | 2.31 | 116.45 | 116.45 |
| **2019** | 1.71 | 114.97 | 196.79 | - | 74.68 | - | 1.34 | 31.20 | 1.56 | 88.11 | 88.11 |
| **2020** | 1.37 | 117.27 | 161.02 | - | 69.82 | - | 1.37 | 23.23 | 1.16 | 65.44 | 65.44 |
| **2021** | 1.10 | 119.61 | 131.75 | - | 69.09 | - | 1.40 | 16.03 | 1.49 | 43.75 | 43.75 |
| **2022** | 0.88 | 122.00 | 107.80 | - | 72.53 | - | 1.42 | 9.15 | 0.91 | 23.79 | 23.79 |
| **2023** | 0.71 | 124.44 | 88.21 | - | 68.68 | - | 1.45 | 4.91 | 0.49 | 12.67 | 12.67 |
| **2024** | 0.57 | 126.93 | 72.18 | - | 68.89 | - | 1.48 | 0.66 | 0.09 | 0.86 | 0.86 |
| **2025** | - | - | - | - | - | 26.92 | - | (4.43) | 0.00 | (22.49) | (22.49) |
| **2026** | - | - | - | - | - | - | - | (0.50) | - | 0.50 | 0.50 |
| **Total (from 2011)** | **20.96** | | **2,298.71** | **240.97** | **835.54** | **26.92** | **16.13** | **287.13** | **12.61** | **879.42** | **879.42** |

| | | |
|---|---|---|
| **NPV @ 5%** | **647.31** | **647.31** |
| **NPV @ 10%** | **484.47** | **484.47** |
| **NPV @ 20%** | **282.58** | **282.58** |
| **IRR** | **102.57%** | **102.57%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2015** | **2015** |

### Amergin Wealden P10 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise

NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc. US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.25 | - | - | (0.25) | (0.25) |
| **2011** | - | - | - | 1.53 | - | - | 0.25 | - | - | (1.78) | (1.78) |
| **2012** | - | - | - | 25.49 | 0.20 | - | 0.26 | - | - | (25.95) | (25.95) |
| **2013** | - | - | - | 76.41 | 0.20 | - | 0.83 | - | - | (77.44) | (77.44) |
| **2014** | 4.48 | 98.12 | 439.69 | 470.04 | 89.66 | - | 1.22 | - | - | (121.22) | (121.22) |
| **2015** | 10.54 | 102.09 | 1,075.96 | - | 133.59 | - | 1.24 | 152.34 | - | 788.79 | 788.79 |
| **2016** | 8.45 | 106.22 | 898.00 | - | 125.97 | - | 1.26 | 190.35 | 7.98 | 572.43 | 572.43 |
| **2017** | 6.78 | 110.50 | 749.41 | - | 111.80 | - | 1.29 | 162.44 | 8.05 | 465.84 | 465.84 |
| **2018** | 5.44 | 112.71 | 613.20 | - | 104.13 | - | 1.32 | 130.15 | 12.22 | 365.38 | 365.38 |
| **2019** | 4.36 | 114.97 | 501.74 | - | 96.35 | - | 1.34 | 103.60 | 10.36 | 290.08 | 290.08 |
| **2020** | 3.50 | 117.27 | 410.54 | - | 86.77 | - | 1.37 | 82.64 | 8.26 | 231.49 | 231.49 |
| **2021** | 2.81 | 119.61 | 335.91 | - | 83.08 | - | 1.40 | 64.63 | 6.46 | 180.34 | 180.34 |
| **2022** | 2.25 | 122.00 | 274.86 | - | 85.38 | - | 1.42 | 48.60 | 6.98 | 132.48 | 132.48 |
| **2023** | 1.81 | 124.44 | 224.90 | - | 78.26 | - | 1.45 | 37.36 | 5.60 | 102.20 | 102.20 |
| **2024** | 1.45 | 126.93 | 184.02 | - | 76.87 | - | 1.48 | 27.40 | 4.11 | 74.15 | 74.15 |
| **2025** | 1.16 | 129.47 | 150.57 | - | 81.36 | - | 1.51 | 17.87 | 2.68 | 47.14 | 47.14 |
| **2026** | 0.93 | 132.06 | 123.20 | - | 75.51 | - | 1.54 | 12.08 | 1.81 | 32.26 | 32.26 |
| **2027** | 0.75 | 134.70 | 100.81 | - | 75.39 | - | 1.57 | 6.52 | 0.98 | 16.35 | 16.35 |
| **2028** | 0.60 | 137.40 | 82.48 | - | 81.28 | - | 1.60 | 0.60 | 0.09 | (1.08) | (1.08) |
| **2029** | - | - | - | - | - | 50.99 | - | (5.37) | - | (45.62) | (45.62) |
| **2030** | - | - | - | - | - | - | - | (0.60) | - | 0.60 | 0.60 |
| **Total (from 2011)** | **55.32** | | **6,165.27** | **573.46** | **1,385.80** | **50.99** | **22.36** | **1,030.63** | **75.59** | **3,026.44** | **3,026.44** |

| | | |
|---|---|---|
| **NPV @ 5%** | **2,160.88** | **2,160.88** |
| **NPV @ 10%** | **1,583.07** | **1,583.07** |
| **NPV @ 20%** | **903.67** | **903.67** |
| **IRR** | **139.43%** | **139.43%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2015** | **2015** |

### Midleton P90 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc. US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | - | - | - | - | - | - | 0.27 | - | - | (0.27) | (0.27) |
| 2011 | - | - | - | 1.53 | 0.20 | - | 0.28 | - | - | (2.00) | (2.00) |
| 2012 | - | - | - | 50.98 | 0.20 | - | 0.95 | - | - | (52.13) | (52.13) |
| 2013 | 7.30 | 8.49 | 61.97 | 77.68 | 12.06 | - | 1.41 | - | - | (29.18) | (29.18) |
| 2014 | 7.30 | 8.66 | 63.21 | - | 13.76 | - | 1.44 | - | - | 48.02 | 48.02 |
| 2015 | 7.30 | 8.83 | 64.48 | - | 16.27 | - | 1.46 | - | - | 46.74 | 46.74 |
| 2016 | 7.30 | 9.01 | 65.77 | - | 17.05 | - | 1.49 | 6.51 | - | 40.72 | 40.72 |
| 2017 | 4.02 | 9.19 | 36.90 | - | 13.78 | - | 1.52 | 5.58 | - | 16.01 | 16.01 |
| 2018 | 3.10 | 9.37 | 29.08 | - | 14.37 | - | 1.55 | 3.50 | - | 9.66 | 9.66 |
| 2019 | 2.48 | 9.56 | 23.73 | - | 13.09 | - | 1.59 | 2.37 | - | 6.69 | 6.69 |
| 2020 | 1.97 | 9.75 | 19.22 | - | 13.22 | - | 1.62 | 1.21 | - | 3.17 | 3.17 |
| 2021 | - | - | - | - | - | 4.85 | - | (0.98) | - | (3.87) | (3.87) |
| 2022 | - | - | - | - | - | - | - | (0.12) | - | 0.12 | 0.12 |
| **Total from 2011** | **40.77** | | **364.36** | **130.19** | **113.99** | **4.85** | **13.31** | **18.07** | - | **83.96** | **83.96** |
| | | | | | | | | | **NPV @ 5%** | **56.81** | **56.81** |
| | | | | | | | | | **NPV @ 10%** | **36.79** | **36.79** |
| | | | | | | | | | **NPV @ 20%** | **10.61** | **10.61** |
| | | | | | | | | | **IRR** | **26.44%** | **26.44%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **2016** **2016**

### Midleton P50 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc. US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | - | - | - | - | - | - | 0.27 | - | - | (0.27) | (0.27) |
| 2011 | - | - | - | 1.53 | 0.19 | - | 0.28 | - | - | (2.00) | (2.00) |
| 2012 | - | - | - | 74.91 | 0.20 | - | 0.95 | - | - | (76.05) | (76.05) |
| 2013 | 10.95 | 8.49 | 92.96 | 53.06 | 14.00 | - | 1.41 | - | - | 24.49 | 24.49 |
| 2014 | 8.54 | 8.66 | 73.96 | 2.16 | 15.50 | - | 1.44 | - | - | 54.86 | 54.86 |
| 2015 | 6.66 | 8.83 | 58.84 | - | 15.00 | - | 1.46 | 9.10 | - | 33.28 | 33.28 |
| 2016 | 5.20 | 9.01 | 46.82 | - | 16.00 | - | 1.49 | 7.61 | - | 21.71 | 21.71 |
| 2017 | 4.05 | 9.19 | 37.25 | - | 14.42 | - | 1.52 | 5.53 | - | 15.77 | 15.77 |
| 2018 | 3.16 | 9.37 | 29.63 | - | 13.93 | - | 1.55 | 3.72 | - | 10.43 | 10.43 |
| 2019 | 2.47 | 9.56 | 23.58 | - | 14.83 | - | 1.59 | 1.96 | - | 5.19 | 5.19 |
| 2020 | 1.92 | 9.75 | 18.76 | - | 13.63 | - | 1.62 | 0.97 | - | 2.54 | 2.54 |
| 2021 | 1.50 | 9.95 | 14.92 | - | 14.09 | - | 1.65 | 0.09 | - | (0.91) | (0.91) |
| 2022 | - | - | - | - | - | 4.95 | - | (0.79) | - | (4.16) | (4.16) |
| 2023 | - | - | - | - | - | - | - | (0.09) | - | 0.09 | 0.09 |
| **Total from 2011** | **44.45** | | **396.72** | **131.66** | **131.81** | **4.95** | **14.96** | **28.09** | - | **85.25** | **85.25** |
| | | | | | | | | | **NPV @ 5%** | **60.96** | **60.96** |
| | | | | | | | | | **NPV @ 10%** | **42.51** | **42.51** |
| | | | | | | | | | **NPV @ 20%** | **17.35** | **17.35** |
| | | | | | | | | | **IRR** | **31.70%** | **31.70%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **2014** **2014**

### Midleton P10 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc. US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | - | - | - | - | - | - | 0.27 | - | - | (0.27) | (0.27) |
| 2011 | - | - | - | 1.53 | 0.19 | - | 0.28 | - | - | (2.00) | (2.00) |
| 2012 | - | - | - | 75.64 | 0.20 | - | 0.95 | - | - | (76.78) | (76.78) |
| 2013 | 12.92 | 8.49 | 109.69 | 53.06 | 16.86 | - | 1.41 | - | - | 38.37 | 38.37 |
| 2014 | 9.75 | 8.66 | 84.39 | - | 16.53 | - | 1.44 | 5.12 | - | 61.31 | 61.31 |
| 2015 | 7.59 | 8.83 | 67.06 | - | 17.13 | - | 1.46 | 11.47 | - | 36.99 | 36.99 |
| 2016 | 5.18 | 9.01 | 46.70 | - | 14.85 | - | 1.49 | 8.04 | - | 22.31 | 22.31 |
| 2017 | 3.65 | 9.19 | 33.54 | - | 13.61 | - | 1.52 | 4.90 | - | 13.51 | 13.51 |
| 2018 | 2.74 | 9.37 | 25.66 | - | 14.00 | - | 1.55 | 2.73 | - | 7.37 | 7.37 |
| 2019 | 2.05 | 9.56 | 19.63 | - | 12.25 | - | 1.59 | 1.56 | - | 4.24 | 4.24 |
| 2020 | 1.54 | 9.75 | 15.02 | - | 11.95 | - | 1.62 | 0.47 | - | 0.98 | 0.98 |
| 2021 | - | - | - | - | - | 4.85 | - | (1.05) | - | (3.79) | (3.79) |
| 2022 | - | - | - | - | - | - | - | (0.12) | - | 0.12 | 0.12 |
| **Total from 2011** | **45.42** | | **401.69** | **130.23** | **117.59** | **4.85** | **13.31** | **33.12** | - | **102.60** | **102.60** |
| | | | | | | | | | **NPV @ 5%** | **77.09** | **77.09** |
| | | | | | | | | | **NPV @ 10%** | **57.45** | **57.45** |
| | | | | | | | | | **NPV @ 20%** | **30.09** | **30.09** |
| | | | | | | | | | **IRR** | **41.76%** | **41.76%** |
| | | | **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | | | | | | | **2014** | **2014** |

### East Kinsale P90 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | - | - | - | 1.63 | - | - | 0.27 | - | - | (1.90) | (1.90) |
| 2011 | - | - | - | 2.04 | 0.20 | - | 0.93 | - | - | (3.16) | (3.16) |
| 2012 | - | - | - | 26.01 | 0.20 | - | 0.93 | - | - | (27.14) | (27.14) |
| 2013 | 0.91 | 8.49 | 7.75 | 76.41 | 3.06 | - | 1.41 | - | - | (73.13) | (73.13) |
| 2014 | 3.65 | 8.66 | 31.61 | - | 9.02 | - | 1.44 | - | - | 21.15 | 21.15 |
| 2015 | 3.65 | 8.83 | 32.24 | - | 11.22 | - | 1.46 | - | - | 19.55 | 19.55 |
| 2016 | 3.65 | 9.01 | 32.88 | - | 11.65 | - | 1.49 | - | - | 19.74 | 19.74 |
| 2017 | 3.65 | 9.19 | 33.54 | - | 13.04 | - | 1.52 | - | - | 18.98 | 18.98 |
| 2018 | 3.65 | 9.37 | 34.21 | - | 15.66 | - | 1.55 | - | - | 17.00 | 17.00 |
| 2019 | 2.92 | 9.56 | 27.95 | - | 14.40 | - | 1.59 | 0.31 | - | 11.65 | 11.65 |
| 2020 | 1.73 | 9.75 | 16.91 | - | 12.23 | - | 1.62 | 0.73 | - | 2.35 | 2.35 |
| 2021 | - | - | - | - | - | 4.86 | - | (0.93) | - | (3.92) | (3.92) |
| 2022 | - | - | - | - | - | - | - | (0.11) | - | 0.11 | 0.11 |
| **Total (from 2011)** | **23.82** | | **217.10** | **104.46** | **90.68** | **4.85** | **13.95** | **0.00** | - | **3.17** | **3.17** |
| | | | | | | | | | **NPV @ 5%** | **(12.23)** | **(12.23)** |
| | | | | | | | | | **NPV @ 10%** | **(22.39)** | **(22.39)** |
| | | | | | | | | | **NPV @ 20%** | **(33.32)** | **(33.32)** |
| | | | | | | | | | **IRR** | **0.87%** | **0.87%** |
| | | | **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | | | | | | | **2019** | **2019** |

### East Kinsale P50 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.27 | - | - | (0.27) | (0.27) |
| **2011** | - | - | - | 1.66 | 0.39 | - | 0.93 | - | - | (2.98) | (2.98) |
| **2012** | - | - | - | 28.09 | 1.76 | - | 0.93 | - | - | (30.78) | (30.78) |
| **2013** | 2.01 | 8.49 | 17.04 | 94.45 | 5.68 | - | 1.41 | - | - | (84.49) | (84.49) |
| **2014** | 8.03 | 8.66 | 69.54 | - | 15.02 | - | 1.44 | - | - | 53.08 | 53.08 |
| **2015** | 8.03 | 8.83 | 70.93 | - | 18.13 | - | 1.46 | - | - | 51.33 | 51.33 |
| **2016** | 8.03 | 9.01 | 72.34 | - | 18.39 | - | 1.49 | 8.25 | - | 44.21 | 44.21 |
| **2017** | 8.03 | 9.19 | 73.79 | - | 20.03 | - | 1.52 | 12.67 | - | 39.57 | 39.57 |
| **2018** | 5.73 | 9.37 | 53.75 | - | 20.61 | - | 1.55 | 8.41 | - | 23.17 | 23.17 |
| **2019** | 3.97 | 9.56 | 37.96 | - | 17.57 | - | 1.59 | 5.02 | - | 13.78 | 13.78 |
| **2020** | 3.10 | 9.75 | 30.21 | - | 17.62 | - | 1.62 | 2.94 | - | 8.03 | 8.03 |
| **2021** | 2.49 | 9.95 | 24.72 | - | 20.30 | - | 1.65 | 0.90 | - | 1.87 | 1.87 |
| **2022** | 1.99 | 10.15 | 20.23 | - | 20.21 | - | 1.68 | 0.07 | - | (1.74) | (1.74) |
| **2023** | - | - | - | - | - | 5.95 | - | (0.62) | - | (5.33) | (5.33) |
| **2024** | - | - | - | - | - | - | - | (0.07) | - | 0.07 | 0.07 |
| **Total (from 2011)** | **51.41** | | **470.50** | **124.20** | **175.71** | **5.95** | **17.28** | **37.57** | - | **109.79** | **109.79** |

| | | |
|---|---|---|
| **NPV @ 5%** | **71.49** | **71.49** |
| **NPV @ 10%** | **44.09** | **44.09** |
| **NPV @ 20%** | **9.89** | **9.89** |
| **IRR** | **24.63%** | **24.63%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2016** | **2016** |

### East Kinsale P10 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 100%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.27 | - | - | (0.27) | (0.27) |
| **2011** | - | - | - | 1.66 | 0.20 | - | 0.93 | - | - | (2.79) | (2.79) |
| **2012** | - | - | - | 28.61 | 0.20 | - | 0.93 | - | - | (29.74) | (29.74) |
| **2013** | 3.19 | 8.49 | 27.11 | 94.45 | 7.62 | - | 1.41 | - | - | (76.36) | (76.36) |
| **2014** | 12.78 | 8.66 | 110.62 | - | 18.65 | - | 1.44 | - | - | 90.54 | 90.54 |
| **2015** | 12.78 | 8.83 | 112.84 | - | 22.37 | - | 1.46 | 15.46 | - | 73.54 | 73.54 |
| **2016** | 12.78 | 9.01 | 115.09 | - | 22.09 | - | 1.49 | 22.31 | - | 69.20 | 69.20 |
| **2017** | 12.78 | 9.19 | 117.40 | - | 23.71 | - | 1.52 | 23.03 | 0.10 | 69.04 | 69.04 |
| **2018** | 12.78 | 9.37 | 119.74 | - | 27.63 | - | 1.55 | 22.88 | 1.03 | 66.85 | 66.85 |
| **2019** | 12.78 | 9.56 | 122.14 | - | 27.05 | - | 1.59 | 23.30 | 1.17 | 69.04 | 69.04 |
| **2020** | 12.60 | 9.75 | 122.90 | - | 28.92 | - | 1.62 | 23.12 | 2.20 | 67.05 | 67.05 |
| **2021** | 6.85 | 9.95 | 68.16 | - | 29.62 | - | 1.65 | 10.61 | 1.06 | 25.22 | 25.22 |
| **2022** | 4.22 | 10.15 | 42.81 | - | 26.81 | - | 1.68 | 4.14 | 0.41 | 9.76 | 9.76 |
| **2023** | 3.38 | 10.35 | 35.03 | - | 28.17 | - | 1.72 | 1.51 | 0.15 | 3.48 | 3.48 |
| **2024** | - | - | - | - | - | 6.07 | - | (1.24) | 0.01 | (4.85) | (4.85) |
| **2025** | - | - | - | - | - | - | - | (0.15) | - | 0.15 | 0.15 |
| **Total (from 2011)** | **106.90** | | **993.83** | **124.72** | **263.01** | **6.07** | **19.00** | **144.78** | **6.13** | **430.13** | **430.13** |

| | | |
|---|---|---|
| **NPV @ 5%** | **302.16** | **302.16** |
| **NPV @ 10%** | **215.09** | **215.09** |
| **NPV @ 20%** | **111.23** | **111.23** |
| **IRR** | **57.93%** | **57.93%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2015** | **2015** |

## Rosscarbary A P90 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 99%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | - | - | - | - | - | - | 0.23 | - | - | (0.23) | (0.23) |
| 2011 | - | - | - | 2.35 | 0.20 | - | 0.23 | - | - | (2.77) | (2.75) |
| 2012 | - | - | - | 28.09 | 0.20 | - | 0.56 | - | - | (28.85) | (28.56) |
| 2013 | 1.00 | 8.49 | 8.52 | 101.03 | 3.25 | - | 0.79 | - | - | (96.54) | (95.58) |
| 2014 | 4.02 | 8.66 | 34.77 | - | 9.60 | - | 0.80 | - | - | 24.36 | 24.12 |
| 2015 | 4.02 | 8.83 | 35.46 | - | 11.85 | - | 0.82 | - | - | 22.79 | 22.56 |
| 2016 | 4.02 | 9.01 | 36.17 | - | 12.34 | - | 0.84 | - | - | 22.99 | 22.76 |
| 2017 | 4.02 | 9.19 | 36.90 | - | 13.78 | - | 0.85 | - | - | 22.27 | 22.05 |
| 2018 | 3.06 | 9.37 | 28.65 | - | 14.25 | - | 0.87 | - | - | 13.53 | 13.40 |
| 2019 | 2.01 | 9.56 | 19.23 | - | 11.50 | - | 0.89 | - | - | 6.83 | 6.77 |
| 2020 | 1.51 | 9.75 | 14.69 | - | 11.19 | - | 0.90 | - | - | 2.60 | 2.57 |
| 2021 | - | - | - | - | - | 4.85 | - | - | - | (4.85) | (4.80) |
| **Total from 2011** | **23.64** | | **214.39** | **131.46** | **88.16** | **4.85** | **7.55** | - | - | **(17.64)** | **(17.46)** |
| | | | | | | | | | **NPV @ 5%** | **(30.45)** | **(30.14)** |
| | | | | | | | | | **NPV @ 10%** | **(38.71)** | **(38.32)** |
| | | | | | | | | | **NPV @ 20%** | **(46.99)** | **(46.52)** |
| | | | | | | | | | **IRR** | **-4.58%** | **-4.58%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **0** **0**

## Rosscarbary A P50 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 99%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | - | - | - | - | - | - | 0.23 | - | - | (0.23) | (0.23) |
| 2011 | - | - | - | 2.35 | 0.20 | - | 0.23 | - | - | (2.77) | (2.75) |
| 2012 | - | - | - | 28.09 | 0.20 | - | 0.56 | - | - | (28.85) | (28.56) |
| 2013 | 2.74 | 8.49 | 23.24 | 119.07 | 6.91 | - | 0.79 | - | - | (103.52) | (102.49) |
| 2014 | 10.95 | 8.66 | 94.82 | - | 17.44 | - | 0.80 | - | - | 76.58 | 75.81 |
| 2015 | 10.95 | 8.83 | 96.72 | - | 20.61 | - | 0.82 | - | - | 75.29 | 74.54 |
| 2016 | 10.95 | 9.01 | 98.65 | - | 20.89 | - | 0.84 | 14.62 | - | 62.30 | 61.68 |
| 2017 | 10.95 | 9.19 | 100.62 | - | 22.53 | - | 0.85 | 19.00 | - | 58.24 | 57.66 |
| 2018 | 10.95 | 9.37 | 102.64 | - | 25.90 | - | 0.87 | 19.00 | - | 56.86 | 56.30 |
| 2019 | 8.31 | 9.56 | 79.48 | - | 23.84 | - | 0.89 | 14.22 | - | 40.54 | 40.13 |
| 2020 | 5.14 | 9.75 | 50.14 | - | 22.07 | - | 0.90 | 7.48 | - | 19.68 | 19.49 |
| 2021 | 3.73 | 9.95 | 37.08 | - | 23.94 | - | 0.92 | 3.43 | - | 8.79 | 8.70 |
| 2022 | 2.99 | 10.15 | 30.34 | - | 23.89 | - | 0.94 | 1.54 | - | 3.96 | 3.92 |
| 2023 | - | - | - | - | - | 5.95 | - | (1.20) | - | (4.75) | (4.70) |
| 2024 | - | - | - | - | - | - | - | (0.15) | - | 0.15 | 0.15 |
| **Total from 2011** | **77.66** | | **713.73** | **149.50** | **208.41** | **5.95** | **9.41** | **77.95** | - | **262.50** | **259.88** |
| | | | | | | | | | **NPV @ 5%** | **181.91** | **180.09** |
| | | | | | | | | | **NPV @ 10%** | **125.71** | **124.45** |
| | | | | | | | | | **NPV @ 20%** | **57.01** | **56.44** |
| | | | | | | | | | **IRR** | **40.03%** | **40.03%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **2016** **2016**

### Rosscarbary A P10 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 99%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | 2.50 | - | - | 0.23 | - | - | (2.73) | (2.70) |
| **2011** | - | - | - | 2.35 | 0.20 | - | 0.23 | - | - | (2.77) | (2.75) |
| **2012** | - | - | - | 28.09 | 0.20 | - | 0.56 | - | - | (28.85) | (28.56) |
| **2013** | 4.56 | 8.49 | 38.73 | 112.49 | 11.66 | - | 0.79 | - | - | (86.20) | (85.34) |
| **2014** | 18.25 | 8.66 | 158.04 | - | 21.35 | - | 0.80 | 2.68 | - | 133.20 | 131.87 |
| **2015** | 18.25 | 8.83 | 161.20 | - | 22.85 | - | 0.82 | 31.24 | - | 106.29 | 105.23 |
| **2016** | 18.25 | 9.01 | 164.42 | - | 26.92 | - | 0.84 | 34.19 | - | 102.47 | 101.45 |
| **2017** | 18.25 | 9.19 | 167.71 | - | 26.20 | - | 0.85 | 35.06 | 4.50 | 101.09 | 100.08 |
| **2018** | 18.25 | 9.37 | 171.06 | - | 27.68 | - | 0.87 | 35.58 | 2.10 | 104.83 | 103.78 |
| **2019** | 17.60 | 9.56 | 168.24 | - | 31.46 | - | 0.89 | 34.14 | 3.24 | 98.51 | 97.53 |
| **2020** | 10.25 | 9.75 | 99.99 | - | 27.54 | - | 0.90 | 19.49 | 1.95 | 50.10 | 49.60 |
| **2021** | 6.71 | 9.95 | 66.74 | - | 26.97 | - | 0.92 | 10.53 | 1.05 | 27.26 | 26.99 |
| **2022** | 5.38 | 10.15 | 54.61 | - | 31.21 | - | 0.94 | 6.02 | 0.60 | 15.83 | 15.67 |
| **2023** | 4.32 | 10.35 | 44.68 | - | 30.43 | - | 0.96 | 3.55 | 0.36 | 9.39 | 9.29 |
| **2024** | 3.46 | 10.56 | 36.56 | - | 32.24 | - | 0.98 | 1.08 | 0.11 | 2.15 | 2.12 |
| **2025** | - | - | - | - | - | 6.19 | - | (1.31) | 0.01 | (4.89) | (4.84) |
| **2026** | - | - | - | - | - | - | - | (0.15) | - | 0.15 | 0.15 |
| **Total from 2011** | **143.54** | | **1,331.98** | **142.92** | **316.91** | **6.19** | **11.35** | **212.11** | **13.91** | **628.57** | **622.29** |
| | | | | | | | | | **NPV @ 5%** | **453.24** | **448.71** |
| | | | | | | | | | **NPV @ 10%** | **332.55** | **329.22** |
| | | | | | | | | | **NPV @ 20%** | **186.00** | **184.14** |
| | | | | | | | | | **IRR** | **78.25%** | **78.25%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | | | | | | | | | | **2014** | **2014** |

### Rosscarbary Wealden P90 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 99%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.23 | - | - | (0.23) | (0.23) |
| **2011** | - | - | - | 2.35 | 0.20 | - | 0.23 | - | - | (2.77) | (2.75) |
| **2012** | - | - | - | 28.09 | 0.20 | - | 0.56 | - | - | (28.85) | (28.56) |
| **2013** | 1.00 | 8.49 | 8.52 | 101.03 | 3.25 | - | 0.79 | - | - | (96.54) | (95.58) |
| **2014** | 4.02 | 8.66 | 34.77 | - | 9.60 | - | 0.80 | - | - | 24.36 | 24.12 |
| **2015** | 4.02 | 8.83 | 35.46 | - | 11.85 | - | 0.82 | - | - | 22.79 | 22.56 |
| **2016** | 4.02 | 9.01 | 36.17 | - | 12.34 | - | 0.84 | - | - | 22.99 | 22.76 |
| **2017** | 4.02 | 9.19 | 36.90 | - | 13.78 | - | 0.85 | - | - | 22.27 | 22.05 |
| **2018** | 3.06 | 9.37 | 28.65 | - | 14.25 | - | 0.87 | - | - | 13.53 | 13.40 |
| **2019** | 2.01 | 9.56 | 19.23 | - | 11.50 | - | 0.89 | - | - | 6.83 | 6.77 |
| **2020** | 1.51 | 9.75 | 14.69 | - | 11.19 | - | 0.90 | - | - | 2.60 | 2.57 |
| **2021** | - | - | - | - | - | 4.85 | - | - | - | (4.85) | (4.80) |
| **Total from 2011** | **23.64** | | **214.39** | **131.46** | **88.16** | **4.85** | **7.55** | - | - | **(17.64)** | **(17.46)** |
| | | | | | | | | | **NPV @ 5%** | **(30.45)** | **(30.14)** |
| | | | | | | | | | **NPV @ 10%** | **(38.71)** | **(38.32)** |
| | | | | | | | | | **NPV @ 20%** | **(46.99)** | **(46.52)** |
| | | | | | | | | | **IRR** | **-4.58%** | **-4.58%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | | | | | | | | | | **0** | **0** |

## Rosscarbary Wealden P50 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 99%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.23 | - | - | (0.23) | (0.23) |
| **2011** | - | - | - | 2.35 | 0.20 | - | 0.23 | - | - | (2.77) | (2.75) |
| **2012** | - | - | - | 28.09 | 0.20 | - | 0.56 | - | - | (28.65) | (28.56) |
| **2013** | 2.01 | 8.49 | 17.04 | 119.07 | 5.68 | | 0.79 | - | | (108.49) | (107.40) |
| **2014** | 8.03 | 8.66 | 69.54 | - | 15.02 | - | 0.80 | - | - | 53.71 | 53.17 |
| **2015** | 8.03 | 8.83 | 70.93 | - | 18.13 | - | 0.82 | - | - | 51.98 | 51.46 |
| **2016** | 8.03 | 9.01 | 72.34 | - | 18.39 | - | 0.84 | - | - | 53.12 | 52.59 |
| **2017** | 8.03 | 9.19 | 73.79 | - | 20.03 | - | 0.85 | 9.39 | - | 43.52 | 43.08 |
| **2018** | 5.73 | 9.37 | 53.75 | - | 20.61 | - | 0.87 | 8.30 | - | 23.97 | 23.73 |
| **2019** | 3.97 | 9.56 | 37.96 | - | 17.57 | - | 0.89 | 5.19 | - | 14.31 | 14.16 |
| **2020** | 3.10 | 9.75 | 30.21 | - | 17.62 | - | 0.90 | 3.12 | - | 8.57 | 8.48 |
| **2021** | 2.49 | 9.95 | 24.72 | - | 20.30 | - | 0.92 | 1.08 | - | 2.42 | 2.40 |
| **2022** | 1.99 | 10.15 | 20.23 | - | 20.21 | - | 0.94 | 0.09 | - | (1.02) | (1.01) |
| **2023** | - | - | - | - | - | 6.99 | - | (0.79) | - | (6.20) | (6.14) |
| **2024** | - | - | - | - | - | - | - | (0.09) | - | 0.09 | 0.09 |
| **Total from 2011** | **51.41** | | **470.50** | **149.50** | **173.95** | **6.99** | **9.41** | **26.30** | - | **104.34** | **103.30** |
| | | | | | | | | | **NPV @ 5%** | **64.32** | **63.68** |
| | | | | | | | | | **NPV @ 10%** | **35.97** | **35.61** |
| | | | | | | | | | **NPV @ 20%** | **1.16** | **1.15** |
| | | | | | | | | | **IRR** | **20.48%** | **20.48%** |
| | | | | | | | | | **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2017** | **2017** |

## Rosscarbary Wealden P10 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 99%

| Year | Gas Production BCF | Gas realisation US$ / BCF | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Landsdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.23 | - | - | (0.23) | (0.23) |
| **2011** | - | - | - | 1.53 | 0.20 | - | 0.23 | - | - | (1.96) | (1.94) |
| **2012** | - | - | - | 28.61 | 0.20 | - | 0.56 | - | - | (29.37) | (29.08) |
| **2013** | 3.38 | 8.49 | 28.66 | 137.11 | 7.89 | | 0.79 | - | | (117.12) | (115.95) |
| **2014** | 13.51 | 8.66 | 116.95 | - | 19.08 | - | 0.80 | - | - | 97.07 | 96.09 |
| **2015** | 13.51 | 8.83 | 119.28 | - | 22.61 | - | 0.82 | 9.20 | - | 86.46 | 85.59 |
| **2016** | 13.51 | 9.01 | 121.67 | - | 22.51 | - | 0.84 | 23.15 | - | 75.18 | 74.43 |
| **2017** | 13.51 | 9.19 | 124.10 | - | 24.12 | - | 0.85 | 24.76 | - | 74.37 | 73.63 |
| **2018** | 13.51 | 9.37 | 126.59 | - | 28.03 | - | 0.87 | 24.46 | 0.05 | 73.18 | 72.44 |
| **2019** | 10.57 | 9.56 | 101.10 | - | 25.70 | - | 0.89 | 19.21 | 0.84 | 54.46 | 53.92 |
| **2020** | 6.62 | 9.75 | 64.56 | - | 24.20 | - | 0.90 | 10.74 | 0.54 | 28.17 | 27.89 |
| **2021** | 4.79 | 9.95 | 47.67 | - | 26.74 | - | 0.92 | 5.49 | 0.27 | 14.24 | 14.10 |
| **2022** | 3.84 | 10.15 | 39.01 | - | 26.05 | - | 0.94 | 3.20 | 0.16 | 8.65 | 8.57 |
| **2023** | 3.08 | 10.35 | 31.92 | - | 29.61 | - | 0.96 | 0.60 | 0.03 | 0.72 | 0.71 |
| **2024** | - | - | - | - | - | 7.13 | - | (1.57) | 0.00 | (5.56) | (5.50) |
| **2025** | - | - | - | - | - | - | - | (0.18) | - | 0.18 | 0.18 |
| **Total from 2011** | **99.82** | | **921.51** | **167.25** | **257.13** | **7.13** | **10.37** | **119.07** | **1.90** | **358.66** | **355.08** |
| | | | | | | | | | **NPV @ 5%** | **251.59** | **249.07** |
| | | | | | | | | | **NPV @ 10%** | **177.28** | **175.51** |
| | | | | | | | | | **NPV @ 20%** | **86.80** | **85.94** |
| | | | | | | | | | **IRR** | **46.97%** | **46.97%** |
| | | | | | | | | | **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2015** | **2015** |

## Rosscarbary Basal Wealden P90 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 99%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2009** | - | - | - | 26.50 | - | - | 0.23 | - | - | (26.73) | (26.46) |
| **2010** | - | - | - | - | - | - | 0.23 | - | - | (0.23) | (0.23) |
| **2011** | - | - | - | 2.35 | 1.47 | - | 0.23 | - | - | (4.05) | (4.01) |
| **2012** | - | - | - | 28.09 | 1.50 | - | 0.24 | - | - | (29.83) | (29.53) |
| **2013** | - | - | - | 153.25 | 1.53 | - | 0.57 | - | - | (155.34) | (153.79) |
| **2014** | 1.10 | 100.09 | 110.11 | - | 64.13 | - | 0.80 | - | - | 45.17 | 44.72 |
| **2015** | 1.21 | 104.14 | 126.06 | - | 66.21 | - | 0.82 | - | - | 59.03 | 58.44 |
| **2016** | 0.97 | 108.34 | 105.20 | - | 66.91 | - | 0.84 | - | - | 37.46 | 37.09 |
| **2017** | 0.78 | 110.60 | 86.08 | - | 65.66 | - | 0.85 | - | - | 19.57 | 19.37 |
| **2018** | 0.62 | 112.71 | 70.44 | - | 65.80 | - | 0.87 | - | - | 3.76 | 3.73 |
| **2019** | 0.50 | 114.97 | 57.63 | - | 56.93 | - | 0.89 | - | - | (0.19) | (0.19) |
| **2020** | - | - | - | - | - | 20.72 | - | - | - | (20.72) | (20.52) |
| **Total from 2011** | **5.19** | | **555.53** | **183.68** | **390.15** | **20.72** | **6.11** | - | - | **(45.13)** | **(44.68)** |
| | | | | | | | | | **NPV @ 5%** | **(52.63)** | **(52.10)** |
| | | | | | | | | | **NPV @ 10%** | **(57.93)** | **(57.35)** |
| | | | | | | | | | **NPV @ 20%** | **(63.57)** | **(62.94)** |
| | | | | | | | | | **IRR** | **n.m** | **n.m** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **0** **0**

## Rosscarbary Basal Wealden P50 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

Oil price case: Base
Gas price case: Base

Landsdowne Share 99%

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.23 | - | - | (0.23) | (0.23) |
| **2011** | - | - | - | 2.35 | 1.47 | - | 0.23 | - | - | (4.05) | (4.01) |
| **2012** | - | - | - | 28.09 | 1.50 | - | 0.24 | - | - | (29.83) | (29.53) |
| **2013** | - | - | - | 189.33 | 1.53 | - | 0.57 | - | - | (191.43) | (189.51) |
| **2014** | 2.24 | 100.09 | 224.26 | - | 72.70 | - | 0.80 | - | - | 150.76 | 149.25 |
| **2015** | 3.84 | 104.14 | 400.02 | - | 85.64 | - | 0.82 | 47.06 | - | 266.50 | 263.83 |
| **2016** | 3.08 | 108.34 | 333.83 | - | 84.04 | - | 0.84 | 61.24 | - | 187.71 | 185.83 |
| **2017** | 2.47 | 110.60 | 273.15 | - | 78.88 | - | 0.85 | 49.74 | 5.38 | 138.30 | 136.92 |
| **2018** | 1.98 | 112.71 | 223.50 | - | 76.73 | - | 0.87 | 37.66 | 2.24 | 106.00 | 104.94 |
| **2019** | 1.59 | 114.97 | 182.88 | - | 58.75 | - | 0.89 | 31.38 | 1.57 | 90.29 | 89.39 |
| **2020** | 1.28 | 117.27 | 149.64 | - | 57.48 | - | 0.90 | 23.61 | 2.21 | 65.43 | 64.78 |
| **2021** | 1.02 | 119.61 | 122.44 | - | 58.62 | - | 0.92 | 16.43 | 1.64 | 44.82 | 44.37 |
| **2022** | 0.82 | 122.00 | 100.18 | - | 62.33 | - | 0.94 | 9.88 | 0.99 | 26.05 | 25.79 |
| **2023** | 0.66 | 124.44 | 81.97 | - | 60.98 | - | 0.96 | 5.43 | 0.54 | 14.06 | 13.92 |
| **2024** | 0.53 | 126.93 | 67.07 | - | 62.20 | - | 0.98 | 1.38 | 0.14 | 2.38 | 2.36 |
| **2025** | - | - | - | - | - | 26.92 | - | (5.29) | 0.01 | (21.64) | (21.43) |
| **2026** | - | - | - | - | - | - | - | (0.60) | - | 0.60 | 0.59 |
| **Total from 2011** | **19.52** | | **2,158.93** | **219.76** | **762.85** | **26.92** | **10.81** | **277.93** | **14.72** | **845.94** | **837.48** |
| | | | | | | | | | **NPV @ 5%** | **613.48** | **607.35** |
| | | | | | | | | | **NPV @ 10%** | **450.83** | **446.32** |
| | | | | | | | | | **NPV @ 20%** | **249.84** | **247.34** |
| | | | | | | | | | **IRR** | **68.76%** | **68.76%** |

**Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** **2015** **2015**

## Rosscarbary Basal Wealden P10 Case Cashflows

All monetary values in money-of-the-day terms
All values are on a gross field (i.e. 100% WI) basis unless specified otherwise
NPV and IRR results are as at 1 January 2011

| | |
|---|---|
| Oil price case: | Base |
| Gas price case: | Base |
| Landsdowne Share | 99% |

| Year | Oil Production MM BBL | Oil realisation US$ / BBL | Revenue US$MM | CAPEX US$MM | OPEX US$MM | Abandonment US$MM | Rentals, fees, etc US$MM | Corporate Tax US$MM | PRRT US$MM | Gross Cashflow US$MM | Lansdowne Share US$MM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | - | - | - | - | - | - | 0.23 | - | - | (0.23) | (0.23) |
| **2011** | - | - | - | 2.35 | 1.47 | - | 0.23 | - | - | (4.05) | (4.01) |
| **2012** | - | - | - | 24.97 | 1.50 | - | 0.24 | - | - | (26.70) | (26.44) |
| **2013** | - | - | - | 329.74 | 1.53 | - | 0.57 | - | - | (331.84) | (328.52) |
| **2014** | 4.09 | 100.09 | 409.78 | - | 85.74 | - | 0.80 | - | - | 323.23 | 320.00 |
| **2015** | 6.33 | 104.14 | 659.29 | - | 103.51 | - | 0.82 | 109.97 | - | 444.99 | 440.54 |
| **2016** | 5.08 | 108.34 | 550.20 | - | 99.79 | - | 0.84 | 113.37 | 6.00 | 330.21 | 326.90 |
| **2017** | 4.07 | 110.50 | 450.19 | - | 90.84 | - | 0.85 | 91.90 | 4.70 | 261.90 | 259.28 |
| **2018** | 3.27 | 112.71 | 368.36 | - | 86.52 | - | 0.87 | 72.18 | 6.77 | 202.02 | 200.00 |
| **2019** | 2.62 | 114.97 | 301.41 | - | 59.97 | - | 0.89 | 61.15 | 6.11 | 173.29 | 171.56 |
| **2020** | 2.10 | 117.27 | 246.62 | - | 57.50 | - | 0.90 | 48.36 | 4.84 | 135.02 | 133.67 |
| **2021** | 1.69 | 119.61 | 201.79 | - | 58.64 | - | 0.92 | 36.71 | 3.67 | 101.85 | 100.83 |
| **2022** | 1.35 | 122.00 | 165.11 | - | 63.61 | - | 0.94 | 26.18 | 2.62 | 71.76 | 71.05 |
| **2023** | 1.09 | 124.44 | 135.10 | - | 60.99 | - | 0.96 | 18.97 | 2.72 | 51.46 | 50.94 |
| **2024** | 0.87 | 126.93 | 110.54 | - | 62.21 | | 0.98 | 12.48 | 1.87 | 33.00 | 32.67 |
| **2025** | 0.70 | 129.47 | 90.45 | - | 67.49 | - | 1.00 | 6.13 | 0.92 | 14.92 | 14.77 |
| **2026** | 0.56 | 132.06 | 74.01 | - | 64.71 | - | 1.02 | 2.41 | 0.36 | 5.50 | 5.45 |
| **2027** | - | - | - | - | - | 49.01 | - | (6.60) | 0.03 | (42.44) | (42.02) |
| **2028** | - | - | - | - | - | - | - | (0.76) | - | 0.76 | 0.75 |
| **Total from 2011** | **33.83** | | **3,762.85** | **357.05** | **966.00** | **49.01** | **12.83** | **592.46** | **40.61** | **1,744.88** | **1,727.43** |

| | Gross Cashflow | Lansdowne Share |
|---|---|---|
| **NPV @ 5%** | **1,258.62** | **1,246.03** |
| **NPV @ 10%** | **925.39** | **916.14** |
| **NPV @ 20%** | **522.39** | **517.17** |
| **IRR** | **85.17%** | **85.17%** |
| **Nominal cashflow breakeven year full-cycle (0 means breakeven not achieved)** | **2015** | **2015** |