THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the contents of this document or as to the action you should take, you are recommended to seek your own personal financial advice immediately from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser authorised under the Financial Services and Markets Act 2000 (as amended), who specialises in advising on the acquisition of shares and other securities.

If you have sold or transferred your Existing Unconsolidated Ordinary Shares you should send this document, along with the Form of Proxy, at once to the purchaser or transferee or the stockholder or other agent through whom the sale or transfer was effected for transmission to the purchaser or transferee. However, the foregoing documents must not be distributed, forwarded or transmitted in or into any Restricted Jurisdiction. If you have sold or transferred only part of your holding of Existing Unconsolidated Ordinary Shares you should retain these documents and consult the stockbroker, bank or other agent through whom the sale or transfer was effected.

This document, which comprises an AIM admission document drawn up in accordance with the AIM Rules, has been issued in connection with the application for admission to trading of the Enlarged Share Capital on AIM. This document contains no offer to the public within the meaning of section 102B of FSMA, the Act or otherwise. Accordingly, this document does not comprise a prospectus within the meaning of section 85 of FSMA and has not been drawn up in accordance with the Prospectus Rules or approved by or filed with the Financial Services Authority or any other competent authority.

Application will be made for the Enlarged Share Capital to be admitted to trading on AIM, a market operated by the London Stock Exchange. AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies. AIM securities are not admitted to the Official List of the UK Listing Authority. A prospective investor should be aware of the risks of investing in such companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser. Each AIM company is required pursuant to the AIM Rules for Companies to have a nominated adviser. The nominated adviser is required to make a declaration to the London Stock Exchange on Admission in the form set out in Schedule Two to the AIM Rules for Nominated Advisers. The London Stock Exchange has not itself examined or approved the contents of this document.

The Company, its Directors and the Proposed Directors (whose names and functions appear in paragraph 13 of Part I of this document) accept responsibility for the information contained in this document and for compliance with the AIM Rules for Companies. To the best of the knowledge of the Company, the Directors and the Proposed Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and contains no omission likely to affect its import.

The whole of this document should be read. Attention is drawn in particular to the "Risk Factors" set out in Part IV of this document.

BAYFIELD ENERGY HOLDINGS PLC

(Incorporated and registered in England and Wales under the Companies Act 2006 with registered number 07535869)

Proposed merger with Trinity Exploration & Production Limited

Proposed 1 for 10 Share Consolidation

Proposed placing of 47,500,000 new Consolidated Ordinary Shares at 120p per share

Proposed change of name to Trinity Exploration & Production plc

Admission of the Enlarged Share Capital to trading on AIM

Notice of General Meeting

Nominated Adviser & Joint Broker	*Co-lead Manager, Joint Broker & Financial Adviser*	*Financial Adviser to Trinity and Joint Bookrunner*	*Joint Bookrunner*
Seymour Pierce	**FirstEnergy Capital LLP**	**RBC Capital Markets**	**Jefferies International Limited**

The Placing Shares and the Consideration Shares will rank pari passu in all respects with the Consolidated Ordinary Shares and will rank in full for all dividends or other distributions declared, made or paid on the Consolidated Ordinary Shares after Admission. It is expected that Admission will take place and that trading in the Consolidated Ordinary Shares will commence on AIM on 14 February 2013.

Seymour Pierce Limited ("Seymour Pierce"), which is authorised and regulated in the United Kingdom by the Financial Services Authority, is acting, up to Admission, as nominated adviser and joint broker to the Company in connection with the Proposals and will not be acting for any other person or otherwise be responsible to any person for providing the protections afforded to customers of Seymour Pierce or for advising any other person in respect of the Proposals. Seymour Pierce's responsibilities as the Company's nominated adviser under the AIM Rules are owed solely to the London Stock Exchange and are not owed to the Company or to any Director, Proposed Director or to any other person in respect of such person's decision to acquire shares in the Company in reliance on any part of this document. Seymour Pierce has not authorised the contents of any part of this document and neither accepts liability for the accuracy of any information or opinions contained in this document nor for the omission of any material information from this document for which the Company, the Directors and Proposed Directors are responsible. No representation or warranty, express or implied, is made by Seymour Pierce as to any of the contents of this document (without limiting the statutory rights of any person to whom this document is issued).

FirstEnergy Capital LLP ("FirstEnergy"), which is authorised and regulated in the United Kingdom by the Financial Services Authority, is acting as financial adviser and co-lead manager and, up to Admission, joint broker to the Company in connection with the Proposals and will not be acting for any other person or otherwise be responsible to any person for providing the protections afforded to customers of FirstEnergy or for advising any other person in respect of the Proposals. FirstEnergy has not authorised the contents of any part of this document and neither accepts liability for the accuracy of any information or opinions contained in this document nor for the omission of any material information from this document for which the Company, the Directors and Proposed Directors are responsible. No representation or warranty, express or implied, is made by FirstEnergy as to any of the contents of this document (without limiting the statutory rights of any person to whom this document is issued).

RBC Europe Limited (trading as RBC Capital Markets) ("RBC"), which is authorised and regulated in the United Kingdom by the Financial Services Authority, is acting as financial adviser to Trinity in connection with the Proposals and joint bookrunner to the Company in connection with the Placing and will not be acting for any other person or otherwise be responsible to any person for providing the protections afforded to customers of RBC or for advising any other person in respect of the Proposals. RBC has not authorised the contents of any part of this document and neither accepts liability for the accuracy of any information or opinions contained in this document nor for the omission of any material information from this document for which the Company, the Directors and Proposed Directors are responsible. No representation or warranty, express or implied, is made by RBC as to any of the contents of this document (without limiting the statutory rights of any person to whom this document is issued).

Jefferies International Limited ("Jefferies"), which is authorised and regulated in the United Kingdom by the Financial Services Authority, is acting as joint bookrunner to the Company in connection with the Placing and will not be acting for any other person or otherwise be responsible to any person for providing the protections afforded to customers of Jefferies or for advising any other person in respect of the Proposals. Jefferies has not authorised the contents of any part of this document and neither accepts liability for the accuracy of any information or opinions contained in this document nor for the omission of any material information from this document for which the Company, the Directors and Proposed Directors are responsible. No representation or warranty, express or implied, is made by Jefferies as to any of the contents of this document (without limiting the statutory rights of any person to whom this document is issued).

Notice to prospective investors in Switzerland

This document is being made available in Switzerland to a limited circle of selected investors only. Such prospective investors will be individually approached by the Company in the context of the Placing from time to time. The Placing Shares are not being offered to the public in or from Switzerland, and neither this document, nor any other offering materials relating to the Placing Shares may be distributed in connection with any such public offering. This document does not constitute an issuance prospectus within the meaning of Article 652a of the Swiss Code of Obligations. Each copy of this document is addressed in Switzerland to a specifically named recipient and shall not be passed on to a third party.

Notice to prospective investors in France

This document is being made available in France to qualified investors and a restricted circle of investors only and accordingly, and pursuant to Article 211-3 of the General Regulation of the Autorité des Marchés Financiers ("AMF"), the attention of potential investors is drawn to the following:

- the offering is not subject to the requirement of a prospectus to be submitted to the AMF for approval ;
- the offering is addressed exclusively to the persons or entities referred to in II 2° of Article L. 411-2 of the financial and monetary code (qualified investors and restricted circle of investors), who may only take part in the offering acting for their own account in accordance with Articles D. 411-1, D. 734-1, D. 744-1, D. 754-1 and D. 764-1 of the financial and monetary code; and
- any securities acquired in the context of this offering may not subsequently be distributed to the public in France, either directly or indirectly, other than in accordance with Articles L. 411-1, L. 411-2, L. 412-1 and L. 621-8 to L. 621-8-3 of the financial and monetary code.

The Company draws the attention of potential investors to the fact that this communication is not a recommendation to sell or purchase any investment.

Notice to prospective investors in Trinidad and Tobago

Disclosure as to purpose of document and limitation on circulation:

This document has been prepared by the Company solely for use in connection with the proposed offering of the Placing Shares described in this document.

These Placing Shares will be or have been issued in Trinidad and Tobago on a limited offering basis exempt from registration under the Securities Act, 2012 of the laws of Trinidad and Tobago (the "Securities Act") and may not be offered, resold, distributed or otherwise transferred to a person in Trinidad and Tobago if such offer, resale, distribution or transfer would cause or require the Placing Shares or the Company to be registered with the Trinidad and Tobago Securities & Exchange Commission in accordance with the Securities Act.

This document is personal to each offeree and does not constitute an offer to any other person or to the public generally to subscribe for or otherwise acquire securities. Distribution of this document to any other person other than the prospective investor and any person retained to advise such prospective investor with respect to its purchase is unauthorized, and any disclosure of any of its contents, without the Company's prior written consent, is prohibited. Each prospective investor, by accepting delivery of this document, agrees to the foregoing and to make no photocopies of this document or any documents referred to in this document.

The Company has not authorised the making or provision of any representation or information regarding the Company or the Placing Shares to any person other than as contained in this document. Any such representation or information should not be relied upon as having been authorised by the Company or any of its affiliates. Neither the delivery of this document nor the offering, sale nor delivery of any Placing Shares shall under any circumstances imply that there has been no change in the business, results of operations, financial condition or prospects of the Company since the date of this document.

Absence of evaluation of security:

The Trinidad and Tobago Securities and Exchange Commission has not in any way evaluated the merits of the Placing Shares distributed hereunder and any representation to the contrary is an offence.

Restrictions on the transferability of the securities:

The Placing Shares are subject to restrictions on transferability and resale and may not be transferred or resold except as permitted under the Securities Act and other applicable securities laws in Trinidad and Tobago. The Placing Shares will be subject to restrictions on resale and transfer as described below under "Transfer Restrictions". By purchasing any Placing Shares, you will be deemed to have represented and warranted that to the effect set forth in, and agreed to, all the provisions contained in that section of this document.

Consultation with advisors:

In making an investment decision, prospective investors must rely on their own examination of the Placing Shares and the terms of the offering, including the merits and risks involved. Prospective investors should not construe anything in this document as legal, business or tax advice. Each prospective investor should consult its own advisors as needed to make its investment decision and to determine whether it is legally permitted to purchase the Placing Shares under applicable legal investment or similar laws or regulations.

Availability of further documentation:

This document contains summaries believed to be accurate with respect to certain documents, but reference is made to the actual documents for complete information. All such summaries are qualified in their entirety by such reference. Copies of certain documents referred to herein will be made available to prospective investors upon request to the Company.

Transfer restrictions:

The terms 'limited offering' 'distribution', 'offer to sell', 'reporting issuer', 'prospectus', 'sale', and 'accredited investor' shall bear the same meanings as are assigned to them in the Securities Act.

The Placing Shares shall be offered to accredited investors not exceeding thirty-four (34) persons in the aggregate in accordance with Section 79(1)(m) of the Securities Act and shall be followed by a statement to the TTSEC of such distribution within ten (10) days of same or within ten (10) days of the first distribution if distribution is completed over a period exceeding ten (10) days. The distribution of the Placing Shares shall not be accompanied by an advertisement other than an announcement of its completion as prescribed by the TTSEC and no selling or promotional expenses shall be paid or incurred in connection with the distribution except for professional services or services performed by the Company.

Pursuant to Section 79(1) of the Securities Act, the Company is exempt from filing a prospectus with the TTSEC.

Unless a proposed sale or distribution of the Placing Shares by a purchaser is exempt from registration under the Securities Act, no purchaser may distribute or offer to sell any Placing Shares without the prior written consent of the Company. The Company shall not give its consent to a purchaser to distribute or offer to sell a Placing Share if such distribution or offer for sale would result in the Company having to comply with Section 73 of the Securities Act.

No purchaser may distribute or offer to sell any Placing Shares if such distribution or offer for sale will result in the purchaser of the Placing Shares not being an accredited investor or the number of holders to exceed thirty-four accredited investors in aggregate.

Each purchaser of the Placing Shares offered and sold in Trinidad and Tobago will be deemed to have represented and agreed as follows: the purchaser (i) is an accredited investor, (ii) is aware that the sale to it is being made in accordance with Section 79(1)(m) of the Securities Act and (iii) is acquiring such Placing Shares for its own account or for the account of an accredited investor.

Each purchaser understands and acknowledges that the Placing Shares are being offered in a transaction involving a limited offering in Trinidad and Tobago within the meaning of the Securities Act, that the Placing Shares have not been, and except as described in the prospectus, will not be registered under the Securities Act or any other applicable securities law and may not be offered, sold or otherwise transferred in Trinidad and Tobago unless exempt from registration under the Securities Act or any other applicable securities law. By acquiring the Placing Shares, each purchaser agrees that (A) if in the future the purchaser decides to offer, resell, pledge or otherwise transfer any of the Placing Shares, such Placing Shares may only be offered, sold, pledged or otherwise transferred pursuant to an exemption from registration and from the filing of a prospectus under the Securities Act, and (B) the purchaser will, and will require each subsequent holder to, notify any subsequent purchaser of such Placing Shares from it of the resale restrictions referred to in (A) above.

Notice to prospective investors in the US

The Placing Shares have not been, and will not be, registered under the United States Securities Act of 1933, as amended (the "US Securities Act") and, subject to certain exceptions, may not be directly or indirectly offered, sold, delivered or transferred into or within the United States. This document is not for distribution in or into the United States and does not constitute an offer to sell, or the solicitation of an offer to buy any Placing Shares in the United States. The Placing Shares will be offered and sold outside the United States in reliance on Regulation S under the US Securities Act and in the United States to certain accredited investors (as defined in Regulation D under the US Securities Act) in reliance on an exemption from the registration requirements of the US Securities Act. The Placing Shares have not been approved or disapproved by the United States Securities and Exchange Commission, any state securities commission in the United States or any other regulatory authority in the United States, nor have any of the foregoing authorities passed upon or endorsed the merit of the offer of the Placing Shares or the accuracy or adequacy of this document. Any representation to the contrary is a criminal offence in the United States.

Notice to prospective investors in Canada

The information contained herein is not, and under no circumstances is to be construed as, a prospectus, an advertisement, a public offering, an offer to sell the Placing Shares described herein, solicitation of an offer to buy the Placing Shares described herein, in Canada or any province or territory thereof. Any offer or sale of the Placing Shares described herein in Canada will be made only under an exemption from the requirements to file a prospectus with the relevant Canadian securities regulators and only by a dealer properly registered under applicable securities laws or, alternatively, pursuant to an exemption from the dealer registration requirement in the relevant province or territory of Canada in which such offer or sale is made. Under no circumstances is the information contained herein to be construed as investment advice in any province or territory of Canada and is not tailored to the needs of the recipient. No securities commission or similar regulatory authority in Canada has reviewed or in any way passed upon these materials, the information contained herein or the merits of the Placing Shares described herein and any representation to the contrary is an offence.

Purchasers' rights

The following statutory rights of action for damages or rescission will only apply to a purchase of securities of the Company in the event that this document is deemed to be an offering memorandum pursuant to applicable securities legislation in the Province of

Ontario. These remedies, or notice with respect thereto, must be exercised, or delivered, as the case may be, by the purchaser within the time limits prescribed by the applicable provisions of such provincial securities legislation. Purchasers should refer to such applicable securities legislation for the complete text of these rights or consult with a legal adviser. Where used in this section, "misrepresentation" means an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made.

Ontario

Securities legislation in Ontario provides that when an offering memorandum is delivered to an investor to whom securities are distributed in reliance upon the "accredited investor" prospectus exemption provided in Section 2.3 of National Instrument 45-106—Prospectus and Registration Exemptions (the "Accredited Investor Exemption"), the right of action described below is applicable, unless the prospective purchaser is: (a) an association governed by the Cooperative Credit Associations Act (Canada) or a central cooperative credit society for which an order has been made under Section 473(1) of that Act; (b) a bank, loan corporation, trust company, trust corporation, insurance company, treasury branch, credit union, caisse populaire, financial services corporation, or league that, in each case, is authorized by an enactment of Canada or a jurisdiction of Canada to carry on business in Canada or a jurisdiction in Canada; (c) a Schedule III bank, meaning an authorized foreign bank named in Schedule III of the Bank Act (Canada); (d) the Business Development Bank of Canada incorporated under the Business Development Bank of Canada Act (Canada); or (e) a subsidiary of any person referred to in paragraphs (a), (b), (c) or (d), if the person owns all of the voting securities of the subsidiary, except the voting securities required by law to be owned by the directors of the subsidiary.

Where an offering memorandum that contains a misrepresentation is delivered in connection with a trade made in reliance on the Accredited Investor Exemption or certain other exemptions available under applicable securities legislation in Ontario, a purchaser who purchases a security offered by the offering memorandum during the period of distribution will have, without regard to whether the purchaser relied on the misrepresentation, a statutory right of action for damages against the issuer and a selling security holder on whose behalf the distribution was made or, while still the owner of securities against the issuer or selling security holder on whose behalf the distribution was made for rescission. If the purchaser elects to exercise the right of rescission, the purchaser will have no right of action for damages. The right of action will be exercisable by the purchaser only if the purchaser commences the action, in the case of any action for rescission, not more than 180 days after the date of the transaction that gave rise to the cause of action and in the case of any action, other than an action for rescission, before the earlier of: (i) 180 days after the plaintiff first had knowledge of the facts giving rise to the cause of action, or (ii) three years after the date of the transaction that gave rise to the cause of action.

A defendant shall not be liable for a misrepresentation if it proves that the purchaser purchased the securities with knowledge of the misrepresentation. In an action for damages, the defendant shall not be liable for all or any portion of the damages that the defendant proves do not represent the depreciation in value of the securities as a result of the misrepresentation relied upon. In no case shall the amount recoverable for the misrepresentation that exceeds the price at which the securities were offered.

Disclosure provided herein in respect of barrel of oil equivalent (boe) may be misleading, particularly in isolation. Where amounts are expressed on a boe basis, natural gas volumes have been converted to a boe at a ratio of 6,000 cubic feet of natural gas to one boe. This conversion ratio is based upon an energy equivalent conversion method primarily applicable at the burner tip and does not represent value equivalence at the wellhead. Information relating to Reserves is deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions about the profitable production of the Reserves described. All Reserve and Resource data disclosed in this document (including the Trinity CPR and the Bayfield CPR) is not prepared in compliance with the Canadian National Instrument NI 51-101.

Notice to other investors

This document does not constitute an offer to sell, or a solicitation of an offer to buy, Placing Shares in any jurisdiction in which such offer or solicitation is unlawful. In particular, this document is not for public distribution in Republic of South Africa, Australia or Japan. The Placing Shares have not been and will not be registered or qualified for distribution to the public under the securities legislation of any province or territory of Republic of South Africa, Australia or Japan or in any country, territory or jurisdiction where to do so may contravene local securities law or regulations. Accordingly, the Placing Shares may not, subject to certain exemption, be offered or sold directly or indirectly in or into South Africa, Australia or Japan.

The distribution of this document in certain jurisdictions may be restricted by law and therefore persons into whose possession this document comes should inform themselves about and observe any such restriction. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction.

Notice convening a general meeting of Bayfield to be held at the offices of Ashurst LLP, Broadwalk House, 5 Appold Street, London EC2A 2HA at 1.00 p.m. on 13 February 2013 is set out at the end of this document. The enclosed Form of Proxy for use at the General Meeting should be completed and returned to Capita Registrars, PXS, 34 Beckenham Road, Beckenham, Kent BR3 4TU as soon as possible and to be valid must arrive no later than 1.00 p.m. on 11 February 2013. Completion and return of Forms of Proxy will not preclude Shareholders from attending and voting at the General Meeting should they so wish. Alternatively, eligible Shareholders may use the CREST Proxy Voting Service, details in respect of which are contained in the notice of General Meeting.

Copies of this document will be available free of charge during normal business hours on any weekday (except Saturdays, Sundays and public holidays) from the Company's registered office from the date of this document until the date which is one month from the date of Admission. A copy of this document will also be available from the Company's website—www.bayfieldenergy.com (up to Admission) or www.trinityexploration.com (following Admission).

CONTENTS

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FORWARD LOOKING STATEMENTS

This document includes statements that are, or may be deemed to be, "forward-looking statements". These forward-looking statements can be identified by the use of forward-looking terminology, including the terms "believes", "envisages", "estimates", "anticipates", "projects", "expects", "intends", "may", "will", "could", "seeks" or "should" or, in each case, their negative or other variations or comparable terminology, or by discussions of strategy, plans, objectives, goals, future events or intentions. These forward-looking statements include matters that are not historical facts. They appear in a number of places throughout this document and include statements regarding the Company's, the Directors' and the Proposed Directors' current intentions, beliefs or expectations concerning, amongst other things, investment strategy, financing strategy, performance, results of operations, financial condition, liquidity, prospects, growth, strategies and the industry in which the Enlarged Group will operate.

By their nature, forward-looking statements involve risks (including unknown risks) and uncertainties because they relate to events and depend on circumstances that may or may not occur in the future. Forward-looking statements are not an assurance of future performance. The Company's actual performance, results of operations, financial condition, liquidity and dividend policy and the development of the business sector in which the Enlarged Group will operate, may differ materially from those suggested by the forward-looking statements contained in this document. In addition, even if the Company's performance, results of operations, financial condition, liquidity and dividend policy and the development of the industry in which the Enlarged Group will operate, are consistent with the forward-looking statements contained in this document, those results or developments may not be indicative of results or developments in subsequent periods.

Prospective investors are advised to read this entire document, including Part IV entitled "Risk Factors", for a more complete discussion of the factors that could affect the Company's future performance and the industry in which the Enlarged Group will operate. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements in this document may or may not occur.

Any forward-looking statements in this document reflect the Company's, the Directors' and the Proposed Directors' current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the matters referred to above. Prospective investors should specifically consider the factors identified in this document which could cause actual results to differ before making an investment decision. Other than in accordance with the Company's obligations under the AIM Rules for Companies, neither the Company nor Seymour Pierce nor FirstEnergy nor RBC nor Jefferies undertakes any obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Neither the forward-looking statements nor the underlying assumptions have been verified or audited by any third party.

SOURCES

Information in Parts II and III pertaining to the petroleum assets in which the Enlarged Group will be interested is derived from the Trinity CPR and Bayfield CPR which are included in their entirety in Parts V and VI of this document. While the information in Parts II and III provides a summary of certain aspects of the Trinity CPR and the Bayfield CPR, such reports include further details, as well as various assumptions and qualifications and should therefore be read in their entirety.

Various market data and forecasts used in this document have been obtained from independent industry sources. Neither the Company nor Seymour Pierce nor FirstEnergy nor RBC nor Jefferies has verified the data, statistics or information obtained from these sources and cannot give any guarantee of the accuracy or completeness of the data. Forecasts and other forward-looking information obtained from these sources are subject to the same qualifications, risks and uncertainties as above.

Various figures and percentages in tables in this document have been rounded and accordingly may not total. Certain financial data has also been rounded. As a result of this rounding, the totals of data presented in this document may vary slightly from the actual arithmetical totals of such data.

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

EXCHANGE RATES

All references to US$ are to US Dollars, £ are to UK Pounds Sterling and TT$ to Trinidad and Tobago Dollars. Unless otherwise stated, the rates of exchange of US$1.00 = £0.63 and US$1.00 = TT$6.41 have been used for the purposes of this document.

RESERVES AND RESOURCES

Unless otherwise stated, references in this document to Reserves are on a 2P basis, to Contingent Resources are on a 2C basis and to Prospective Resources are on a "best" estimate basis. Unless otherwise stated, references in this document to net Resources, net Contingent Resources or net Prospective Resources are based on the WI share before the deduction of government royalty and Petrotrin over-riding royalty.

Where amounts are expressed on a boe basis, the Directors and the Proposed Directors have converted natural gas volumes to boe at a ratio of 6,000 cubic feet of natural gas to one boe.

All Reserve and Resource data disclosed in this document (including the Trinity CPR and the Bayfield CPR) is not prepared in compliance with the Canadian National Instrument NI 51-101.

OVERVIEW

This summary is intended solely as an introduction to this document. Any decision to invest in Existing Unconsolidated Ordinary Shares or Consolidated Ordinary Shares should be based on consideration of this document as a whole. Attention is drawn in particular to the section headed "Risk Factors" set out in Part IV of this document.

- On 15 October 2012 Bayfield Energy Holdings PLC ("**Bayfield**") announced it had reached a conditional agreement with approximately 77 per cent. of the shareholders of Trinity Exploration & Production Limited ("**Trinity**") to merge with Trinity, with the enlarged group proposed to be renamed Trinity Exploration & Production plc (the "**Enlarged Group**"). Bayfield has since conditionally agreed to acquire 100 per cent. of Trinity's issued and to be issued share capital.
- The Enlarged Group intends to seek admission to trading on AIM and has conditionally raised gross proceeds of £57 million (approximately US$90 million) through the issue of the Placing Shares pursuant to the Placing.
- The Enlarged Group will be led by Bruce Dingwall CBE (current Chairman of Trinity) and Joel "Monty" Pemberton (current Chief Executive Officer of Trinity). The proposed Board and executive team of the Enlarged Group will have an exceptional track record of building businesses of scale and creating value for investors in the E&P sector.
- The Enlarged Group's initial focus will be on Trinidad, which is a prolific hydrocarbon province that has been under-exploited and offers significant growth opportunities.
- The Enlarged Group will be the leading Trinidad focused independent exploration and production company, with a diverse portfolio of assets both offshore Trinidad's East and West coasts and also onshore. The Enlarged Group will operate all of its assets, allowing it to control its work programme and capital budget.
- The Enlarged Group's management and operating team will be based in Trinidad and will have a deep understanding of the local operating environment and business culture including strong government, supply chain and other stakeholder relationships.
- The Enlarged Group will have current production of approximately 3,965 bbl/d (net) (100 per cent. oil).
- As of 30 June 2012, the Enlarged Group had 2P Reserves of 31 MMBbl (net) (100 per cent. oil) and 2C Contingent Resources of 38 MMboe (net) (89 per cent. oil).
- The Enlarged Group will pursue an active exploration programme with six offshore exploration wells proposed to be drilled during 2013 and 2014 targeting net unrisked best estimate Prospective Resources of 46 MMboe, based on the Directors' estimates. The prospects proposed to be drilled are located close to the Enlarged Group's operated infrastructure, allowing for rapid commercialisation upon success.
- The Enlarged Group Board and management will own 21.61 per cent. of the Enlarged Share Capital and therefore their interests will be well aligned with those of other Shareholders.
- The Enlarged Group will also hold a three year exploration licence over the Pletmos Inshore Block in South Africa. The block is situated off the south coast of South Africa covering an area of approximately 10,800 km^2 and is estimated to contain gross unrisked best estimate Prospective Resources of 2.7 TCF. This asset is not expected to be a core area of focus for the Enlarged Group, but offers the potential to add value.
- The Enlarged Group will seek to grow its portfolio through mergers and acquisition opportunities and new licensing rounds with onshore, offshore and deepwater bid rounds expected in Trinidad in 2013.
- Following the Placing the Enlarged Group will be fully funded to fulfil its existing licence obligations. The Enlarged Group's assets are expected to generate strong cash flows and the business is expected to be self-financing by the end of 2013.
- The estimated net proceeds of the Placing of £50 million (approximately US$78 million) will be used to accelerate the delivery of what the Directors and Proposed Directors believe to be significant upside that exists in the combined portfolio.

SHARE CAPITAL AND PLACING STATISTICS[1]

Placing Price	120 pence
Number of Existing Unconsolidated Ordinary Shares in issue at date of this document prior to the Share Consolidation[2]	216,479,450
Basis of the Share Consolidation	1 new Consolidated Ordinary Share for every 10 Existing Unconsolidated Ordinary Shares
Number of Consolidated Ordinary Shares in issue immediately after the Share Consolidation and prior to the issue of the Placing Shares and the Consideration Shares	21,647,945
Number of Placing Shares[3]	47,500,000
Number of Consideration Shares	25,652,041
Number of Consolidated Ordinary Shares in issue at Admission	94,799,986
Estimated gross proceeds of the Placing	£57 million
Estimated net proceeds of the Placing receivable by the Company	£50 million
Percentage of Enlarged Share Capital represented by the Placing Shares	50.11 per cent
Percentage of Enlarged Share Capital represented by the Consideration Shares	27.06 per cent
Market capitalisation of the Company at the Placing Price on Admission	£114 million
ISIN number	GB00B8JG4R91
SEDOL number	B8JG4R9
New TIDM	TRIN

EXPECTED TIMETABLE OF PRINCIPAL EVENTS[4]

Publication of this document	25 January 2013
Latest time and date for receipt of Forms of Proxy	1.00 p.m. on 11 February 2013
General Meeting	1.00 p.m. on 13 February 2013
Record date for the Share Consolidation	6.00 p.m. on 13 February 2013
Completion of the Merger	8.00 a.m. on 14 February 2013
Expected date of Admission and dealings in the Enlarged Share Capital expected to commence on AIM	8.00 a.m. on 14 February 2013
CREST accounts credited in respect of the Placing Shares by	14 February 2013
Despatch of definitive share certificates in respect of the Placing Shares, Consideration Shares and Consolidated Ordinary Shares (where applicable) by	28 February 2013

Notes:

1 All Share Capital and Placing Statistics set out above and in the rest of this document assume (unless stated otherwise or the context otherwise requires) that the Resolution to approve the Share Consolidation is duly passed by Bayfield Shareholders at the General Meeting.

2 The number of Existing Unconsolidated Ordinary Shares includes eight Existing Unconsolidated Ordinary Shares intended to be issued after the date of this document and prior to Admission.

3 This comprises 45,199,000 Placing Shares to be issued pursuant to the Placing Agreement and 2,301,000 Placing Shares to be issued pursuant to the Company Direct Placing.

4 Each of the above dates is subject to change at the absolute discretion of the Company. Any such change will be notified to Bayfield Shareholders by an announcement on a Regulatory Information Service.

DIRECTORS, SECRETARY AND ADVISERS

Directors	Finian Rory O'Sullivan *(Executive Chairman)* Hywel Rhys Richard John *(Chief Executive Officer)* Andrey Ilich Pannikov *(Non-Executive Director)* Jonathan Gervaise Fitzpatrick Cooke *(Independent Non-Executive Director)* David Archibald MacFarlane *(Independent Non-Executive Director)* *whose business address is at the Company's registered office:* Fourth Floor Burdett House 15-16 Buckingham Street London WC2N 6DU United Kingdom
Proposed Directors following completion of the Merger	Bruce Alan Ian Dingwall (*Executive Chairman*) Joel Montgomery Pemberton (*Chief Executive Officer*) Jonathan David Murphy (*Non-Executive Director*) Charles Anthony Brash Junior (*Non-Executive Director*) Ronald Harford (*Independent Non-Executive Director*) *whose business address is:* c/o Pinsent Masons LLP 13 Queen's Road Aberdeen AB15 4YL United Kingdom
Company Website up to Admission	www.bayfieldenergy.com
Trinity Website and Company Website following Admission	www.trinityexploration.com
Company Secretary	Amanda Bateman AMBA Company Secretarial Services Limited 12 Clifton Park Road Caversham Reading Berkshire RG4 7PD United Kingdom
Nominated Adviser and Joint Broker to the Company, up to Admission	Seymour Pierce Limited 20 Old Bailey London EC4M 7EN United Kingdom
Co-lead Manager in connection with the Placing and, up to Admission, Joint Broker to the Company	FirstEnergy Capital LLP 85 London Wall London EC2M 7AD United Kingdom
Financial Adviser to Trinity and Joint Bookrunner to the Company in connection with the Placing and, from Admission, Nominated Adviser and Joint Broker to the Company	RBC Europe Limited (trading as RBC Capital Markets) Riverbank House 2 Swan Lane London EC4R 3BF

Joint Bookrunner in connection with the Placing and, from Admission, Joint Broker to the Company	Jefferies International Limited Vintners Place 68 Upper Thames Street London EC4V 3BJ United Kingdom
Solicitors to the Company as to English Law	Ashurst LLP Broadwalk House 5 Appold Street London EC2A 2HA United Kingdom
Solicitors to Trinity as to English law	Pinsent Masons LLP 1 Earl Grey Street Edinburgh EH3 9AQ United Kingdom
Legal Advisers to the Company as to Trinidadian Law	M. Hamel-Smith & Co. Eleven Albion Cor. Dere & Albion Streets Port-of-Spain Trinidad and Tobago
Legal Advisers to Trinity as to Trinidadian Law	Johnson, Camacho & Singh First Floor Briar Place 10 Sweet Briar Road St Clair Trinidad and Tobago
Legal Advisers to the Company as to South African Law	Norton Rose South Africa 10th Floor Norton Rose House 8 Riebeek Street Cape Town 8001 South Africa
Solicitors to RBC, Jefferies, FirstEnergy and the Nominated Adviser	Nabarro LLP Lacon House 84 Theobald's Road London WC1X 8RW United Kingdom
Auditors to the Company	Deloitte LLP 2 New Street Square London EC4A 3BZ United Kingdom
Reporting Accountants	PricewaterhouseCoopers LLP 32 Albyn Place Aberdeen AB10 1YL United Kingdom
Bayfield Competent Person	Gaffney, Cline & Associates Ltd Bentley Hall Blacknest Alton Hampshire GU34 4PU United Kingdom

Trinity Competent Person	RPS Energy Consultants Limited Centurion Court 85 Milton Park Abingdon Oxfordshire OX14 4RY United Kingdom
Registrar	Capita Registrars Limited The Registry 34 Beckenham Road Beckenham Kent BR3 4TU United Kingdom
Financial Public Relations Adviser to Bayfield	M: Communications Limited CityPoint 11th Floor 1 Ropemaker Street London EC2Y 9AW United Kingdom
Financial Public Relations Adviser to Trinity and, from Admission, to the Company	Brunswick 16 Lincolns Inn Fields London WC2A 3ED United Kingdom

PART I

LETTER FROM THE CHAIRMAN OF BAYFIELD

Bayfield Energy Holdings PLC

(*Registered in England and Wales No. 07535869*)

Directors:	*Registered Office:*
Finian O'Sullivan (*Executive Chairman*)	Fourth Floor
Hywel John (*Chief Executive Officer*)	Burdett House
Andrey Pannikov (*Non-Executive Director*)	15-16 Buckingham Street
Jonathan Cooke (*Independent Non-Executive Director*)	London WC2N 6DU
David MacFarlane (*Independent Non-Executive Director*)	United Kingdom

25 January 2013

To Shareholders and, for information only, to holders of Options

Dear Shareholder

1. **Introduction**

On 15 October 2012 the Company announced that it had reached agreement on the terms of a conditional merger of Bayfield and Trinity. Bayfield has conditionally agreed to acquire 100 per cent. of Trinity's issued and to be issued share capital. It is proposed that the Company's name be changed to "Trinity Exploration & Production plc" and that the Company's existing issued ordinary shares of US$0.10 each will be consolidated on a one for ten basis so as to result in Consolidated Ordinary Shares of US$1.00 each in the capital of the Company. Trinity Shareholders will receive approximately 747.8 new Consolidated Ordinary Shares for each Trinity Share resulting in the issue by Bayfield, credited as fully paid, of approximately 25,652,041 new Consolidated Ordinary Shares to the current shareholders of Trinity pursuant to the Merger. Following the Merger (and prior to the Placing referred to below and on the basis that Centrica will not convert its Centrica Loan Notes which are referred to below), on a fully diluted basis Legacy Trinity Shareholders will own approximately 55 per cent. of the Enlarged Group and Legacy Bayfield Shareholders will own approximately 45 per cent. of the Enlarged Group.

Upon completion of the Merger, the Enlarged Group will be the largest Trinidad focused independent E&P company. The Enlarged Group will have a diversified portfolio with 11 operated fields including assets onshore and offshore both the East and West coasts of Trinidad. The Enlarged Group will have 2P Reserves of 31 MMbbl (net) and Contingent Resources of 38 MMboe (net) based on the Directors' calculation of gas in terms of boe. Currently, the Enlarged Group is producing approximately 4,855 bbl/d (gross) and approximately 3,965 bbl/d (net) (100 per cent. oil). In addition, the Enlarged Group will hold an exploration licence over the Pletmos Inshore Block in South Africa.

The Company has also announced today that it has conditionally raised £57 million (approximately US$90 million) before expenses by way of a placing of 47,500,000 new Consolidated Ordinary Shares at a price of 120 pence per Consolidated Ordinary Share. RBC and Jefferies are acting as joint bookrunners, and FirstEnergy is acting as co-lead manager, in connection with the Placing (in each case other than in respect of the Placing Shares which are the subject of the Company Direct Placing).

The proceeds of the Placing are proposed to be used to accelerate delivery of what the Directors and Proposed Directors believe to be significant upside that exists in the combined portfolio. The work programme of the Enlarged Group contemplates drilling 14 offshore development wells, 27 onshore development wells and six offshore exploration wells during 2013 and 2014. In aggregate, this programme is expected to deliver production growth to 5,000 bbl/d (net) by the end of 2013 and expose investors to unrisked net best estimate Prospective Resources of 46 MMboe, according to the Directors' and Proposed Directors' estimates. The exploration programme is focused on prospects located near to the Enlarged Group's operated production infrastructure allowing for rapid commercialisation upon success.

The Enlarged Group will be led by Bruce Dingwall (as Executive Chairman) and Monty Pemberton (as Chief Executive Officer). Bruce and Monty will lead a management team with an exceptional track record of building high quality E&P companies of scale. The management team of the Enlarged Group will be based in Trinidad and bring excellent local relationships including with the Trinidad Ministry, Petrotrin and both the local and international supply chain. The Enlarged Group has a highly skilled team with strong operating capabilities to deliver the work programme. Further details of the directors and management of the Enlarged Group are set out at paragraph 13 of this Part I of this document.

Following the Placing, the Enlarged Group will be fully funded to pursue its current work programme and is expected to generate strong cash flows from its production assets.

The Enlarged Group will be focused on Trinidad, a world class petroleum basin, which has produced 3.5 billion bbl of oil and 22 TCF of gas to date. The Directors and Proposed Directors believe Trinidad offers significant remaining potential for oil and gas producers.

The Merger constitutes a reverse takeover under the AIM Rules for Companies. As such, the Merger is subject to the approval of Shareholders, which is being sought at the General Meeting to be held at 1.00 p.m. on 13 February 2013, notice of which is at the end of this document.

Should the approval of Bayfield Shareholders be granted for the Merger, the Placing, the change of name and the Share Consolidation, the admission of the Consolidated Ordinary Shares to trading on AIM will be cancelled and the Enlarged Share Capital will be admitted to trading on AIM. Subject to approval by Bayfield Shareholders and the satisfaction of the other conditions relating to the Merger, completion of the Merger is expected to take place on 14 February 2013, being the expected date of Admission.

The purpose of this document is to set out the background to and reasons for the Proposals, to provide information on the Proposals, to explain why the Proposals are in the best interests of the Company and Bayfield Shareholders as a whole and to recommend that Bayfield Shareholders vote in favour of the Resolution to be proposed at the General Meeting which has been convened for 13 February 2013 notice of which is set out at the end of this document.

2. **Background and reasons for the Merger**

During May and June 2012, Bayfield sought to execute an equity financing to strengthen its cash position and fund its ongoing drilling commitments. Despite success in securing a measure of institutional support, the Company was unable to complete the fundraising to the level required at the time. Consequently, the Company commenced a strategic review in July 2012 and, following extensive review of the financial and strategic options available to manage the Company's financial commitments the Board concluded that the Merger would deliver the most value to Shareholders. This culminated in the announcement on 15 October 2012 regarding the Merger.

The Directors strongly support the Merger and the Company and Trinity have received signed irrevocable undertakings from 50.54 per cent. of the current Shareholders of Bayfield to vote in favour of the Resolution to approve the Proposals at the General Meeting. In addition, the Enlarged Group Board and management of Trinity will be significant shareholders in the Enlarged Group, holding 20,486,809 of the Consolidated Ordinary Shares in aggregate representing 21.61 per cent. of the Enlarged Share Capital.

Completion of the Proposals will establish the Enlarged Group as the largest independent Trinidad focused oil and gas company and, in particular, will:

- create a company with 2P Reserves of 31 MMbbl (net), 2C Contingent Resources of 38 MMboe (net) and unrisked best estimate Prospective Resources of 503.8 MMboe (net);
- create a diversified onshore, West coast and East coast portfolio of 11 operated fields, and net production of approximately 3,965 bbl/d based on current production rates;
- provide investors with exposure to a balanced mix of existing production, significant near-term production growth opportunities from low risk developments and exposure to multiple exploration prospects with potential to deliver meaningful Reserves/Resources upside;
- create a company that is fully funded to fufil its existing licence commitments;
- enable the Enlarged Group to generate operational and commercial synergies; and
- position the Enlarged Group for further growth through acquisition opportunities and new licensing rounds.

3. Summary of the Enlarged Group's Reserves and Resources

The Enlarged Group's Reserves and Resources are summarised in the below tables which are based on information extracted from the Trinity CPR and the Bayfield CPR, which can be found in their entirety in Parts V and VI of this document respectively.

Summary of gross field oil Reserves and net oil Reserves as at 1 July 2012 (in the case of Trinity's Reserves) and as of 30 June 2012 (in the case of Bayfield's Reserves)

	Gross Reserves (MMbbl)			Net Reserves (MMbbl)[6]		
	1P	**2P**	**3P**	**1P**	**2P**	**3P**
Trinity (as of 1 July 2012)[1,2]	3.442	7.289	12.964	3.360	7.090	12.661
Bayfield (as of 30 June 2012)[3,4,5]	10.83	37.11	51.68	7.04	24.12	33.584
Total	**14.272**	**44.399**	**64.644**	**10.400**	**31.210**	**46.245**

Notes

1 With respect to Trinity, individual 1P, 2P and 3P values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1P (Low Case) may be very conservative and the arithmetic total 3P (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

2 1P, 2P and 3P cases each include Developed Producing; Developed Non-producing and Undeveloped Reserves.

3 Includes Reserves from continued production plus Bayfield's work-over and side-track programmes. No gas Reserves are attributed.

4 Gross Reserves are 100% of the volumes estimated to be economically recoverable after 30 June 2012 onwards.

5 With respect to Bayfield, 1P, 2P and 3P Reserves have been estimated using a deterministic methodology so that 1P = Proved, 2P = Proved + Probable and 3P = Proved + Probable + Possible.

6 Net Reserves account for working interest share of Reserves before the deduction of government royalty and Petrotrin over riding royalty.

7 The Directors and Proposed Directors have aggregated the Reserves stated in the Bayfield CPR and Trinity CPR in the full knowledge that they have been estimated using different methodologies and that the totals may have been different if a common methodology had been used.

Summary of gross unrisked Contingent Resources and net unrisked Contingent Resources as at 1 July 2012 (in the case of Trinity's Contingent Resources) and as of 30 June 2012 (in the case of Bayfield's Contingent Resources)

	Gross Contingent Resources (MMboe)			Net Contingent Resources (MMboe)[5]		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Trinity (as of 1 July 2012)[1]	4.04	9.87	22.16	3.61	8.75	19.62
Bayfield (as of 30 June 2012)[2,3,4]	25.64	44.92	70.62	16.67	29.22	45.89
Total	**29.68**	**54.79**	**92.78**	**20.28**	**37.97**	**65.51**

Notes

1 Individual 1C, 2C and 3C values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1C (Low Case) may be very conservative and the arithmetic total 3C (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

2 Includes Bayfield Contingent Gas Resources. GCA has stated oil and gas separately in the Bayfield CPR.

3 Gross Contingent Resources are 100% of the volumes estimated to be economically recoverable without any economic cut off being applied.

4 The volumes reported here are "Unrisked" in the sense that Chance of Development values have not been arithmetically applied to the designated volumes within this assessment. Chance of Development represents an indicative estimate of the probability that the Contingent Resource will be developed, which would warrant the reclassification of that volume as a Reserve.

5 Net Resources account for working interest share of Resources before the deduction of government royalty and Petrotrin over riding royalty.

Summary of Bayfield's gross unrisked Prospective Resources (Prospects) as of 30 June 2012

				Gross Unrisked Prospective Resources—Prospects						
			Bayfield Working Interest	**Oil (MMBbl)**			**Gas (Bscf)**			**GCoS**
Country / Block	**Prospect**	**Interval**	**(%)**	**Low**	**Best**	**High**	**Low**	**Best**	**High**	**(%)**
Trinidad / Galeota	NE Trintes	H3	65	3.39	6.51	10.25	—	—	—	39
		M	65	7.04	12.96	24.13	—	—	—	41
		N	65	1.92	5.55	9.77	—	—	—	17
	EG-3	O1	65	3.34	5.82	9.04	—	—	—	18
		O2	65	2.31	4.03	6.26	—	—	—	32
		O3	65	1.57	2.74	4.23	—	—	—	32
		O4	65	3.72	6.43	10.02	—	—	—	31
		E	65	1.54	3.18	5.59	—	—	—	12
	Thais	O1	65	3.07	5.36	8.31	—	—	—	10
		O2	65	3.23	5.60	8.71	—	—	—	18
		O3	65	2.17	3.76	5.84	—	—	—	18
		O4	65	5.13	8.86	13.77	—	—	—	17
		B	65	—	—	—	3.19	4.81	6.82	17
		C	65	1.52	2.64	4.09	—	—	—	17
	South Trintes	F	65	1.23	2.41	4.00	—	—	—	7
		F1	65	0.76	1.48	2.48	—	—	—	7
		G	65	0.69	1.33	2.27	—	—	—	10
		H0	65	0.43	0.88	1.60	—	—	—	7
		M	65	5.58	10.96	18.94	—	—	—	8
	GAL21	A	65	1.70	8.04	17.51				25
	Updip	B	65	1.44	6.42	14.46				36
	EG-8	E	65	0.53	1.91	4.47	—	—	—	16
	EG-2	LaSv-N1	65	0.04	0.10	0.24	—	—	—	33
	Tatiana	LaSv-N1	65	0.24	1.78	5.33	—	—	—	30
		E	65	0.33	1.65	4.34	—	—	—	16
	Denise	LaSv-N1	65	0.67	3.01	7.66	—	—	—	30
		E	65	0.58	2.40	6.06	—	—	—	16
		H	65	—	—	—	4.24	14.19	29.82	25
		Denise Deep	65	—	—	—	0.68	2.98	7.76	14
		LaSv-Tbs	65	—	—	—	3.67	17.46	46.38	14
	Gaby	COS1-I	65	1.16	4.10	7.91	—	—	—	15
		COS1-L	65	0.97	2.82	5.00	—	—	—	13
		COS1-PA	65	1.40	3.01	4.64	—	—	—	13
		COS1-PB	65	0.70	1.42	2.19	—	—	—	13
		COS1-PC	65	3.82	9.76	16.21	—	—	—	15
South Africa / Pletmos Basin . . .	1		90	—	—	—	11.9	234.5	447.7	18
	2		90	—	—	—	9.3	85.0	175.4	15
	3		90	—	—	—	35.4	184.5	415.8	13
	5		90	—	—	—	5.5	33.6	79.9	8
	9		90	—	—	—	43.0	169.5	370.4	6
	10		90	—	—	—	518.2	1,757.6	3,753.3	6
	GA-VI		90	—	—	—	63.4	240.1	518.4	10

Notes

1 Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.

2 Gross Unrisked Prospective Resources are 100% of the volumes estimated to be recoverable from the field.

3 The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for a Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked".

4 It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Prospect/Lead and the potential dependencies between them. Similarly, it is inappropriate to aggregate Prospective Resources with Reserves or Contingent Resources.

Summary of Bayfield's net unrisked Prospective Resources (Prospects) as of 30 June 2012

				Net Bayfield Unrisked Prospective Resources—Prospects						
			Bayfield Working Interest	Oil (MMBbl)			Gas (Bscf)			GCoS
Country / Block	Prospect	Interval	(%)	Low	Best	High	Low	Best	High	(%)
Trinidad / Galeota	NE Trintes	H3	65	2.20	4.23	6.66	—	—	—	39
		M	65	4.58	8.42	15.68	—	—	—	41
		N	65	1.25	3.61	6.35	—	—	—	17
	EG-3	O1	65	2.17	3.78	5.88	—	—	—	18
		O2	65	1.50	2.62	4.07	—	—	—	32
		O3	65	1.02	1.78	2.75	—	—	—	32
		O4	65	2.42	4.18	6.51	—	—	—	31
		E	65	1.00	2.07	3.63	—	—	—	12
	Thais	O1	65	2.00	3.48	5.40	—	—	—	10
		O2	65	2.10	3.64	5.66	—	—	—	18
		O3	65	1.41	2.44	3.80	—	—	—	18
		O4	65	3.33	5.76	8.95	—	—	—	17
		B	65	—	—	—	2.07	3.13	4.43	17
		C	65	0.99	1.72	2.66	—	—	—	17
	South Trintes	F	65	0.80	1.57	2.60	—	—	—	7
		F1	65	0.49	0.96	1.61	—	—	—	7
		G	65	0.45	0.86	1.48	—	—	—	10
		H0	65	0.28	0.57	1.04	—	—	—	7
		M	65	3.63	7.12	12.31	—	—	—	8
	GAL21 Updip	A	65	1.11	5.23	11.38	—	—	—	25
		B	65	0.94	4.17	9.40	—	—	—	36
	EG-8	E	65	0.34	1.24	2.91	—	—	—	16
	EG-2	LaSv-N1	65	0.03	0.07	0.16	—	—	—	33
	Tatiana	LaSv-N1	65	0.16	1.16	3.46	—	—	—	30
		E	65	0.21	1.07	2.82	—	—	—	16
	Denise	LaSv-N1	65	0.44	1.96	4.98	—	—	—	30
		E	65	0.38	1.56	3.94	—	—	—	16
		H	65	—	—	—	2.76	9.22	19.38	25
		Denise Deep	65	—	—	—	0.44	1.94	5.04	14
		LaSv-Tbs	65	—	—	—	2.39	11.35	30.15	14
	Gaby	COS1-I	65	0.75	2.67	5.14	—	—	—	15
		COS1-L	65	0.63	1.83	3.25	—	—	—	13
		COS1-PA	65	0.91	1.96	3.02	—	—	—	13
		COS1-PB	65	0.46	0.92	1.42	—	—	—	13
		COS1-PC	65	2.48	6.34	10.54	—	—	—	15
South Africa / Pletmos Basin	1		90	—	—	—	10.7	211.0	402.9	18
	2		90	—	—	—	8.4	76.5	157.9	15
	3		90	—	—	—	31.9	166.0	374.2	13
	5		90	—	—	—	4.9	30.2	71.9	8
	9		90	—	—	—	38.7	152.5	333.4	6
	10		90	—	—	—	466.4	1,581.8	3,378.0	6
	GA-VI		90	—	—	—	57.1	216.1	466.6	10

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.

2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for a Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked".

3. It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Prospect/Lead and the potential dependencies between them. Similarly, it is inappropriate to aggregate Prospective Resources with Reserves or Contingent Resources.

Summary of Trinity's gross Prospective Resources (Prospects) as at 1 July 2012

Gross Prospective Resources (Mbbl)			GPoS[1]
Low	**Best**	**High**	**(%)**
1,663	6,843	20,700	19

Note

1 This aggregation assumes that all prospects are successful. The probability of this occurring is the product of the GPoS values for each individual prospect.

Additional information on the Enlarged Group's Reserves and Resources are set out in paragraph 4 of Part II and paragraph 4 of Part III of this document.

4. **Background information on Trinity**

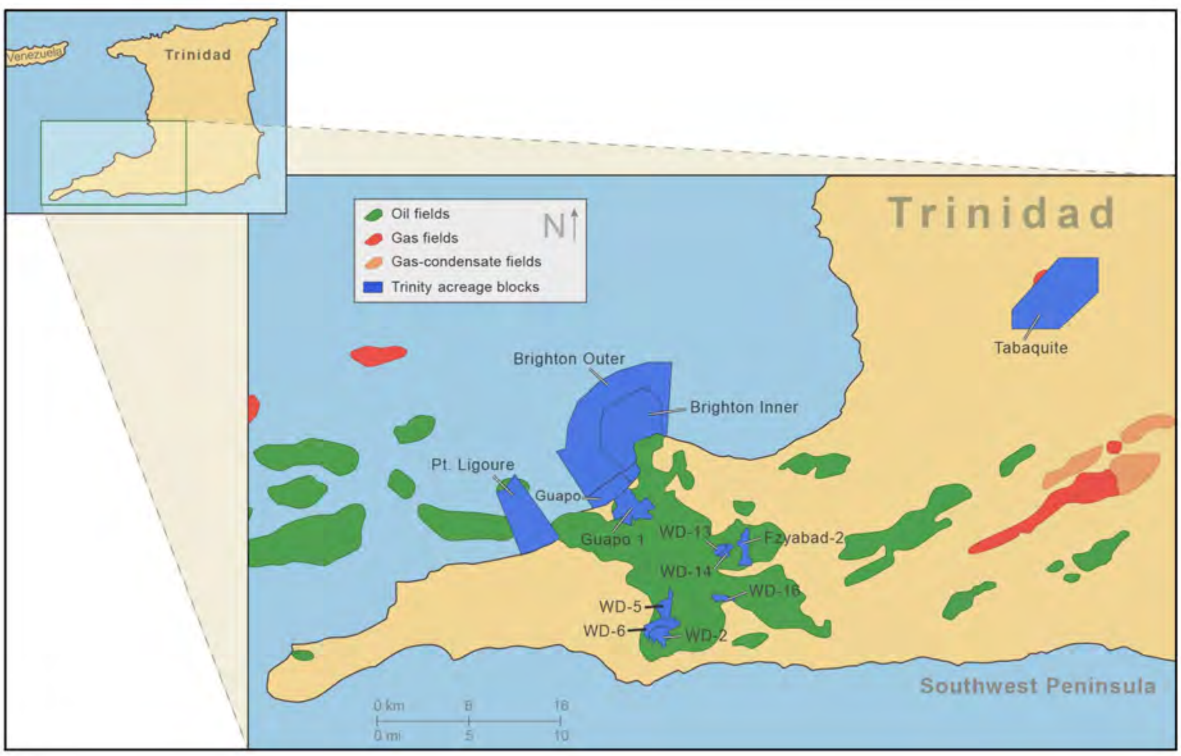
Trinity is a private independent oil and gas company with onshore and offshore assets in Trinidad. It is led by an executive team with significant Trinidadian and international operating expertise and a track record of value creation for shareholders in the international E&P industry.

Trinity was formed in 2005 when a group of founding shareholders led by Bruce Dingwall acquired Venture Production plc's Trinidad operations. Since then, the business has grown organically via drilling and further acquisitions.

Trinity is headquartered in San Fernando, Trinidad, where the senior management team is based, and has significant local ownership. Trinity employs more than 200 staff and this team has an excellent understanding of the local operating environment and business culture including strong government, banking, supply chain and other stakeholder relationships.

Trinity operates ten licences in Trinidad, including two licences in the Gulf of Paria, offshore Trinidad's West coast, and eight onshore licences. Trinity's portfolio offers a balance of current production (approximately 2,405 bbl/d net), low risk development opportunities and exploration/appraisal upside. In aggregate, Trinity's assets are estimated to contain net 2P Reserves of 7.1 MMbls, net 2C Contingent Resources of 8.7 MMbbls and gross Prospective Resources of 6.8 MMbbls.

Figure 1: Overview of Trinity's assets



Source: Trinity

Additional information on the Trinity Group is set out at Part II of this document.

5. **Trinity's current trading and prospects**

Since its inception in 2005, Trinity has built a strong asset base and a reputation for operating to the highest standards in Trinidad. Trinity has grown rapidly in recent years through a combination of organic drilling and further acquisitions and notably in 2011, Trinity merged with Oilbelt Holdings, the holder of the WD-5/6 LOA, adding approximately 1,300 bbl/d of production. Trinity's assets are profitable and generate strong cash flows, with operating cash flow before movement in working capital of US$14.6 million in 2011 (including only five months of contribution from the Oilbelt Holdings assets).

Trinity plans to undertake an active programme of onshore drilling to grow its production base. Offshore, Trinity acquired new seismic data over the Brighton Marine Block in 2009 which identified a number of infill drilling opportunities and untested fault blocks. Some of this prospectivity extended beyond the Brighton Marine licence so in 2011 Trinity expanded its acreage position by licencing the Guapo and Brighton Outer leases and harmonised these with its Point Ligoure licence. Trinity now plans to commence the re-development of the entire area with a programme of development and exploration wells, with 20 locations identified.

6. **Background information on Bayfield**

Bayfield is the parent company of an independent oil and gas E&P group, which was established in order to develop a portfolio of interests providing current production and near-term development, appraisal and exploration opportunities. The Bayfield Group was established in 2008 by former executives of Burren Energy who left that company following its acquisition by Eni. The Company was admitted to AIM in July 2011.

The Bayfield Group's current major focus is on Trinidad and Tobago where, in April 2009, it secured a 25 year exploration and production licence over the Galeota Block which covers an area of 122 km^2 offshore Trinidad and, consequently, assumed operatorship of the producing Trintes Field. The Bayfield Group has also recently acquired an exploration licence over the Pletmos Inshore Block off the south coast of South Africa covering an area of approximately 10,800 km^2.

The Bayfield Group's key licence is the Galeota Block which contains the Trintes Field and numerous undeveloped discoveries, and offers significant exploration potential. The Trintes Field has net 2P Reserves of 24.1 MMBbl. Numerous infill drilling locations have been identified in order to increase production from the field and deliver the asset's full potential.

The Galeota Block contains four discoveries dating from the 1980s with aggregate gross 2C Contingent Resources of oil of 38.3 MMBbl and 39.9 Bscf of gas. More recently, in March 2012, the Company announced that the EG-8 exploration well on the Galeota Block had been suspended as an oil and gas discovery. The discovery extends into the adjacent acreage, held by Repsol, and the Company has signed a memorandum of understanding with Repsol to identify development concepts for the discovery and plans to drill an appraisal well to further ascertain the full extent of the reservoir in 2013. The Directors believe the discovery is estimated to have demonstrated gross development potential of 32 MMbbl of oil and 69 Bscf of gas over both blocks.

In total the Directors estimate the Galeota Block to contain 93.3 MMboe of net unrisked Prospective Resources. An exploration and appraisal programme consisting of five wells during 2013 and 2014, targeting net unrisked Prospective Resources of 44 MMboe, will assist in assessing the full potential of the block and define the development concept to develop the Galeota Block's Contingent Resources and any future discoveries.

Additional information on the Bayfield Group is set out in Part III of this document.

7. **Bayfield's current trading and prospects**

Since commencing operatorship of the Galeota Block in May 2009, Bayfield has invested significant capital to upgrade infrastructure and grow production at the Trintes Field. The Trintes Field is currently producing approximately 2,400 bbl/d (gross) and the continuing platform based rig programme to work over the existing well inventory and to drill new side track wells is targeted to further increase production during 2013. Since the end of 2010 Bayfield has carried out some 66 workovers and drilled 14 side track wells almost doubling the production rate compared to a year ago. Additionally, Bayfield has drilled two exploration wells, including one discovery, to grow its Reserves and Resources.

However, a slower than expected growth in production and significant rig liabilities meant that the Company needed additional financing which it was not able to obtain. On 2 July 2012 the Company announced that it was entering into a strategic review process. After careful deliberation and review of a range of alternatives, the Board concluded that a combination with Trinity to create the leading Trinidad focused independent E&P company was in the best interests of Shareholders.

The Company recently successfully renegotiated its Crude Oil Sales Contract Agreement with Petrotrin resulting in a substantially better pricing for its oil, which has improved cash flow and provides a better foundation from which to fund the Company's growth potential. Additionally, the Company has reduced its rig commitments by assigning upcoming rig slots for the "Rowan Gorilla III" to EOG Resources. The Board is confident that the Enlarged Group can unlock the potential of the Galeota Block and deliver Shareholder value.

As a result of the enhanced oil pricing terms under the COSA and recent increases in production volumes, Bayfield has seen an improvement in its operating cashflow position and a fall in its breakeven gross production level from approximately 2,049 bbl/d to approximately 1,587 bbl/d. The Company expects its breakeven gross production level to fall further in 2013 to approximately 1,032 bbl/d due to the anticipated decrease in operating expenses as a result of Petrotrin becoming obliged under the terms of the Galeota Farm Out Agreement to pay 35 per cent. of the costs of Bayfield and Petrotrin's joint operations on the Galeota Block.

On 27 December 2012 Bayfield Galeota and Galeota Oilfield Services Limited entered into the Trinity Loan. The purpose of the Trinity Loan is to enable the Bayfield Group to meet its working capital requirements and to repay certain existing debts of the Company in connection with its operations in Trinidad until completion of the Merger. The Trinity Loan has since been drawn down and used to repay these debts of the Company.

8. Key strengths and work programme of the Enlarged Group

The Directors and Proposed Directors believe that the Enlarged Group will be well positioned to benefit from a number of contributing factors as set out below.

The Enlarged Group will be focused on Trinidad, which is under exploited and offers significant opportunities for growth

Trinidad is a prolific hydrocarbon province on trend with Venezuela's El Furrial play that historically has been dominated by Majors and NOCs. These companies have left significant "stranded" Reserves which the Directors and Proposed Directors believe smaller and more nimble operators can efficiently develop.

Trinidad has a progressive tax regime with numerous incentives provided to promote investment in the oil and gas sector in recent years. In addition, the frequency of licencing rounds is increasing, offering the opportunity for the Enlarged Group to expand its portfolio. There is still under explored acreage throughout Trinidad and Tobago, which the Enlarged Group will review during these forthcoming bid rounds. This under-explored acreage provides an excellent opportunity to further explore this prolific hydrocarbon province.

With a well understood fiscal and operating environment, as well as a stable political backdrop, the Directors and Proposed Directors believe that Trinidad offers attractive investment opportunities in the E&P sector.

The Enlarged Group will have a competitive advantage in Trinidad

The Enlarged Group will be the leading Trinidad focused E&P company. It is intended that the Enlarged Group will be headquartered and managed from San Fernando in Trinidad. The Enlarged Group will employ approximately 270 people, of which more than 95 per cent. will be based in Trinidad. This team will have an excellent understanding of the local operating environment and business culture including strong government, supply chain and other stakeholder relationships. In particular, the Enlarged Group will have a strategic relationship with one of Trinidad's leading drilling contractors, Well Services Petroleum Company Limited, whose holding company Well Services Holdings Limited will be a 3.07 per cent. shareholder in the Company following Admission. Anthony Brash, Managing Director of Well Services Holdings Limited, will be a director of the Company following Completion.

The Enlarged Group will offer a balanced portfolio with a diversified risk profile

The Enlarged Group will have a balanced portfolio of existing production, near-term production growth potential from identified development opportunities and exploration upside. The Enlarged Group's assets will offer a diversified risk profile, extending across different geological plays and spanning operated producing assets offshore Trinidad's East and West coasts as well as onshore. The Enlarged Group will also have a frontier exploration licence in South Africa which the Directors estimate to have gross unrisked Prospective Resources of 2.7 TCF.

The Enlarged Group will be well placed to grow its portfolio in Trinidad

As the largest independent E&P group in Trinidad, the Enlarged Group will be well placed to grow its portfolio via new licencing rounds and through merger and acquisition opportunities. The Enlarged Group intends to seek exploration or brown field development opportunities which have (i) low entry costs and (ii) controlling participation, which will enable the Enlarged Group to exercise control over its assets.

Proposed Board members have an exceptional track record of creating and realising shareholder value

Several members of the Board, as it will be constituted following Completion, have previously been executives of highly successful E&P companies. Bruce Dingwall (Executive Chairman) and Jon Murphy (Non-Executive Director) were Chief Executive Officer and Chief Operating Officer, respectively, of Venture Production which was sold to Centrica in 2009 for £1.3 billion. Finian O'Sullivan was a founder and Chief Executive Officer of Burren Energy which floated on the London Stock Exchange with a market capitalisation of approximately £175.0 million in 2003 and was sold to Eni for £1.7 billion in 2008. David MacFarlane was Finance Director of Dana Petroleum plc when it was acquired by Korea National Oil Corporation in 2010 for approximately £1.9 billion.

Further, the Board and management team of the Enlarged Group following Completion will be significant shareholders in the Company, owning 21.61 per cent. in aggregate of the Enlarged Share Capital and therefore their interests are well aligned with those of other Shareholders.

Work programme

The Enlarged Group proposes to undertake an active programme of development and exploration activities to grow production and increase the Enlarged Group's Resource base. Specifically, the Enlarged Group proposes to undertake:

- an ongoing onshore drilling campaign with 12 wells planned for 2013 and 15 wells for 2014.
- an active programme of workovers and infill/sidetrack wells at the Trintes Field utilising the platform based slant rig. Eight sidetrack wells are planned for 2013 and six for 2014.
- a workover programme on the Brighton Marine Block in 2013 and a full re-development of the Brighton Marine Block to begin in 2014.
- a material and high-value infrastructure-led exploration programme through 2013 and 2014 targeting total unrisked Prospective Resources of 46 MMboe (according to Directors' estimates) across:
    - five exploration wells on the Galeota Licence, including
        - three exploration wells to be drilled using the platform based slant rig: located close to existing operated infrastructure allowing for rapid monetisation upon success; and
        - two exploration wells to be drilled, including appraisal of the EG-8 discovery in partnership with Repsol; and
        - one exploration well at PGB: the El Dorado prospect, to test an undrilled fault block in the Brighton fairway which could be rapidly tied back to existing Brighton infrastructure if successful; and
- the acquisition of seismic data over the PGB Licence and the South African Pletmos Licence in 2014.

In aggregate, this work programme is expected to grow net production to 5,000 bbl/d by the end of 2013 and to provide investors with exposure to six exploration wells targeting net unrisked Prospective Resources of 46 mmboe (according to Directors' and Proposed Directors' estimates). The Enlarged

Group's assets have further development potential to deliver production beyond 10,000 bbl/d (net) (89 per cent. oil) in the medium term excluding any exploration upside.

The Enlarged Group's assets are expected to generate strong cash flows for re-investment which will be utilised to fund the proposed 2014 exploration programme and deliver production growth in the longer term.

9. Use of proceeds

The Enlarged Group will utilise the proceeds of the Placing to accelerate delivery of the significant upside that exists in the combined portfolio.

Use of Proceeds	Amount (US$ million)
2013 development and infrastructure spending	30
2013 exploration spending (four wells)	38
Centrica Loan repayment	6.4
General corporate purposes (including transaction fees)	15.6
Total	*90*

The 2013 development programme is anticipated to be funded in part by operating cash flows. The 2014 work programme, which contemplates a further two exploration wells, seismic data acquisition at the Enlarged Group's PGB Licence and Pletmos Licence as well as continued onshore and offshore drilling, is all anticipated to be funded from operating cash flows. Further, the Enlarged Group will operate all of its assets and can therefore control its rate of spend (subject to the minimum work obligations under its licences) as appropriate.

10. Principal terms of the Merger

Pursuant to the Merger Agreements, the Company has conditionally agreed to acquire the entire issued and to be issued share capital of Trinity. Trinity Shareholders will receive approximately 747.8 new Consolidated Ordinary Shares for each Trinity Share held, resulting in the issue by Bayfield of 25,652,041 new Consolidated Ordinary Shares in aggregate to the current shareholders of Trinity. Legacy Trinity Shareholders will own approximately 55 per cent. of Bayfield and Legacy Bayfield Shareholders will own approximately 45 per cent. of Bayfield on a fully diluted basis but before the issue of the Placing Shares (and on the basis Centrica will not convert its Centrica Loan Notes which are referred to below).

Both Petrotrin and the Trinidad Minister of Energy have given their respective consents to the Merger. The Merger is conditional upon, inter alia, the following further matters:

- the approval by Bayfield Shareholders of the Resolution to be proposed at the General Meeting;
- Bayfield acquiring not less than 90 per cent. of the Trinity Shares;
- the Placing Agreement becoming unconditional (save for Admission and any condition relating to the Merger Agreements becoming unconditional), and not having been terminated in accordance with its terms; and
- Admission.

Irrevocable undertakings have been received from Finian O'Sullivan, Andrey Pannikov, Alta Limited, Brian Thurley and Jonathan Cooke to vote and to procure that their Associates vote in favour of the Resolution to be proposed at the General Meeting in respect of their aggregate holdings of 109,415,867 Existing Unconsolidated Ordinary Shares representing approximately 50.54 per cent. of the current issued ordinary share capital of the Company.

The holders of 120 Trinity Options have chosen to exercise their Trinity Options on Completion and to transfer those Trinity Shares they acquire by way of such exercise to Bayfield on Completion on the same terms as the existing Trinity Shareholders. The holders of the remaining 3,518 Trinity Options have chosen to surrender their Trinity Options in consideration for the grant by Bayfield of share options over Consolidated Ordinary Shares on Completion. Similarly, Oriel has confirmed that it does not intend to exercise its 83 Trinity Warrants on Completion, and pursuant to the terms of the warrant instrument under which those Trinity Warrants have been issued, Trinity's rights, benefits and obligations will be novated, assigned and transferred to Bayfield resulting in Oriel holding new warrants to subscribe for 62,067 Consolidated Ordinary Shares following Completion.

Further details on the Trinity Options and the Trinity Warrants are set out in paragraph 16 of this Part I and paragraphs 4.2 and 11.2(f) respectively of Part XII of this document.

The Main Merger Agreement contains business and other warranties given by Bayfield to the Trinity Management Shareholders and by the Trinity Management Shareholders to Bayfield respectively as well as various undertakings in relation to the management of the businesses of each of the Bayfield Group and the Trinity Group up until Completion. Further details of the Merger Agreements are set out at paragraph 11.1(q) of Part XII of this document.

In view of the size of the Merger in relation to the Company, the Merger constitutes a reverse takeover under the AIM Rules for Companies.

11. **Details of the Placing**

The Company is proposing to raise approximately £57 million (approximately US$90 million) before expenses by the issue of 47,500,000 new Consolidated Ordinary Shares at 120 pence per Placing Share with certain Bayfield Shareholders, Trinity Shareholders and new investors. The Placing Shares represent 219.42 per cent. of the existing issued share capital of the Company and 50.11 per cent. of the Enlarged Share Capital and will when issued rank *pari passu* with the Consolidated Ordinary Shares and the Consideration Shares.

Certain Bayfield Shareholders, Trinity Shareholders and new investors have conditionally agreed to subscribe for the Placing Shares at the Placing Price. Settlement of the Placing with placees procured by the Placing Agents has been underwritten by the Placing Agents. The issue of the Placing Shares is conditional, inter alia, upon the approval by Bayfield Shareholders of the Resolution to be proposed at the General Meeting convened for 13 February 2013, upon the Merger Agreements becoming unconditional (save for Admission), and being completed in escrow, and upon Admission becoming effective on 14 February 2013 (or such later date as the Company, the Nominated Adviser and the Joint Bookrunners may agree but not later than 28 February 2013).

On 25 January 2013, the Company, the Placing Agents, the Nominated Adviser, Finian O'Sullivan, David MacFarlane, the Proposed Directors and Trinity entered into the Placing Agreement pursuant to which the Placing Agents agreed, subject to certain conditions, to use their reasonable endeavours to procure subscribers for 45,199,000 of the Placing Shares at the Placing Price. The balance of the Placing Shares are being placed directly by the Company with new investors. The Placing Agreement contains provisions entitling the Nominated Adviser and the Joint Bookrunners to terminate the Placing (and the arrangements associated with it), at any time prior to Admission in certain circumstances. If this right is exercised, the Placing will lapse, any monies received in respect of the Placing will be returned to the applicants without interest and Admission and Completion will not occur.

Further details of the Placing Agreement are set out at paragraph 11.1(b) of Part XII of this document.

Separate from the arrangements which are the subject of the Placing Agreement, the Company is proposing to carry out the Company Direct Placing, comprising a placing of 2,301,000 Placing Shares at the Placing Price direct to certain investors.

Following Admission RBC will replace Seymour Pierce as the Company's nominated adviser and joint broker and Jefferies will replace FirstEnergy as the Company's joint broker.

In view of the fact that the Placing Shares are not being offered on a pro rata basis to existing Bayfield Shareholders, the Placing is conditional, *inter alia*, upon Bayfield Shareholders resolving to disapply statutory pre-emption rights. As such, the Merger and the Placing are subject to the approval of Bayfield Shareholders, which is being sought at the General Meeting to be held at 1.00 p.m on 13 February 2013, notice of which is set out at the end of this document. Following the Merger and the Placing, the Legacy Trinity Shareholders will have an aggregate holding of 29,511,746 Consolidated Ordinary Shares representing approximately 31.13 per cent. of the Enlarged Share Capital.

12. Financial summary and adjusted capitalisation of the Enlarged Group

A summary of the recent financial performance of both Trinity and Bayfield is detailed in the table below.

	12-months to 31 December 2011 (US$ million)	6-months to 30 June 2012 (US$ million)
Bayfield		
Revenue	22.0	12.2
Net loss after tax	(14.3)	(15.1)
Operating cash flow before movement in working capital	(7.6)	(3.1)
Net assets	118.7	104.2
Cash	59.4	19.2
Trinity		
Revenue	53.2	40.5
Net profits after tax	12.8	2.4
Operating cash flow before movement in working capital	14.6	3.9
Net assets	55.4	61.2
Cash	26.8	18.5

Adjusted capitalisation of the Enlarged Group

As at 30 September 2012, the Enlarged Group's adjusted capitalisation (following certain adjustments following the Merger but excluding any proceeds or commissions in connection with the Placing) is detailed below.

	Amount (US$ million)
Cash	23.2
Debt	
Citibank facility	20.0
Centrica Loan Notes	6.9
Promissory note	2.0
Total debt	28.9

In particular, the figures above reflect the Enlarged Group's cash balances following the payment of transaction fees in relation to the Merger, estimated at US$7.7 million, and the payment of approximately US$8.8 million of overdue balances due to AMSI in relation to well costs associated with Bayfield's EG-7 well as referred to at Part IV of this document which costs have since been paid to AMSI.

The Enlarged Group's debt comprises:

- A loan facility up to the amount of US$20,000,000 (which replaces a previous facility of US$13,000,000) pursuant to a facility agreement between Trinity T&T and Citibank dated 6 December 2012. Further details of the 2012 Citibank Loan Agreement are contained in paragraph 11.2(g) of Part XII of this document.
- A loan of US$2,051,111.11 from The David and Christina Segel Living Trust pursuant to a promissory note issued by Oilbelt Services, an indirect subsidiary of Trinity, to The David and Christina Segel Living Trust on 1 October 2012. Further details of the Segel Promissory Note are contained in paragraph 11.2(h) of Part XII of this document.
- A loan of US$6.8 million (US$6.9 million including accrued interest) from Centrica pursuant to a convertible loan instrument and related loan notes issued by Trinity to Centrica. Further details of the Centrica Loan Notes are contained in paragraph 11.2(c) of Part XII of this document. Following a payment of US$561,374 (comprising a redemption of US$500,000 of principal loan notes and a payment of US$61,374 of accrued interest) made by Trinity to Centrica on or around 31 December 2012, the amount outstanding in respect of the loan notes as at 1 January 2013 was US$6,337,246.58. It is proposed that the amount outstanding will be repaid immediately following Admission.

The Enlarged Group Board intend that the Enlarged Group's existing cash resources as well as funds made available under the 2012 Citibank Loan will be used to fund, in part, the working capital commitments of the Enlarged Group.

13. **Directors, Proposed Directors, Senior Managers and employees**

The Board currently consists of five directors. On completion of the Merger, it is proposed that all of the current Board will resign, save for Finian O'Sullivan and David MacFarlane. On Completion, Bruce Dingwall, Joel Montgomery Pemberton, Jon Murphy, Anthony Brash and Ronald Harford will be appointed to the Board, and accordingly the Board following Completion will consist of seven directors, each of whom has significant oil and gas and/or public company experience.

The Directors of Bayfield and their current functions are as follows:

Finian O'Sullivan	*Executive Chairman*
Hywel John	*Chief Executive Officer*
Andrey Pannikov	*Non-Executive Director*
Jonathan Cooke OBE	*Non-Executive Director*
David MacFarlane	*Non-Executive Director*

Upon Completion, the directors of Bayfield and their functions will be as follows:

Bruce Dingwall	*Executive Chairman*
Joel Montgomery Pemberton	*Chief Executive Officer*
Finian O'Sullivan	*Non-Executive Director*
Jon Murphy	*Non-Executive Director*
Anthony Brash	*Non-Executive Director*
David MacFarlane	*Non-Executive Director*
Ronald Harford	*Non-Executive Director*

Upon Completion, the Senior Managers of the Enlarged Group and their functions will be as follows:

Bryan Ramsumair	*Chief Financial Officer*
Ian MacDonald	*Chief Operating Officer*
Sookdeo Heeralal	*Executive Manager, Commercial*
Brian Besson	*Executive Manager, Developments*
Robert Gair	*Executive Manager, Corporate Development*
Lennox Wiltshire	*Executive Manager, Health and Safety*
Jim Strachan	*Executive Manager, Geoscience and Technical*

Profiles of the Directors, Proposed Directors and Senior Managers are set out below. Further information on the Directors' and Proposed Directors' previous directorships and their terms of appointment are set out in paragraph 6.3 of Part XII of this document.

Current Directors

Finian O'Sullivan, Executive Chairman (aged 57)

Finian holds an honours degree in Geology from University College Galway. Finian has pursued an international career in the oil industry spanning 33 years with Chevron, Geophysical Systems, Olympic Oil and Gas and Burren Energy. Finian founded Burren Energy in 1994 and developed its business in Turkmenistan and West Africa leading to Burren's flotation on the London Stock Exchange with a market capitalisation of £175 million in 2003. As Chief Executive, Finian expanded Burren's activities with successful exploration and steady growth in production. In 2008, Burren Energy was sold to Eni for £1.7 billion. Finian joined the Bayfield Group in July 2008.

Hywel John, Chief Executive Officer (aged 48)

Hywel holds an honours degree in Law from Cambridge University. Following qualification as a Chartered Accountant with Arthur Andersen in London he held progressively more senior roles in the oil and gas sector with Kerr McGee and Powergen North Sea. Hywel worked for Burren Energy between 2000 and 2008 in a number of executive positions with legal, commercial and financial responsibilities including being Burren Energy's operating committee representative on the 50,000 bbl/d MBoundi Field in Congo

(Brazzaville). Most recently he was Chief Financial Officer of Candax Energy Inc, a Canadian oil and gas company listed on the Toronto Stock Exchange. Hywel joined the Bayfield Group in September 2010.

Andrey Pannikov, Non-Executive Director (aged 63)

Andrey has worked in the oil industry for almost 30 years. He was a co-founder of Lukoil and, in 1990, he established Urals Trading to work in Russia, Kazakhstan and Western Europe. In 1995, Andrey became a director and major shareholder in Burren Energy and continued to be a substantial shareholder in the company until its sale to Eni in 2008. Andrey joined the Bayfield Group in July 2008.

Jonathan Cooke, OBE, Non-Executive Director (aged 69)

Jonathan served in the Royal Navy for 35 years, principally as a submariner, where he commanded diesel and nuclear submarines, including a squadron. He had operational experience in Indonesia, the Falklands and the Cold War. More recently he served as a British naval attaché in Paris and as director of intelligence in the ministry of defence. He left the Royal Navy having obtained the rank of Commodore in 1996 and became Chief Executive of The Leathersellers' Company until 2009. In 1997 he became a non-executive director of the Anglo Siberian Oil Company plc prior to its flotation on AIM and remained a director until it was acquired by Rosneft in 2003. Jonathan joined the Board in July 2011.

David MacFarlane, Non-Executive Director (aged 55)

David is an economics graduate and Chartered Accountant. He has more than 25 years' experience in financial control and management in the upstream oil and gas industry. Between 1985 and 1993 he was Finance Director of the MOM Group, later becoming Finance Director for two key sub-groups of John Wood Group plc. He joined Dana Petroleum plc in 2002 from Amerada Hess where, during the previous six years, he headed finance for its fast growing international exploration and production group. David was Finance Director of Dana Petroleum plc when it was acquired by Korea National Oil Corporation in 2010 for £1.87 billion, representing a premium of 59 per cent. to the pre-bid share price. David joined the Board in July 2011.

Proposed Directors

In addition to Finian O'Sullivan and David MacFarlane who will remain on the Board, the following individuals will join the Board.

Bruce Alan Ian Dingwall, Executive Chairman (aged 53)

Bruce has over 30 years' experience in the oil and gas industry. Bruce began his career with Exxon as a geophysicist in the North Sea before moving to Lasmo where he held numerous senior management roles in their South East Asian operations. In 1997, Bruce founded, and was CEO of, Venture Production plc (now Centrica Production Limited) which grew to production of 45,000 boepd and was sold to Centrica Resources (UK) Limited in 2009 for £1.3 billion. A Trinidadian national, Bruce founded the Trinity Group in 2005 with the acquisition of the Trinidadian assets of Venture Production (Trinidad) Limited (now TDN Operating). Bruce is a geologist and studied at Aberdeen University.

Joel "Monty" Pemberton, Chief Executive Officer (aged 37)

Monty joined the Trinity Group in 2005 as Chief Financial Officer and became Chief Executive Officer in 2009. Under Monty's leadership the Trinity Group has significantly grown its business, through attracting external capital and undergoing a period of rapid organic drilling and merger and acquisition led growth. Monty began his career with Ernst & Young's audit team where he qualified as a Chartered Certified Accountant and worked in both Trinidad and the UK with a focus on energy clients. Monty then moved back to Trinidad working in the energy finance division of RBTT Merchant Bank prior to joining the Trinity Group. Monty is a Fellow Chartered Certified Accountant from the Association of Certified Chartered Accountants.

Jonathan Murphy, Non-Executive Director (aged 56)

Jon joined the Trinity Group at the time of acquisition from Venture Production (Trinidad) Limited (now TDN Operating) in 2005 and has over 30 years of experience in mid-cap exploration and production companies. Jon's career includes several years with Lasmo where he held various positions in geology, planning and new business, based in the UK and Asia. In 1999, Jon joined Venture Production plc (now

Centrica Production Limited) as Chief Operating Officer. Jon holds a BSc. Geology from the University of London and is also a Non-Executive Director of Hurricane Exploration plc.

Charles Anthony Brash Junior, Non-Executive Director (aged 50)

Anthony has been involved in the oil and gas industry for over 25 years and is Managing Director of Well Services Holdings Limited. Well Services Holdings Limited is the owner of a large drilling rig fleet in Trinidad and offers a wide range of other oilfield services as well as being a material onshore oil producer. Anthony has directly negotiated and managed service contracts with BP, EOG, Repsol and Petrotrin. Anthony holds a BA in Management and a MBA in General Business from St. Edward's University in Austin, Texas.

Ronald Harford, Non-Executive Director (aged 67)

Ronald, Chairman of Republic Bank Limited, is a career banker with over 45 years of service with Republic Bank Limited (formerly Barclays), the leading indigenous financial institution in the Caribbean.

Ronald is a Fellow of the UK Chartered Institute of Bankers, the Institute of Banking of Trinidad and Tobago and the Caribbean Association of Banking and Finance. He is the Chairman of The University of the West Indies (UWI) Development and Endowment Fund, serves as the Financial Advisor of the Red Cross Society of Trinidad and Tobago and was a Campaign Chairman in 2006 and 2007 for the International Charity Body, United Way. Ronald is a member of the Board of Directors of the Arthur Lok Jack Graduate School of Business-UWI and the Caribbean Information & Credit Rating Services Limited. He is a past President of the Bankers Association of Trinidad and Tobago.

Senior Managers

Bryan Ramsumair, Chief Financial Officer

Bryan joined Trinity in 2011. Bryan began his career with RBTT Merchant Bank in credit risk management before moving into senior roles in the capital markets division before co-founding a corporate finance boutique in 2005, ONE1 Financial, which was sold to a large Caribbean conglomerate in 2007. Bryan holds both a Honours Business Administration and an MBA from Richard Ivey School of Business in Canada.

Ian MacDonald, Chief Operating Officer

Ian joined Trinity in 2007 and leads the Trinity Group's development of technical and operational competencies for onshore and offshore based operations. Ian is a petroleum engineer and worked for Amoco and BP for 25 years in various technical and commercial roles in the UK, US, Egypt, Trinidad and Norway. Ian holds a B.Eng. Chemical Engineering from the Technical University of Nova Scotia.

Sookdeo Heeralal, Executive Manager, Commercial

Sookdeo joined Trinity in 2012. A geologist, Sookdeo spent more than 30 years with Petrotrin in various technical and commercial roles including negotiating the majority of Petrotrin's joint venture agreements. Most recently, Sookdeo was Commercial & Compliance Manager for Niko Resources. Sookdeo holds a BSc. Geology from the University of the West Indies and a MBA from Heriot-Watt University.

Brian Besson, Executive Manager, Developments

Brian joined Trinity in 2011 following a career of over 30 years with Amoco and BP in Trinidad and the UK. Brian is an engineer with wide ranging experience in both operational and managerial roles. Brian has significant expertise in project delivery and managing large teams and budgets, including managing large offshore fields such as the Teak, Samaan and Poui fields in Trinidad. Brian holds a BSc. in Mechanical Engineering from the University of the West Indies.

Robert Gair, Executive Manager, Corporate Development

Robert joined Trinity in 2012. Prior to joining Trinity, Robert was an investment banker with Deutsche Bank, CIBC World Markets and latterly with RBC Capital Markets where he gained extensive experience advising and raising capital for international E&P companies. Robert holds a BSc. in Mathematics from Edinburgh University.

Lennox Wiltshire, Executive Manager, Health and Safety

Lennox joined Trinity in 2012 and has more than 35 years of oil and gas related HSE experience. Lennox spent much of his career with Amoco/BP in Trinidad and Vietnam as HSE team leader for various drilling and production operations. More recently, Lennox was HSE advisor to Repsol for its Caribbean exploration and workover drilling programme.

James (Jim) Strachan, Executive Manager, Geoscience and Technical

Jim joined Trinity late in 2012 to lead our subsurface geoscience team. A career petroleum geologist, Jim has over 30 years of experience in the oil and gas industry. Having worked for BP and Deminex on UK and international E&P projects, Jim became Chief Geologist for Veba UK in 1999 and remained in that role following its acquisition by Petro-Canada where Jim led a large and diverse international subsurface team. Jim holds a BSc (Hons) Geology from Edinburgh University.

Employees

The Directors and the Proposed Directors consider that the capacity to recruit, retain, develop and integrate staff into the Enlarged Group is fundamental to executing its strategy. As at the date of this document, excluding the Directors and the Proposed Directors, the Bayfield Group has 55 employees and the Trinity Group has 230 employees, the majority of whom in each case are based in Trinidad.

14. **Competent persons' reports**

Shareholders' attention is drawn to the full text of the Trinity CPR and the Bayfield CPR which are set out in Parts V and VI of this document respectively.

15. **Share Consolidation**

As part of the Proposals, the Company is seeking Shareholder approval at the General Meeting for the Share Consolidation, whereby the Existing Unconsolidated Ordinary Shares of US$0.10 each are consolidated into Consolidated Ordinary Shares of US$1.00 each in the capital of the Company on the basis of one Consolidated Ordinary Share for every ten Existing Unconsolidated Ordinary Shares held.

The purpose of the Share Consolidation is to reduce the total number of shares in issue following completion of the Proposals. The Directors and Proposed Directors believe that this may reduce the volatility in the price of the Company's shares, may lead to more meaningful earnings per share figures, may avoid large dealing spreads in the shares and may ensure that the price of the shares is more appropriate for a company of its size following Completion.

It is proposed that the Share Consolidation will consist of the following steps:

(a) every ten Existing Unconsolidated Ordinary Shares in issue will be consolidated into one new Consolidated Ordinary Share; and

(b) fractional entitlements arising out of the consolidation under sub-paragraph (i) above by reason of there being either less than ten Existing Unconsolidated Ordinary Shares or a number not divisible by ten shall be rounded down to the nearest whole number. All such fractional entitlements shall be aggregated into new Consolidated Ordinary Shares and the whole number of new Consolidated Ordinary Shares so arising shall be sold in the market as part of the Placing and the net proceeds of sale held for the benefit of the Company.

The Companies Act and the Articles require that Shareholder consent is sought for the Share Consolidation and approval will be sought at the General Meeting which has been convened for 1.00 p.m. on 13 February 2013 at the offices of Ashurst LLP, Broadwalk House, 5 Appold Street, London EC2A 2HA. It is anticipated that new certificates for the new Consolidated Ordinary Shares will be issued and dispatched by 28 February 2013 and that CREST holders will have their CREST accounts credited with their new holdings on the date of Admission. Pending the issue of new share certificates, existing share certificates will remain valid until the record date in respect of the Share Consolidation, which is 6.00 p.m. on 13 February 2013, being the date occurring on the date of the General Meeting. The new Consolidated Ordinary Shares will carry the rights and be subject to the same restrictions as the Existing Unconsolidated Ordinary Shares as set out in the Articles.

The resolution to effect the Share Consolidation is set out in the Notice which can be found at the end of this document.

16. **Warrants and Options**

Trinity

As at 23 January 2013 (being the last practicable date prior to the date of this document), Trinity has options in issue over 3,638 Trinity Shares, 3,188 of which are exercisable at a price of US$1,000 per Trinity Share and 450 of which are exercisable at a price of US$4,185 per Trinity Share. Trinity also has warrants in issue to subscribe for 83 Trinity Shares exercisable at a price of US$4,185 per Trinity Share, all of which are held by Oriel.

The Trinity Options and the Trinity Warrants become exercisable on Completion.

Jonathan Murphy has chosen to exercise his Trinity Option over 100 Trinity Shares and Bryan Ramsumair has chosen to exercise his Trinity Option over 20 Trinity Shares conditional upon Completion, and both have agreed to sell the new Trinity Shares they will be allotted as a result of such exercise to Bayfield and receive Consolidated Ordinary Shares for such transfer on the same terms as the existing Trinity Shareholders. The remaining holders of Trinity Options (including Bryan Ramsumair in respect of his remaining Trinity Option over 55 Trinity Shares), who together hold 3,518 Trinity Options, have agreed to surrender their Trinity Options upon Completion in consideration for the grant by Bayfield of New Options over 747.8 Consolidated Ordinary Shares per Trinity Option held (the same conversion ratio on which the Trinity Shareholder's consideration is based) each with an exercise price equal to the lower of the Placing Price and US$5.59614615 per Consolidated Ordinary Share in the case of the replacement for the surrendered Trinity Options which had an exercise price of US$4,185 and US$1.33725951 per Consolidated Ordinary Share in the case of the replacement for the surrendered Trinity Options which had an exercise price of US$1,000 per Trinity Share. No Trinity Options shall exist following Completion.

Oriel has chosen not to exercise its 83 Trinity Warrants on Completion and Trinity's rights, benefits and obligations under the warrant instrument under which the Trinity Warrants were issued shall be novated, assigned and transferred to Bayfield upon Completion. Accordingly, following Completion Oriel shall hold warrants over 62,027 Consolidated Ordinary Shares with an exercise price of US$5.60 per Consolidated Ordinary Share (based on the same conversion ratio of 747.8 new Consolidated Ordinary Shares per Trinity Share on which the Trinity Shareholder's consideration is based).

Further details on the Trinity Options and the Trinity Warrants are set out in paragraphs 4.2 and 11.2(f) respectively of Part XII of this document.

Bayfield

As at 23 January 2013 (being the last practicable date prior to the date of this document), a total of 4,447,546 Options have been granted by the Company and are outstanding and a total of 13,325,648 LTIP Awards have been granted and are outstanding.

Following Completion, and after taking into account the Share Consolidation and the grant of New Options over Consolidated Ordinary Shares to holders of Trinity Options who have elected to surrender their Trinity Options for options over Consolidated Ordinary Shares, Bayfield will have:

(a) 444,754 Options over Consolidated Ordinary Shares outstanding;

(b) 173,650 LTIP Awards over Consolidated Ordinary Shares outstanding; and

(c) 2,630,759 New Options over Consolidated Ordinary Shares outstanding,

which will together represent 3.43 per cent. of the Enlarged Share Capital.

It is also anticipated that following Admission, the Board will (subject to approval by the Remuneration Committee) grant further awards under the LTIP (or a new LTIP to be adopted by the Board) over up to a further 7,583,999 Consolidated Ordinary Shares representing eight per cent. of the Enlarged Share Capital.

Further details of the Options, the LTIP Awards and the New Options are set out in paragraphs 4.1 and 4.2 of Part XII of this document.

17. **Lock-in and orderly marketing arrangements**

On Admission, the Enlarged Group Board (and their Associates) will be interested, in aggregate, in 20,486,809 Consolidated Ordinary Shares, representing approximately 21.61 per cent. of the Enlarged Share Capital (on the basis that Jon Murphy subscribes for 1,750,000 Placing Shares pursuant to the arrangement referred to in paragraph 11 of Part I of this document). The Locked-In Shareholders have agreed with the Company, RBC and Jefferies not to dispose (except in certain limited circumstances) of 31,006,158 Consolidated Ordinary Shares in which they are directly or indirectly interested for the following periods:

(a) in the case of 16,797,078 Consolidated Ordinary Shares, for a period of 12 months from Admission and for a further period of six months thereafter each such Locked-In Shareholder has agreed not to dispose of their Consolidated Ordinary Shares other than through RBC or Jefferies to ensure an orderly market in the Consolidated Ordinary Shares;

(b) in the case of 12,482,357 Consolidated Ordinary Shares, for a period of six months from Admission and for the period of six months thereafter each such Locked-In Shareholder has agreed not to dispose of their Consolidated Ordinary Shares other than through RBC or Jefferies to ensure an orderly market in the Consolidated Ordinary Shares; and

(c) in the case of 1,726,722 Consolidated Ordinary Shares, for a period of 12 months from Admission each such Locked-In Shareholder has agreed not to dispose of their Consolidated Ordinary Shares other than through RBC or Jefferies to ensure an orderly market in the Consolidated Ordinary Shares.

In addition certain other Bayfield Shareholders have agreed not to dispose (except in certain limited circumstances) of, in aggregate, a further 102,436 Consolidated Ordinary Shares in which they are directly or indirectly interested up until 18 July 2013 other than through the Company's brokers for the time being.

Further details of the lock-in and orderly market arrangements described above are set out in paragraphs 11.1(i), 11.1(j) and 11.1(m) of Part XII of this document.

18. **Corporate governance and share dealing code**

The Directors and the Proposed Directors recognise the importance of sound corporate governance commensurate with the size and nature of the Company and the interests of its Shareholders. The Corporate Governance Code does not apply to companies quoted on AIM and there is no formal alternative for AIM companies. The Quoted Companies Alliance has published a set of corporate governance guidelines for AIM companies, which include a code of best practice for AIM companies, comprising principles intended as a minimum standard, and recommendations for reporting corporate governance matters. The Directors believe that the Company complies with the Corporate Governance Code, so far as it is practicable having regard to the size and current stage of development of the Company. Set out below is a description of the Company's corporate governance practices. The Directors and the Proposed Directors intend to continue with these corporate governance practices following Completion and Admission.

The Board

The Board meets regularly and is responsible for strategy, performance, approval of any major capital expenditure and the framework of internal controls. The Board has a formal schedule of matters specifically reserved to it for decision, including matters relating to major capital expenditure, management structure and appointments, strategic and policy considerations, corporate transactions and finance.

The Board is responsible for establishing and maintaining the Bayfield Group's system of internal financial controls and, following Completion, will be responsible for establishing and maintaining the Enlarged Group's system of internal financial controls. Importance is placed on maintaining a robust control environment. The Board recognises, however, that such a system of internal financial control can only provide reasonable, not absolute, assurance against material misstatement or loss. The effectiveness of the system of internal financial controls is therefore subject to, and will in the future be subject to, regular review by the Board in light of the future growth and development of the Company.

To enable the Board to discharge its duties, members of the Board receive timely information. The Board, following Admission, will include five non-executive directors. If necessary, the non-executive directors are authorised to take independent advice, and there is a procedure in place to allow them to do this. The Board has delegated specific responsibilities to the committees referred to below.

Remuneration committee

The remuneration committee comprises at least two independent non-executive members of the Board. The remuneration committee's main functions include inter alia, determining the framework or broad policy for the remuneration of the Company's Chairman, the Company's executive Directors and other members of the executive management, the design of all share incentive plans and the determination each year of individual awards to executive directors and other senior executives thereunder and the performance targets to be used. On Admission, the members of the committee will be Jonathan Murphy, David MacFarlane and Ronald Harford with Jonathan Murphy acting as chairman.

Audit committee

The audit committee comprises at least two independent non-executive members of the Board. The audit committee's main functions include, inter alia, monitoring the integrity of the Company's financial statements, keeping under review the effectiveness of the Company's internal controls and risk management systems, making recommendations to the Board in relation to the appointment of the Company's auditors, overseeing the approval of their remuneration and terms of engagement and assessing annually their independence, objectivity and qualifications and the effectiveness of the audit process. On Admission, the members of the committee will be Jonathan Murphy, David MacFarlane and Ronald Harford with David MacFarlane acting as chairman.

Nomination committee

There is not a separate nomination committee and recommendations for appointments to the Board will be considered by the Board as a whole.

Share dealing code

The Company has adopted a code on dealings in securities which the Board regards as appropriate for an AIM company, including compliance with Rule 21 of the AIM Rules for Companies relating to Directors' and employees' dealings in the share capital of the Company.

19. **Dividend policy**

It is the intention of the Board to achieve capital growth for Shareholders. In the short term, the Board therefore intends that any future profits in the Company be retained for reinvestment in the business and, accordingly, the Board is unlikely to declare dividends in the foreseeable future. However, the Board will consider the payment of dividends, subject to the availability of distributable reserves, when it considers it is appropriate to do so.

20. **Working capital**

In the opinion of the Directors and the Proposed Directors, having made due and careful enquiry and taking into account the proceeds of the Placing and the Enlarged Group's loan facilities, the working capital available to the Enlarged Group will be sufficient for its present requirements that is for at least the next 12 months from the date of Admission.

21. **Taxation**

Information regarding taxation is set out in Part XII of this document. These details are, however, intended only as a general guide to the current tax position under UK taxation law.

Shareholders who are in any doubt as to their tax position or who are subject to tax in jurisdictions other than the UK are strongly advised to consult their own independent financial adviser immediately.

22. **CREST**

The Consolidated Ordinary Shares are eligible for CREST settlement. Accordingly, settlement of transactions in the Consolidated Ordinary Shares may take place within the CREST system if the relevant Shareholder so wishes. CREST is a voluntary system and Shareholders who wish to receive and retain share certificates will be able to do so.

23. **Risk factors**

Shareholders' attention is drawn to the Risk Factors set out in Part IV of this document and to the section entitled "Forward Looking Statements" on page 1 of this document. Shareholders and prospective investors should, in addition to all other information set out in this document, carefully consider the risks described in Part IV of this document before making a decision of whether to invest in the Company.

24. **Admission and dealings**

Application will be made to the London Stock Exchange for the Enlarged Share Capital to be admitted to trading on AIM. It is expected that Admission will become effective and that dealings in the Enlarged Share Capital will commence on 14 February 2013.

25. **Shareholder notification and disclosure requirements**

Shareholders are obliged to comply with the shareholding notification and disclosure requirements set out in Chapter 5 of the DTR. The DTR can be accessed and downloaded from the FSA's website at http://fsahandbook.info/FSA/html/handbook/DTR/5. Shareholders are urged to consider their notification and disclosure obligations carefully as a failure to make a required disclosure to the Company may result in disenfranchisement.

26. **General Meeting**

The General Meeting, notice of which is set out at the end of this document, has been convened for 1.00 p.m. on 13 February 2013 at the offices of Ashurst LLP, Broadwalk House, 5 Appold Street, London EC2A 2HA for the purpose of considering and, if thought fit, passing the following Resolution which needs to be passed to permit the Proposals to proceed:

Special resolution to:

(a) approve the Merger for the purposes of Rule 14 of the AIM Rules;

(b) authorise the Directors to allot the Consideration Shares, the Trinity Warrant Shares and the Placing Shares;

(c) disapply statutory pre-emption rights in relation to the allotment of the Consideration Shares, the Placing Shares and the Trinity Warrant Shares;

(d) change the name of the Company to "Trinity Exploration & Production plc"; and

(e) approve the Share Consolidation.

To be passed, the Resolution requires a majority of not less than 75 per cent. of Bayfield Shareholders voting in person or by proxy to vote in favour.

27. **Action to be taken**

Shareholders will also find enclosed with this document a Form of Proxy for use at the General Meeting.

It is important that Shareholders complete and sign the enclosed Form of Proxy in accordance with the instructions printed thereon and return it to the Company's registrars, Capita Registrars, PXS, 34 Beckenham Road, Beckenham, Kent BR3 4TU, as soon as possible and in any event so as to arrive no later than 1.00 p.m. on 11 February 2013. Other than as agreed by any Shareholders under the Bayfield Undertakings, completion and return of the Form of Proxy will not preclude Shareholders from attending and voting at the meeting, should they wish to do so. Alternatively, eligible Shareholders may use the CREST Proxy Voting Service details in respect of which are contained in the notes to the notice of General Meeting.

28. **Additional information**

The attention of investors is drawn to the information contained in Parts XI to XII of this document, which provides additional information on the Enlarged Group, and in particular Part IV which set out certain risk factors relating to the Enlarged Group.

29. **Recommendation**

The Directors, who have been so advised by Seymour Pierce, consider that the Proposals, including the Placing and the exercise of the Trinity Options and the New Options, are fair and reasonable and are in the best interests of the Company and the Shareholders as a whole.

Accordingly, the Directors unanimously recommend Shareholders to vote in favour of the Resolution to be proposed at the General Meeting, as they have undertaken to do in respect of their own beneficial holdings of Existing Unconsolidated Ordinary Shares amounting, in aggregate, to approximately 74,877,464 Existing Unconsolidated Ordinary Shares representing in total 34.59 per cent. of the Existing Unconsolidated Ordinary Shares. The Company has also received irrevocable undertakings from certain other Shareholders to vote in favour of the Resolution in respect of a further 34,538,403 Existing Unconsolidated Ordinary Shares representing in total 15.95 per cent. of the Existing Unconsolidated Ordinary Shares. Accordingly, when taken together with those Existing Unconsolidated Ordinary Shares beneficially owned by the Directors, the Company has received undertakings to vote in favour of the Resolution in respect of a total of 109,415,867 Existing Unconsolidated Ordinary Shares representing in total 50.54 per cent. of the Existing Unconsolidated Ordinary Shares.

Shareholders should note that in the event the Resolution is not passed at the General Meeting, the Proposals would not proceed and the Company would need to expeditiously seek alternative sources of funds to enable it to fund its working capital needs. There can be no guarantee that such funds would be available to the Company or, if they are available to the Company, that they would be available on terms which would not result in a substantial dilution of Shareholders' interests.

Yours faithfully

Finian O'Sullivan
Executive Chairman

PART II

FURTHER INFORMATION ON THE TRINITY GROUP

1. Introduction

The Trinity Group undertakes the exploration, development, production and sale of crude oil and natural gas under exploration and production, farmout and lease operatorships with Petrotrin. Its exploration and production activities are focused in the Gulf of Paria and in the South Western part of Trinidad and Tobago, primarily in the regions of Fyzabad, Erin, Pt. Fortin and Palo Seco. One of Trinity's subsidiaries, Ten Degrees North Services Limited, provides administrative, drilling and workover services to the Trinity Group.

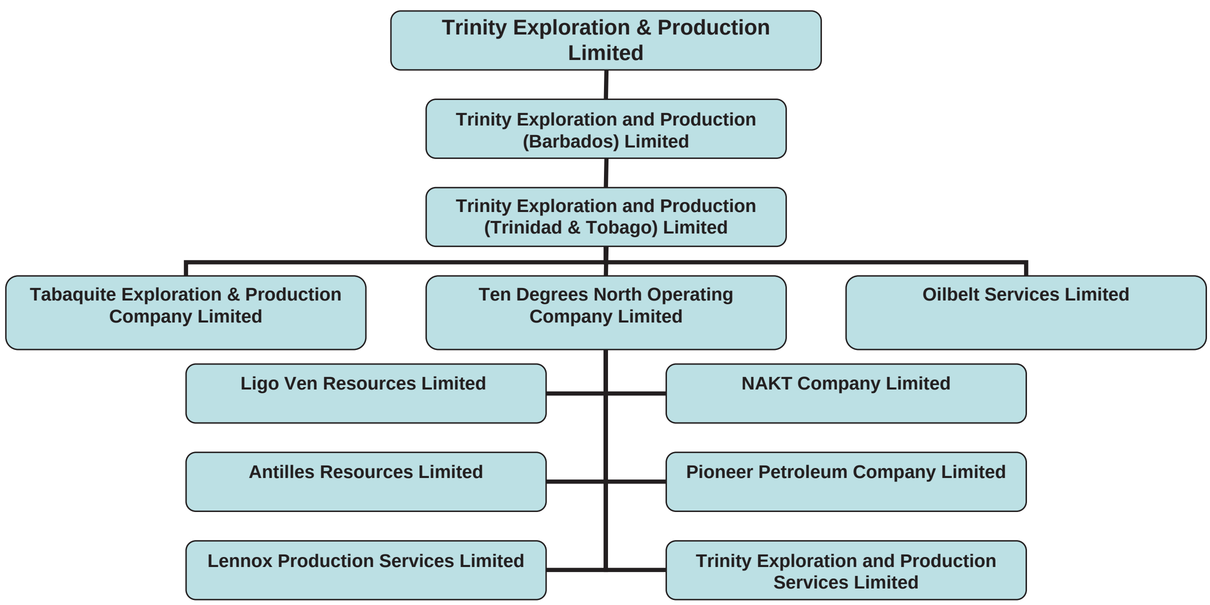
2. Group Structure and History

TDN was formed in 2005 when a group of founding shareholders led by Bruce Dingwall CBE acquired Venture Production (Trinidad) Limited (now TDN Operating). TDN further expanded its licence portfolio in 2007 with the acquisition of Pioneer Petroleum Company Limited and Lennox Production Services Limited, adding four onshore licences (WD-2, FZ-2, WD-16 and Guapo).

Trinity was incorporated in Scotland on 4 April 2011 under the name "Pacific Shelf 1651 Limited" and subsequently changed its name to "Trinity Exploration & Production Limited". Trinity Barbados was incorporated as a wholly owned subsidiary of Trinity and Old Trinity T&T was incorporated as a wholly owned subsidiary of Trinity Barbados. As part of a group reorganisation, Trinity replaced TDN as the ultimate parent company of the Trinity Group. TDN merged with Oilbelt Holdings (which held the WD-5/6 lease operatorship through its subsidiary Oilbelt Services) by way of an amalgamation to create TDN 2011. TDN 2011 (a subsidiary of TDN) then merged with Old Trinity T&T by way of a second amalgamation to create Trinity T&T. The entire issued share capital of Trinity T&T was then held by Trinity Barbados (the wholly owned direct subsidiary of Trinity). The old shareholders of TDN received shares in Trinity equal to approximately 75 per cent. of Trinity's issued share capital at that time, and the old shareholders of Oilbelt received shares in Trinity equal to approximately 25 per cent. of Trinity's issued share capital at that time.

The structure chart below details the companies in the Trinity Group:

Figure 2: The Trinity Group structure



Source: Trinity

Notes:

1 All 100 per cent. ownership

2 All incorporated under the laws of Trinidad and Tobago with the exception of Trinity Exploration & Production Limited which is incorporated under the laws of Scotland and Trinity Exploration and Production (Barbados) Limited which is incorporated under the laws of Barbados.

3 Ten Degrees North Operating Company Limited previously had a branch, Coastline International Inc., which held the interest in the licence with Petrotrin for the Tabaquite Block, which the Trinity Group intends will be held by Tabaquite Exploration and Production Company Limited once it has been renewed.

3. **Summary of Licences and Lease Operatorships**

Trinity's licences are summarised in the below tables which is based on information extracted from the Trinity CPR which can be found in its entirety in Part V of this document.

Onshore

Asset	Operator	Interest (%)	Status	Licence Expiry	Licence Area (Km2)	Comments
Fyzabad-2	TDN Operating	100.0	Production	31 Dec 2020	4.4	
Guapo-1	TDN Operating	100.0	Production	31 Dec 2020	6.5	
Tabaquite	TDN Operating	100.0	Production	01 Sept 2018	31.0	Licence terms are under discussion with agreement anticipated in early 2013
WD-2	TDN Operating	100.0	Production	31 Dec 2020	3.8	
WD-5	TDN Operating	100.0	Production	31 Dec 2020	5.8	
WD-6	TDN Operating	100.0	Production	31 Dec 2020		
WD-13	TDN Operating	100.0	Production	31 Dec 2020	1.5	
WD-14	TDN Operating	100.0	Production	31 Dec 2020	1.4	
WD-16	TDN Operating	100.0	Production	31 Dec 2020	1.5	

Source: Trinity CPR

Offshore West Coast

Asset	Operator	Interest (%)	Status	Licence Expiry	Licence Area (Km2)	Comments
Brighton Inner	TDN Operating	100.0	Production	06 Oct 2024	22.1	100% interest achieved through Petrotrin converting their 50% interest into an overriding royalty rate.
Brighton Outer	TDN Operating	70.0	Exploration	01 Sept 2018	42.4	
Guapo	TDN Operating	70.0	Exploration	01 Sept 2018	3.0	
Point Ligoure	TDN Operating	70.0	Production	01 Sept 2018	17.3	

Source: Trinity CPR

Note:

1 The new PGB Licence entered in December 2012 replaces the expired Point Ligoure licence and merges it with the newly acquired Brighton Outer and Guapo Licences referred to above.

4. **Summary of Exploration and Production Interests**

The following tables summarise the Trinity Group's oil and gas Reserves and Resources in respect of its interests as set out in the Trinity CPR. The Trinity CPR is set out in its entirety in Part V of this document.

Summary of Reserves as of 1 July 2012

	Gross Oil Reserves (Mstb)[2]			Trinity Net WI Oil Reserves (Mstb)[2]			Trinity Net Oil Reserves Entitlement[2,3] (Mstb)		
Field	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
Brighton	2,250	4,541	6,916	2,250	4,541	6,916	1,816	3,734	5,736
Fyzabad-2	39	74	147	39	74	147	21	41	81
Guapo-1	35	94	179	35	94	179	19	51	98
Point Ligoure	274	664	1011	192	465	708	168	407	619
Tabaquite	8	39	111	8	39	111	6	27	77
WD-2	147	415	687	147	415	687	107	292	481
WD-5/6	626	1,330	3,476	626	1,330	3,476	347	737	1,898
WD-13	34	77	295	34	77	295	19	43	177
WD-14	26	55	139	26	55	139	14	30	76
WD-16	1	1	1	1	1	1	1	1	1
ARITHMETIC TOTAL[1]	**3,442**	**7,289**	**12,964**	**3,360**	**7,090**	**12,661**	**2,518**	**5,361**	**9,245**

1 Individual 1P, 2P and 3P values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1P (Low Case) may be very conservative and the arithmetic total 3P (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

2 1P, 2P and 3P cases each include Developed Producing; Developed Non-producing and Undeveloped Reserves.

3 Trinity Net Reserves Entitlement is Trinity's WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

Source: Trinity CPR

Summary of the Contingent Resources as of 1 July 2012

	Contingent Resources (Mstb)								
	Gross Field			**Trinity Working Interest**			**Trinity Net Entitlement[1]**		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Brighton Inner[2]	1,386	3,316	7,686	1,386	3,316	7,686	1,165	2,785	6,456
Point Ligoure/Guapo/Brighton Outer[2]	1,447	3,747	8,479	1,013	2,623	5,935	886	2,295	5,193
WD-2	138	461	731	138	461	731	93	301	477
WD-13	262	545	1,128	262	545	1,128	146	326	712
WD-14	323	624	1,332	323	624	1,332	176	368	837
Fyzabad-2	63	139	423	63	139	423	33	74	241
Guapo-1	49	102	337	49	102	337	27	58	208
Tabaquite	52	150	428	52	150	428	44	128	353
WD-5/6	318	787	1,616	318	787	1,616	168	414	904
ARITHMETIC TOTAL[3]	**4,040**	**9,870**	**22,160**	**3,606**	**8,746**	**19,616**	**2,737**	**6,750**	**15,381**

Notes

1 Trinity's net entitlement is Trinity's WI share of Resources after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

2 Assuming 53% of the Contingent Resources in Brighton Marine are within the Brighton Marine Inner Block and 47% within the Brighton Marine Outer Block.

3 Individual 1C, 2C and 3C values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1C (Low Case) may be very

conservative and the arithmetic total 3C (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

Source: Trinity CPR

For each licence, the 1C, 2C and 3C Contingent Resources are treated as incremental to the 2P Reserves case for total licence calculations including the Petrotrin over-riding royalty. In some instances the additional Contingent Resources may extend the economic life of the field. The Contingent Resources shown in the table above also include any incremental barrels from any extension of the field. The table below shows the possible addition to the gross 2P Reserves from the extended life of the field due to the addition of the respective 1C, 2C and 3C gross Contingent Resources.

	Contingent Resources Only (Mstb)			Field Extensions (Mstb)			Contingent Resources Including Field extensions (Mstb)		
Field	**1C**	**2C**	**3C**	**1P**	**2P**	**3P**	**1C**	**2C**	**3C**
Brighton	1,386	3,316	7,686	0	0	0	1,386	3,316	7,686
Fyzabad-2	18	76	331	45	64	92	63	139	423
Guapo-1	12	50	246	37	52	91	49	102	337
Point Ligoure/Guapo/Brighton Outer	1,447	3,741	8,473	0	6	6	1,447	3,747	8,479
Tabaquite	40	131	404	13	19	23	52	150	428
WD-2	138	432	693	0	29	38	138	461	731
WD-5/6	186	550	1,226	132	237	390	318	787	1,616
WD-13	207	487	1,070	55	58	58	262	545	1,128
WD-14	249	549	1,256	74	76	76	323	624	1,332
ARITHMETIC TOTAL[1]	**3,684**	**9,330**	**21,386**	**356**	**540**	**774**	**4,040**	**9,870**	**22,160**

1 Individual 1C, 2C and 3C values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1C (Low Case) may be very conservative and the arithmetic total 3C (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

Source: Trinity CPR

Summary of Prospective Resources as of 1 July 2012

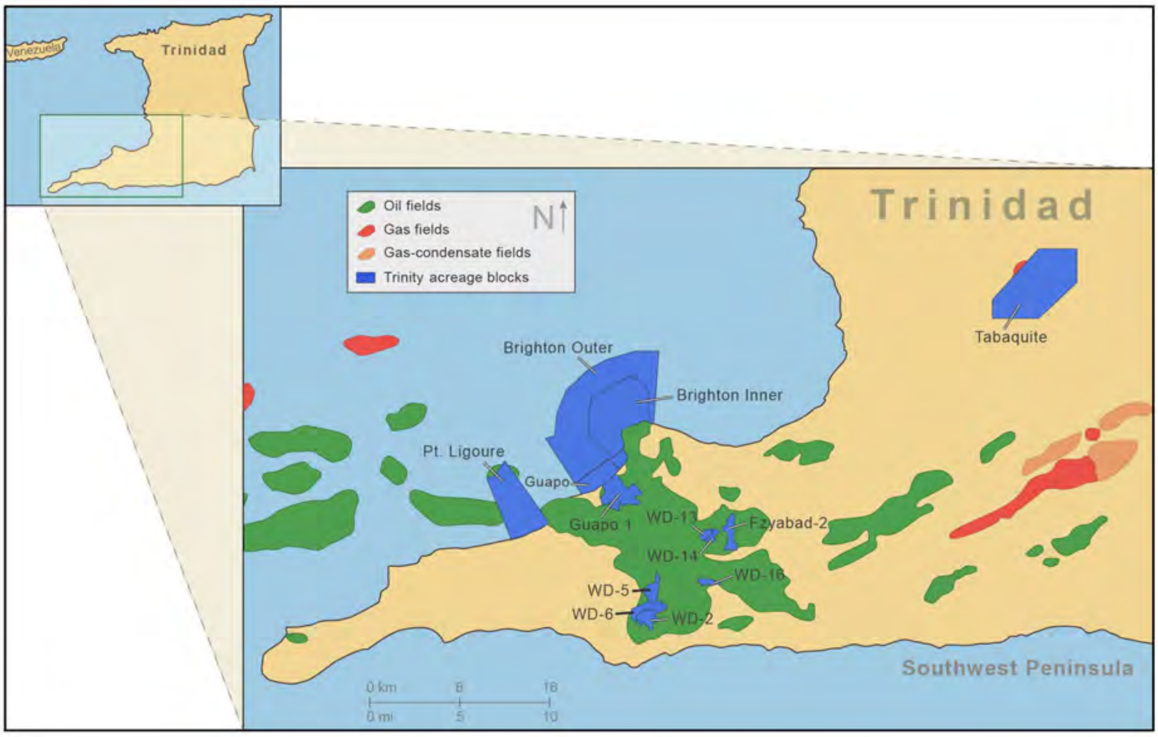
Gross Prospective Resources			
Low (Mstb)	**Best (Mstb)**	**High (Mstb)**	**GPoS[1] (%)**
1,663	**6,843**	**20,700**	**19**

1 This aggregation assumes that all prospects are successful. The probability of this occurring is the product of the GPoS values for each individual prospect.

Source: Trinity CPR

Trinity's assets

Figure 3: Overview of Trinity's assets



Source: Trinity

Onshore

The Trinity Group holds a 100 per cent. operated working interest in eight onshore licences by way of seven LOAs and the Tabaquite Farmout Agreement. These licences cover a total acreage of 12,581 acres (55.8 km^2) and Trinity currently operates 291 producing wells onshore.

The LOAs are ten year licences that expire on 31 December 2020 and can be extended for a further five year term upon expiry. The Tabaquite Farmout Agreement has expired, but Trinity continues to operate the field under the old licence terms. A new licence is under negotiation with the Trinidad Ministry and is expected in the first quarter of 2013.

The area that is the subject of the Tabaquite Farmout Agreement is the Tabaquite Block, which was discovered in 1911. The areas that are the subject of the LOAs are located in Trinidad's Forest Reserve Area, which began production in 1910. Onshore Trinidad has produced approximately 1.6 billion bbl of oil to date, however this represents a low recovery of estimated in-place volumes. This low recovery rate is due to under-investment and limited application of modern production techniques. Trinity's onshore assets provide low-risk exploitation opportunities: wells in the Forest Reserve Area intersect multiple reservoirs sands (Morne L'Enfer, Forest and Cruse) providing significant re-completion opportunities to arrest base declines and the Trinity Group has an extensive inventory of well re-activations and new well locations to grow production.

The Trinity Group's onshore assets have been estimated to contain remaining 2P Reserves of 2.1 MMbbl and Contingent Resources of 2.8 MMboe. These assets currently produce approximately 1,925 bbl/d of which WD-5/6 is the most significant contributor with current production of 1,320 bbl/d.

Trinity intends to pursue a programme of drilling and recompletion activities to grow production from its onshore assets including 12 wells in 2013 and 15 wells in 2014. Each new well is estimated by RPS to have an initial production rate in the range of 26 - 57 bbl/d and costs between US$600,000 and US$1,000,000 per well to drill. New onshore wells generate attractive returns and generate strong cash flows.

Offshore West Coast

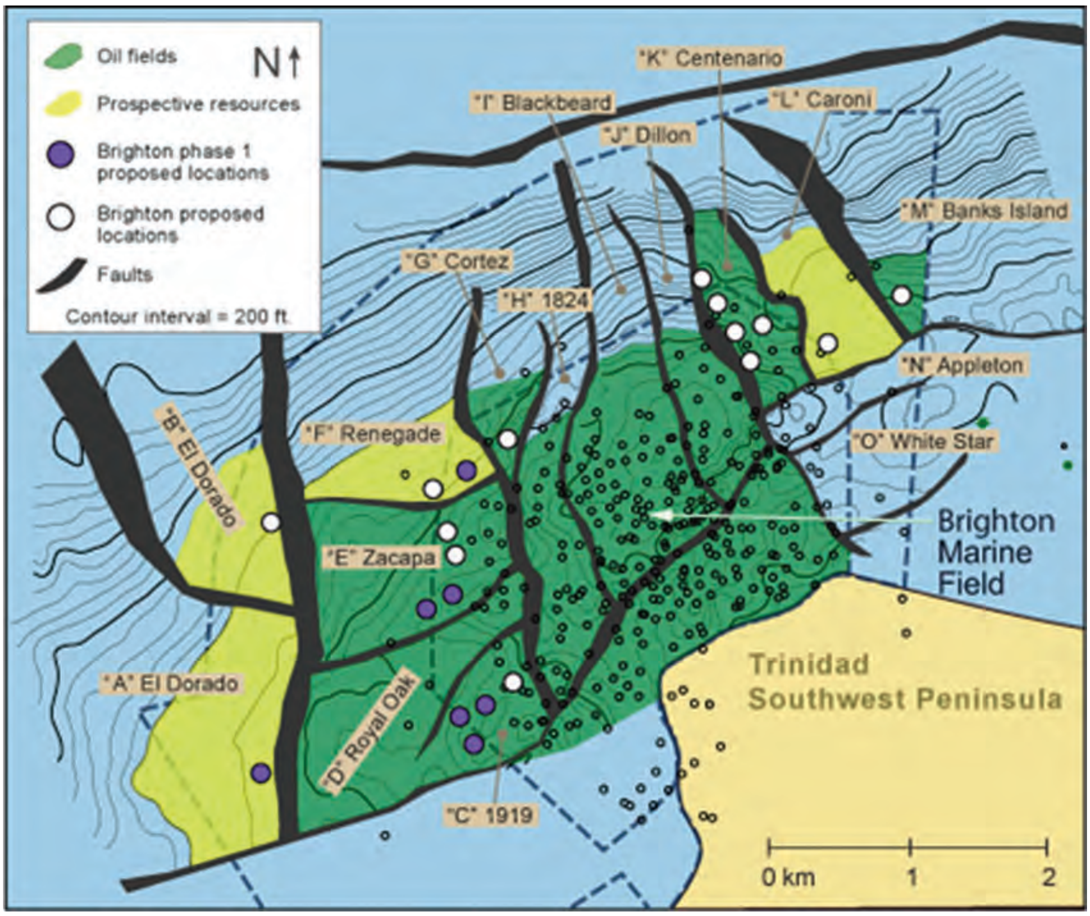
The Trinity Group holds two licences which it operates offshore Trinidad's West Coast, one of which is the PGB Licence and the other is the Brighton Marine Licence.

Brighton Marine

Members of the Trinity Group, and their predecessor companies, have held the Brighton Marine Licence since 1999 and the licence is for a 25-year term. TDN Operating holds a 100 per cent. interest in the field following the conversion of Petrotrin's 45 per cent. interest in the licence to an over-riding royalty. The licence is located offshore in shallow waters (<100 ft) in the Gulf of Paria.

The Brighton Marine field was discovered in 1951 and was initially developed from long-reach wells deviated from eleven land batteries. Nine offshore platforms were later installed to access further undeveloped Reserves. The field produces high quality 26-46º API crude oil with current production of 360 bbl/d from 67 wells.

Figure 4: Brighton Marine field



Source: Trinity

The field was developed without seismic: in 2009, the Trinity Group acquired 3D seismic over the whole Brighton Marine Block to complement a dataset from 1997 which has identified a number of infill drilling opportunities and well defined undrilled fault blocks. In total, 20 drilling locations have been identified. Certain of these locations are considered to contain Prospective Resources as they are in fault blocks that are un-penetrated. It should be noted that certain of the fault blocks extend beyond the Brighton Marine Licence, into the PGB Licence. This is further discussed below.

Trinity plans to undertake a programme of light and heavy workovers on existing wells in 2013. In order to accommodate the heavy workover rig, certain infrastructure upgrades are required at the MP-8 platform. The total project costs are estimated at approximately US$6.2 million and the workover activity is expected to recover an incremental 1.2 MMBbl.

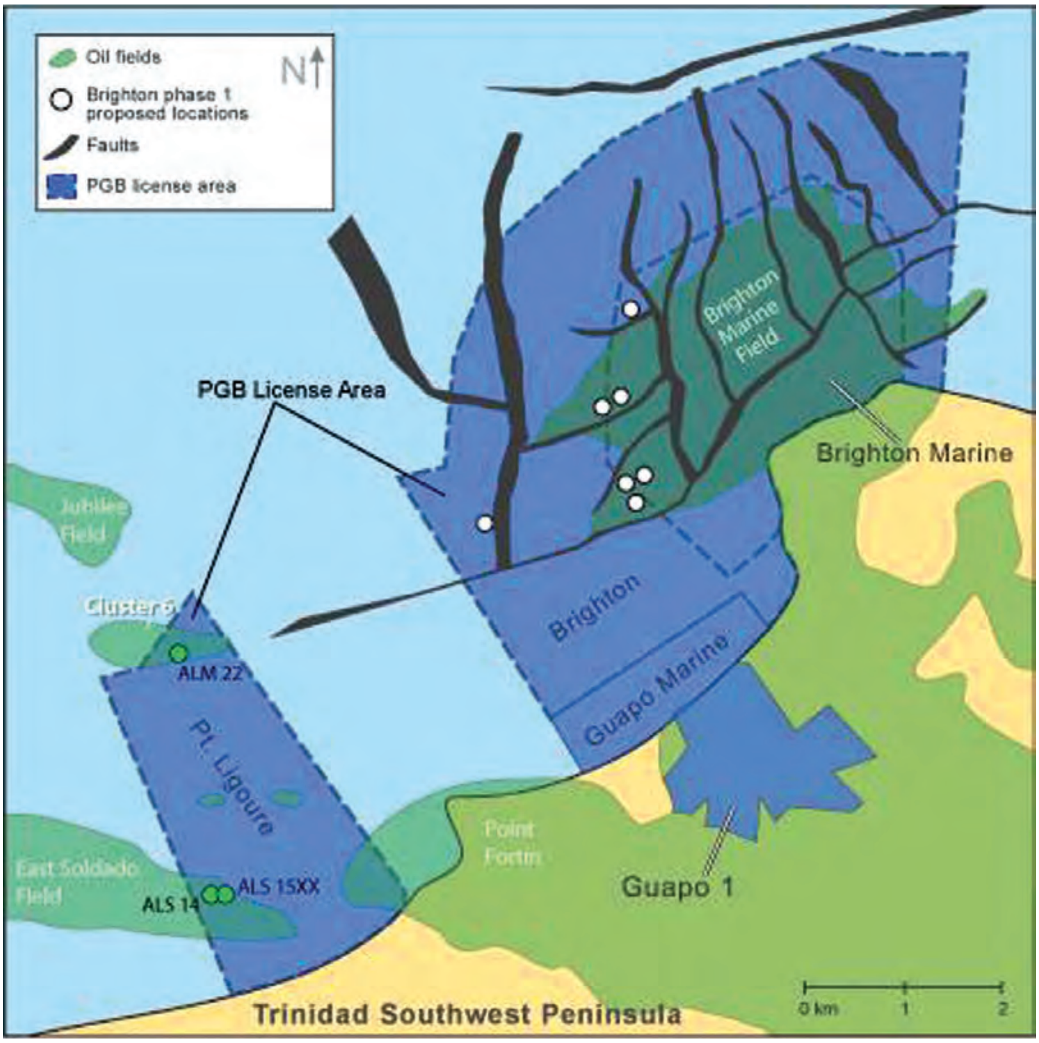
In 2014, Trinity plans to begin a major re-development of the Brighton Marine Block, with an initial development phase of six wells planned for Q4 2014 and into Q1 2015. In a P50 case, each well is estimated by RPS to recover 364,000 bbls (gross). Using only more recent well data, Trinity believes that each well should recover approximately 528,000 bbls (gross) in a P50 case. Depending on the outcome of this initial phase of development, Trinity intends to undertake a further phase of drilling activities to develop the remaining identified locations.

The Brighton Marine Block is estimated to contain remaining net 2P Reserves of 4.5 MMBbls, net Contingent Resources of 3.3 MMbbls and gross Prospective Resources of 6.8 MMbbls.

PGB

TDN Operating was awarded the PGB Licence in December 2012 and holds a 70 per cent. operated interest with Petrotrin holding the remaining 30 per cent.

Figure 5: PGB



Source: Trinity

Trinity sought to acquire this acreage following its review of the seismic survey over the Brighton Marine Block and an assessment that the play fairway may extend through the Gulf of Paria. Trinity already held a 42.5 per cent. interest in the licence over the Point Ligoure Block which had been awarded to Venture Production in 2002. The Trinity Group was awarded a licence for the Guapo Offshore Block and sub-area A of the Brighton Marine Block in 2011 and this was merged with the licence for the Point Ligoure Block to form the PGB Licence in December 2012. The PGB Licence is for an initial six-year term which may be extended to 25 years in the event of a commercial discovery.

PGB is located primarily offshore in shallow waters (<100 ft) in the Gulf of Paria. It extends onshore and currently has two producing wells which currently produce 120 bbl/d (net).

Under the terms of the PGB Licence, Trinity has committed to acquire seismic over the Point Ligoure Block, re-process existing seismic over the acreage, drill an exploration well to a minimum depth of 5,000 feet in the first 24 months of the licence term and a further exploration well to a minimum depth of 5,000 feet in the first 36 months of the PGB Licence. Petrotrin will be fully carried through these activities.

Certain of the fault blocks extend into the acreage licenced under the PGB Licence from the acreage licenced under the Brighton Marine Licence, and certain of the fault blocks are primarily located on the acreage licenced under the PGB Licence. In 2013, Trinity intends to drill the largest of these fault blocks which contains the El Dorado prospect. The El Dorado prospect is estimated to contain 3.2 MMBbl of gross unrisked Prospective Resources with a chance of success of 90 per cent. Upon a successful exploration well, Trinity believes that El Dorado could be tied back to the Brighton Marine Block infrastructure allowing for rapid monetisation of any discovery.

The PGB Licence also holds a heavy oil (16° API) discovery, ALM-22, drilled by Venture Production in 2002. The recent Jubilee discovery made by Petrotrin near the Cluster 6 platform, an estimated 48MMBbl field, further demonstrates the potential of the area.

In order to further delineate the ALM-22 discovery and identify future drilling locations, Trinity intends to acquire seismic over the Point Ligoure Block. A seismic crew is expected to be available in early 2014 and the cost of such a survey is estimated at US$7 million.

The PGB Licence is estimated to contain remaining net 2P Reserves of 0.5 MMBbls and net Contingent Resources of 2.6 MMBbls.

A summary of the PGB Licence is set out in paragraph 2 of Part XI of this document.

5. **Corporate Social Responsibility, Health and Safety**

The Trinity Group is committed to:

(a) conducting its business in an open and socially responsible way;

(b) actively developing positive relationships with the local communities where it works;

(c) the safe, efficient and responsible management of all aspects of its business;

(d) ensuring that health and safety matters are not compromised and are given priority when engaging in production or any other business activities;

(e) meeting all health and safety regulatory statutory requirements;

(f) taking responsibility for protecting the environment; and

(g) minimising the negative impact of its operations on the natural environment.

PART III

FURTHER INFORMATION ON THE BAYFIELD GROUP

1. Introduction

Bayfield Energy is the parent company of an independent oil and gas E&P group, which was established in order to develop a portfolio of interests providing current production and near-term development, appraisal and exploration opportunities. The Bayfield Group was established in 2008 by former executives of Burren Energy who left that company following its acquisition by Eni. The Company was admitted to AIM in July 2011.

The Bayfield Group's current major focus is on Trinidad and Tobago where, in April 2009, it secured a 25 year exploration and production licence over the Galeota Block which covers an area of 122 km^2 offshore Trinidad and, consequently, assumed operatorship of the producing Trintes Field. The Bayfield Group has also recently acquired an exploration licence over the Pletmos Inshore Block off the south coast of South Africa covering an area of approximately 10,800 km^2.

2. Group structure and history

Bayfield Energy was incorporated in February 2011 and is the parent company of the Bayfield Group whose main operating subsidiaries are Bayfield Galeota, and Bayfield South Africa. Other subsidiary companies are set out at paragraph 2.7 in Part XII of this document.

In February 2008, Eni sold Burren Energy (Trinidad) Limited to former executives of Burren Energy who subsequently changed the name of this company to Bayfield Energy Limited in July 2008. BEL was the original holding company for Bayfield Galeota, the holder of the Galeota Licence. Bayfield Galeota was founded in November 2007 as Burren Energy (Galeota) Limited for the purpose of applying for and holding the Galeota Licence and exploring and developing the Galeota Block which covers an area of 122 km^2 offshore Trinidad and which was awarded on 17 April 2012.

Bayfield South Africa was formed in November 2010 with the intention for it to become the licence-holder of the exploration licence over the Pletmos Inshore Block off the south coast of South Africa covering an area of approximately 10,800 km^2. However, as at the date of this document, BEL is the licence-holder of the exploration licence over the Pletmos Inshore Block.

In 2011, the Bayfield Group was reorganised pursuant to the Scheme, under which Bayfield Energy became the holding company of BEL.

3. Summary of Bayfield Group's Licences

The Bayfield Group's Licences are summarised in the below table which is extracted from the Bayfield CPR which can be found in its entirety in Part VI of this document.

Country	Block/Permit	Operator	Bayfield Working Interest (%)	Area (km^2)	Current Phase Expiration Date
Trinidad	Galeota	Bayfield	65	121.6	20 April 2034
South Africa	Pletmos Inshore	Bayfield	90	10,800	16 April 2015
Russia	Karelatsky	AGOC	74	1,500	

Notes:

1 The initial term of the Galeota Licence is six years which is extendable to 25 years from 21 April 2009, if Bayfield Galeota declares a commercial discovery of petroleum.

2 Bayfield Energy will pay 100 per cent of costs in the Pletmos Inshore Block during the exploration phase. In the event of a commercial discovery being developed, the South African state company, PetroSA, has a 10 per cent back-in right, paying only the forward costs. Bayfield Energy's 90 per cent Working Interest shown in this table is based on PetroSA exercising its back-in right. An option also exists for a further 10 per cent to be taken by Historically Disadvantaged South Africans (HDSA), paying their share of forward costs and of past costs.

3 Bayfield also owns the Karalatsky licence an exploration and production licence over an inshore portion of the Volga Delta. However Bayfield is in the course of surrendering this licence.

Source: The above table and notes above are extracted from Table 0.1 of the Bayfield CPR set out in Part VI of this document

The Company is committed under the terms of the Galeota Licence to drill seven appraisal and exploration wells within the Galeota Block by March 2015, two of which have been drilled to date.

The Company is committed under the terms of the Pletmos Licence in the three year exploration period to reprocess 2,500km of existing 2D data and to acquire an additional 2,000 km of 2D data.

4. **Summary of the Bayfield Group's exploration and production interests**

The following tables summarise the Bayfield Group's oil and gas Reserves and Resources in respect of its interests as set out in the Bayfield CPR. The Bayfield CPR is set out in its entirety in Part VI of this document.

Summary of Gross Field Oil Reserves and Bayfield Net Entitlement Oil Reserves as at 30 June 2012

		Gross Field Oil Reserves (MMBbl)			Bayfield Net EntitlementOilReserves (MMBbl)		
Country	**Field and Area / Reservoir**	**Proved**	**Proved plus Probable**	**Proved plus Probable plus Possible**	**Proved**	**Proved plus Probable**	**Proved plus Probable plus Possible**
Trinidad	Trintes Field Main	9.85	22.77	25.05	6.40	14.80	16.28
	Trintes NE extension M	—	6.63	10.10	—	4.31	6.56
	Trintes NE extension G	—	2.19	5.53		1.42	3.59
	Trintes SW extension M	—	1.70	4.49	—	1.11	2.92
	Trintes extension GAL-9 G and H	0.60	2.10	4.48	0.39	1.36	2.91
	Trintes extension GAL-12 H	0.38	1.72	2.03	0.25	1.12	1.32
Total		**10.83**	**37.11**	**51.68**	**7.04**	**24.12**	**33.58**

Notes:

1 Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field after 30th June, 2012 onwards.

2 "Trintes Field Main" includes Reserves from continued production plus Bayfield's work-over and side-track programmes.

3 No gas Reserves are attributed to the Trintes Field.

Summary of Gross Unrisked Contingent Resources as at 30 June 2012

	Gross Unrisked Contingent Resources					
	Oil (MMBbl)			Gas (Bscf)		
Discovery	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
EG-2 & EG-8	1.22	2.81	5.51	16.31	29.13	47.48
EG-3	1.92	3.26	5.09	3.15	4.65	6.58
EG-4	18.17	31.23	47.85	3.19	5.31	7.99
GAL-21 updip	0.44	0.96	1.65	0.66	0.84	1.05
Total	**21.75**	**38.26**	**60.10**	**23.31**	**39.93**	**63.10**

Notes:

1 Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the field without any economic cut-off being applied.

2 The volumes reported here are "Unrisked" in the sense that Chance of Development values have not been arithmetically applied to the designated volumes within this assessment. Chance of Development represents an indicative estimate of the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve.

3 The primary Contingent Resource volume reported here is the 2C, or 'Best Estimate', value.

Summary of Bayfield Net Entitlement Unrisked Contingent Resources as at 30 June 2012

Discovery	Bayfield Working Interest (%)	Net Bayfield Unrisked Contingent Resources					
		Oil (MMBbl)			Gas (Bscf)		
		1C	2C	3C	1C	2C	3C
EG-2 & EG-8	65	0.79	1.83	3.58	10.60	18.93	30.85
EG-3	65	1.25	2.12	3.31	2.05	3.02	4.28
EG-4	65	11.81	20.30	31.10	2.07	3.45	5.19
GAL-21 updip	65	0.29	0.64	1.07	0.43	0.55	0.68
Total		**14.14**	**24.89**	**39.06**	**15.15**	**25.95**	**41.00**

Notes:

1 The volumes reported here are Unrisked in the sense that Chance of Development values have not been arithmetically applied to the designated volumes within this assessment. Chance of Development represents an indicative estimate of the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve.

2 The primary Contingent Resource volume reported here is the 2C, or 'Best Estimate', value.

Summary of Gross Unrisked Prospective Resources (Prospects) as at 30 June 2012

				Gross Unrisked Prospective Resources—Prospects						
			Bayfield Working Interest	Oil (MMBbl)			Gas (Bscf)			
Country / Block	**Prospect**	**Interval**	**(%)**	**Low**	**Best**	**High**	**Low**	**Best**	**High**	**GCoS (%)**
Trinidad / Galeota	NE Trintes	H3	65	3.39	6.51	10.25	—	—	—	39
		M	65	7.04	12.96	24.13	—	—	—	41
		N	65	1.92	5.55	9.77	—	—	—	17
	EG-3	O1	65	3.34	5.82	9.04	—	—	—	18
		O2	65	2.31	4.03	6.26	—	—	—	32
		O3	65	1.57	2.74	4.23	—	—	—	32
		O4	65	3.72	6.43	10.02	—	—	—	31
		E	65	1.54	3.18	5.59	—	—	—	12
	Thais	O1	65	3.07	5.36	8.31	—	—	—	10
		O2	65	3.23	5.60	8.71	—	—	—	18
		O3	65	2.17	3.76	5.84	—	—	—	18
		O4	65	5.13	8.86	13.77	—	—	—	17
		B	65	—	—	—	3.19	4.81	6.82	17
		C	65	1.52	2.64	4.09	—	—	—	17
	South Trintes	F	65	1.23	2.41	4.00	—	—	—	7
		F1	65	0.76	1.48	2.48	—	—	—	7
		G	65	0.69	1.33	2.27	—	—	—	10
		H0	65	0.43	0.88	1.60	—	—	—	7
		M	65	5.58	10.96	18.94	—	—	—	8
	GAL21 Updip	A	65	1.70	8.04	17.51				25
		B	65	1.44	6.42	14.46				36
	EG-8	E	65	0.53	1.91	4.47	—	—	—	16
	EG-2	LaSv-N1	65	0.04	0.10	0.24	—	—	—	33
	Tatiana	LaSv-N1	65	0.24	1.78	5.33	—	—	—	30
		E	65	0.33	1.65	4.34	—	—	—	16
	Denise	LaSv-N1	65	0.67	3.01	7.66	—	—	—	30
		E	65	0.58	2.40	6.06	—	—	—	16
		H	65	—	—	—	4.24	14.19	29.82	25
		Denise Deep	65	—	—	—	0.68	2.98	7.76	14
		LaSv-Tbs	65	—	—	—	3.67	17.46	46.38	14
	Gaby	COS1-I	65	1.16	4.10	7.91	—	—	—	15
		COS1-L	65	0.97	2.82	5.00	—	—	—	13
		COS1-PA	65	1.40	3.01	4.64	—	—	—	13
		COS1-PB	65	0.70	1.42	2.19	—	—	—	13
		COS1-PC	65	3.82	9.76	16.21	—	—	—	15
South Africa / Pletmos Basin	1		90	—	—	—	11.9	234.5	447.7	18
	2		90	—	—	—	9.3	85.0	175.4	15
	3		90	—	—	—	35.4	184.5	415.8	13
	5		90	—	—	—	5.5	33.6	79.9	8
	9		90	—	—	—	43.0	169.5	370.4	6
	10		90	—	—	—	518.2	1,757.6	3,753.3	6
	GA-VI		90	—	—	—	63.4	240.1	518.4	10

Notes:

1 Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.

2 Gross Unrisked Prospective Resources are 100% of the volumes estimated to be recoverable from the field.

3 The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for a Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked".

4 It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Prospect/Lead and the potential dependencies between them. Similarly, it is inappropriate to aggregate Prospective Resources with Reserves or Contingent Resources

Summary of Net Unrisked Prospective Resources (Prospects) as at 30 June 2012

Country/Block	Prospect	Interval	Bayfield Working Interest (%)	Net Bayfield Unrisked Prospective Resources—Prospects: Oil (MMBbl) Low	Best	High	Gas (Bscf) Low	Best	High	GCoS (%)
Trinidad / Galeota	NE Trintes	H3	65	2.20	4.23	6.66	—	—	—	39
		M	65	4.58	8.42	15.68	—	—	—	41
		N	65	1.25	3.61	6.35	—	—	—	17
	EG-3	O1	65	2.17	3.78	5.88	—	—	—	18
		O2	65	1.50	2.62	4.07	—	—	—	32
		O3	65	1.02	1.78	2.75	—	—	—	32
		O4	65	2.42	4.18	6.51	—	—	—	31
		E	65	1.00	2.07	3.63	—	—	—	12
	Thais	O1	65	2.00	3.48	5.40	—	—	—	10
		O2	65	2.10	3.64	5.66	—	—	—	18
		O3	65	1.41	2.44	3.80	—	—	—	18
		O4	65	3.33	5.76	8.95	—	—	—	17
		B	65	—	—	—	2.07	3.13	4.43	17
		C	65	0.99	1.72	2.66	—	—	—	17
	South Trintes	F	65	0.80	1.57	2.60	—	—	—	7
		F1	65	0.49	0.96	1.61	—	—	—	7
		G	65	0.45	0.86	1.48	—	—	—	10
		H0	65	0.28	0.57	1.04	—	—	—	7
		M	65	3.63	7.12	12.31	—	—	—	8
	GAL21 Updip	A	65	1.11	5.23	11.38	—	—	—	25
		B	65	0.94	4.17	9.40	—	—	—	36
	EG-8	E	65	0.34	1.24	2.91	—	—	—	16
	EG-2	LaSv-N1	65	0.03	0.07	0.16	—	—	—	33
	Tatiana	LaSv-N1	65	0.16	1.16	3.46	—	—	—	30
		E	65	0.21	1.07	2.82	—	—	—	16
	Denise	LaSv-N1	65	0.44	1.96	4.98	—	—	—	30
		E	65	0.38	1.56	3.94	—	—	—	16
		H	65	—	—	—	2.76	9.22	19.38	25
		Denise Deep	65	—	—	—	0.44	1.94	5.04	14
		LaSv-Tbs	65	—	—	—	2.39	11.35	30.15	14
	Gaby	COS1-I	65	0.75	2.67	5.14	—	—	—	15
		COS1-L	65	0.63	1.83	3.25	—	—	—	13
		COS1-PA	65	0.91	1.96	3.02	—	—	—	13
		COS1-PB	65	0.46	0.92	1.42	—	—	—	13
		COS1-PC	65	2.48	6.34	10.54	—	—	—	15
South Africa / Pletmos Basin	1		90	—	—	—	10.7	211.0	402.9	18
	2		90	—	—	—	8.4	76.5	157.9	15
	3		90	—	—	—	31.9	166.0	374.2	13
	5		90	—	—	—	4.9	30.2	71.9	8
	9		90	—	—	—	38.7	152.5	333.4	6
	10		90	—	—	—	466.4	1,581.8	3,378.0	6
	GA-VI		90	—	—	—	57.1	216.1	466.6	10

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for a Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked".
3. It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Prospect/Lead and the potential dependencies between them. Similarly, it is inappropriate to aggregate Prospective Resources with Reserves or Contingent Resources.

Galeota Block, Trinidad and Tobago

The Galeota Block is situated within the established oil play of the Columbus Basin in shallow waters off the south-east coast of Trinidad.

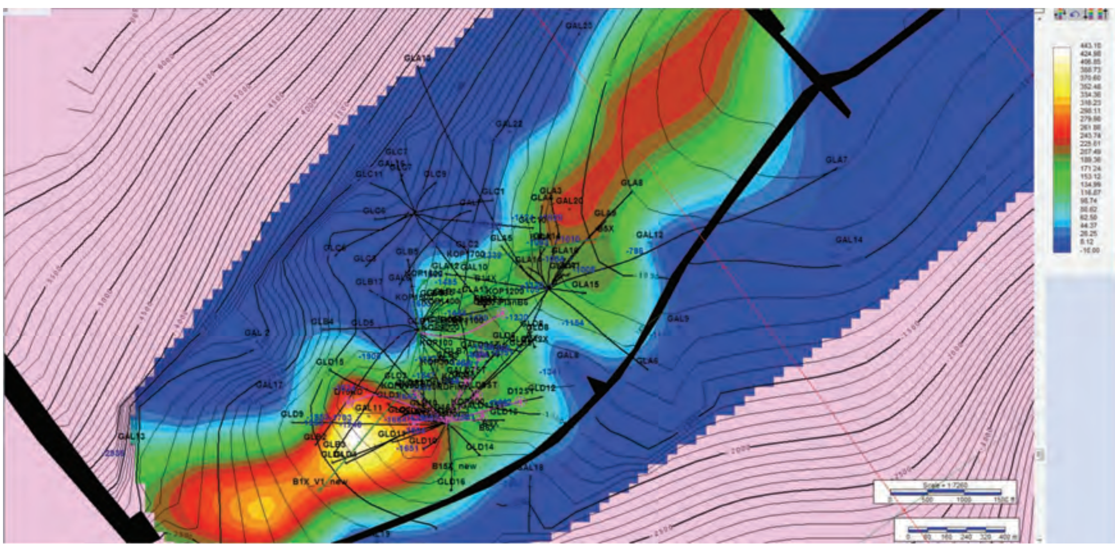
In April 2009, Bayfield Galeota and Petrotrin were awarded an exploration and production licence over the Galeota Block by the Trinidad Ministry. The Galeota Licence is for an initial term of six years extendable to 25 years from 21 April 2009, if Bayfield Galeota declares a commercial discovery of petroleum, with further five year extensions after this 25 year extension period granted at the discretion of the Trinidad Ministry.

The Galeota Licence covers 122 km^2 in the shallow waters of the prolific hydrocarbon-rich Columbus Basin off the south-east coast of Trinidad. The Galeota Block contains the Trintes Field, which was discovered in 1963 and commenced production in 1972. The Trintes Field qualifies for the 25 year extension to the Galeota Licence from 21 April 2009.

The Galeota Block also contains four discoveries dating from the 1980s with aggregate 2C Contingent Resources of oil of 38.3 MMBbl and 39.93 Bscf of gas. More recently, in March 2012, the Company announced that the EG-8 exploration well on the Galeota Block had been suspended as an oil and gas discovery. The find extends into the adjacent acreage held by Repsol and the Company has signed a memorandum of understanding with Repsol to identify development concepts for the discovery and plans to drill an appraisal well to further ascertain the full extent of the reservoir in 2013. The Directors believe the discovery is estimated to have demonstrated gross development potential of 32 MMbbl of oil and 69 Bcf of gas over both blocks.

A further exploration well, EG-7, was drilled in May 2012 the results of which were disappointing.

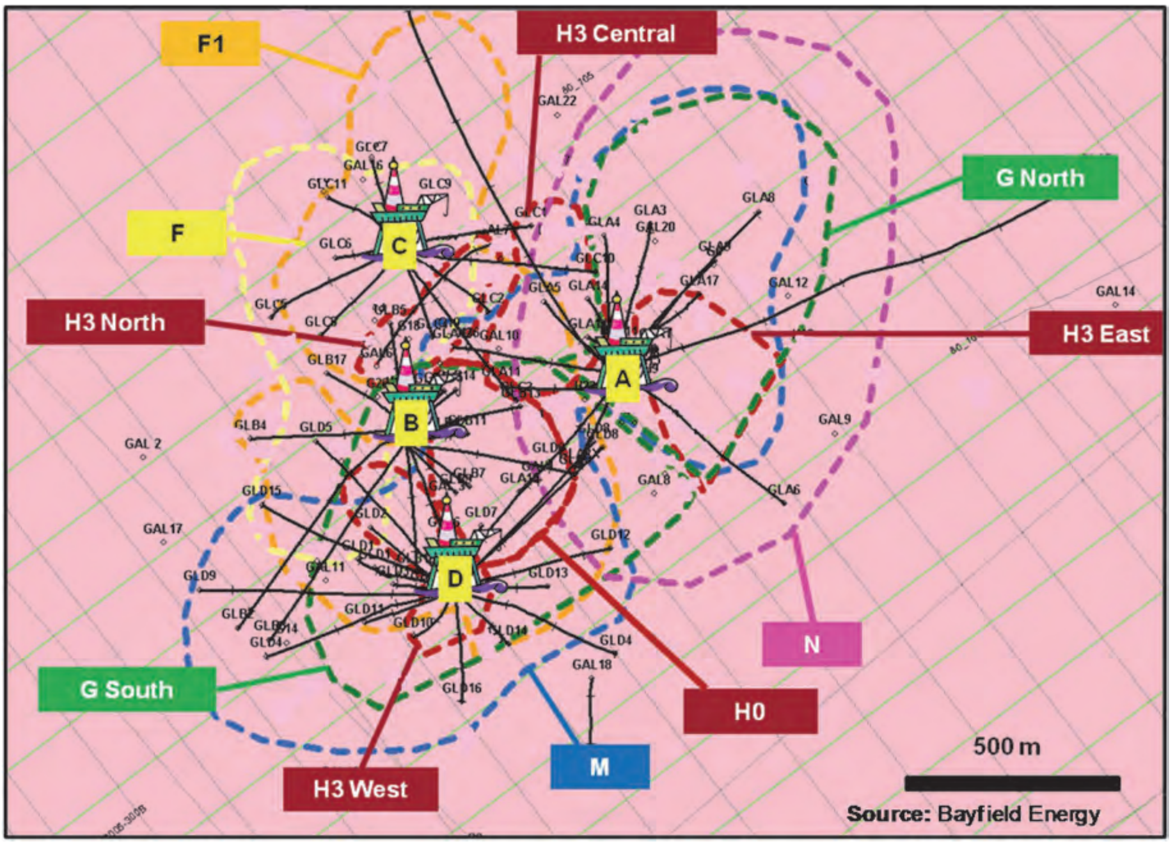
Figure 6: Net oil and M-sand structure map



Source: Bayfield

The Trintes Field commenced production in 1972 and consists of five main reservoir zones (F, F1, G, H3 and M) ranging in depth from less than 150 metres to approximately 600 metres. A total of 62 development wells have been drilled and there are currently 22 wells in production from four fixed steel platforms (Alpha, Bravo, Charlie and Delta). Bayfield has been actively pursuing an aggressive programme to revitalise the Trintes Field with a series of planned work-overs, side-tracks, including extended reach drilling and the installation of modern artificial lift methods. A 10 km, eight inch sub-sea pipeline carries production from the Alpha platform to the Galeota Tank Farm. The production infrastructure dates from the 1970s and due to its age some of the facilities have as a consequence been subject to failures which have caused disruptions to production. Since the IPO, the Bayfield Group has addressed some of these issues which has improved reliability and lead to an increase in production.

Figure 7: Trintes Field layout showing reservoirs, wells and platforms



Source: Bayfield CPR

Since acquiring the Galeota Licence, Bayfield has invested heavily in the area to upgrade the infrastructure and increase production. The Trintes Field is currently producing approximately 2,400 bbl/d (gross) and the continuing platform based rig programme to work over the existing well inventory and to drill new side-track wells is targeted to further increase production during 2013. Since the end of 2010 Bayfield has carried out some 66 work-overs and drilled 15 side track wells more than doubling the production rate compared to a year ago.

Numerous infill drilling locations have been identified in order to increase production from the field and deliver the asset's full potential with eight sidetrack wells planned for 2013 and six in 2014. The Company also proposes to continue to invest in the infrastructure and in particular one platform, Charlie, remains to be refurbished. This is planned for the second half of 2013 and the first half of 2014.

A further exploration and appraisal programme consisting of five wells during 2013 and 2014 will assist in assessing the full block potential. Three of these wells are proposed to be drilled using the platform-based rig, which will allow for reduced well costs as well as for rapid monetisation if the wells prove to be successful. Two further wells are proposed to be drilled, including appraisal of the EG-8 discovery in partnership with Repsol.

Commercial terms for the sale of Bayfield Galeota's 65 per cent. share of production are set out in a Crude Oil Sales Agreement entered into in May 2009 (as amended in September 2012) between Bayfield Galeota and Petrotrin following the award of the Galeota Licence. The COSA obliges Petrotrin to continue to accept all crude oil production from the Galeota Block on the terms specified in the COSA for the duration of the Galeota Licence. The price per barrel to be paid was based on a formula referable to the settlement prices per barrel of "NYMEX Light Sweet Oil" futures contracts less an adjustment factor, and a transportation cost of US$1.00 per gross barrel delivered. Since the amendments to the COSA in September 2012, the payment terms have been improved in Bayfield's favour and are now based on a reference price for Brent crude discounted by 9.5 per cent. This represents a significant improvement on the terms of the original agreement, in which pricing was defined as a 17.5 per cent. discount to WTI, and has resulted in an increase in the price per barrel of US$27 and in a significant improvement in the profitability of the Trintes Field.

Further details of the COSA are set out in paragraph 11.1(h) of Part XII of this document.

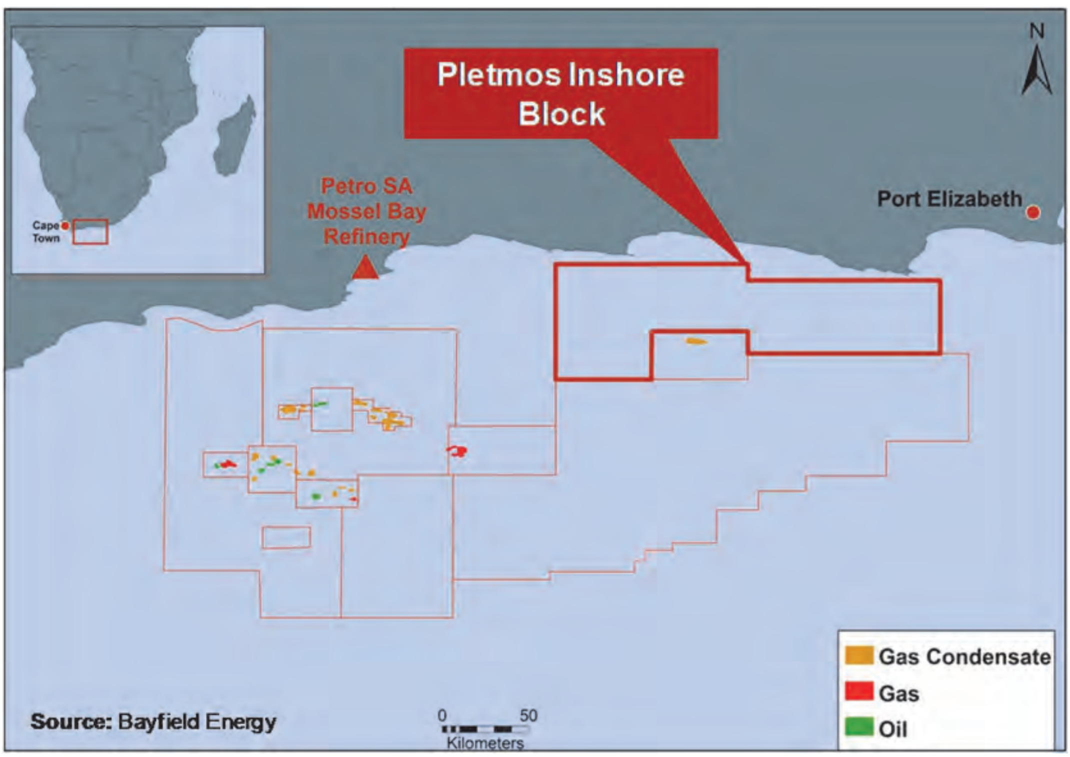
Pletmos Inshore Block, South Africa

The Pletmos Licence was granted to BEL with an effective date of 17 April 2012. The Pletmos Inshore Block in which BEL holds a 100 per cent participating interest during the exploration phase (with 10 per cent State back-in right in the event of a commercial discovery and a further 10 per cent available on commercial terms for participation by historically disadvantaged South Africans), is situated off the southern coast of South Africa, approximately 200 km east of the Mossel Bay gas to liquids plant, and covers an area of approximately 10,800 km^2. The block lies within the greater Outeniqua basin where over 4 TCF of gas has been discovered to date. Earlier exploration activity on the Pletmos Inshore Block resulted in an untested gas discovery in well Ga-VI and, to the south, several gas discoveries were tested in the same geological play. The last phase of this exploration activity ended in 1990. Subsequent studies on the Pletmos Inshore Block have identified younger geological targets. Six prospects have been mapped and require detailed seismic programmes to evaluate the potential.

Bayfield's focus during the initial three-year term of the licence will be a low cost (US$3.5-4 million) exploration programme to reprocess existing 2D seismic data over the block and a programme for the acquisition of new 2D data and 3D data to help define drilling locations. The work programme to reprocess the existing 2D seismic data has commenced, and the reprocessing should be completed in the first quarter of 2013. An environmental study of the Pletmos Inshore Block was completed in January 2011.

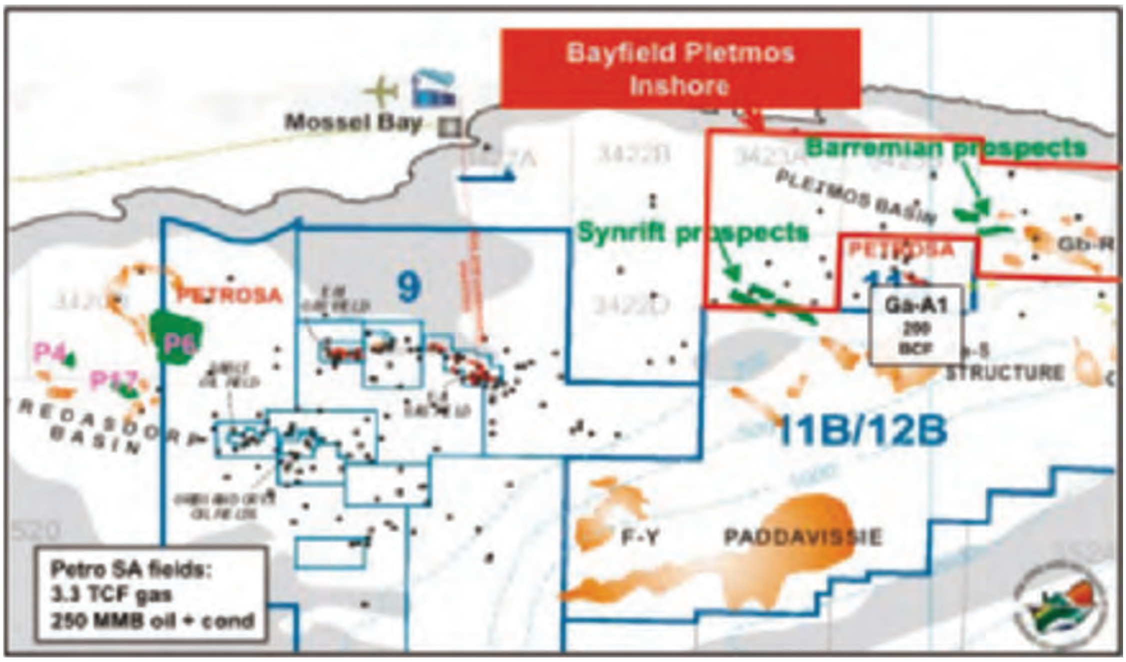
The Pletmos Inshore Block is not expected to be a core area of focus for the Enlarged Group but offers the potential to add value and the Company may choose to farm it out.

Figure 8: Location Map for the Pletmos Inshore Block, South Africa



Source: Bayfield CPR

Figure 9: Pletmos Inshore Block—area in detail:



Source: Bayfield

5. **Corporate social responsibility, environmental, health and safety**

An integral part of Bayfield Energy's strategy is to pay significant attention to the various environmental and social aspects of its operations so that it not only fully complies with all relevant legislation but also seeks to make a significant contribution to local communities. The Bayfield Group treats the health and safety of all employees as a high priority, and complies with all environmental obligations aiming to ensure that its operations do not harm the environment or affect the ecosystem in the areas which it operates.

PART IV

RISK FACTORS

All the information set out in this document should be carefully considered, in particular those risks described below.

A number of factors affect the operating results, financial condition and prospects of the Bayfield Group and the Trinity Group and, following Completion, will affect the Enlarged Group. The risks and uncertainties described below, which are not set out in any order of priority, represent those known to the Directors and the Proposed Directors as at the date of this document which the Directors and the Proposed Directors consider to be material. However, these risks and uncertainties are not the only ones facing the Bayfield Group and the Trinity Group and which will, after Completion, face the Enlarged Group; additional risks and uncertainties not presently known to the Directors or the Proposed Directors, or that the Directors or the Proposed Directors currently consider to be immaterial, could also impair the business of the Bayfield Group and Trinity Group and may impair the business of the Enlarged Group in the future. In addition, as a result of the Merger, the risks identified below may be further aggravated. If any, or a combination of, these risks actually occurs, the business, financial condition, operating results and prospects of the Bayfield Group, the Trinity Group and, after Completion, the Enlarged Group could be materially and adversely affected. In such case, the market price of the Consolidated Ordinary Shares could decline and, as a result, investors may lose all or part of their investment. Shareholders and prospective investors should carefully consider whether an investment in the Enlarged Group is suitable for them in light of the matters referred to in this documents their personal circumstances and the financial resources available to them.

1. Risks Related to the Merger

Bayfield may experience difficulties in integrating Trinity's business with Bayfield's existing business

The Merger involves the integration of two groups of companies that have previously operated independently. The difficulties of combining the companies' operations include:

- the necessity of coordinating and consolidating organisations, systems and facilities; and
- the task of integrating the management and personnel of the Bayfield Group and the Trinity Group, maintaining employee morale and retaining and incentivising key employees.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of the Enlarged Group's business and the loss of key personnel. The diversion of management's attention and any delays or difficulties encountered in connection with the Merger and the integration of the operations of the two groups could have an adverse effect on the business, results of operations, financial conditions or prospects of the Enlarged Group after the Merger. Moreover, if management is unable to successfully integrate the operations of the two groups, the anticipated benefits of the Merger may not be realised.

The Enlarged Group may not achieve the synergies Bayfield and Trinity anticipate

The Enlarged Group may fail to achieve the cost savings and revenue enhancements that Bayfield and Trinity hope will arise from the Merger. In particular, the Enlarged Group's ability to successfully realise cost synergies and revenue enhancements and the timing of this realisation may be affected by a variety of factors, including, but not limited to, unforeseeable events, including major changes in the oil and gas industry in Trinidad.

If the cost savings or revenue benefits that Bayfield and Trinity expect are not realised or are delayed, the Enlarged Group's results of operations and the market price of the Consolidated Ordinary Shares may be adversely affected.

Uncertainties associated with the Merger may cause the Bayfield Group or the Trinity Group to lose key employees

The success of the Enlarged Group after the Merger will depend in part upon Bayfield's and Trinity's ability to retain key employees. The Bayfield Group's and the Trinity Group's employees are among their most important assets. If the Enlarged Group fails to integrate, motivate and retain these employees after the Merger the performance of the Enlarged Group may be adversely affected.

Third parties may terminate or alter existing contracts with Bayfield or Trinity

The Bayfield Group and the Trinity Group have contracts with suppliers, customers, licensors, licencees, lessors, lenders, insurers and other business partners that have "change of control" or similar clauses that allow the counterparty to terminate or change the terms of their contract upon the closing of the transactions contemplated by the Merger Agreements. Bayfield and Trinity will seek to obtain consent from these other parties, but if these third party consents cannot be obtained, or are obtained on unfavourable terms, the Enlarged Group may suffer a loss of potential future revenue and other rights and protections that are material to the business of the Enlarged Group.

The Merger may be completed even if Bayfield or Trinity has experienced a material adverse change

In general, under the Merger Agreement, either party can refuse to complete the Merger if there is a material breach of an obligation, warranty or material adverse change affecting the other party between 15 October 2012 and Completion.

However, either party may choose to waive the right to terminate the Merger Agreements even in the event of a breach of an obligation, warranty or material adverse change affecting the other party.

If such breaches or adverse changes occur and the Merger is completed, Bayfield's share price may suffer.

The Company will be liable for certain transaction costs if the Merger is not completed

Shareholders should be aware that the Company will be required to pay certain transaction fees and costs if the Merger is not approved or does not otherwise complete. In these circumstances, these costs would reduce the level of cash within the Company's business.

If the Proposals are not completed, the Company would need to expeditiously seek alternative sources of funds

The Proposals are conditional upon a number of matters including the approval of the Proposals by the Bayfield Shareholders. In the event that the Proposals are not approved and subsequently completed, the Company would need to expeditiously seek alternative sources of funds to enable it to fund its working capital needs. There can be no guarantee that such funds would be available to the Company or, if they are available to the Company, that they would be available on terms which would not result in a substantial dilution of Shareholders' interests.

The due diligence process carried out by the Company may not have uncovered all potential risks and liabilities

The Company has carried out commercial, technical, legal and financial due diligence in respect of the Enlarged Group's assets. However, certain enquiries pursuant to these exercises are outstanding and could remain so at the time when the Directors may consider completion of the Merger to be commercially justified. The Company believes that it has carried out sufficient investigations to confirm that the Enlarged Group has satisfactory title to its interests in its assets. However due to the limitations of the due diligence exercises, there is no assurance that, following completion of the Merger, all potential risks and liabilities associated with the Enlarged Group's assets have been uncovered or quantified.

Centrica has a right to convert certain of the Centrica Loan Notes into Trinity Shares

Centrica currently holds Centrica Loan Notes in the principal amount of US$6,337,246.58. Completion will constitute: (i) an Accelerated Repayment Event (as defined in the Restated and Amended Loan Note Instrument) and thereby entitle Centrica to require Trinity to repay the Centrica Loan Notes in full unless otherwise redeemed or converted; and (ii) a Conversion Event (as defined in the Restated and Amended Loan Note Instrument) and thereby entitle Centrica to convert such number of Centrica Loan Notes as Centrica might elect, subject to a minimum of US$1,000,000 and a maximum of US$5,000,000, and receive such number of Trinity Shares as is equivalent to 110 per cent. of the aggregate of the total nominal amount of the Centrica Loan Notes to be converted divided by the aggregate of the consideration per Trinity Share payable to the Trinity Shareholders as consideration pursuant to the terms of the Merger. In the event that Centrica was to exercise its conversion rights, Trinity would not become a wholly owned subsidiary of the Company. Assuming that Centrica does not elect to exercise its conversion rights, Trinity intends to exercise a right to voluntarily early repay all of the Centrica Loan Notes (in an amount equal to US$6,337,246.58 together with interest accrued from 1 January 2013) shortly after Completion.

However, in the event that Centrica was to exercise its conversion rights (and thus become a minority shareholder in an unlisted subsidiary of the Company) in full (i.e. in respect of the maximum of US$5,000,000) it would be entitled to receive such number of shares in Trinity as equals US$5,500,000 (i.e. $5,000,0000 multiplied by 110 per cent.) divided by the Conversion Price (as defined in the Restated and Amended Loan Note Instrument), the Conversion Price being a price equal to the aggregate consideration per Trinity Share payable to Trinity Shareholders on completion of the Merger. The Conversion Price can only be determined at Completion but would be equal to the price (converted into US$) of a Consolidated Ordinary Share as at Completion multiplied by 747.8 (being the number of Consolidated Ordinary Shares which pursuant to the Merger are to be issued by Bayfield in exchange for the acquisition of each Trinity Share). As at Completion, it is anticipated that the issued share capital of Trinity will comprise 34,302 Trinity Shares.

The conversion formula in the Restated and Amended Loan Note Instrument provides that on conversion Centrica is entitled to a number of shares in Trinity "N", where N = C/D and where:

C = 110% of the aggregate of the notes being converted (accordingly C would be $5,500,000 assuming a maximum $5,000,000 of loan notes were converted)

D = the "Conversion Price". In relation to the Merger, the Conversion Price is the aggregate of the consideration per Trinity Share payable to Trinity Shareholders at Completion. The Merger terms provide that each Trinity Shareholder is to receive 747.8 Consolidated Ordinary Shares in exchange for each Trinity Share sold to Bayfield by that Trinity Shareholder. The value of a Consolidated Ordinary Share will only be known at Completion. However, by way of illustrative example only, if the value of a Consolidated Ordinary Share at Completion was £1.20 then the value of a Trinity Share would be 747.8 multiplied by £1.20, which equals £897.36 (equivalent to US$1,435.78 using an exchange rate of £1 = US$1.60). Accordingly, under this illustrative example the Conversion Price of a Trinity Share would be US$1,435.78.

Accordingly, in this illustrative example N would equal 5,500,000 divided by 1,435.78, such that the number of Trinity Shares which Centrica would be entitled to on conversion of the maximum of US$5,000,000 would be 3,830.

As at Completion, it is anticipated that there will be 34,302 Trinity Shares in issue. Assuming a Centrica conversion on terms of the above illustrative example, the number of Trinity Shares in issue would increase to 38,132 and Centrica would therefore hold approximately 10.0% of the issued share capital of Trinity.

2. **Risks Relating to Bayfield and to Trinity**

The Enlarged Group has a limited history of operations

Although the Enlarged Group's management has experience in Trinidad, the Bayfield Group's business was only established in 2007 and the Trinity Group's business was only established in 2005. As a result, the Enlarged Group has a limited operating history upon which prospective investors may assess its future performance. Prospective investors do not have the same level of historical operating information on which to base their investment decision as would be available with respect to a more established company. The Enlarged Group's prospects must be considered in light of the risks, expenses and difficulties frequently encountered by companies in early stage of operations in markets that are often quickly evolving. If the Enlarged Group is unable to successfully address or manage such risks, expenses or difficulties, this could have a material adverse effect on the Enlarged Group's business, prospects, financial condition and results of operations, and the trading price of the Consolidated Ordinary Shares.

The Enlarged Group holds interests in a number of exploration licences or in licences which are in their initial terms

The Enlarged Group holds interests in exploration licences or in other licences which are in their initial terms. The early stages of an exploration period of a licence are commonly the most risky. These phases of the term of a licence may require high levels of relatively speculative capital expenditure without a commensurate degree of certainty of a return on that investment.

The Trinity Group has not fulfilled all of its minimum work obligations in respect of all of its licences on an asset by asset basis

The ability of the Enlarged Group to develop and exploit oil and gas Reserves depends on the Enlarged Group's compliance with its obligations under its licences. The licences granted by the Trinidad Minister of Energy set out the term of the licence and the minimum work obligations and expenditure obligations that need to be complied with by the licencee during such term. The Trinidad Minister of Energy is entitled to revoke the licence and the licencee's right to carry out petroleum operations where there is a failure by the licencee to fulfil the minimum work obligations or to meet its expenditure obligations. The Trinity Group has not fulfilled all of its minimum work obligations in respect of all of its licences on an asset by asset basis. However, the Trinidad Minister of Energy typically considers compliance by a licencee with its minimum work obligations on a portfolio basis and on this basis the Trinity Group has substantially fulfilled these obligations. The Trinity Group has not received any notification from the Trinidad Minister of Energy of any breach by any licencees within the Trinity Group of its licence obligations. The revocation by the Trinidad Minister of Energy of the Trinity Group's licences in these circumstances could have a material adverse effect on the Enlarged Group's business, results of operations and financial condition.

Petrotrin currently purchases all of the Trinity Group's and the Bayfield Group's crude oil

Petrotrin currently purchases all of the Trinity Group's and the Bayfield Group's crude oil. Accordingly, each of the Trinity Group's revenue and the Bayfield Group's revenue is heavily dependent on Petrotrin. The price Petrotrin pays the Trinity Group and the Bayfield Group for its crude oil is not fixed and maintenance of the current pricing is not guaranteed. Accordingly, there is limited transparency as to the ultimate pricing the Enlarged Group will receive for its oil. In addition, the revised pricing terms in respect of Bayfield's crude oil agreed under the COSA Amendment Agreement are effective for a minimum period of 12 months only. Any long term disruption to Petrotrin's refinery operations could impact the Trinity Group's and the Bayfield Group's ability to sell to Petrotrin. Whilst each of Trinity's and Bayfield's crude oil sales agreements with Petrotrin contain termination provisions designed to protect the Trinity Group and the Bayfield Group respectively in the short term, the loss of Petrotrin as a customer could have a material adverse effect on the revenue and future growth of the Enlarged Group's business as the Enlarged Group would need to seek a new purchaser for its crude oil in Trinidad. Should the Enlarged Group be unable to meet the requirements of Petrotrin, this may damage its reputation in the market place in Trinidad with investors and other contractors and impair its ability to attract new investors, contractors and purchasers for its production.

Trinity's Tabaquite sub-licence has expired

The Trinity Group's sub-licence in respect of the Tabaquite Block has expired. A final draft of a new licence for the Tabaquite Block to Tabaquite Exploration & Production Company Limited, a subsidiary of Trinity T&T, has been finalised and is awaiting execution and issuance by the Trinidad Ministry. Trinity expects the new licence will be executed and issued in 2013. Trinity T&T has continued to operate the Tabaquite Block with the knowledge and consent of the Trinidad Ministry pending the grant of the new licence. The Tabaquite Block accounts for only a minimal amount of the Trinity Group's current production, therefore should the Trinidad Ministry not enter into the new licence with Trinity T&T or any other Member of the Enlarged Group (or provide its consent to Petrotrin entering into the new licence with Trinity T&T) there would only be a minimal effect on the revenue and future growth of the Enlarged Group's business.

The Enlarged Group may experience unexpected shutdowns at its facilities

Mechanical problems, accidents, oil leaks or other events at the Enlarged Group's platforms or its pipelines or subsea infrastructure may cause an unexpected production shutdown at these platforms. The Bayfield Group's oil platforms in the Trintes Field (and the equipment used on such platforms) are relatively old, and in the past have been subject to several mechanical failures, thereby disrupting the Bayfield Group's ability to maintain its level of production. Whilst steps have been taken to rectify such failures, the Enlarged Group is likely to continue to be subject to such failures. Some of the Bayfield Group's offshore production pipes and connectors in the Trintes Field need to be replaced, and there is a risk that spillage of fluids may leak into the sea, causing pollution. The Bayfield Group is currently reviewing and consulting on its options regarding its offshore production pipes and connectors in the Trintes Field with a view to ultimately resolving its export route. At the current time the Bayfield Group has in place a risk mitigation protocol with respect to any actual or potential spillage of fluids, which thus far has proved effective in mitigating the risk of pollution. This protocol includes regularly inspecting the Galeota Block and if any oil is found on the surface, Bayfield immediately notifies Petrotrin and investigates the cause of the spillage. In addition, Bayfield measures the volume of oil which enters each pipeline and the volume of oil which exits such pipeline. If there is any disparity between such amounts, Bayfield inspects the pipeline immediately to identify and repair the leak. If any leak is identified, Bayfield usually fixes the pipeline within 48 hours of becoming aware of the leak. Any unplanned production shutdown of the Enlarged Group's facilities or environmental damage caused by pollution from the Enlarged Group's facilities could have a material adverse effect on the Enlarged Group's business, oil production, financial condition and results of operations.

Overpressures have been encountered in deeper wells in the Galeota Block

Given the nature of E&P drilling, overpressures are a general drilling risk. However, specific overpressures have been encountered in deeper wells in the Galeota Block and regionally in the Columbus Basin. Several scientific papers have been published on the distribution of abnormal pressures, which occur at shallower depths towards the northeast of the basin. Mud and casing programmes are designed to take account of this issue to mitigate the likelihood of well blow outs.

Darcy Carr may bring an unfair prejudice claim against members of the Bayfield Group in relation to 3,500,000 options over Existing Unconsolidated Ordinary Shares

Darcy Carr and Wajang, a company understood to be controlled by Darcy Carr, have made various requests and/or assertions against certain members of the Bayfield Group, further details of which are set out at paragraph 12.1 of Part XII of this document. Wajang is a shareholder of the Company, which will, following Admission, be interested in approximately 0.22 per cent. of the Enlarged Share Capital. Darcy Carr was previously a director of BEL, a subsidiary of Bayfield.

Darcy Carr has:

(i) requested that certain vesting conditions over 3,500,000 share options granted to Wajang ("**Wajang Options**") be removed in association with his stepping down as a director of BEL and has asserted that the period to exercise the Wajang Options be extended as described below; and

(ii) requested that Bayfield Galeota ratify and confirm the terms of a production bonus consultancy agreement purportedly entered into between Bayfield Galeota and Investments International (Trinidad) Limited on 17 June 2008.

In accordance with the terms of the option agreement in relation to the Wajang Options, Wajang was given the opportunity occasioned by the change of control of BEL pursuant to the Scheme, to exercise the Wajang Options. Wajang claimed that it was being treated differently to those optionholders who were employees or officers of BEL. These optionholders were given the opportunity to surrender their options over shares in BEL in exchange for equivalent options over shares in the Company. Darcy Carr has asserted that the only reason he was not involved in the affairs of BEL was because he had been improperly removed as a director in March 2011. He sought to obtain an extension to the exercise period within which the Wajang Options needed to be exercised. BEL refused to grant such an extension. Wajang did not exercise the Wajang Options, and in accordance with the terms of the option agreement pursuant to which the Wajang Options were granted, in the Company's opinion, the Wajang Options have now lapsed. Darcy Carr has however asserted that he has been treated unfairly and has reserved his rights in relation to making an unfair prejudice claim in relation to the loss of the Wajang Options. The Company considers that BEL has complied with its obligations under the option agreement in relation to the Wajang Options and refutes that Darcy Carr has been treated unfairly. The Company also considers that Darcy Carr was properly removed as a director in accordance with BEL's articles of association and the shareholders agreement between the then shareholders of BEL.

Bayfield Galeota may be found liable to make a payment to Darcy Carr or to companies associated with Darcy Carr in connection with a production bonus consultancy agreement

Darcy Carr has requested that Bayfield Galeota ratify and confirm the terms of a production bonus consultancy agreement purportedly entered into between Bayfield Galeota and Investments International (Trinidad) Limited ("**Investments Trinidad**") on 17 June 2008 ("**Investments Trinidad Agreement**"). The Company is not aware that the Investments Trinidad Agreement exists, but is aware of a similar agreement made between Bayfield Galeota and Sceptre dated 11 September 2008, further details in respect of which are set out at paragraph 11.1(a) of Part XII of this document. Notwithstanding Darcy Carr's request referred to above, in relation to the Investments Trinidad Agreement, Darcy Carr subsequently indicated to BEL that the Sceptre Agreement was intended to supersede the terms of such agreement. The Sceptre Agreement was entered into at a time when Darcy Carr was a director and employee of both BEL and Bayfield Galeota the terms of which stated that Sceptre was to provide advice to Bayfield Galeota in connection with the farm-in of the Galeota Block. So far as the Directors are aware no services have ever been provided by Sceptre pursuant to the Sceptre Agreement. Neither the purported Investments Trinidad Agreement nor the Sceptre Agreement were approved by the boards of either Bayfield Galeota or Bayfield Galeota's ultimate parent at such time, BEL.

In light of the above, the Company believes that Bayfield Galeota does not have any obligation to Investments Trinidad or to Sceptre in relation to either the purported Investments Trinidad Agreement or the Sceptre Agreement. However, in the event that any of Investments Trinidad, Sceptre or Darcy Carr do establish a basis for a claim against Bayfield Galeota which is upheld in the courts, the maximum liability that Bayfield Galeota could incur would be limited to the maximum consulting fee payable thereunder of up to US$5.5 million in aggregate plus any costs and expenses incurred in relation to the claim.

On 28 September 2012, Bayfield Galeota received a pre-action notice from lawyers representing Sceptre claiming a sum of US$500,000 in respect of the first amount due in respect of the consultancy fee under the Sceptre Agreement. On 12 December 2012, the lawyers advising Bayfield Galeota replied to such pre-action notice, denying, for the reasons set out above, any liability of Bayfield Galeota to Sceptre and asserting that Bayfield Galeota considers the Sceptre Agreement to be null and void. Bayfield Galeota intends to continue to vigorously resist this claim and any other claim in relation to the Investments Trinidad Agreement and the Sceptre Agreement. Further details of this claim are set out at paragraph 12.1 of Part XII of this document.

Bayfield Galeota may suffer adverse consequences if it fails to maintain a performance guarantee in a form acceptable to the Trinidad Minister of Energy

Clause 7 of the Galeota Licence requires Bayfield Galeota to provide the Trinidad Minister of Energy with a performance guarantee for US$16.25 million, in the form of a bond or bankers guarantee or "such other form acceptable to the Trinidad Minister of Energy". Regulations 45(2) to 47 of the Petroleum Act provide for the reduction of the amount of the performance guarantee required by Clause 7 of the Galeota Licence at the end of each twelve-month period by the actual qualifying expenditure incurred pursuant to the Galeota Licence during the period.

The total expenditure incurred by Bayfield Galeota to date has been in excess of US$16.25 million, which consequently should reduce the performance guarantee requirement to zero. However, Bayfield Galeota is in technical breach of Regulation 45 of the Petroleum Act and Clause 7 of the Galeota Licence as a result of not having a performance guarantee in place. Any failure by Bayfield Galeota to maintain a performance guarantee in a form acceptable to the Trinidad Minister of Energy is a breach of its obligations under the Galeota Licence and gives the Trinidad Minister of Energy the right to revoke the Galeota Licence under Clause 17 thereof. However, such revocation right can only be exercised by the Trinidad Minister of Energy after providing reasonable notice to Bayfield Galeota in advance of the proposed revocation, specifying the material breach complained of and requiring Bayfield Galeota to remedy its breach within the time specified by the Trinidad Minister of Energy. Bayfield Galeota has not received any such notification from the Trinidad Minister of Energy.

Bayfield Galeota may become liable for the failure by Niko Resources (Trinidad and Tobago) Limited to observe its obligations under the Drilling Contract

On 1 April 2011, a drilling contract for the provision of the jack-up "Rowan Gorilla III" drilling unit (the "**Rig**") and related services was entered into between Niko, Bayfield Galeota and Rowan Drilling (Trinidad) Limited and subsequently novated pursuant to a novation agreement dated 26 May 2011 between Niko, Bayfield Galeota, Rowan Drilling (Trinidad) Limited and AMSI (together, the "**Drilling Contract**"), which was amended pursuant to an Amendment Agreement No. 1 dated 22 July 2011 and pursuant to an Amendment Agreement No.2 dated on or around 24 October 2012. Further details of the Drilling Contract are set out at paragraph 11.1 of Part XII of this document.

The Drilling Contract makes Bayfield Galeota and Niko jointly and severally liable for each other's obligations, regardless of which entity has operational control over the drilling unit. Any failure by Niko to comply with its obligations under the Drilling Contract may immediately make Bayfield Galeota liable. These obligations include the obligation to make payment for the drilling services, but also extends to issues such as the knock for knock liability, liability in relation to well blowouts, loss of or damage to the wells and loss, destruction or damage to the drilling equipment while in the hole. On 1 April 2011 Niko and Bayfield Galeota entered into an amended and restated shared services agreement (the "**SSA**") under which each of Niko and Bayfield Galeota granted the other an indemnity against their default under the Drilling Contract. However, were Niko to default in their indemnification obligations, Bayfield Galeota would remain liable to AMSI for a default under the Drilling Contract by Niko. The Company has no reason to believe that a default by Niko under the Drilling Contract is likely to occur.

Under the SSA, Bayfield Galeota is entitled and obliged to use the drilling rig for five firm and two optional wells, in the sequence specified in the SSA. It is also required to pay for 185 days of the drilling period and bear an agreed proportion of the mobilisation and demobilisation fee.

However, in the event that Bayfield Galeota is unable to drill the number of wells or in the sequence required under the SSA, it is not able to assign its rights under the Drilling Contract without Niko's consent. Instead, Bayfield Galeota will have to continue to pay for the rig and its proportion of the mobilisation and demobilisation fee. Even where Niko is able to use the rig or renegotiate the drilling schedule, Bayfield Galeota will still only receive a reimbursement of 80 per cent. of the rig rate paid and no reimbursement of the mobilisation and demobilisation fee (unless another operator comes into the contract).

In order to mitigate this risk, on or around 24 October 2012, Bayfield Galeota entered into the Rig Sharing Agreement, the EOG Assignment and Amendment No. 2 in order to transfer Bayfield Galeota's rig slots and future obligations under the Drilling Contract to EOG. The Rig was released to EOG on 13 November 2012. Further details of these agreements are set out at paragraph 11.1 of Part XII of this document.

Bayfield may become liable to pay certain amounts under the Drilling Contract to Niko

On 11 September 2012, Niko wrote to Bayfield enclosing an invoice in respect of an amount of US$1,269,600 which equates to 20 per cent. of the termination fee under the Drilling Contract, which Niko claims is payable by the Bayfield Group pursuant to the SSA. Bayfield Galeota responded to Niko on 25 September 2012 stating that, given the collaboration between Bayfield Galeota and Niko to secure the Drilling Contract, it does not accept that there is any obligation on Bayfield Galeota under the SSA to pay the amount claimed by Niko.

If Niko does not withdraw its demand for payment as anticipated, the Bayfield Group may be liable to pay up to US$1,269,600 to Niko.

A change of control of the Company following Admission could trigger a right for Petrotrin to acquire Bayfield Galeota's participating interest in the Galeota Block on the same terms as the purchaser

The Galeota JOA contains a change of control provision, such that if (following Admission) there is any change in the ownership of 50 per cent. or more of the voting rights of Bayfield Galeota or the Company and the market value of the assets the subject of the Galeota JOA (being the Galeota Block) represents 25 per cent. or more of the aggregate market value of the assets of Bayfield Galeota or the Company then, inter alia, Petrotrin would be entitled to exercise its pre-emption rights and acquire the participating interest of Bayfield Galeota in the Galeota Block. In such circumstances, the consideration payable by Petrotrin would be the same monetary value offered by the proposed purchaser, and subject to the same terms and conditions negotiated with the proposed purchaser. Accordingly, if a purchaser were to acquire more than 50 per cent. of the voting rights of the Company following Admission then Petrotrin's pre-emption right would be triggered if the market value of the Galeota Block represents 25 per cent. or more of the aggregate market value of the assets of Bayfield Galeota or the Enlarged Group.

The Enlarged Group cannot accurately predict its future decommissioning liabilities

The Enlarged Group, through its licence interests, has assumed certain obligations in respect of the decommissioning of its fields and related infrastructure and is expected to assume additional decommissioning liabilities in respect of its future operations. These liabilities are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and require the Enlarged Group to make provision for and/or underwrite the liabilities relating to such decommissioning. Any significant increase in the actual or estimated decommissioning costs that the Enlarged Group incurs may adversely affect its financial condition.

The Enlarged Group's success is dependent upon its ability to attract and retain key personnel

The Enlarged Group's success depends, to a large extent, on certain of its key personnel. The loss of the services of any key personnel could have a material adverse effect on the Enlarged Group. The Enlarged Group does not maintain, nor does it plan to obtain, key person insurance against the loss of any of its key personnel. In addition, the competition for qualified personnel in the oil and gas industry is intense. There can be no assurance that the Enlarged Group will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

The Enlarged Group is subject to the risk of labour disputes and adverse employee relations

The Enlarged Group's partners, contractors or service providers may be limited in their flexibility in dealing with their staff due to the presence of trade unions among their staff. If there is a material disagreement between partners, contractors or service providers and their staff belonging to trade unions (as has been the case before in respect of the Trinity Group, where labour disputes at Petrotrin have disrupted the Trinity Group's production and in the case of Oilbelt Services where a collective bargaining agreement expired on 30 June 2012 and is currently being renegotiated), the Enlarged Group's operations could suffer an interruption or shutdown that could have a material adverse effect on its business, results of operations or financial condition.

The Enlarged Group's tax liabilities could increase substantially as a result of changes in, or new interpretations of, tax laws in the UK, Trinidad and South Africa

The Enlarged Group is or will be subject to taxation in the UK, Trinidad and South Africa, and is faced with increasingly complex tax laws. The amounts of taxes the Enlarged Group pays could increase substantially as a result of changes in, or new interpretations of, these laws, which could have a material adverse effect on its liquidity and results of operations. During periods of high profitability, there have historically been calls for increased or windfall taxes on oil and gas revenue. Taxes have increased or been imposed in the past and may increase or be imposed again in the future. In addition, tax authorities could review and question the Enlarged Group's tax returns leading to additional taxes and penalties which could be material. Decommissioning (where relevant) could also have a material tax impact.

The Enlarged Group may not be able to generate cash flows or finance its activities if it is unable to raise additional capital

The Enlarged Group will be required to make substantial capital expenditure for the acquisition, exploration, development and production of oil and gas Reserves in the future. If the Enlarged Group's revenues do not increase, it may have limited ability to raise the capital necessary to undertake or complete future drilling programmes. There can be no guarantee that cash generated by operations or debt or equity financing will be available or sufficient to meet the Enlarged Group's funding requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Enlarged Group. The Enlarged Group's inability to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects. This risk factor does not however affect the working capital statement set out at paragraph 9 of Part XII of this document.

The Enlarged Group may be unable to identify or complete any potential acquisitions or may not be able to acquire such interests on satisfactory terms or at all

The Enlarged Group is currently focused on the development of its assets in Trinidad and South Africa, but intends, in due course, to expand through the acquisition of other assets in the oil and gas sector whether in Trinidad, South Africa or elsewhere. The Enlarged Group may face significant competition in acquiring additional oil and gas assets, and many of its competitors may have greater financial resources and larger technical staffs than the Enlarged Group has. There can be no assurance that the Enlarged Group will be able to identify suitable acquisitions and strategic investment opportunities, acquire interests on satisfactory terms or obtain the financing necessary to complete and support such acquisitions.

Any failure to identify and execute future acquisitions successfully could adversely impact the Enlarged Group's long term growth strategy. In addition, acquisitions and investments involve a number of risks, including possible adverse effects on the Enlarged Group's operating results, diversion of management's attention, failure to retain key personnel, risks associated with unanticipated events or liabilities and difficulties in the assimilation and integration of the operations.

If the Enlarged Group fails to integrate future acquisitions successfully, its rate of expansion could slow

The assimilation and integration of acquired businesses requires significant time and effort of the Enlarged Group's senior management. Integration of new businesses can be difficult, and potential problems may include, but would not be limited to, integration of management, integration of common financial reporting procedures and accounting policies, the assumption of disclosed and undisclosed liabilities, including in relation to tax and environmental matters relating to the acquired assets or businesses, the possibility that indemnification agreements with the sellers of those assets may be unenforceable or insufficient to cover potential tax or other liabilities, and implementation of agreed headcount reductions. The Enlarged Group could experience difficulties in integrating future acquisitions, which could materially and adversely affect its business.

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

Currency exchange rate fluctuations and currency devaluations could have a material adverse effect on the Enlarged Group's results of operations from time to time. Historically, most of the Enlarged Group's revenue has been generated in US dollars, but it predominantly incurs or will incur operating expenses in the Trinidad and Tobago dollar and South African Rand. As the Enlarged Group's reporting currency is the US dollar, a depreciation of the US dollar against these other currencies would adversely affect the Enlarged Group's reported results of operations. Although the Enlarged Group may periodically undertake limited hedging activities (where such a market exists for these types of instruments) in an attempt to reduce certain currency fluctuation risks, these activities provide only limited protection against currency-related losses. In addition, in some circumstances hedging activities could require the Enlarged Group to make cash outlays.

The Company's ability to pay dividends on the Consolidated Ordinary Shares will depend on the availability of distributable reserves

The Company's ability to pay dividends is limited under company law, which limits a company to only paying dividends to the extent that it has distributable reserves and cash available for this purpose.

As a holding company, the Company's ability to pay dividends in the future is affected by a number of factors, principally its ability to receive sufficient dividends from subsidiaries. The payment of dividends to the Company by its subsidiaries is, in turn, subject to restrictions, including certain regulatory requirements and the existence of sufficient distributable reserves and cash in the Company's subsidiaries.

Investing in Bayfield Energy's Consolidated Ordinary Shares involves an investment in emerging markets

Generally, investment in emerging markets is only suitable for sophisticated investors who fully appreciate the significance of the risks involved in, and are familiar with, investing in emerging markets. Investors should also note that emerging markets such as Trinidad and Tobago and South Africa, are subject to rapid change and that the information set forth in this document may become outdated relatively quickly. Moreover, financial turmoil in any emerging market country tends to adversely affect prices in equity markets of all emerging market countries as investors move their money to more stable, developed markets. As has happened in the past, financial problems or an increase in the perceived risks associated with investing in emerging economies could dampen foreign investment in Trinidad and Tobago and South Africa and adversely affect the Trinidad and Tobago and South Africa economies. Thus, even if these economies remain relatively stable, financial turmoil in other emerging market countries could adversely affect the Enlarged Group's business, as well as result in a decrease in the price of the Consolidated Ordinary Shares.

3. **Risks Relating to the Oil and Gas Industry**

The Enlarged Group's success depends on its ability to appraise, find, acquire, develop and produce oil and gas Reserves that are economically recoverable

The Enlarged Group's long-term commercial success depends on its ability to appraise, find, acquire, develop and commercially produce oil and gas Reserves. The Enlarged Group will need continually to locate and develop or acquire new Reserves to replace its existing Reserves that are being depleted by production. Future increases in the Enlarged Group's Reserves will depend not only on its ability to explore and develop its existing interests in Trinidad and South Africa but also on its ability to select and acquire suitable additional interests either through awards at licensing rounds or through acquisitions. There are many reasons why the Enlarged Group may not be able to find or acquire oil and gas Reserves or develop them for commercially viable production. For example, the Enlarged Group may be unable to negotiate commercially reasonable terms for its acquisition, exploration, development or production activities. Factors such as adverse weather conditions, natural disasters, equipment or services shortages, procurement delays or difficulties arising from the political, environmental and other conditions in the areas where the Reserves are located or through which the Enlarged Group's products are transported may increase costs and make it uneconomical to develop potential Reserves. Moreover, the Enlarged Group may become dependent on the competence and judgement of third-party operators in relation to the development of Reserves where it is not itself the operator. Without successful further development exploration or acquisition activities, the Enlarged Group's Reserves, production and revenues will not increase. There is no assurance that the Enlarged Group will discover, acquire or develop further commercial quantities of oil and gas.

The Enlarged Group's Reserves and Resources information represents estimates that may turn out to be incorrect or inaccurate

The process of estimating oil and gas Reserves and Resources and the cash flows that may be derived from them is very complex. The Reserves and Resources information relating to the Enlarged Group set out in this document represent estimates only. In general, estimates of the quantity and value of economically recoverable oil and gas Reserves and the possible future net cash flows are based upon a number of variable factors and assumptions, such as historic production rates, ultimate Reserves recovery, interpretation of geological and geophysical data, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, continuity of current fiscal policies and regulatory regimes, future oil and gas prices, operating costs, development and production costs and workover and remedial costs, all of which may vary from actual results. Estimates are also to some degree speculative, and classifications of Reserves are only attempts to define the degree of speculation involved. In addition, there are uncertainties inherent in estimating the quantity of Resources and Prospective Resources and in projecting future rates of production, including factors beyond the Enlarged Group's control. Estimating the amount of hydrocarbon Resources and Prospective Resources is a subjective process and, in addition, results of drilling, testing and production subsequent to the date of an estimate may result in material revisions to original estimates. For these reasons, estimates of the economically recoverable oil and gas Reserves attributable to a particular Enlarged Group of properties, the classification of such Reserves based on risk of recovery and estimates of expected future net revenues prepared by different engineers, or by the same engineers at different times, may vary. As a result, the estimates of the Enlarged Group's Reserves may require substantial upward or downward revisions if subsequent drilling, testing and production reveal differences. Any downward adjustment could indicate lower future production and thus adversely affect the Enlarged Group's financial condition, future prospects and market value. Furthermore, a decline in the Enlarged Group's Reserves, or an inability to increase the amount of the Enlarged Group's Reserves, may affect its ability to raise or access sufficient capital for its future operations.

Estimates of Proved, Probable and Possible Reserves that may be developed and produced in the future are often not based on actual production history but on volumetric calculations and analogies to similar types of Reserves. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same Reserves based on production history and production practices may result in variations in the estimated Reserves and these variations could be material.

The Resources and Prospective Resource data contained in this document, and specifically in the Bayfield CPR, and the Trinity CPR, are estimates only and should not be construed as representing exact quantities. The nature of Reserve quantification studies means that there can be no guarantee that estimates of quantities and quality of oil and gas disclosed will be available for extraction. Therefore, actual production, revenues, cash flows, royalties and development and operating expenditures may vary from these estimates. Such variances may be material.

In this document, the standards applied by the Society of Petroleum Engineers PRMS are applied with respect to estimates of the Enlarged Group's Reserves. Under the PRMS standards, Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward from known reservoirs and under defined economic conditions, operating methods and government regulations. Probable Reserves are those additional Reserves which analysis of geoscience and engineering data suggests are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. Possible Reserves are those additional Reserves which analysis of geoscience and engineering data suggests are less likely to be recoverable than Probable Reserves. Prospective investors should be aware that certain categories of Reserves and Resources (such as Prospective and Contingent Resources) are inherently less certain than other categories (such as 1P or 2P Reserves).

The Enlarged Group may not be able to develop commercially its Contingent and Prospective Resources

Under PRMS standards, Contingent Resources are those deposits that are estimated, on a given date, to be potentially recoverable from known accumulations by application of development projects, but that are not currently considered commercially recoverable due to one or more contingencies. As at the date of this document, a material proportion of the Enlarged Group's oil and gas resources fall into this category. The Contingent Resources may not be considered commercially recoverable by the Enlarged Group for a variety of reasons, including the high costs involved in recovering the resources, the price of oil and gas at the time, the availability of the Enlarged Group's resources and other development plans that the Enlarged Group may have. By contrast, Prospective Resources are those deposits that are estimated, on a given date, to be potentially recoverable from undiscovered accumulations. The Enlarged Group's estimates of its Contingent and Prospective Resources are uncertain and can change with time and there can be no guarantee that the Enlarged Group will be able to develop these resources commercially. The Enlarged Group will need to undertake a substantial drilling campaign in Trinidad, with a view to reclassifying its Contingent Resources into Reserves. There is no guarantee that such drilling campaign will be successful.

A decrease in oil or gas prices may adversely affect the Enlarged Group's results of operations and financial condition

Oil and gas prices are volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Enlarged Group's net production revenue. Historically, oil prices have fluctuated widely for many reasons, including global and regional supply and demand, and expectations regarding future supply and demand for oil and petroleum products; geopolitical uncertainty; access to pipelines, tanker ships and other means of transporting oil, gas and petroleum products; prices, availability and government subsidies of alternative fuels; prices and availability of new technologies; the ability of the members of OPEC and other oil-producing nations to set and maintain specified levels of production and prices; political, economic and military developments in oil producing regions, particularly the Middle East; domestic and foreign governmental regulations and actions, including export restrictions, taxes, repatriations and nationalisations; global and regional economic conditions; and weather conditions and natural disasters.

It is impossible to predict accurately future oil and gas price movements. Accordingly, oil and gas prices may not remain at their current levels. The economics of producing from some of the Enlarged Group's wells may change as a result of lower prices, which could result in a reduction in the volumes of the Enlarged Group's Reserves if some are no longer economically viable to develop. The Enlarged Group might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Enlarged Group's net production revenue causing a reduction in its oil and gas acquisition, development and exploration activities and financial condition. In addition, bank borrowings available to the Enlarged Group in the future are expected in part to be determined by the Enlarged Group's borrowing base. A sustained material decline in prices from historical average prices could reduce the Enlarged Group's borrowing base, therefore reducing the bank credit available to the Enlarged Group.

Exploration projects do not necessarily result in a profit on the investment or the recovery of costs

A significant focus for the Enlarged Group will be its exploration activities on its licences in Trinidad and South Africa. Exploration activities are capital intensive and inherently uncertain in their outcome. The Enlarged Group's future oil and gas exploration projects may involve unprofitable efforts, either from dry wells or from wells that are productive but do not produce sufficient net revenues to return a profit after development, operating and other costs. Completion of a well does not guarantee a profit on the investment or recovery of the costs associated with that well. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or adverse geological conditions. While diligent well supervision and effective maintenance operations can contribute to maximising production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and may adversely affect the Enlarged Group's revenues and cash flows.

Exploration, development and production activities are dependent on the availability of equipment and services

The Enlarged Group's oil and gas exploration and development activities are dependent on the availability of drilling and other equipment and onshore and offshore services and delivery infrastructure in Trinidad and South Africa. As an example, the availability of appropriate rigs can be limited, particularly given there is only one provider of onshore rigs based in Trinidad and Tobago. This rig provider is Well Services which is a related party of Trinity (further details of this relationship are set out in paragraph 14.2(a) of Part XII of this document). Even where the Enlarged Group has secured rigs under a contract, the rigs may only be available for use after the current user has finished its drilling programme. If there are delays in the completion of the user's drilling programme, the Enlarged Group could be delayed in procuring contracted rigs. Under the terms of its exploration licences, the Enlarged Group may have a commitment to drill within a certain time frame. The Enlarged Group, therefore, risks losing licences if it is delayed in obtaining rigs and thus meeting its drilling commitments. Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect the Enlarged Group's development, exploration and production operations, which could have a material adverse effect on its business, financial condition or results of operations. In addition, oil and natural gas exploration and development activities are dependent on the availability of delivery infrastructure, including, but not limited to, access to production facilities that have the capacity to process crude oil and natural gas in the particular areas where those activities will be conducted. In addition, the Enlarged Group may not become the operator of all of its oil and gas properties. To the extent that the Enlarged Group is not the operator of any of its oil and gas properties, the Enlarged Group will be largely dependent on third-party operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

The Enlarged Group may miss out on exploration opportunities if it is unable to successfully co-ordinate its exploration projects

The Enlarged Group intends to undertake significant exploration projects in Trinidad and South Africa. These projects require the co-ordination of a number of activities including obtaining seismic data, carrying out subsea surveys, obtaining partner approvals and securing rig capacity for the necessary drilling. In the current high-demand market environment, there can be long lead times to arrange these activities. If the Enlarged Group fails to successfully co-ordinate the timely delivery or completion, as the case may be, of any of these activities, it may miss out on exploration opportunities or may be required to make additional expenditure.

The Enlarged Group's onshore and offshore operations are subject to a number of risks and hazards that may result in material losses in excess of insurance proceeds

Oil and gas exploration, development and production operations are inherently risky and hazardous. Risks typically associated with these operations include unexpected formations or pressures, premature decline of reservoirs and the intrusion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on the Enlarged Group's results of operations, liquidity and financial condition. Hazards typically associated with onshore and offshore oil and gas exploration, development and production operations include fires, explosions, blowouts, marine perils, including severe storms and other adverse weather conditions, vessel collisions, gas leaks and oil spills, each of which could result in substantial damage to oil and gas wells, production facilities, other property and the environment or in personal injury. Oil and gas installations are also known to be likely objects, and even targets, of military operations and terrorism.

Although the Enlarged Group obtains insurance prior to drilling in accordance with industry standards to cover certain of these risks and hazards, insurance is subject to limitations on liability and, as a result, may not be sufficient to cover all of the Enlarged Group's losses. In addition, the risks or hazards associated with the Enlarged Group's onshore and offshore operations may not in all circumstances be insurable or, in certain circumstances, the Enlarged Group may elect not to obtain insurance to deal with specific events due to the high premiums associated with such insurance or for other reasons. The occurrence of a significant event against which the Enlarged Group is not fully insured, or the insolvency of the insurer of such event, could have a material adverse effect on the Enlarged Group's financial position, results of operations and prospects.

The Enlarged Group's business is subject to government regulation with which it may be difficult to comply and which may change

The Enlarged Group's oil and gas exploration and production operations are principally subject to the laws and regulations of Trinidad and South Africa, including those relating to health and safety and the production, development, operation, transportation, storage, pricing and marketing of oil and gas. In addition, the Enlarged Group will be subject to laws in those jurisdictions affecting foreign ownership, government participation, taxation, royalties, duties, rates of exchange, exchange control and the environmental and health and safety matters. In order to conduct its operations in compliance with these laws and regulations, the Enlarged Group must obtain licences and permits from various government authorities. The Enlarged Group may incur substantial costs in order to maintain compliance with these existing laws and regulations and additional costs if these laws are revised or if new laws affecting the Enlarged Group's operations are passed. Furthermore, there can be no assurance that the Enlarged Group will be able to obtain all necessary licences and permits that may be required to carry out exploration, development and production operations on its properties.

The Enlarged Group's operations expose it to significant compliance costs and liabilities in respect of environmental and/or health and safety matters

The Enlarged Group's operations and assets are affected by numerous international and national laws and regulations concerning health and safety and environment ("HSE") matters including, but not limited to, those relating to discharges of hazardous substances into the environment, the handling and disposal of waste. The technical requirements of these laws and regulations are becoming increasingly complex, stringently enforced and expensive to comply with and this trend is likely to continue. The failure to comply with current HSE laws and regulations may result in regulatory action, the imposition of fines or the payment of compensation to third parties; each of which could in turn have a material adverse effect on the Enlarged Group's business, financial condition and results of operations.

Certain HSE laws provide for strict, joint and several liability without regard to negligence or fault for natural resource damages, health and safety, remediation and clean-up costs of spills and other releases of hazardous substances, and such laws may impose liability for personal injury or property damage as a result of exposure to hazardous substances. Further, such HSE laws and regulations may expose the Enlarged Group to liability for the conduct of others or for acts that complied with all applicable HSE laws when they were performed. In addition, the enactment of new HSE laws or regulations or stricter enforcement or new interpretations of existing HSE laws or regulations could have a significant impact on the Enlarged Group's operating costs and require further expenditure to modify operations, install pollution control equipment, perform cleanup operations, curtail or cease certain operations, or pay fines or make other payments for pollution, discharges or other breaches of HSE requirements. There can be no assurances that the Enlarged Group will be able to comply with such HSE laws in the future. The failure to comply with such HSE laws or regulations could result in substantial costs and/or liabilities to third parties or government entities which could have a material adverse effect on the Enlarged Group's business, financial condition and results of operations.

The Enlarged Group must comply with its licences and the work programmes thereunder

Each of the Enlarged Group's exploration and production licences have incorporated within them significant obligations and detailed work programmes which have to be complied with and fulfilled. These may include seismic surveys to be performed, wells to be drilled, production to be attained, limits to production and construction matters.

Failure by the Enlarged Group to comply with such obligations, whether inadvertent or otherwise, may lead to fines, penalties, restrictions and withdrawal of licences, any of which could materially and adversely affect the Enlarged Group's results of operations or financial condition.

Oil production companies, including the Company, may be adversely affected by current global economic conditions

The current global recessionary environment and the volatility of international markets have caused governments and central banks to undertake unprecedented intervention designed to stabilise global and domestic financial systems, stimulate new lending and support structurally important institutions at risk of failing. Many developed economies have experienced recession over the past year and growth has slowed in many emerging economies, with serious adverse consequences for asset values, employment levels, consumer confidence and levels of economic activity. Interest rate yield curves have flattened; interest rates have fallen in absolute terms in many markets; and trade flows have contracted. Global equity markets are recovering following severe declines and various currencies have depreciated significantly against the US dollar. Numerous governments and central banks have responded by proposing programmes to make substantial funds and guarantees available to boost liquidity and confidence in their financial systems, as well as cutting taxes and lowering interest rates. The Enlarged Group's financial condition and business prospects are affected by global and local economic and market conditions. A further deterioration of these conditions could have a material adverse effect on the Enlarged Group's business, prospects, financial condition and results of operations, and the trading price of the Consolidated Ordinary Shares.

The Enlarged Group may become exposed to a variety of risks relating to joint venture parties and contractors

The Enlarged Group may become exposed to a variety of risks related to any co-venturers, joint venture parties and contractors retained by the operators of the assets owned by or licenced to the Enlarged Group with which the Enlarged Group contracts that may adversely affect its current and proposed activities and current and proposed interest, including:

- financial default, non-compliance with obligations or default by a participant in any joint venture or farm-in/farm-out arrangement to which it is, or may become a party;
- insolvency or other managerial default by any of the contractors used by any joint venture or farm-in/farm-out party in the proposed exploration activities; and
- insolvency or other managerial default by any of the other service providers used by any joint venture or farm-in/farm-out party for any activity.

The Enlarged Group will compete with numerous other organisations that have substantially greater resources than the Enlarged Group

The oil and gas industry is competitive in all of its phases. The Enlarged Group will compete, and will continue to be in competition, with numerous other organisations in the search for, and the acquisition of, oil and gas assets and, in due course, possibly in the marketing of oil and natural gas. Its competitors include oil and gas companies that have substantially greater financial resources, staff and facilities than the Enlarged Group. The Enlarged Group's ability to acquire and/or increase its oil and gas interests in the future will depend not only on its ability to explore and develop its licence interests, but also on its ability to select and acquire other suitable prospects for exploratory drilling.

The marketability of oil and gas is affected by numerous factors beyond the Enlarged Group's control

The marketability of oil and gas is affected by and dependent on numerous factors beyond the Enlarged Group's control, the precise effects of which cannot be accurately predicted. These factors include market fluctuations, general economic activity, action taken by other oil and gas producing nations, proximity, distance to markets and capacity of oil and gas pipelines and processing equipment, availability of transportation capacity, the availability and pricing of other competitive fuels and government regulations such as regulations relating to taxation, royalties, production levels, imports and exports, land tenure and land use, offshore licences, health and safety and the environment.

The Group may be unable to acquire, retain, convert or renew the licences, permits and other regulatory approvals necessary for its operations

The ability of the Enlarged Group to develop and exploit oil and gas Reserves depends on the Enlarged Group's continued compliance with the obligations of its current licences and the Enlarged Group's ability to convert its exploration opportunities into production licences. The Enlarged Group depends on licences whose grant and renewal are subject to the discretion of the relevant governmental authorities and cannot be assured.

It is also possible that the Enlarged Group may be unable or unwilling to comply with the terms or requirements of the licences it holds, including the meeting of specified deadlines for prescribed tasks and other obligations set out in the work programmes attached to the licences, in circumstances that entitle the relevant authority to suspend or withdraw the terms of such licence. Non-compliance with these obligations may give rise to enforcement action by the relevant authorities, who may agree to waivers and extensions or may require remedial action but who are also entitled to revoke the licences in such circumstances.

Moreover, some of the production licences may expire before the end of what the Enlarged Group estimates to be the productive life of its licenced fields. There is no assurance that the Enlarged Group will be able to secure extensions to the terms of its licences. Any premature termination, suspension or withdrawal of licences may have a material adverse effect on the Enlarged Group's business, results of operations and financial condition.

The Enlarged Group may, from time to time become involved in legal disputes the outcome of which can be difficult to predict

The Enlarged Group may from time to time become involved in legal disputes and legal proceedings related to the Enlarged Group's operations or otherwise. Damages claimed under any litigation are difficult to predict, and may be material. The outcome of such litigation may materially impact the Enlarged Group's business, results of operations or financial condition. While the Enlarged Group will assess the merits of any such lawsuit and defend itself accordingly, it may be required to incur significant expenses or devote significant resources to defending itself against such litigation. In addition, adverse publicity surrounding such claims may have a material adverse effect on the Enlarged Group's business, financial condition and results of operations.

Breaches of covenant in relation to the Enlarged Group's borrowing facilities resulting in an acceleration of outstanding debt would have a material adverse effect on the Enlarged Group's financial condition

Any breach of existing covenants and undertakings under the Enlarged Group's borrowing facilities with a subsequent acceleration of outstanding debt would have a material adverse effect on the Enlarged Group's financial condition. Furthermore, market conditions may restrict the Enlarged's Group's ability to borrow which could affect the expansion plans of the Enlarged Group. Events in the credit markets in recent years have significantly restricted the supply of credit, as financial institutions have applied more stringent lending criteria or exited the market entirely. If current market conditions continue, it is likely to be more costly and more difficult for the Enlarged Group to refinance its debt and to raise new loan facilities to take advantage of opportunities.

4. **Risks Relating to the ownership of the Consolidated Ordinary Shares**

There may be a lack of liquidity in the Consolidated Ordinary Shares

There can be no assurance that an active trading market will develop after the Placing, that any active trading market that may develop will be sustained or that the Consolidated Ordinary Share price will not decline below the Placing Price. No financial institution is obliged to make a market in the Consolidated Ordinary Shares, and to the extent that any financial institution undertakes any market-making activities, these activities may be terminated at any time without notice. The Placing Price will be determined by way of a bookbuilding procedure and may not be indicative of prices that will prevail in the market following the Placing. The Company cannot predict the extent to which investor interest in the Consolidated Ordinary Shares will lead to the development of a trading market or how liquid such a market might become. Investors may experience greater price volatility and less efficient execution of buy and sell orders and may not be able to resell the Consolidated Ordinary Shares at or above the Placing Price.

Investment in AIM-traded securities involves a high degree of risk

Investment in shares traded on AIM involves a higher degree of risk, and such shares may be less liquid, than shares in companies which are listed on the Official List. The AIM Rules for Companies are less demanding than those of the Official List. It is emphasised that no application is being made for the admission of the Company's securities to the Official List.

The price of the Consolidated Ordinary Shares may be volatile

Following the Placing, the price of the Consolidated Ordinary Shares could fluctuate significantly. The price of shares sold in an offering is frequently subject to relatively higher volatility for a period of time following the offering.

The market price of the Consolidated Ordinary Shares may, in addition to being affected by the Company's actual or forecast operating results, fluctuate significantly as a result of factors beyond the Company's control, including the results of exploration, appraisal and development programmes and production operations; changes in securities analysts' recommendations or estimates of earnings or financial performance of the Company, its competitors or the industry, or the failure to meet expectations of securities analysts; fluctuations in the prices of oil, gas and other petroleum products, fluctuations in stock market prices and volumes; general market volatility; changes in laws, rules, regulations and taxes, applicable to the Enlarged Group, its operations and the operations in which the Enlarged Group has interests; loss of key personnel and involvement in litigation.

Future sales of Consolidated Ordinary Shares could result in a material adverse effect on the market price of the Consolidated Ordinary Shares

The Company is unable to predict when and if substantial numbers of Consolidated Ordinary Shares will be sold in the open market following Admission. Any such sales, or the perception that such sales might occur, could result in a material adverse effect on the market price of the Consolidated Ordinary Shares.

The Enlarged Group may require additional capital in the future which may not be available to it. If available, future financings to provide this capital may dilute Shareholders' proportionate ownership in the Company

The Company may raise capital in the future through public or private equity financings or by raising debt securities convertible into Consolidated Ordinary Shares, or rights to acquire these securities. Any such issues may exclude the pre-emption rights pertaining to the then outstanding shares. If the Company raises significant amounts of capital by these or other means, it could cause dilution for the Company's existing Shareholders. Moreover, the further issue of Consolidated Ordinary Shares could have a negative impact on the trading price and increase the volatility of the market price of the Consolidated Ordinary Shares. The Company may also issue further Consolidated Ordinary Shares, or create further options over Consolidated Ordinary Shares, as part of its employee remuneration policy, which could in aggregate create a substantial dilution in the value of the Consolidated Ordinary Shares and the proportion of the Company's share capital in which investors are interested.

Securities or industry analysts may not publish research or reports about the Company's business or may adversely change their recommendations regarding the Consolidated Ordinary Shares

The market price for the Consolidated Ordinary Shares may be influenced by the research and reports that industry or securities analysts publish about the Enlarged Group's industry or the Company itself. If one or more of the analysts who cover the oil and gas sector downgrades the Consolidated Ordinary Shares or reports negatively on the industry, the market price of the Consolidated Ordinary Shares would likely decline. If one or more of these analysts ceases coverage of the Company or fails to publish reports on the Company regularly, the Company could lose visibility in the financial markets, which could cause the market price or liquidity of the Consolidated Ordinary Shares to decline.

Exchange rate fluctuations may impact the price of the Consolidated Ordinary Shares or the value of any dividends paid

The Consolidated Ordinary Shares, and any dividends to be announced in respect of such Consolidated Ordinary Shares, will be quoted in Sterling. An investment in the Consolidated Ordinary Shares by an investor in a jurisdiction whose principal currency is not Sterling exposes the investor to foreign currency rate risk. Any depreciation of Sterling in relation to such foreign currency will reduce the value of the investment in the Consolidated Ordinary Shares in foreign currency terms and may adversely impact the value of any dividends.

Holders of Consolidated Ordinary Shares outside the UK may not be able to participate in future equity offerings

The Companies Act provide for pre-emptive rights generally to be granted to Shareholders, unless such rights are disapplied by shareholder resolution. However, Shareholders outside the UK may not be entitled to exercise these rights. US holders of the Consolidated Ordinary Shares are customarily excluded from exercising any such pre-emption rights they may have unless a registration statement under the US Securities Act is effective with respect to those rights, or an exemption from the registration requirements or similar requirements in other jurisdictions thereunder is available. The Company has no current intention to file any such registration statement, and cannot assure prospective investors that any exemption from the registration requirements would be available to enable US or other overseas holders to exercise such pre-emption rights or, if available, that it will utilise any such exemption.

Consolidated Ordinary Shares may be unsuitable as an investment

The Consolidated Ordinary Shares may not be a suitable investment for all recipients of this document. Before making any investment, prospective investors are advised to consult an investment adviser, authorised by the FSA, who specialises in advising on the acquisition of AIM securities. The value of the Consolidated Ordinary Shares and the income received from them can go down as well as up and investors may get back less than their original investment.

Forward Looking Statements

Certain statements within this document constitute forward looking statements. Such forward looking statements involve risks and other factors which may cause the actual results, achievements or performance of the Enlarged Group to be materially different from any future results, achievements or performance expressed or implied by such forward looking statements. Such risks and factors include, without limitation, general economic and business conditions, changes in government regulation, competition, changes in development plans and other risks described in this Part IV. There can be no assurance that the results and events contemplated by the forward looking statements in this document will, in fact, occur. The Company will not undertake any obligation to release publicly any revisions to these forward looking statements to reflect events, circumstances or unanticipated events occurring after the date of this document, except as required by law or by regulatory authority.

PART V

COMPETENT PERSON'S REPORT ON TRINITY

RPS Energy

309 Reading Road, Henley-on-Thames, Oxfordshire RG9 1EL, United Kingdom
T +44 (0)1491 415400 F +44 (0)1491 415415 E rpshen@rpsgroup.com W www.rpsgroup.com

Trinity Exploration and Production Services Limited
3rd Floor
SSL Building
40-44 Sutton Street
San Fernando
Trinidad
West Indies

Jefferies International Limited
Vintners Place
68 Upper Thames Street
London
EC4V 3BJ
United Kingdom

FirstEnergy Capital LLP
85 London Wall
London
EC2M 7AD
United Kingdom

Seymour Pierce Limited
20 Old Bailey
London
EC4M 7EN

RBC Europe Limited
(trading as RBC Capital Markets)
Riverbank House
2 Swan Lane
London
EC4R 3BF
United Kingdom

ECV1870
January 25th 2013

VALUATION OF PETROLEUM ASSETS IN TRINIDAD

In response to Trinity's request of March 2012 and the Letter of Engagement dated May 1st 2012 with Trinity Exploration and Production Services Limited (the "Agreement"), a subsidiary of Trinity Exploration & Production Limited ("Trinity"), RPS Energy Consultants Limited ("RPS") has completed an independent valuation of liquid hydrocarbons in offshore Brighton Marine, Point Ligoure, one farmout operatorship and eight onshore lease operated licence areas, Trinidad (the "Properties") in which Trinity and its subsidiaries has an interest.

This report is issued by RPS under the appointment by Trinity Exploration and Production Services Limited and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

The Company may disclose the signed and dated report to third parties as contemplated by the Purpose defined in the Agreement but in making any such disclosure the Company shall require the third party (including any Sponsor and Third Parties) to accept it as confidential information only to be used or passed on to other persons as the Company is permitted to do under the Agreement.

This report fulfils the requirements of the AIM Guidance Note for Mining, Oil and Gas Companies, June 2009 ("the AIM Guidance") using the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System (See Appendix B).

This report has been prepared for inclusion in the prospectus to be published in relation with the reverse takeover of Bayfield Energy Holdings plc ("Bayfield") by Trinity and the re-admission of the enlarged share capital of Bayfield to trading on the AIM market of the London Stock Exchange.

The report is based on data and information available up to June 30th 2012. An effective date of July 1st 2012 has been assumed for the valuation.

The Services have been performed by an RPS team of professional petroleum engineers, geoscientists and economists and is based on the Operator's data, supplied through Trinity. All Reserves and Resources definitions and estimates shown in this report are based on the 2007 SPE/AAPG/WPC/SPEE Petroleum Resource Management System ("PRMS").

Our approach has been to review the Operator's technical interpretation of their base case geoscience and engineering data for the field for reasonableness and to review the ranges of uncertainty for each parameter around this base case in order to estimate a range of petroleum initially in place and recoverable. For the prospects, Trinity's technical interpretation of geoscience data was reviewed.

SUMMARY OF RESERVES AND RESOURCES

Fields and Discoveries

Reserves in the fields and discoveries as of 01 July 2012 that have been estimated by RPS are summarised in Table 1.

	Gross Oil Reserves (Mstb)[2]			Trinity Net WI Oil Reserves (Mstb)[2]			Trinity Net Oil Reserves Entitlement[2,3] (Mstb)		
Field	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
Brighton	2,250	4,541	6,916	2,250	4,541	6,916	1,816	3,734	5,736
Fyzabad-2	39	74	147	39	74	147	21	41	81
Guapo-1	35	94	179	35	94	179	19	51	98
Point Ligoure	274	664	1011	192	465	708	168	407	619
Tabaquite	8	39	111	8	39	111	6	27	77
WD-2	147	415	687	147	415	687	107	292	481
WD-5/6	626	1,330	3,476	626	1,330	3,476	347	737	1,898
WD-13	34	77	295	34	77	295	19	43	177
WD-14	26	55	139	26	55	139	14	30	76
WD-16	1	1	1	1	1	1	1	1	1
ARITHMETIC TOTAL[1]	**3,442**	**7,289**	**12,964**	**3,360**	**7,090**	**12,661**	**2,518**	**5,361**	**9,245**

1 Individual 1P, 2P and 3P values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1P (Low Case) may be very conservative and the arithmetic total 3P (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

2 1P, 2P and 3P cases each include Developed Producing; Developed Non-producing and Undeveloped Reserves.

3 Trinity Net Reserves Entitlement is Trinity's WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

Table 1: Reserves as of 01 July 2012

Contingent Resources as of 01 July 2012 that have been estimated by RPS are summarised in Table 2.

	Contingent Resources (Mstb)								
	Gross Field			Trinity Working Interest			Trinity Net Entitlement[1]		
	1C	2C	3C	1C	2C	3C	1C	2C	3C
Brighton Inner[2]	1,386	3,316	7,686	1,386	3,316	7,686	1,165	2,785	6,456
Point Ligoure / Guapo / Brighton Outer[2]	1,447	3,747	8,479	1,013	2,623	5,935	886	2,295	5,193
WD-2	138	461	731	138	461	731	93	301	477
WD-13	262	545	1,128	262	545	1,128	146	326	712
WD-14	323	624	1,332	323	624	1,332	176	368	837
Fyzabad-2	63	139	423	63	139	423	33	74	241
Guapo-1	49	102	337	49	102	337	27	58	208
Tabaquite	52	150	428	52	150	428	44	128	353
WD-5/6	318	787	1,616	318	787	1,616	168	414	904
ARITHMETIC TOTAL[3]	**4,040**	**9,870**	**22,160**	**3,606**	**8,746**	**19,616**	**2,737**	**6,750**	**15,381**

Notes

1 Trinity's net entitlement is Trinity's WI share of Resources after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

2 Assuming 53% of the Contingent Resources in Brighton Marine are within the Brighton Marine Inner Block and 47% within the Brighton Marine Outer Block.

3 Individual 1C, 2C and 3C values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1C (Low Case) may be very conservative and the arithmetic total 3C (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

Table 2: Contingent Resources as of 01 July 2012

For each license, the 1C, 2C and 3C Contingent Resources are treated as incremental to the 2P Reserves case for total license calculations including the Petrotrin Over-riding Royalty. In some instances the additional contingent resources may extend the economic life of the field. The contingent resources shown in Table 2 also include any incremental barrels from any extension of the field. Table 3 shows the possible addition to the gross 2P reserves from the extended life of field due to the addition of the respective 1C, 2C and 3C gross Contingent Resources.

	Contingent Resources Only (Mstb)			Field Extensions (Mstb)			Contingent Resources Including Field extensions (Mstb)		
Field	1C	2C	3C	1P	2P	3P	1C	2C	3C
Brighton	1,386	3,316	7,686	0	0	0	1,386	3,316	7,686
Fyzabad-2	18	76	331	45	64	92	63	139	423
Guapo-1	12	50	246	37	52	91	49	102	337
Point Ligoure / Guapo / Brighton Outer	1,447	3,741	8,473	0	6	6	1,447	3,747	8,479
Tabaquite	40	131	404	13	19	23	52	150	428
WD-2	138	432	693	0	29	38	138	461	731
WD-5/6	186	550	1,226	132	237	390	318	787	1,616
WD-13	207	487	1,070	55	58	58	262	545	1,128
WD-14	249	549	1,256	74	76	76	323	624	1,332
ARITHMETIC TOTAL[1]	**3,684**	**9,330**	**21,386**	**356**	**540**	**774**	**4,040**	**9,870**	**22,160**

1 Individual 1C, 2C and 3C values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1C (Low Case) may be very conservative and the arithmetic total 3C (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

Table 3: Gross Contingent Resources as of 01 July 2012

Prospective Resources

The recoverable volumes for key prospects are summarised in Table 4.

Gross Prospective Resources			
Low (Mstb)	**Best (Mstb)**	**High (Mstb)**	**GPoS[1] (%)**
1,663	**6,843**	**20,700**	**19**

1 This aggregation assumes that all prospects are successful. The probability of this occurring is the product of the GPoS values for each individual prospect.

Table 4: Prospective Resources

Economic valuation of reserves and resources are linked to a long term price forecast for West Texas Intermediate crude (WTI). The RPS Base Case price used for all valuations presented in this report is given in Table 5. Appropriate price differentials to WTI have been applied to each field.

Year	Base Price Case (US$/stb, MOD)
2012 (6 months)	91.50
2013	90.00
2014	89.00
2015	90.20
2016	92.01
2017	93.85
2018	95.72
2019	97.64
2020	99.59
2021	101.58
2022	103.61
2023	105.69
2024	107.80
2025 onwards	+2% p.a.

Table 5: Base Case WTI Oil Price Forecasts

The post-tax Net Present Values (NPV) of Trinity's Reserves at 10% discount rates in US$ MM Money of the Day (MoD), applying the Base Case price forecasts, are tabulated in Table 6.

	Post-Tax Net Present Value NPV_{10} (US$ Million, MoD)		
	1P	**2P**	**3P**
Brighton	2.4	36.5	73.2
Fyzabad-2	0.0	0.2	0.7
Guapo-1	−0.2	0.1	0.3
Point Ligoure	2.5	4.9	6.9
Tabaquite	0.0	0.2	0.5
WD-2	−3.3	1.2	5.1
WD-5/6	1.2	6.9	18.3
WD-13	−0.1	0.4	2.8
WD-14	−0.1	0.1	0.7
WD-16	−0.1	−0.1	−0.1
Total Value from Fields	**2.3**	**50.3**	**108.5**
Consolidation Effects[1]	12.7	16.0	17.4
Total Value	**15.0**	**66.3**	**125.9**

1 Consolidation effects include benefits from consolidating Petroleum Profits Tax including tax losses and capital depreciation balances. No Corporate overhead has been included in the valuations.

Table 6: Post-Tax Valuation (Net Trinity's Share) of Trinity's Reserves in Trinidad (as of 01 July 2012)

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Mr Gordon Taylor, Director, Subsurface 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 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 results 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 Services have 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 Trinity. 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. As stated in the Agreement, RPS cannot and does not guarantee the accuracy or correctness of any interpretation made by it of any of the data, documentation and information provided by the Company or others in accordance with the Agreement. The Consultant does not warrant or guarantee, through the Services, this report or otherwise, any geological or commercial outcome.

A site visit to both the onshore and offshore production facilities was performed by RPS during July 2012.

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 only be used in accordance with the Agreement. It must not be reproduced or redistributed, in whole or in part, to any other person than the addressees or published, in whole or in part, for any purpose without the express written consent of RPS. The reproduction or publication of any excerpts, other than in relation to the circular and prospectus in connection with an IPO, is not permitted without the express written permission of RPS.

RPS has given and not withdrawn its written consent to the issue of the admission document, with its name included within it, and to the inclusion of this report and references to this report in the admission document.

As at the date of this letter, RPS is not aware of any material change since the effective date of this report that should be included in the report. RPS accepts responsibility for the information contained in the RPS report set out in this part of the admission document and those parts of the admission document which include references to this report and declares that 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,
Head of Subsurface

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1. EXECUTIVE SUMMARY

In response to Trinity's request of March 2012 and the Letter of Engagement dated May 1st 2012 with Trinity Exploration and Production Services Limited (the "Agreement"), RPS Energy Consultants Limited ("RPS") has completed an independent valuation of liquid hydrocarbons in offshore Brighton Marine, Point Ligoure, one farmout operatorship and eight onshore lease operated licence areas, Trinidad (the "Properties") in which Trinity Exploration and Production Services Limited ("Trinity") has an interest. The Trinity interest is through Ten Degree North Operating Company Limited ("Ten Degree North"), a wholly owned subsidiary of Trinity Exploration & Production (Trinidad and Tobago) Limited. Some assets are held by wholly owned subsidiaries of Ten Degree North.

Trinity Exploration and Production Services Limited ("Trinity") has interests in four offshore blocks (Brighton Inner, Brighton Outer, Guapo and Point Ligoure) and nine onshore licences (Guapo-1, Fzyabad-2, Tabaquite, WD-2, WD-5, WD-6, WD-13, WD-14 and WD-16), Trinidad. All the onshore blocks, except Tabaquite, are operated under lease operatorships under a programme introduced by the national oil company (Petrotrin) to reactivate idle wells. The Tabaquite licence is a farmout operatorship. The Brighton Inner and Pointe Ligoure licences are Joint Ventures; the former including the Brighton Marine field. The Guapo and Pointe Ligoure blocks are expected by Trinity to be combined with Brighton Outer block and converted into one licence in November 2012.

Trinity has a 100% working interest in all the licences with the exception of the future licence of Point Ligoure / Guapo / Brighton Outer in which Trinity expects to have a 70% working interest with no Petrotrin over-riding royalty.

The Brighton Marine field produces high-quality 26 to 46 degrees API crude. Several new wells were drilled into the field by Venture in 2001, including the highly prolific ABM 151 well with cumulative production exceeding 500,000 barrels of oil. Current production has averaged 410 barrels of oil per day for Q1 2012 with 67 of the field areas 316 wells still producing oil.

Wells within the Point Ligoure Block have produced in excess of 6 MMBbls of oil. Production within the Point Ligoure Block commenced in the 1950's with long-reach, deviated wells drilled from shore into offshore traps along the south side of the Los Bajos Fault. Two wells are currently active and produce approximately 180 barrels of oil per day. The ALM-22 well tested 300 bopd of 16 API oil from sand within the Forest Formation and is currently suspended.

The onshore producing fields leased to Trinity lie to the south of Trinidad in the Southern Sub-Basin, the main oil-producing region. Five principal reservoir intervals ranging in depth from less than 150 to over 1800 metres have been developed from these blocks onshore Trinidad. Trinity has an aggressive programme to revitalise the onshore fields with a series of planned workovers, side-tracks, replacement and infill wells. Approximately eleven wells are planned onshore Trinidad in 2012, mainly in the WD-2 and WD-5/6 blocks.

The Properties that have been valued are summarised in Table 1-1.

Asset	Operator	Interest (%)	Status	Licence Expiry	Licence Area (Km^2)	Comments
Brighton Inner	TDN	100.0	Production	06 Oct 2024	22.1	
Brighton Outer	TDN	70.0	Exploration	01 Sept 2018	42.4	Agreement expired. Renewal expected November 2012 for a further 6 years.
Guapo	TDN	70.0	Exploration	01 Sept 2018	3.0	Agreement expired. Renewal expected November 2012 for a further 6 years.
Point Ligoure	TDN	70.0	Production	01 Sept 2018	17.3	Agreement expired. Renewal expected November 2012 for a further 6 years.
Fyzabad-2	TDN	100.0	Production	31 Dec 2020	4.4	
Guapo-1	TDN	100.0	Production	31 Dec 2020	6.5	
Tabaquite	TDN	100.0	Production	01 Sept 2018	31.0	Licence terms are under discussion with agreement anticipated in early 2013
WD-2	TDN	100.0	Production	31 Dec 2020	3.8	
WD-5	TDN	100.0	Production	31 Dec 2020	5.8	
WD-6	TDN	100.0	Production	31 Dec 2020		
WD-13	TDN	100.0	Production	31 Dec 2020	1.5	
WD-14	TDN	100.0	Production	31 Dec 2020	1.4	
WD-16	TDN	100.0	Production	31 Dec 2020	1.5	

TDN—Ten Degrees North Operating Company Limited, a wholly owned subsidiary of Trinity Exploration & Production (Trinidad and Tobago) Limited.

Table 1-1: Summary of Trinity Assets

The estimated Reserves and Resources, as of July 1st 2012 defined using the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System are shown below.

Field	Gross Oil Reserves (Mstb)[2]			Trinity Net WI Oil Reserves (Mstb)[2]			Trinity Net Oil Reserves Entitlement[2,3] (Mstb)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Brighton	2,250	4,541	6,916	2,250	4,541	6,916	1,816	3,734	5,736
Fyzabad-2	39	74	147	39	74	147	21	41	81
Guapo-1	35	94	179	35	94	179	19	51	98
Point Ligoure	274	664	1011	192	465	708	168	407	619
Tabaquite	8	39	111	8	39	111	6	27	77
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WD-13	34	77	295	34	77	295	19	43	177
WD-14	26	55	139	26	55	139	14	30	76
WD-16	1	1	1	1	1	1	1	1	1
ARITHMETIC TOTAL[1]	**3,442**	**7,289**	**12,964**	**3,360**	**7,090**	**12,661**	**2,518**	**5,361**	**9,245**

1 Individual 1P, 2P and 3P values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1P (Low Case) may be very conservative and the arithmetic total 3P (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

2 1P, 2P and 3P cases each include Developed Producing; Developed Non-producing and Undeveloped Reserves.

3 Trinity Net Reserves Entitlement is Trinity's WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

Table 1-2: Reserves as of 01 July 2012

	Contingent Resources (Mstb)								
	Gross Field			Trinity Working Interest			Trinity Net Entitlement[1]		
	1C	2C	3C	1C	2C	3C	1C	2C	3C
Brighton Inner[2]	1,386	3,316	7,686	1,386	3,316	7,686	1,165	2,785	6,456
Point Ligoure / Guapo / Brighton Outer[2]	1,447	3,747	8,479	1,013	2,623	5,935	886	2,295	5,193
WD-2	138	461	731	138	461	731	93	301	477
WD-13	262	545	1,128	262	545	1,128	146	326	712
WD-14	323	624	1,332	323	624	1,332	176	368	837
Fyzabad-2	63	139	423	63	139	423	33	74	241
Guapo-1	49	102	337	49	102	337	27	58	208
Tabaquite	52	150	428	52	150	428	44	128	353
WD-5/6	318	787	1,616	318	787	1,616	168	414	904
ARITHMETIC TOTAL[3]	**4,040**	**9,870**	**22,160**	**3,606**	**8,746**	**19,616**	**2,737**	**6,750**	**15,381**

Notes

1 Trinity's net entitlement is Trinity's WI share of Resources after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

2 Assuming 53% of the Contingent Resources in Brighton Marine are within the Brighton Marine Inner Block and 47% within the Brighton Marine Outer Block.

3 Individual 1C, 2C and 3C values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1C (Low Case) may be very conservative and the arithmetic total 3C (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

Table 1-3: Contingent Resources as of 01 July 2012

Gross Prospective Resources			
Low (Mstb)	**Best (Mstb)**	**High (Mstb)**	**GPoS[1] (%)**
1,663	**6,843**	**20,700**	**19**

1 This aggregation assumes that all prospects are successful. The probability of this occurring is the product of the GPoS values for each individual prospect.

Table 1-4: Prospective Resources

Economic evaluation of the Reserves provides the following post-tax Net Present Values.

	Post-Tax Net Present Value NPV_{10} (US$ Million, MoD)		
	1P	**2P**	**3P**
Brighton	2.4	36.5	73.2
Fyzabad-2	0.0	0.2	0.7
Guapo-1	−0.2	0.1	0.3
Point Ligoure	2.5	4.9	6.9
Tabaquite	0.0	0.2	0.5
WD-2	−3.3	1.2	5.1
WD-5/6	1.2	6.9	18.3
WD-13	−0.1	0.4	2.8
WD-14	−0.1	0.1	0.7
WD-16	−0.1	−0.1	−0.1
Total Value from Fields	**2.3**	**50.3**	**108.5**
Consolidation Effects[1]	12.7	16.0	17.4
Total Value	**15.0**	**66.3**	**125.9**

1 Consolidation effects include benefits from consolidating Petroleum Profits Tax including tax losses and capital depreciation balances. No Corporate overhead has been included in the valuations.

Table 1-5: Post-Tax Valuation (Net Trinity's Share) of Trinity's Reserves in Trinidad (as of 01 July 2012)

2. INTRODUCTION

The evaluation presented in this Competent Persons Report ("CPR") has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the properties.

Our estimates of potential resources and risks are based on the limited data set available to, and provided by, Trinity. We have accepted, without independent verification, the accuracy and completeness of these data.

2.1 Resource Classification

Volumes and risk factors are presented in accordance with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System (PRMS). The key definitions of the PRMS are summarised in Appendix B.

In estimating reserves we have used standard petroleum engineering techniques. These techniques combine geological and production data with detailed information concerning fluid characteristics and reservoir pressure. RPS has estimated the degree of uncertainty inherent in the measurements and interpretation of the data and has calculated a range of recoverable reserves. RPS has assumed that the working interest in each asset advised by Trinity is correct and RPS has not investigated nor does it make any warranty as to the Trinity interest in these properties.

Hydrocarbon resource and reserve estimates are expressions of judgement based on knowledge, experience and industry practice and are restricted to the data made available. They are, therefore, imprecise and depend to some extent on interpretations, which may prove to be inaccurate. Estimates that were reasonable when made may change significantly when new information from additional exploration or appraisal activity becomes available.

2.2 Risk Assessment

For all prospects and appraisal assets estimates of the commercial chance of success for Contingent Resources, and estimates of geological chance of success for Prospective Resources, may be made. In PRMS the former is called Chance of Development (CoD) and the latter Chance of Discovery (also CoD) in the PRMS system. To avoid confusion with acronyms we have used the term Geological Probability of Success (GPoS) in this document synonymously with Chance of Discovery.

2.2.1 Contingent Resources

The chance of success in this context means the estimated chance, or probability, that the volumes will be commercially extracted.

A Contingent Resource includes both proved hydrocarbon accumulations for which there is currently no development plan or sales contract and proved hydrocarbon accumulations that are too small or are in reservoirs that are of insufficient quality to allow commercial development at current prices. As a result the estimation of the chance that the volumes will be commercially extracted may have to address both commercial (i.e. contractual or oil price considerations) and technical (i.e. technology to address low deliverability reservoirs) issues.

2.2.2 Prospective Resources (Exploration Prospects)

Unlike risk assessment for Contingent Resources, when dealing with undrilled prospects there is a more accepted industry approach to risk assessment for Prospective Resources. It is standard practice to assign a Geological Probability of Success (GPoS) which represents the likelihood of source rock, charge, reservoir, trap and seal combining to result in a present-day hydrocarbon accumulation. RPS assesses risk by considering both a Play Risk and a Prospect Risk. The chance of success for the Play and Prospect are multiplied together to give a Geological Probability of Success (GPoS). We consider three factors when assessing Play Risk: source, reservoir, seal and we consider four factors when assessing Prospect Risk: trap, seal, reservoir and charge. The result is the chance or probability of discovering hydrocarbon volumes within the range defined (Section 2.3). It is not an estimation of commercial chance of success.

2.3 Uncertainty Estimation

The estimation of expected hydrocarbon volumes is an integral part of the evaluation process. It is normal practice to assign a range to the volume estimates because of the uncertainty over exactly how large the discovery or prospect will be. Estimating the range is normally undertaken in a probabilistic way (i.e. using Monte Carlo simulation), using a range for each input parameter to derive a range for the output volumes. Key contributing factors to the overall uncertainty are data uncertainty, interpretation uncertainty and model uncertainty.

Volumetric input parameters, gross rock volume (GRV), porosity, net-to-gross ratio (N:G), water saturation (Sw), fluid expansion factor (Bo or Bg) and recovery factor, are considered separately. RPS has internal guidelines on the best practice in characterising appropriate input distributions for these parameters.

Systematic bias in volumetric assessment is a well-established phenomenon. There is a tendency to estimate parameters to a greater degree of precision than is warranted[1] and to bias pre-drill estimates to the high side[2]. Rose and Edwards observe the tendency towards assessing volumes in too narrow a rage with overly large low-side and mean estimates. RPS uses benchmarked P90/P10 ratios and known field size distributions to check the reasonableness if estimated volumes.

1 Rose, P.R., 1987. Dealing with Risk and Uncertainty in Exploration: How Can We Improve? AAPG Bulletin, 71 (1), pp. 1-16.

2 Rose, R.P. and Edwards, B., 2001. Could this prospect turn out to be a mediocre little one-well field? Abstract, AAPG Bulletin, 84(13)

2.4 Methodology for Reserves estimation

Reserves estimation for the Trinity assets in Trinidad was undertaken in two stages: the first consisted of analysing the Decline Curves of existing and producing wells in each field, and the second in generating notional profiles for planned recompletions, infill and replacement wells. The methodology followed in these two stages is explained below.

Trinity has supplied production data up to April 30th 2012. RPS has estimated the production to June 30th 2012 and then forecast future production from the effective date of July 1st 2012.

2.4.1 Decline Curves Analysis (DCA) On Existing Wells

Using Schlumberger's OFM software, RPS analysed all wells that are currently on production and have a sustained average flow greater than 0.5 bbl/d. Some wells, however, are producing by swabbing, showing very low average production rates, so these wells were combined and declined as a group.

Individual profiles for some wells in field WD5/6 were not available in the original database, but instead their production was presented as an aggregated group. Therefore, reserves for these wells were analysed as a single group.

Once this subset of wells was identified, RPS performed a decline curve analysis (DCA). RPS used the Oil Rate against Cumulative Production plot and the Oil and Water Rate against Time plots to select an established exponential decline which was then used to generate the P50 forecasts. The P90 and P10 forecasts were generated by either selecting other established periods of decline or different decline assumptions as appropriate.

The technical limit for the forecast production profiles is an average production rate of 0.5 stb/d or the license expiry date, which varied depending on the asset (Table 2-1). These estimated technical recoveries were then subject to an economic analysis to determine Reserves.

Field	Agreement Expiry Date	Renewal Option	Reserves Limit Date
Brighton Marine (Inner)	06/10/2024	5 years	31/12/2029
Brighton Marine (Outer)	01/09/2018	19 years	01/09/2037
Point Ligoure[1]	01/09/2018	19 years	01/09/2037
Fyzabad-2	31/12/2020	5 years	31/12/2025
Guapo-1	31/12/2020	5 years	31/12/2025
Tabaquite[1]	01/09/2018	19 years	01/09/2037
WD-2	31/12/2020	5 years	31/12/2025
WD-5/6	31/12/2020	5 years	31/12/2025
WD-13	31/12/2020	5 years	31/12/2025
WD-14	31/12/2020	5 years	31/12/2025
WD-16	31/12/2020	5 years	31/12/2025

1 Point Ligoure, Guapo, Brighton Outer and Tabaquite agreements are currently expired. Trinity is in the final stages of reaching agreement on renewal of the Point Ligoure, Guapo and Brighton Outer licence (expected November 2012) for a further 6 years After the initial 6 years period there is a discretionary option for further 19 years. The Tabaquite licence terms are under discussion with agreement anticipated in early 2013. RPS has assumed all approvals are reasonably certain based on recent history.

Table 2-1: Agreement and Reserves Limit Dates

2.4.2 Notional Profiles for Planned Recompletions and New Wells

Trinity provided a list of planned well works and drilling activity to be carried out in the near future. The approval for these workovers and new wells has already been requested and in many cases has been obtained. In some cases, clearance is still pending but there is evidence of a firm commitment from Trinity to progress with its development plan. RPS considers that the resources to be produced from the most immediate wells are classified as Reserves divided in two categories: Developed Non-Producing Reserves for recompletions and Undeveloped Reserves for infill and replacement wells.

The resources from new wells and recompletions still under evaluation by Trinity are classified as Contingent Resources.

The first step in preparing the production profiles was to take the values of expected ultimate recovery (EUR) following recompletion for recent worked-over wells or total EUR for recent new wells estimated from the P50 exponential decline curves; and the actual initial production (IP) rate following recompletion or drilling. Then, RPS determined the percentiles (P90, P50 and P10) for the EUR and IP assuming log-normal or normal distributions, depending on which statistical distribution gave a better fit to the data. Finally, the corresponding nominal annual decline rates (D) were estimated assuming an exponential decline and a final rate of 0.5 bopd. Production profiles for each formation and field were then calculated using these values.

2.4.3 Economic Limit

2.4.3.1 Licence Term and Economic Limit

RPS forecasts of production extend to the term of the licence plus one possible renewal, assuming that Government approval of any extension is not unreasonably withheld. Agreement on an extension to the Point Ligoure, Guapo and Brighton Marine (PGB) for an initial six year term, extended to 25 years if capable of continued commercial production, was received in December 2012. Negotiations continue on a renewal of the Tabaquite licence with agreement forecast by Trinity for early 2013. Trinity has provided the proposed licence terms that will exist for these licences and we have used these in our assessment.

An economic limit has been applied to the forecasts of field production in accordance with PRMS guidelines: "Economic limit is defined as the production rate beyond which the net operating cash flows (after royalties or share of production owing to others) from a project, which may be an individual well, lease, or entire field, are negative." The economic limit test for each field is therefore based upon the operating cashflow calculated as follows:

Field Revenues less Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

SPT is included in the operating cashflow as it effectively acts as a royalty: SPT is a percentage of revenues after Government Royalty and Petrotrin ORR have been deducted.

2.4.3.2 Economic Conditions

Economic assumptions applied in the determination of reserves are as follows:

1) A valuation date of 1st July 2012 and a range of discount rates;
2) Inflation of costs is assumed at 2% per annum from 2013 onwards;
3) Oil revenues have been calculated using the RPS Base price of 1st July 2012 for West Texas Intermediate (WTI) crude, plus local price differentials to WTI, see Table 2-2;
4) The local price differentials to WTI provided by Trinity and based on data from January 2011 to June 2012 have been accepted by RPS and used in the evaluation, see Table 2-2.
5) The forecast of annual fixed and variable operating costs for all years is based on the 2012 Budget but with a 10% contingency applied.
6) Trinity's estimates of capital costs for well recompletions, replacement wells and infill wells have been reviewed and increased by a 15% contingency. Similarly a 15% contingency has been applied to the Trinity estimate of tie-back costs for the new Brighton Marine wells.
7) Licence and Government terms remain unchanged for the duration of the economic life the fields.

The evaluation is linked to a long term price forecast for West Texas Intermediate (WTI) crude. The RPS Base Case price is given in Table 2-2. Appropriate differentials have been applied to the fields.

	Oil Price (US$/stb, MOD)							
Year	Brent	WTI Base Price Case	Brighton Marine	Fyzabad-2	Guapo-1	Tabaquite	WD-2, WD-5/6, WD-13, WD-14, WD-16	Point Ligoure, Guapo, Brighton
2012 (6 months)	106.70	91.50	90.59	89.67	85.10	91.50	89.67	89.67
2013	99.00	90.00	89.10	88.20	83.70	90.00	88.20	88.20
2014	96.00	89.00	88.11	87.22	82.77	89.00	87.22	87.22
2015	95.51	90.20	89.30	88.40	83.89	90.20	88.40	88.40
2016	97.42	92.01	91.09	90.17	85.57	92.01	90.17	90.17
2017	99.37	93.85	92.91	91.97	87.28	93.85	91.97	91.97
2018	101.35	95.72	94.77	93.81	89.02	95.72	93.81	93.81
2019	103.38	97.64	96.66	95.69	90.80	97.64	95.69	95.69
2020	105.45	99.59	98.60	97.60	92.62	99.59	97.60	97.60
2021	107.56	101.58	100.57	99.55	94.47	101.58	99.55	99.55
2022	109.71	103.61	102.58	101.54	96.36	103.61	101.54	101.54
2023	111.90	105.69	104.63	103.57	98.29	105.69	103.57	103.57
2024	114.14	107.80	106.72	105.64	100.25	107.80	105.64	105.64
2025+	+2% p.a	+2% p.a	+2% p.a	+2% p.a	+2% p.a	+2% p.a	+2% p.a	+2% p.a

Table 2-2: RPS Price Base Case Forecast (US$/stb Money of the Day)

2.5 Methodology for Contingent Resources Estimation

Contingent Resources estimation for the Trinity assets in Trinidad was undertaken separately for offshore (Brighton Marine and Point Ligoure fields) and onshore assets.

2.5.1 Notional Profiles for planned recompletions and new wells in Onshore Assets

For the onshore assets, Trinity supplied information regarding new wells and recompletions to be carried out in the near future. Some of these wells have been already sanctioned and therefore their future production classified as Reserves, as explained in Section 1.2.2. However, the resources from new wells and recompletions still under evaluation are classified as Contingent Resources. The production profiles per well for these future development plans were derived with the same methodology explained in Section 1.2.2.

2.5.2 Resource Classification for Brighton Marine and Point Ligoure Fields

In accordance with PRMS the oil volumes for the Brighton Marine and Point Ligoure fields are classified according to whether or not they are discovered and their commerciality. Discovered volumes are either already produced, Reserves or Contingent Resources. Reserves are assigned to those volumes that are yet to be produced from existing wells, workovers and sanctioned infill drilling. Contingent Resources include unsanctioned infill drilling and volumes that will not be recovered from the existing wells.

Those volumes that are undiscovered in undrilled reservoir layers or fault blocks are classified as Prospective Resources.

3. DESCRIPTION OF ASSETS

Trinity Exploration and Production Services Limited ("Trinity") has interests in four offshore blocks (Brighton Inner, Brighton Outer, Guapo and Point Ligoure) and nine onshore licences (Guapo-1, Fzyabad-2, Tabaquite, WD-2, WD-5, WD-6, WD-13, WD-14 and WD-16), Trinidad (Figure 3-1). All the onshore blocks, except Tabaquite, are operated under lease operatorships (section 6.1.1) under a programme introduced by the national oil company (Petrotrin) to reactivate idle wells. The Tabaquite licence is a farmout operatorship (section 6.1.2). The Brighton Inner and Pointe Ligoure licences are Joint Ventures; the former including the Brighton Marine field. The Guapo and Pointe Ligoure blocks were combined with the Brighton block and converted into one licence in December 2012.

Trinity has a 100% working interest in all the licences with the exception of the future licence of Point Ligoure / Guapo / Brighton in which Trinity expects to have a 70% working interest with no Petrotrin over-riding royalty.

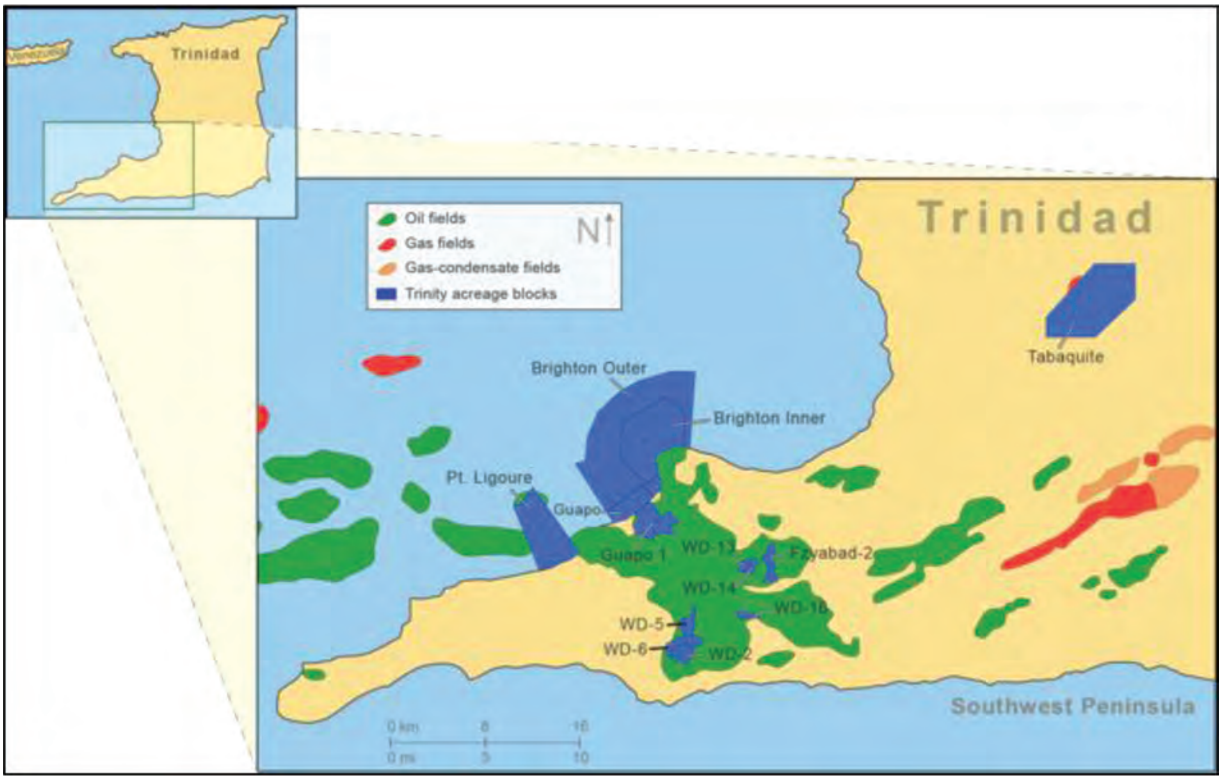

Figure 3-1: Licence Location Map

Trinidad is located along a plate boundary zone created by eastward translation of the Caribbean plate relative to the South American plate. This plate interaction has occurred diachronously across Trinidad since the Miocene, following periods of rifting (Jurassic) and passive margin (Cretaceous to Oligocene) tectonics (Figure 3-2). The Orinoco delta has been a major source of sediment input into the area since the Miocene, continuing through to present day. Prolific passive margin Cretaceous source rocks are overlain by deep marine to shallow paralic reservoir rocks. Commercial oil and gas production in Trinidad is established from Oligocene to Pleistocene sediments. Stacked hydrocarbon columns of 600 to 900 metres are common in many Trinidad fields, including Brighton Marine. Brighton Marine field, like much of Trinidad, is part of an active petroleum system overprinted with structural and stratigraphic complexity due to the geological setting.

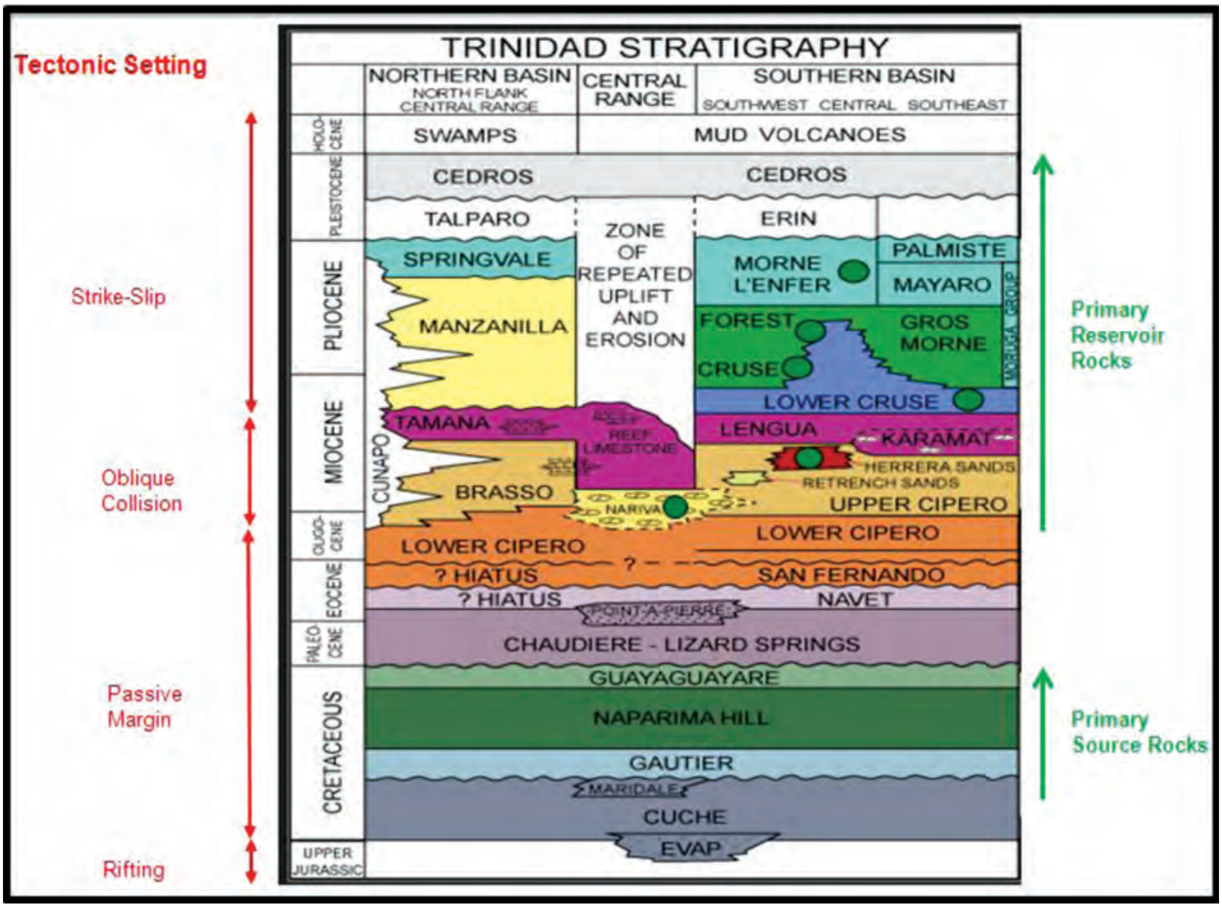

Figure 3-2: Trinidad Stratigraphy

Source rocks occur within the Cretaceous and Jurassic section and hydrocarbons have migrated up faults to source Tertiary reservoirs.

Reservoir targets include marginal marine sandstones of the Miocene to Pliocene Cruse and Forest formations. This system shows pronounced lateral facies changes, making log correlations difficult, especially where complicated by thrusting. At Brighton Marine reservoirs include gravity-driven continental slope and basinal deposits of the Miocene Nariva fed primarily by the proto-Orinoco delta. Cretaceous units are penetrated by only three wells.

4 BRIGHTON MARINE LICENCES

Trinity's Brighton Marine field is located slightly offshore within Trinidad's shallow five to twenty metres Gulf of Paria waters. From 1951 to 1957 Brighton Marine's hydrocarbons were accessed from long-reach wells deviated from eleven land pads. Between 1951 and 2001 wells were drilled as both standalone wells and from nine marine platforms. The Brighton Marine field produces high-quality 26 to 46 degrees API crude. Several new wells were drilled into the field by Venture in 2001, including the highly prolific ABM 151 well with cumulative production exceeding 500,000 barrels of oil. Current production has averaged 410 barrels of oil per day for Q1 2012 with 67 of the field areas 316 wells still producing oil. All drilling prior to 2001 was without the benefit of 3D seismic data. The current interpretation benefits from two 3D seismic surveys: one acquired in 1997 and the other shot in 2009.

The Brighton Marine field is a thrust anticline cut by younger strike-slip faults (Figure 4-1). In general, seismic imaging is poorer over the crest of the field relative to the flanks, probably due to structural complexity (Figure 4-2). The field produces hydrocarbons from a number of fault-separated compartments (Designated Fault Panels A through P). Hydrocarbon production is proven both on the crest of the Brighton Marine field and also within down-thrown fault compartments. Structurally down-thrown flank areas include some of the larger cumulative production wells due to decreased structural complexity and lower drilling density. The highly laminated nature of sands and shales of these gravity-driven deep water deposits enhance the sealing potential for faults.

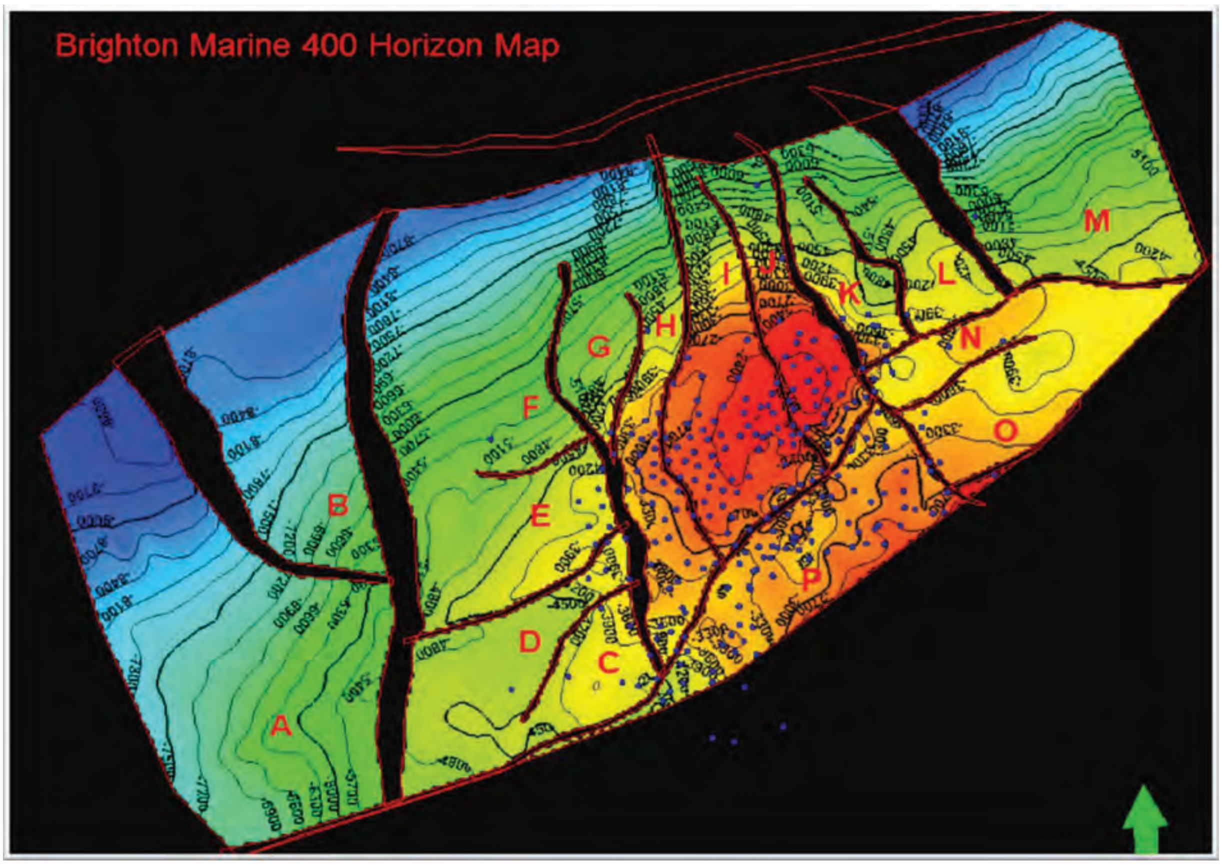

Figure 4-1: Brighton Marine Structural Depth Map (feet)

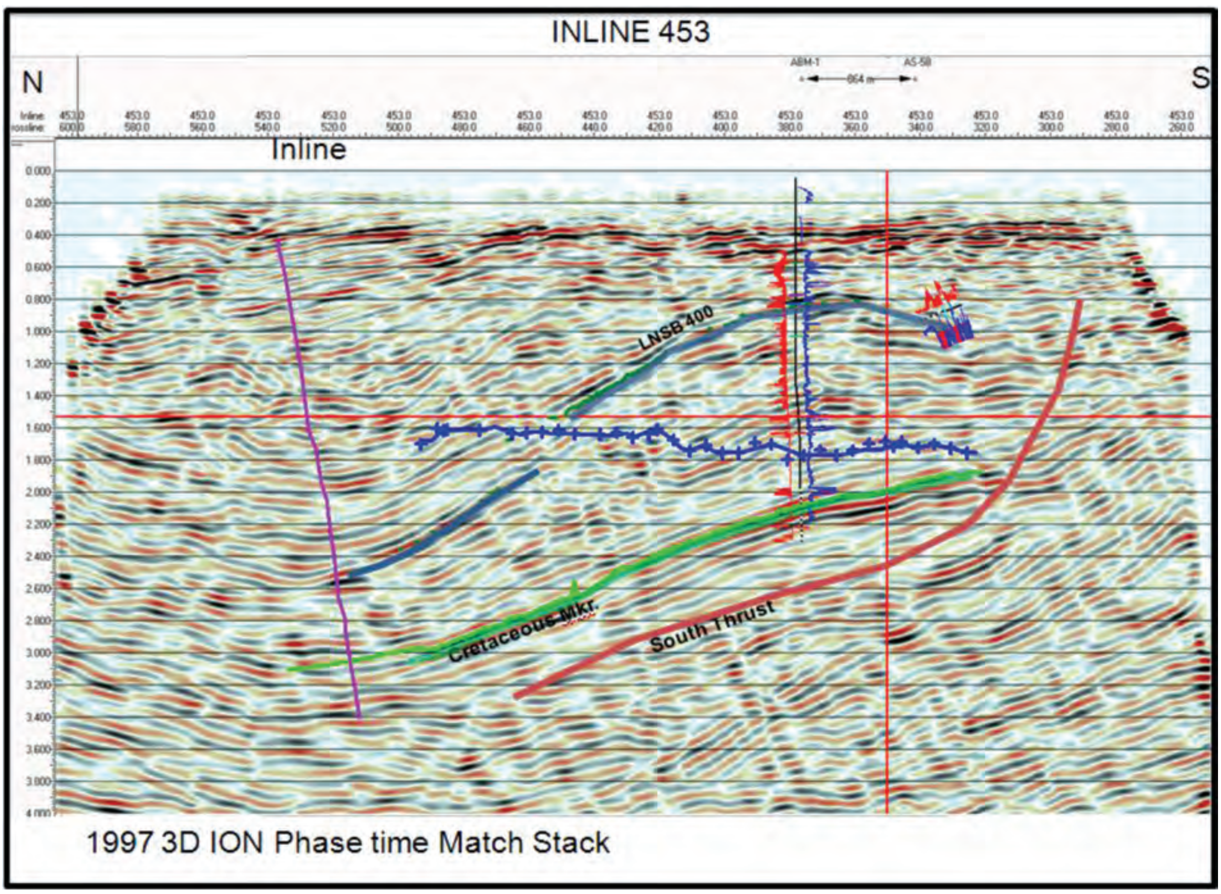

Figure 4-2: Example Seismic Line—Brighton Marine Field

Brighton Marine's structural history includes a period of Lower to Middle Miocene south-southeast directed thrusting and folding. During Upper Miocene through to present time, earlier folding and thrusting was cut by later northwest-southeast or east-west trending right-lateral strike-slip faulting which accommodated north-northwest to east-southeast trending translation of the thrust sheets. The last event was extension and/or transtension associated with the Gulf of Paria pull-apart and Los Bajos faults. This complicated structural history is reflected in the Brighton Marine field structural style, as even minor pre-existing features can affect the deformation depending upon orientation relative to the principal stress direction. Another key point is that thin-bedded sandstones interbedded with incompetent overpressured deep water Nariva shales may have a high degree of fault and fold-related deformation in the crest of the fold. This structural complexity affects seismic imaging in areas such as the crest of the Brighton Marine field.

4.1 Discovered In Place Volumes

The in place discovered oil volumes associated with the flank fault panels (Figure 4-3) have been estimated by RPS. The extensively drilled and produced core area of the field has been excluded whereas all flank fault compartments and zones which contain sandstones interpreted to be oil bearing from wireline logs and which have not been extensively drilled have been included. Flank fault block areas have not been as intensively drilled as the crestal part of the field, so significant undrained potential is interpreted to exist in these areas. Areas which contain proved oil in at least one zone are illustrated in Figure 4-3. Some of these areas also contain Prospective Resources, as there are zones which have not yet been proven oil bearing within these compartments.

The productive Nariva sequence in Brighton Marine is subdivided into eight intervals, as illustrated in Figure 4-4. The Upper, Middle and Lower Nariva, 800 to 400 sequences all produce oil in at least one part of the field. Free water levels appear to differ between sequences and between major fault compartments but oil-water contacts or even extensive water bearing sands have only been defined in a few areas. This, together with the long production history of the field and the limited amount of pressure data, means that it is not possible to define free-water levels in flank areas for most of the zones. Trinity has assumed that each zone and each major compartment has a separate free water level. RPS has used the same assumption. In some areas sequences are interpreted to be oil bearing on the evidence of wireline logs but have not been produced to date. The reasons for this are not clear, and probably vary from place to place. The long history of the field means that completion strategies have changed through time, and the development of modern wireline logs has enabled older logs to be reinterpreted to varying extents. Differing views of the commercial potential of thin layers has probably also changed with time.

One seismic horizon has been interpreted and mapped over the Brighton Marine area, the Lower Nariva Sequence Boundary at the base of the 400 Zone, identified as LNSB400 on Figure 4-4. This time horizon has been converted to depth using a simple time/depth function and used to construct a series of structure maps at each reservoir zone top by fitting surfaces to the well tops, guided by the LNSB 400 structure. Oil has been found and is being produced from sandstones above the 800 sequence, but these sandstones are only locally developed and have not been analysed in this review. There are also sandstones in the Basal Nariva 300 and 200 sequences which are interpreted to be oil bearing, but these sequences have not been penetrated in many wells so in view of the absence of seismic mapping below the LNSB400 sequences and the structural complexity of the area it is not possible to map them with any confidence.

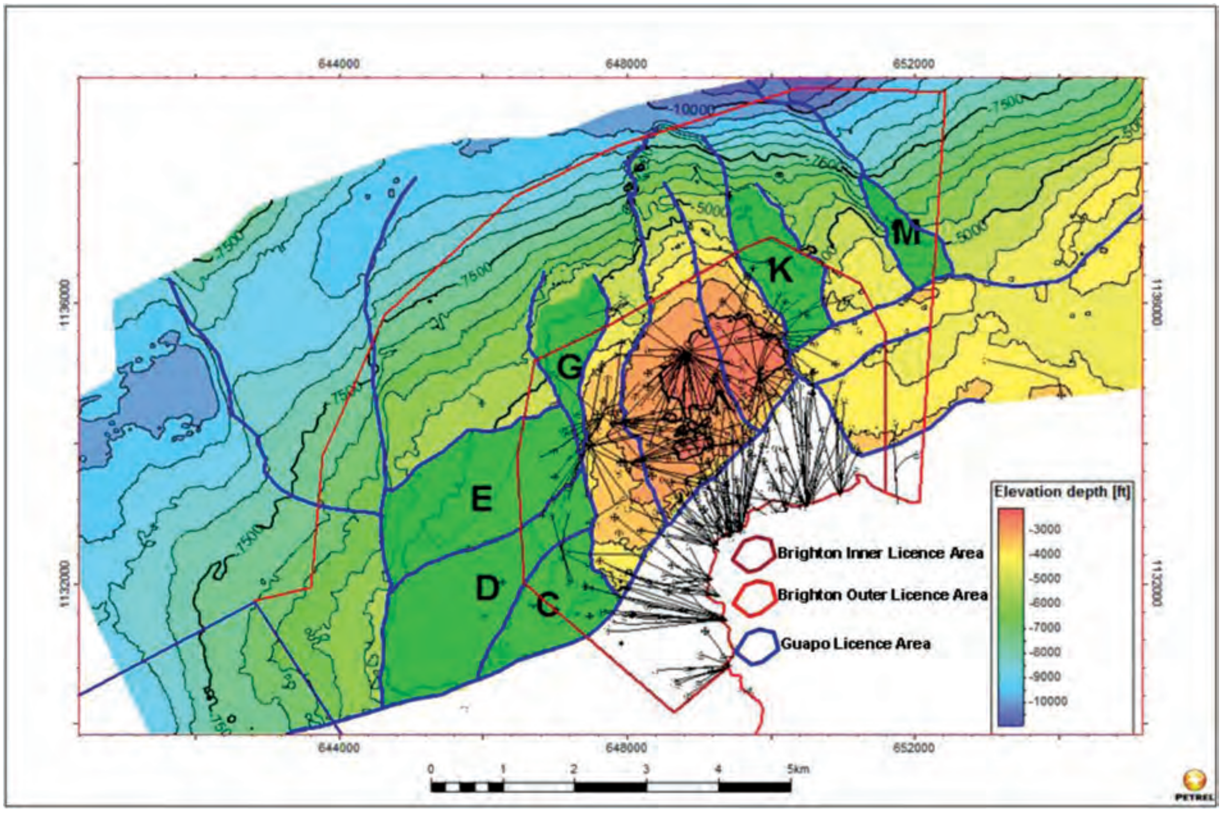

Figure 4-3: Brighton Marine Flank Areas with Discovered Volumes

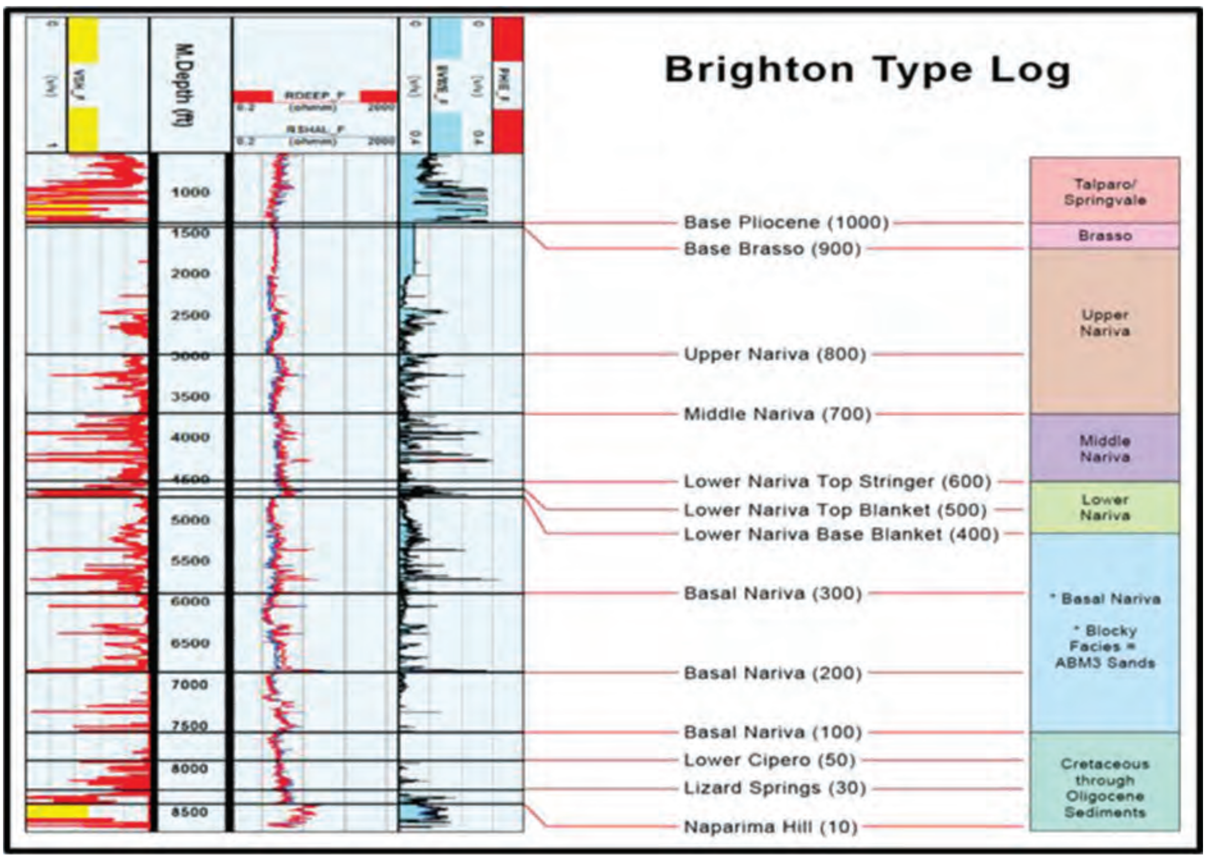

Figure 4-4: Brighton Marine Field Stratigraphy

Petrophysical analysis by Trinity is reasonable. Many wells are old and have limited low resolution wireline logs, so the ten modern wells with good data provide the best estimates of reservoir quality and hydrocarbon saturation. No lateral or vertical variations in reservoir quality or hydrocarbon saturation have been mapped. It is likely that transition zones exist but in view of the high porosities observed they are likely to be limited and have not been considered. Porosity estimated from modern wells ranges from 0.17 to 0.21, and water saturation from 0.25 to 0.42. Oil gravity in the field varies from 26° to 42° API, with one outlier of 45°. The average is 35° API. In view of the limited number of high quality data points the same reservoir and oil parameters have been used in all volumetric estimates. These are shown in Table 4-1.

Parameter	P90	P50	P10
Porosity (fraction)	0.17	0.18	0.19
Water Saturation (fraction)	0.30	0.35	0.40
FVF (Bo)	1.23	1.25	1.27

Table 4-1: Brighton Marine Reservoir and Fluid Parameters

Discovered oil volumes within the licence block have been estimated (Table 4-2 to Table 4-7) using structural maps and logged deepest oil in wells in each fault compartment. In some situations P90 case areas have been restricted to robust closures. In the few cases where a well defined oil-water contact has been identified this has been used as the P50 case and an area uncertainty applied. Similarly, where logged oil columns suggest that pay extends across the whole of a mapped fault block, uncertainty in the mapped area has been applied. High cases have been estimated using the extent of the fault compartment or the mapped area that corresponds to a maximum oil column of 2,500ft based on well log derived maximum oil columns in wells in the field. Pay thicknesses are generalised averages taken from relevant wells in the area and zone. The M area extends off the Trinity licensed areas.

REP software has been used to calculate the discovered in place and recoverable oil volumes for each area. These have been estimated by calculating the volumes for each reservoir layer and then statistically adding (consolidating) the reservoirs within each area (Table 4-2 to Table 4-6). It should be noted that the volumes for each reservoir within each area have not been arithmetically added as summation of P90, P50 or P10 would give values that do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) would be very conservative and the arithmetic total P10 (High Case) very optimistic.

The discovered, on Block, oil initially in place (STOIIP) for each flank fault block reservoir are shown in Table 4-2 to Table 4-6 and the discovered totals are summarised in Table 4-7.

	STOIIP (MMstb)[1] On Block		
Reservoir	P90	P50	P10
300	0.5	1.1	2.1
400	0.5	1.2	2.3
500	2.0	3.7	5.7
600	21.8	28.7	37.4
700	5.8	11.6	18.5
800	1.0	2.03	3.2
Statistical Total[2]	**39.5**	**49.2**	**60.3**

1 All Area C volumes are on Block

2 This is a statistical total. Arithmetic summation of P90, P50 or P10 would give values that do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 4-2: Area C Discovered Oil In Place (On Block) in Brighton Marine

	STOIIP (MMstb)[1] On Block		
Reservoir	P90	P50	P10
400	5.7	9.0	13.2
600	2.7	7.4	19.7
700	3.3	5.8	9.9
Statistical Total[2]	**16.0**	**23.4**	**36.4**

1 All Area D volumes are on Block

2 This is a statistical total. Arithmetic summation of P90, P50 or P10 would give values that do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 4-3: Area D Discovered Oil In Place (On Block) in Brighton Marine

Reservoir	STOIIP (MMstb)[1] On Block		
	P90	P50	P10
300	0.2	0.9	3.7
400	0.7	1.9	4.4
500	1.6	2.1	2.7
600	12.0	26.8	60.3
700	27.2	36.4	48.5
800	13.0	20.7	32.8
Statistical Total[2]	**71.0**	**93.4**	**129.0**

1 All Area E volumes are on Block

2 This is a statistical total. Arithmetic summation of P90, P50 or P10 would give values that do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 4-4: Area E Discovered Oil In Place (On Block) in Brighton Marine

Reservoir	STOIIP (MMstb)[1] On Block		
	P90	P50	P10
400	0.8	1.8	3.4
500	0.8	1.6	2.5
600	1.5	3.3	6.7
700	1.3	2.7	4.4
800	4.1	8.5	17.2
Statistical Total[2]	**13.0**	**18.9**	**28.1**

1 All Area K volumes are on Block

2 This is a statistical total. Arithmetic summation of P90, P50 or P10 would give values that do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 4-5: Area K Discovered Oil In Place (On Block) in Brighton Marine

Reservoir	STOIIP (MMstb)[1] On Block		
	P90	P50	P10
500	1.4	1.9	2.6
700	0.6	1.2	1.9
800	2.1	4.1	6.3
Statistical Total[2]	**5.2**	**7.4**	**9.7**

1 Approximately 90% of the Area M volume is on Block

2 This is a statistical total. Arithmetic summation of P90, P50 or P10 would give values that do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 4-6: Area M Discovered Oil In Place (On Block) in Brighton Marine

Area	STOIIP (MMstb) P90	P50	P10
C[1]	39.5	49.2	60.3
D[1]	16.0	23.4	36.4
E[1]	71.0	93.4	129.0
G[2]	1.12	2.23	4.35
K[1]	13.0	18.9	28.1
M[1,3]	5.16	7.35	9.73
Arithmetic Total[4]	**145.8**	**194.5**	**267.9**

1 Statistically derived total. See tables above.

2 Area G has discovered volumes in reservoir layer 400 only.

3 Approximately 90% of the Area M volume is on Block

4 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic

Table 4-7: Discovered Oil In Place (On Block) by Area in Brighton Marine

4.2 Prospective In Place Volumes

All zones within flank fault compartments which have not been proven to be hydrocarbon bearing and which are mapped as being in traps isolated laterally or vertically from adjacent oil bearing segments are classified as Prospective Resources. Areas which have Prospective Resources are illustrated in Figure 4-5. Areas A, B and M all extend outside the area licenced to Trinity in the high cases.

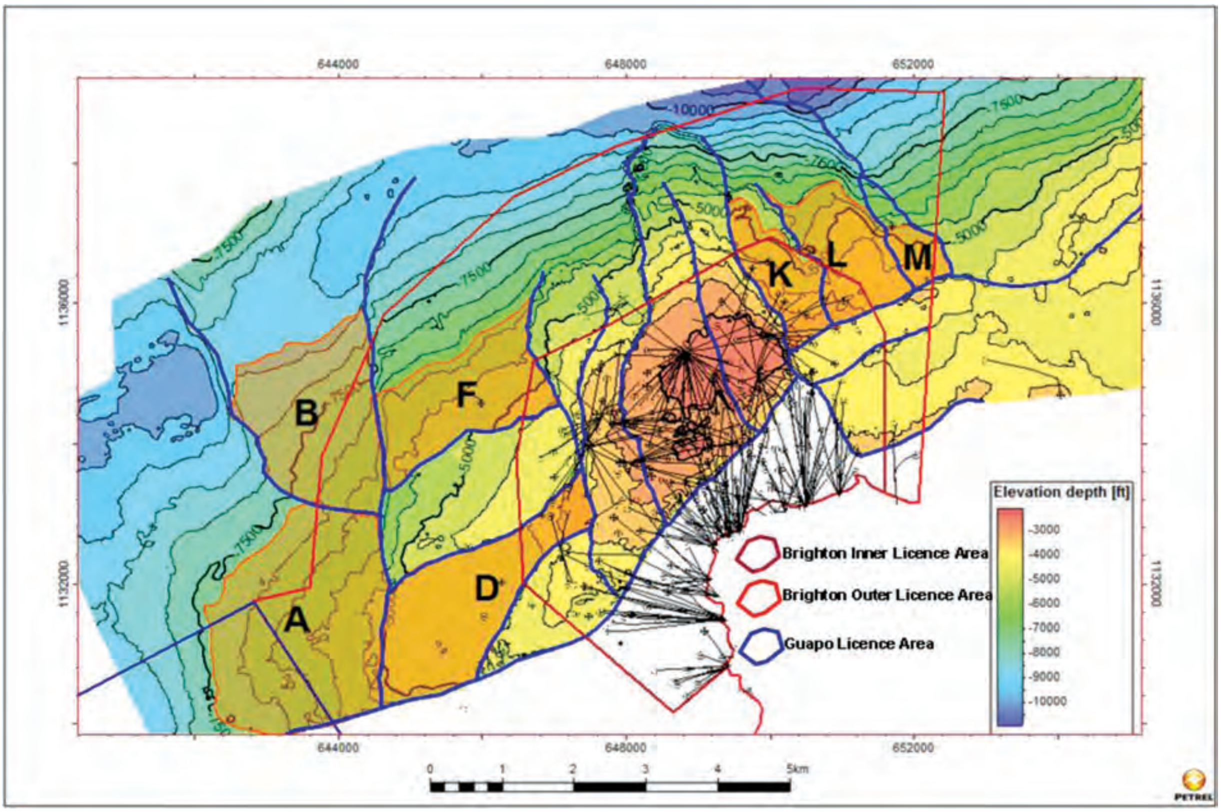

Figure 4-5: Brighton Marine Prospective Resource Areas

The same reservoir and oil parameters used for the discovered resources have been applied for prospective areas (Table 4-8). No gas volumes have been estimated.

Parameter	P90	P50	P10
Porosity	0.17	0.18	0.19
Water Saturation	0.40	0.35	0.30
FVF (Bo)	1.27	1.25	1.23

Table 4-8: Brighton Marine Reservoir and Fluid Properties for Prospect Volumetrics

Prospective oil volumes have been estimated (Table 4-9 to Table 4-16) using structural maps. P90 areas have been restricted to robust closures or to areas defined by 1,000ft oil columns, as this is the maximum robustly defined oil column in the flank areas of the field. High cases have been estimated using the extent of the fault compartment or the mapped area that corresponds to a maximum oil column of 2,500ft based on well log derived maximum oil columns in wells in the field. Pay thicknesses are generalised averages taken from relevant wells in the area and zone. Each prospective area has a number of potentially productive intervals which have been considered to be independent from a risk perspective. As the zones all lie adjacent to or even vertically above existing discovered oil the chance of oil migration has been estimated as 1. The Nariva sequence is dominated by shales so a top seal chance of 1 has been applied. Risks for all areas and zones lie in reservoir presence and trap effectiveness. As each zone is considered to be independent of the others in the same fault compartment, even though individual zone risks may be relatively high for near field exploration, the chance of finding at least one productive zone is high in all areas.

The estimates of Prospective STOIIP for each reservoir and the associated geological chance of success (GPoS) by Area are shown in Table 4-9 to Table 4-14 and the total Prospective volumes on Block for the flank areas (Figure 4-5) are summarised in Table 4-15 with the structure total within the same areas shown in Table 4-16.

	STOIIP (MMstb)[1] On Block			
Reservoir	P90	P50	P10	GPoS (%)
300	4.7	7.5	12.2	27
400	5.9	9.7	15.7	32
500	5.6	15.1	40.8	32
600	9.4	25.8	71.4	38
700	7.2	20.3	58.0	32
800	7.9	19.1	46.9	27
Statistical Total[2]	**9.6**	**35.7**	**94.9**	**90**

1 Approximately 90% of Areas A volumes are on Block.

2 Statistical aggregation assuming at least one reservoir is successful. This total takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.

Table 4-9: Area A Prospective Oil In Place (On Block) in Brighton Marine

	STOIIP (MMstb)[1] On Block			
Reservoir	P90	P50	P10	GPoS (%)
300	1.3	1.8	2.7	32
400	1.9	2.8	4.2	32
500	2.1	5.1	12.6	32
600	4.6	13.9	42.3	38
700	2.7	7.2	19.6	32
800	2.4	5.5	13.0	27
Statistical Total[2]	**2.9**	**12.7**	**39.0**	**90**

1 Approximately 70% of Areas A volumes are on Block.

2 Statistical aggregation assuming at least one reservoir is successful. This total takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.

Table 4-10: Area B Prospective Oil In Place (On Block) in Brighton Marine

Reservoir	STOIIP (MMstb)[1] On Block P90	P50	P10	GPoS (%)
300	2.2	5.2	12.4	43
800	1.6	5.0	15.8	50
Statistical Total[2]	**2.2**	**6.8**	**18.4**	**72**

1 All Area D volumes are on Block.

2 Statistical aggregation assuming at least one reservoir is successful. This total takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.

Table 4-11: Area D Prospective Oil In Place (On Block) in Brighton Marine

Reservoir	STOIIP (MMstb)[1] On Block P90	P50	P10	GPoS (%)
300	1.7	2.8	4.6	27
400	2.4	4.3	7.8	41
500	0.8	2.2	6.4	32
600	1.3	3.7	10.9	41
700	2.5	6.9	19.1	41
800	2.1	4.9	11.8	41
Statistical Total[2]	**3.3**	**10.8**	**25.6**	**94**

1 All Area F volumes are on Block.

2 Statistical aggregation assuming at least one reservoir is successful. This total takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.

Table 4-12: Area F Prospective Oil In Place (On Block) in Brighton Marine

Reservoir	STOIIP (MMstb)[1] On Block P90	P50	P10	GPoS (%)
300	0.3	0.9	2.3	32
400	1.4	2.5	4.6	32
500	0.3	0.4	0.8	32
600	0.2	0.4	0.7	32
700	3.8	6.9	12.6	23
800	8.7	13.5	20.8	23
Statistical Total[2]	**0.5**	**4.4**	**18.8**	**87**

1 All Area L volumes are on Block.

2 Statistical aggregation assuming at least one reservoir is successful. This total takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.

Table 4-13: Area L Prospective Oil In Place (On Block) in Brighton Marine

Reservoir	STOIIP (MMstb)[1] On Block P90	P50	P10	GPoS (%)
300	0.2	0.3	0.6	32
400	0.4	0.8	1.4	32
600	0.9	1.6	2.9	32
Statistical Total[2]	**0.3**	**1.1**	**2.8**	**68**

1 Approximately 70% of Areas M volumes are on Block.

2 Statistical aggregation assuming at least one reservoir is successful. This total takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.

Table 4-14: Area M Prospective Oil In Place (On Block) in Brighton Marine

Area	STOIIP (MMstb) P90	P50	P10	GPoS (%)
A[2,3]	9.6	35.7	94.9	90
B[2,3]	2.9	12.7	39.0	90
D[3]	2.2	6.8	18.4	72
F[3]	3.3	10.8	25.6	94
K	0.2	0.5	1.5	58
L[3]	0.5	4.4	18.8	87
M[2,3]	0.3	1.1	2.8	68
Arithmetic Total[1]	**19.0**	**72.0**	**201.0**	**19**

1 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic. It assumes that all prospects are successful. The probability of this occurring is the product of the GPoS values of each Area.

2 Approximately 90%, 70% and 70% of Areas A, B and M volumes are on Block, respectively.

3 Statistically derived total of multiple reservoir layers. See tables above.

Table 4-15: Prospective Oil In Place (On Block) for Flank Areas in Brighton Marine Field

Area	STOIIP (MMstb) P90	P50	P10	GPoS (%)
A[1]	10.6	39.0	105.0	90
B[1]	4.8	18.6	51.6	90
D[1]	2.2	6.8	18.6	72
F[1]	3.3	10.7	25.5	94
K	0.2	0.5	1.5	58
L[1]	0.5	4.3	18.7	87
M[1]	0.5	1.5	3.7	68

1 Statistically derived total of multiple reservoir layers.

Table 4-16: Total Prospective Oil In Place for Flank Areas in Brighton Marine Field

4.3 Remaining Recoverable Volumes from Existing Wells

This section addresses volumes classified as Reserves. It includes estimates of ultimate remaining recoverable volumes and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5.

Expected remaining recoverable volumes from existing developed producing wells were estimated by decline curve analysis (DCA) of existing wells. The results are shown in Table 4-17. These are prior to an economic limit test (ELT) being applied.

Gross Expected Remaining Recovery from Developed Producing Wells[1]

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
ABM 0023	0.0	0.0	0.2
ABM 0028	0.3	0.8	3.5
ABM 0031	67.6	98.8	129.6
ABM 0044	0.6	1.6	14.9
ABM 0057	12.3	18.6	34.5
ABM 0061	32.0	45.7	69.9
ABM 0068	10.0	16.2	37.3
ABM 0069	1.1	1.5	2.6
ABM 0071	16.7	25.0	47.8
ABM 0076	101.9	151.3	172.7
ABM 0077	4.2	5.9	17.7
ABM 0078	0.0	0.1	0.7
ABM 0082	0.0	0.1	0.2
ABM 0083	0.0	0.1	0.1
ABM 0084	2.0	3.8	27.2
ABM 0097	2.4	7.9	21.2
ABM 0098	1.1	3.3	18.8
ABM 0102	5.9	7.6	9.9
ABM 0104	0.0	0.1	0.1
ABM 0105	0.1	0.4	4.0
ABM 0106B	2.8	4.8	9.4
ABM 0108	1.2	14.7	23.4
ABM 0112	5.3	15.2	38.0
ABM 0115	0.1	0.6	0.7
ABM 0125	0.0	0.0	0.1
ABM 0127	1.7	2.7	7.9
ABM 0129	0.3	0.8	1.8
ABM 0134	0.4	1.0	3.0
ABM 0138	5.6	7.8	18.2
ABM 0139	8.0	13.4	28.7
ABM 0142	3.9	19.2	52.4
ABM 0148	16.4	25.8	43.5
ABM 0150	16.0	30.9	50.0
ABM 0151	488.3	541.5	616.9
AS 0129	0.6	5.2	15.2
AS 0130	4.5	11.7	13.7
Swabbed Wells[2]	28.7	50.4	72.3
Arithmetic Total[3]	**841.9**	**1134.1**	**1607.9**

1 Before economic limit test. See Section 9 for results of economic limit test

2 Swabbed wells: ABM-010, ABM-013, ABM-014, ABM-021, ABM-029, ABM-045 and ABM-047

3 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 4-17: Brighton Marine Field Developed Producing Gross Expected Remaining Recovery by well

4.3.1 Brighton Infill Drilling

Trinity plan to further develop the Brighton Marine field through an infill drilling campaign to be carried out in two phases. The company have had Phase I of this plan sanctioned and therefore the resources from these new wells are categorised as reserves. The first stage of the campaign involves six wells drilled into three fault blocks, two each in Areas C, E and K.. The resources for the wells to be drilled in future phases are allocated as contingent resources.

4.3.1.1 Production Profile Generation

The production wells on the field have been drilled either at an approximate well spacing of 6 acres (pre 1967) or 40 acres (post 1967) when Texaco changed its drilling strategy. The original close well spacing was based upon drilling from shore and the change was in response to the introduction of offshore drilling, the recognition that the closer well spacing was unnecessary to access the oil volume and that a similar recovery was achievable with fewer wells. As a consequence the expected ultimate recovery per well increased for wells drilled after 1967. Recent drilling on the flanks of the field (e.g. Block E) where the structure is geologically less complex has also demonstrated improved production behaviour.

To estimate future production profiles RPS has aggregated the P90 profile from the post 1967 wells for the P90 case, used the improved (Block E) profile for the P10 case and used the mean of these for the P50 case. This gives a set of predictions that, while honouring past performance, give a reasonable range of possible outcomes for the six new wells. The resulting per well forecast is P90 137 Mstb, P50 364 Mstb and P10 590 Mstb, which for the six wells gives total Undeveloped Estimated Remaining Resources of P90 823 Mstb, P50 2,181 Mstb and P10 3,541 Mstb (Table 4-18).

Gross Expected Recovery in Undeveloped Areas[1]

Planned Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
C1	137.2	363.6	590.1
C3	137.2	363.6	590.1
E1	137.2	363.6	590.1
E3	137.2	363.6	590.1
K1	137.2	363.6	590.1
K3	137.2	363.6	590.1
Arithmetic Total[2]	**823.2**	**2181.4**	**3540.6**

1 Before economic limit test. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 4-18: Brighton Marine Field Gross Undeveloped Expected Recovery

4.3.2 Brighton Recompletions and Work Overs

In addition to the current active well production, Trinity has plans to perform works on wells and production facilities that include capillary coil gas lift and work over well interventions.

Capillary coil gas lift implementation during Phase 1 is planned in eleven wells. Trinity estimate the aggregated reserves from these works to be around 290 Mstb, 360 Mstb and 480 Mstb for P90, P50 and P10 cases respectively. Initial incremental rates are in a range between 135 and 150 stb/d whilst the decline rates are estimated to be 18%, 14%, and 10% for P90, P50 and P10 cases respectively, which are consistent with recent DCA Brighton field decline estimates. RPS considers this estimation to be reasonable and has added these as Developed Non-Producing volumes.

The heavy intervention work comprises seven well rejuvenations by accessing shallower stratigraphic horizons in existing wells. The candidates are ABM136, ABM129, ABM139, ABM138, ABM131, ABM151 WO1 and 2. These wells have logged pay behind pipe that cannot currently be accessed due to existing completion issues. Trinity estimates the aggregated reserves from these works to be 475 Mstb, 1224 Mstb and 3210 Mstb for P90, P50 and P10 cases respectively. RPS considers the values for P90 case are reasonable. However values for P50 and P10 cases were adjusted and the range narrowed in line with calculations made for the infill drilling campaign.

The resulting estimated remaining Developed Non-Producing volumes for the capillary gas lift work and heavy well intervention are shown in Table 4-19.

	Gross Developed Non-Producing Expected Remaining Recovery[1]		
Planned Well	**P90 (Mstb)**	**P50 (Mstb)**	**P10 (Mstb)**
Capillary Coil Gas Lift	288.2	360.4	478.8
Heavy Well Interventions	475.0	865.1	1,289.2
Arithmetic Total[2]	763.2	1,225.5	1,768.0

1 Before economic limit test. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 4-19: Brighton Marine Field Developed Non-Producing Expected Remaining Recovery

The total Expected Remaining Recovery which is the arithmetic aggregation of the remaining recovery from the existing producing wells, the proposed new wells in undeveloped areas and the planned work on wells and production facilities (including capillary coil gas lift and work over well interventions) for the Brighton Field is presented in Table 4-20, whilst the resulting profiles are shown in Figure 4-6.

	Gross Arithmetic Total[1] Expected Remaining Recovery[2]	
Low (Mstb)	**Best (Mstb)**	**High (Mstb)**
2,428.3	**4,541.0**	**6,916.5**

1 Before economic limit test. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.2

Table 4-20: Brighton Marine Field Total Expected Remaining Recovery

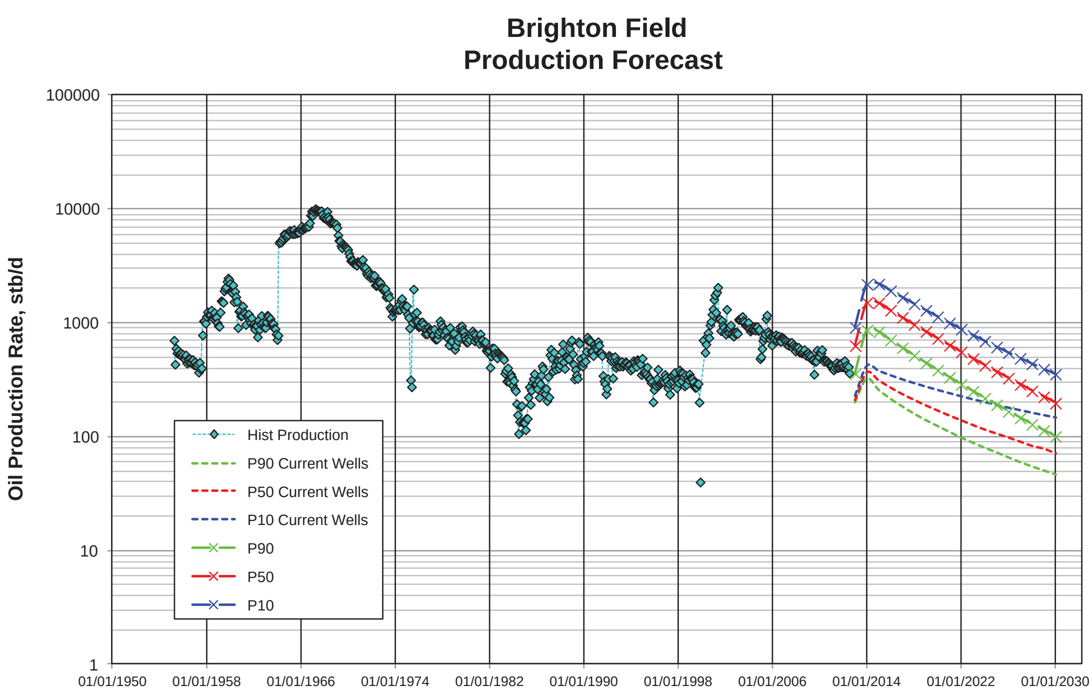

Figure 4-6: Brighton Marine Production Forecast

4.4 Contingent and Prospective Resources

This section addresses volumes classified as Contingent or Prospective Resources. It includes estimated ultimate recoverable volume estimates and production forecasts before an economic limit test is applied.

As described above, the Brighton Marine field is formed by sixteen lettered fault blocks (A to P) and six numbered geological layers (300-800). Those block/layer combinations that have been drilled and shown to contain oil are treated as discovered (contingent resources and/or reserves) and those that haven't are prospective resources.

The split between resources for those areas and layers considered in the report is presented in Table 4-21.

Discovered		Prospective	
Area	Layers	Area	Layers
		A	800-300
		B	800-300
C	800-300		
D	700. 600, 400	D	800, 300
E	800-300		
		F	800-300
G	400		
K	800-400	K	300
		L	800-300
M	800, 700, 500	M	600, 400, 300

Table 4-21: Split between Discovered and Prospective Layers in Brighton Marine

The discovered STOIIP on Block is summarised in Table 4-7 and the total prospective volumes are summarised in Table 4-15. These were used to give an upper bound to the Expected Ultimate

Recoverable volume (EUR) achievable from each layer. In order to estimate the contingent resources, volumes already produced and those allocated as reserves were subtracted from these totals. In estimating the recoverable volumes RPS has estimated recovery factors of 5% (P90), 10% (P50) and 15% (P10).

RPS has estimated the number of wells needed to realise these resources, using as reference the notional profiles per well generated for the infill drilling reserves estimation. In this case, we would need approximately 22, 21 and 29 wells (1C, 2C and 3C cases respectively) to produce the contingent resources. This also guided the staggering of the production profile by virtue of the number of years needed to complete these wells (three years). Infill recoverable volumes were assumed to be approximately 360 mbd per well because of depletion and interaction with other wells. This is possibly slightly conservative for the prospects on the west flank.

The prospective resources are by definition in block/layer combinations that are un-penetrated so no prior production exists. However because of the different GPoS for each area the profiles were generated on a block by block basis with a calculation of wells per block and a staggering of one block developed per year producing an overall prospective resources volume. The total number of wells needed for the prospective resources is 14, 20 and 35 wells for low, best and high estimates respectively.

The aggregated full field contingent and prospective Resources volumes resulting from this estimation are presented in Table 4-22 and Table 4-23.

Gross Contingent Volumes[1]		
Low (Mstb)	**Best (Mstb)**	**High (Mstb)**
3,030	**7,616**	**17,218**

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 4-22: Brighton Marine Field Contingent Volumes

Gross Prospective Resources			
Low (Mstb)	**Best (Mstb)**	**High (Mstb)**	**GPoS[1] (%)**
1,663	**6,843**	**20,700**	**19**

1 This aggregation assumes that all prospects are successful. The probability of this occurring is the product of the GPoS values for each Area in Table 4-15.

Table 4-23: Brighton Marine Field Prospective Resources

Figure 4-7 shows the resulting production forecast for Expected Remaining Recovery (ERR), ERR plus Contingent, and ERR plus Contingent and Prospective volumes cases.

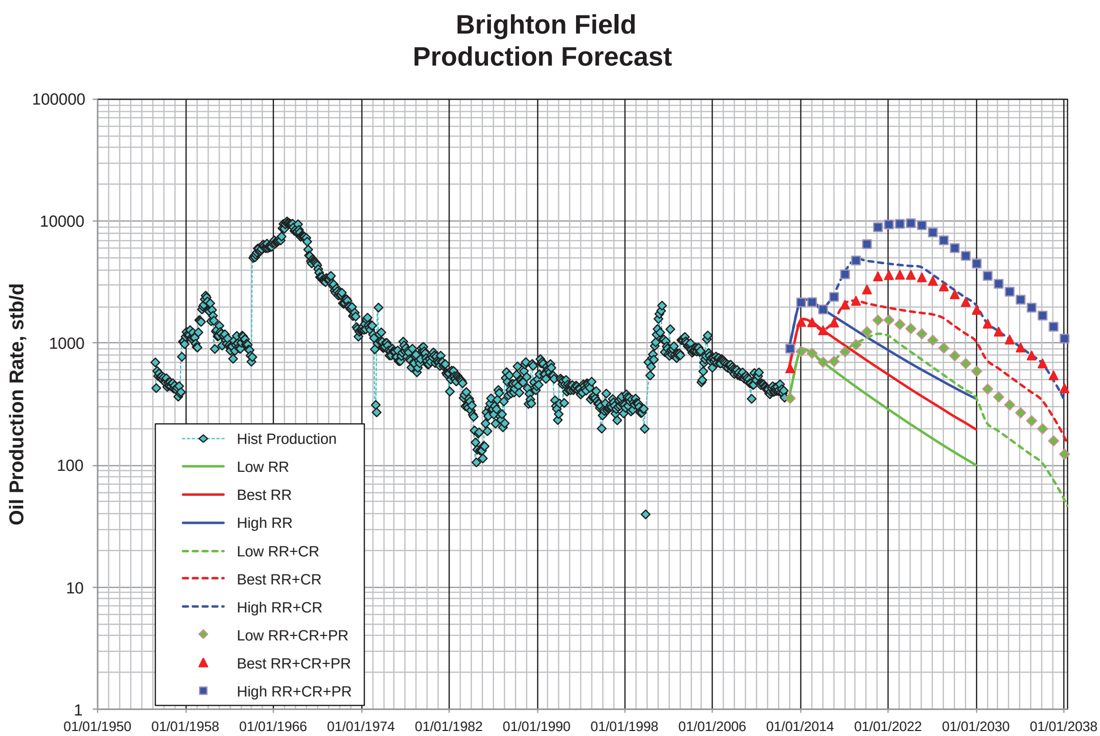

Figure 4-7: Brighton Marine Production Forecast including Expected Remaining Recovery, Contingent and Prospective Volumes

5. POINT LIGOURE LICENCE

The local geology around the Point Ligoure block is characterised by large, southeast-vergent, thrust-cored anticlines (Figure 5-1, red faults) and related, antithetic back thrusts (Figure 5-1, blue fault). These were cut and offset by seven kilometres of right lateral, strike-slip motion along the north-dipping Los Bajos Fault (black fault). The Erin and Siperia synclines (grey trends) represent the leading edge of a major blind thrust culmination. Smaller, secondary thrusts cut all of the trends. Structuring appears to have begun in the Pliocene during Forest Formation deposition (Figure 3-2) and continues to the present.

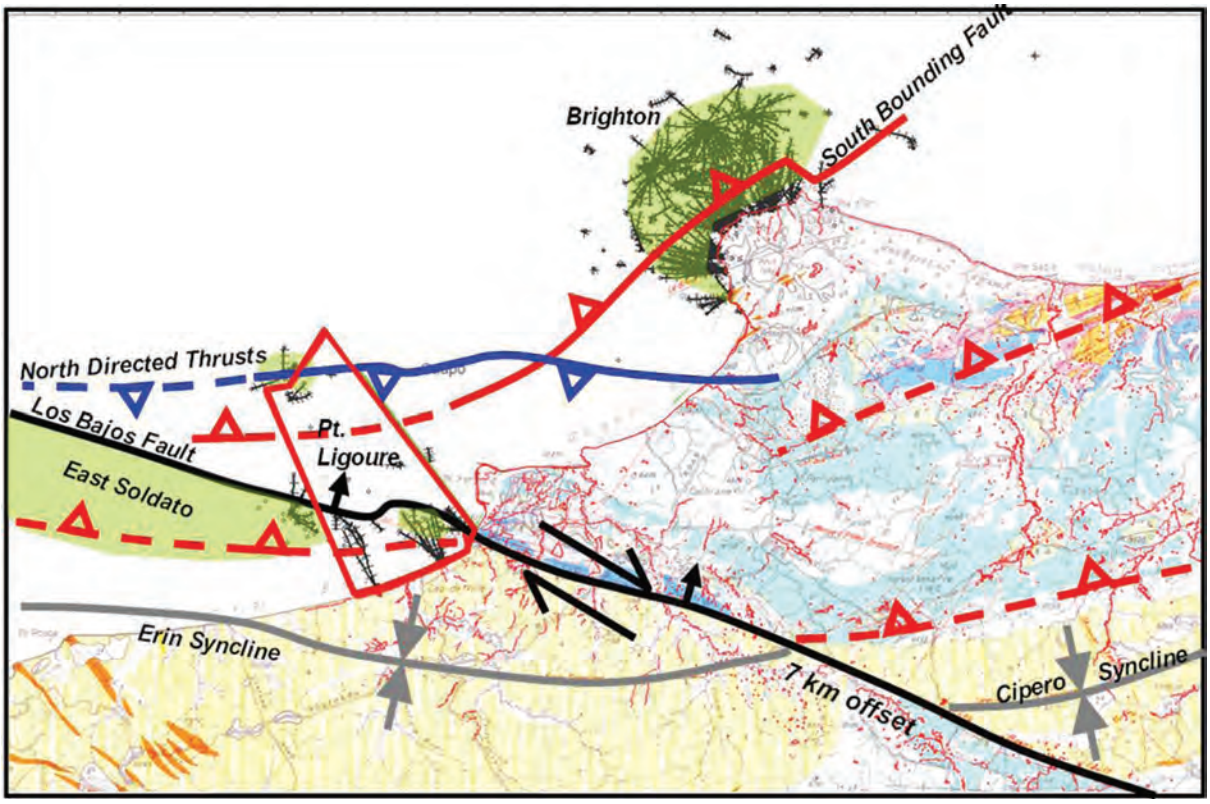

Figure 5-1: Point Ligoure Tectonic Setting

The figure below shows these features in cross section. The early thrust structures culminate along the northern flank of the Erin Syncline to form a structural triangle zone. It is comprised of a blind, south-directed floor thrust (red) that tips out below the Cruse package and several antithetic, north-directed back thrusts (blue) that cut up section into the Cruse and Forest packages. Later right-lateral, transpressive strike-slip motion along the north-dipping Los Bajos Fault (black) offset the thrust structures by approximately seven kilometres laterally and 600 metres vertically. Smaller scale, south-directed thrusts branch off the larger structures and are important in determining local trap geometries. Early growth of the triangle zone appears to have controlled Cruse and Forest preservation and/or deposition and dates the beginning of structuring to the lower Pliocene. Strike-slip movement along the Los Bajos continues today.

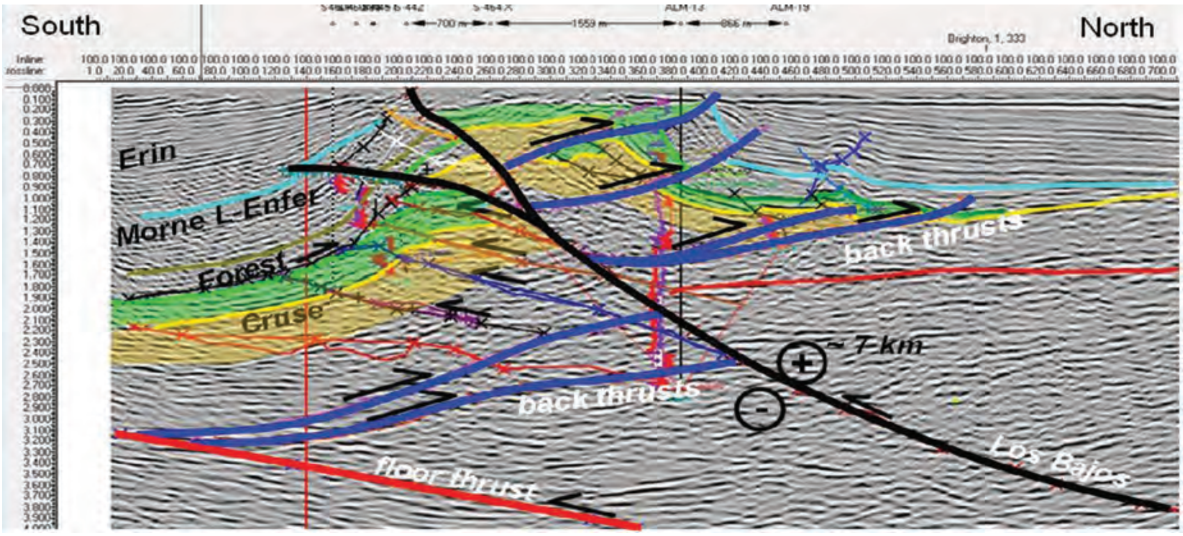

Figure 5-2: Example Seismic Line, Point Ligoure

The current Trinity seismic coverage consists of older 3D surveys merged together. This provides almost complete coverage except in the northwest of the Point Ligoure block. There are plans to acquire a new 3D survey comprising at least 48 square kilometres in the Point Ligoure block and also reprocess the existing seismic data.

Seismic data quality is variable and generally improves from south to north. The southern part of the survey captures the deep and complex structure south of the Los Bajos Fault (Figure 5-2). Data quality are sufficient to discern numerous small scale thrusts cutting the northern limb of the Erin Syncline, however, they are insufficient to map these smaller scale features with confidence. The Los Bajos Fault is also not readily evident on the data, however mapping its location is aided by existing well control. Seismic data quality generally improves north of the Los Bajos fault. The North trend in particular has good data quality, allowing some details of the thrust systems to be mapped.

Correlations between wells are difficult due to highly variable stratigraphy and complex faulting. The Forest package thins from south to north. Such thinning appears to be the result of early growth of the thrust structures. It is likely that faults in combination with stratigraphic pinch-outs form the prospective traps within the blocks.

5.1 Discovery and Prospects

There are three prospective trends within the Pt Ligoure and adjacent areas that are of interest.

These are the North Trend, Central Trend and South Trend as shown in Figure 5-3.

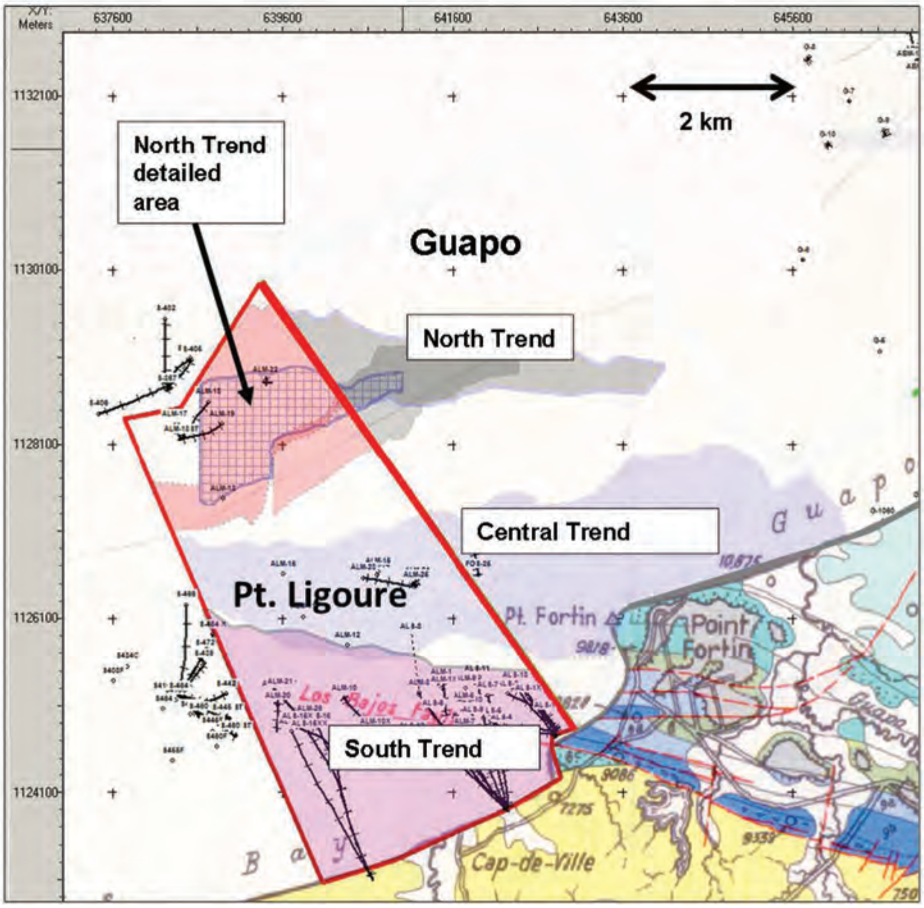

Figure 5-3: Prospective Trends in Pt. Ligoure

The prospective intervals are in the sandstones of the Pliocene Forest and Cruse Formations at depths ranging from 1,000ft to 8,000ft.

The potential of the South and Central Trends is difficult to assess from the current database as improved seismic imaging will be necessary before new targets can be defined and therefore prospective areas are classed as leads within these two trends. There are plans to acquire new 3D seismic data over these Trends

The seismic imaging over the North Trend is of better quality where two fault bounded closures have been identified in the North Trend detailed mapping area (see Figure 5-3).

The North Trend is divided into three thrust sheets, Upper, Middle and Lower. These are shown on an example seismic line Figure 5-4.

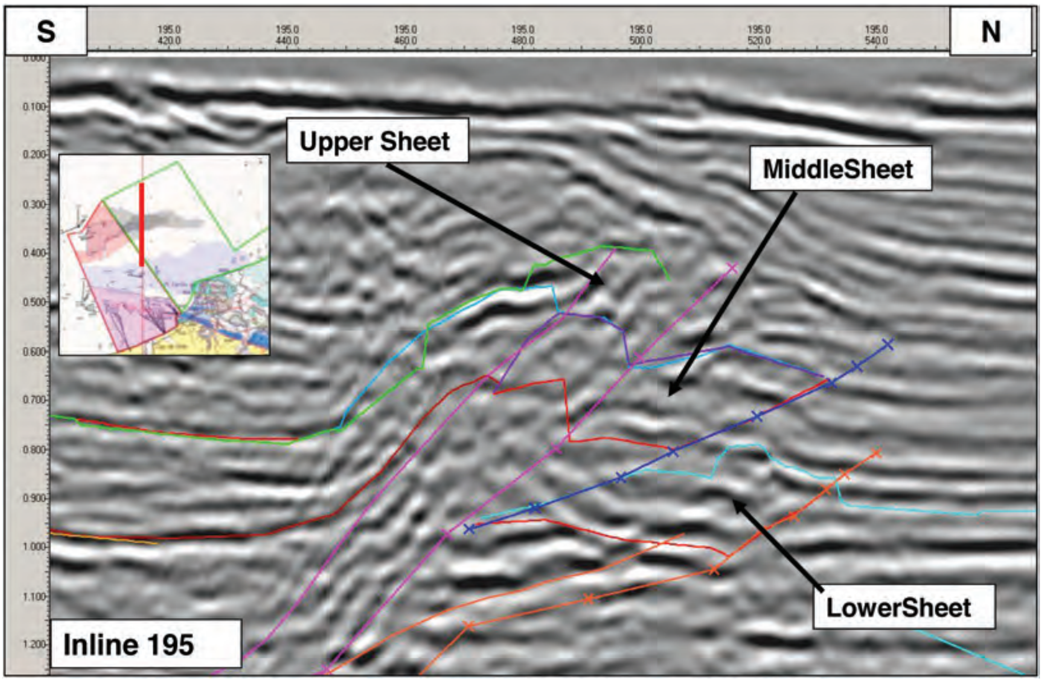

Figure 5-4: Seismic Display-north Trend

The area of interest is within the Lower Sheet. The ALM-22 well tested 300 bopd of 16 API oil from sand within the Forest Formation and was suspended. The sand has been mapped within the fault compartment which has been divided into Area A and Area B as there is the possibility of a fault between the two areas. Figure 5-5 shows an arbitrary seismic line across the mapped structure and the depth structure map of the area is shown in Figure 5-6. The total area of the fault compartment is 48.66 acres. Both areas could be drained via a horizontal well.

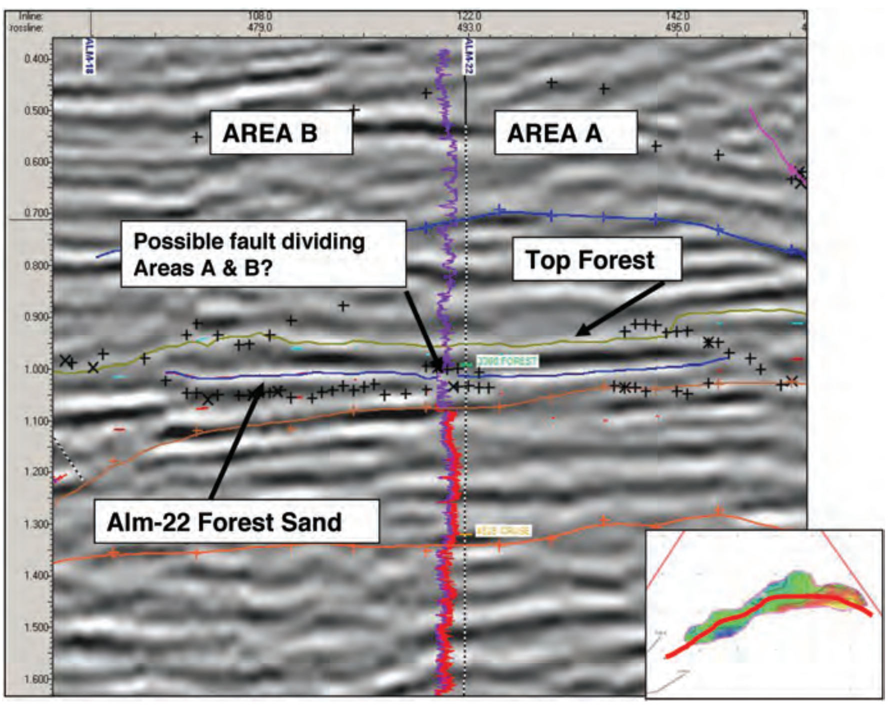

Figure 5-5: Seismic Display-North Trend Forest Sand in ALM-22

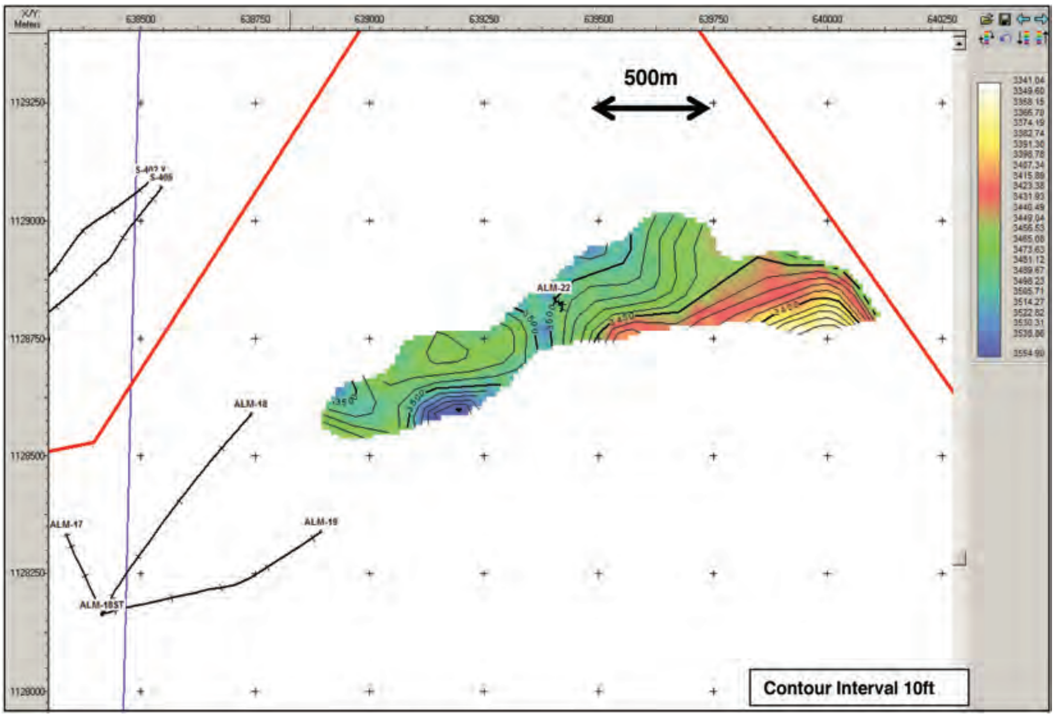

Figure 5-6: Forest Sand in ALM-22 Depth Structure Map

The second fault bounded structure is an anticlinal structure to the south that is largely unfaulted. This is updip from the ALM-22 well to the north and the ALM-17, −18 and −19 wells to the west. The structure is shown in an arbitrary seismic line in Figure 5-7.

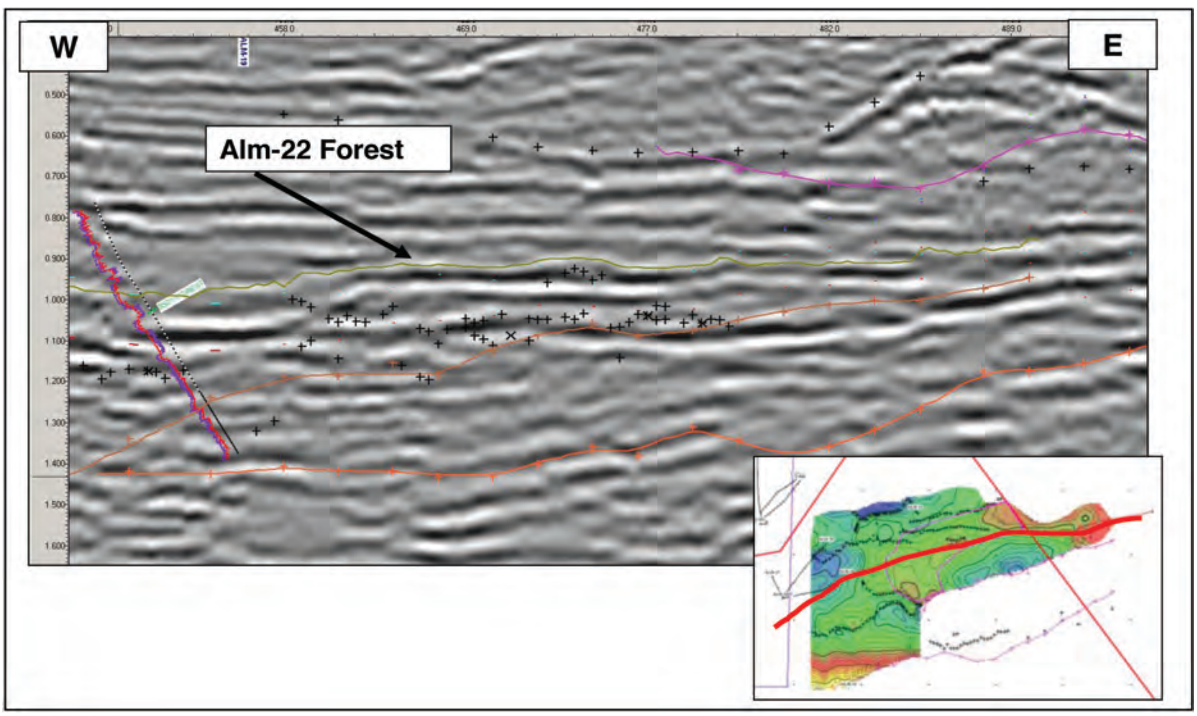

Figure 5-7: Arbitrary Seismic Display

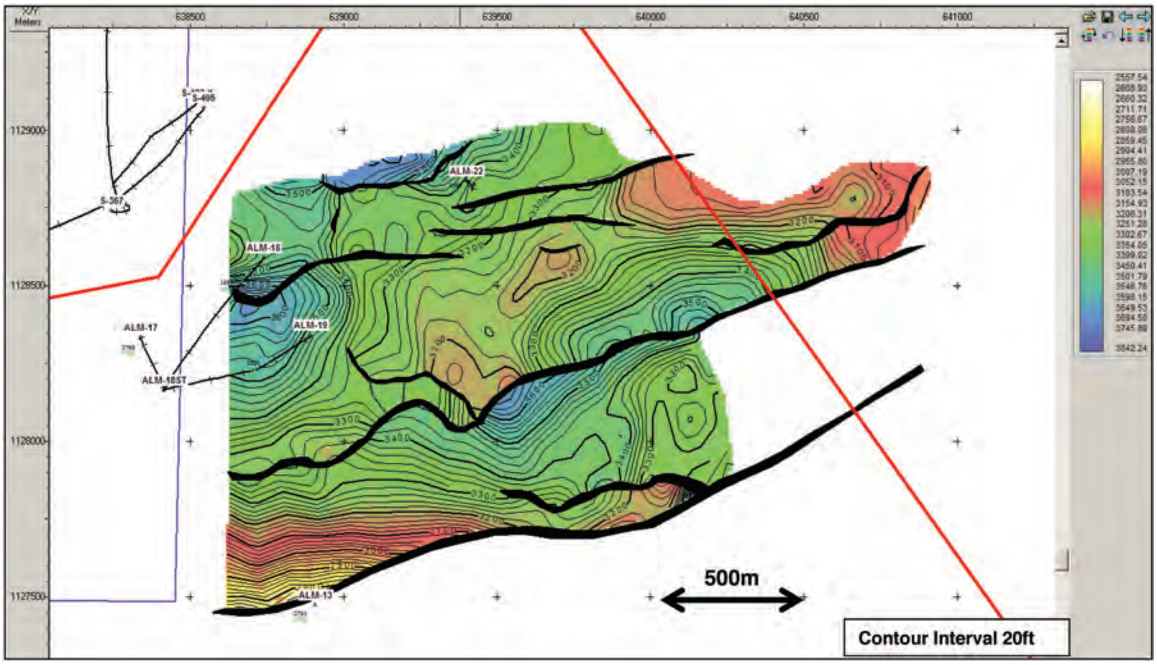

Figure 5-8: Top Forest Depth Structure Map

The structure has an area of 120 acres at the maximum closing contour of 3240ft (SS) (Figure 5-8). There is some upside potential if there is fault closure to the northeast and to the south west.

A seismic dip line across the two fault bounded structures is shown in Figure 5-9.

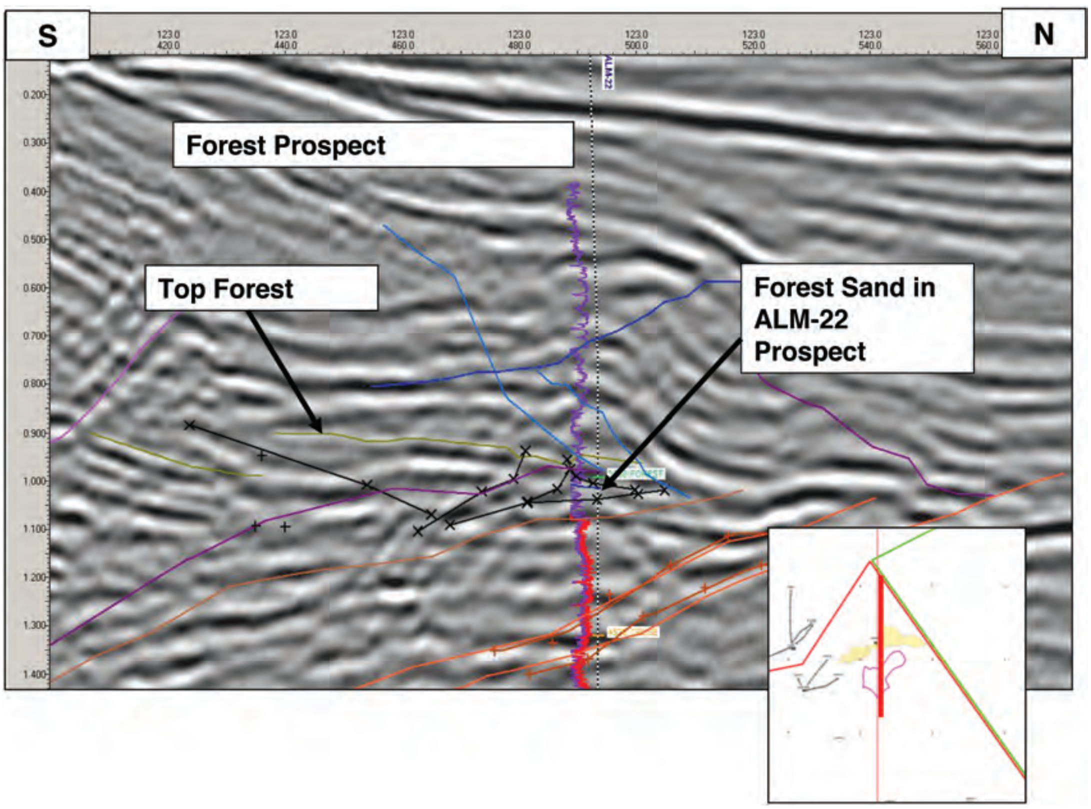

Figure 5-9: Seismic Display Inline 123

There is potential for reservoirs in the deeper Cruse Formation, though there are no plans to test this potential with the present work plan. Other potential leads lie in the Middle and Lower sheets, which remain untested at present.

Reservoir parameters used are based on work presented by Trinity (Table 5-1) and the estimated oil in place for the ALM-22 discovery is shown in Table 5-2.

Parameter	P90	P50	P10
Net to gross	0.3	0.45	0.6
Porosity	0.24	0.28	0.32
Water Saturation	0.36	0.28	0.20
FVF (Bo)	1.15	1.10	1.05

Table 5-1: ALM-22 Reservoir Parameters

	STOIIP (MMstb)		
	P90	P50	P10
ALM-22	1.25	2.22	3.61

Table 5-2: Point Ligoure ALM-22 Oil in Place

5.2 Remaining Recoverable Volumes from Existing Wells

This section addresses volumes classified as Reserves. It includes estimates of ultimate remaining recoverable volumes and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5.

Expected remaining recoverable volumes estimated by DCA of the two existing and producing wells in Point Ligoure Field (Developed Producing) are shown in Table 5-3. Figure 5-10 shows forecast profiles for the field. Further development of area near well ALM-22 is under consideration, but as there is no project commitment at the moment all the resources from these works are classified as Contingent Resources.

Gross Developed Producing Remaining Recoverable Volumes			
Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
ALS 015XX	10	17	81
ALS 014	292	653	930
Arithmetic Total[1]	**302**	**670**	**1,011**

1 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 5-3: Point Ligoure Developed Producing Remaining Recovery by Well

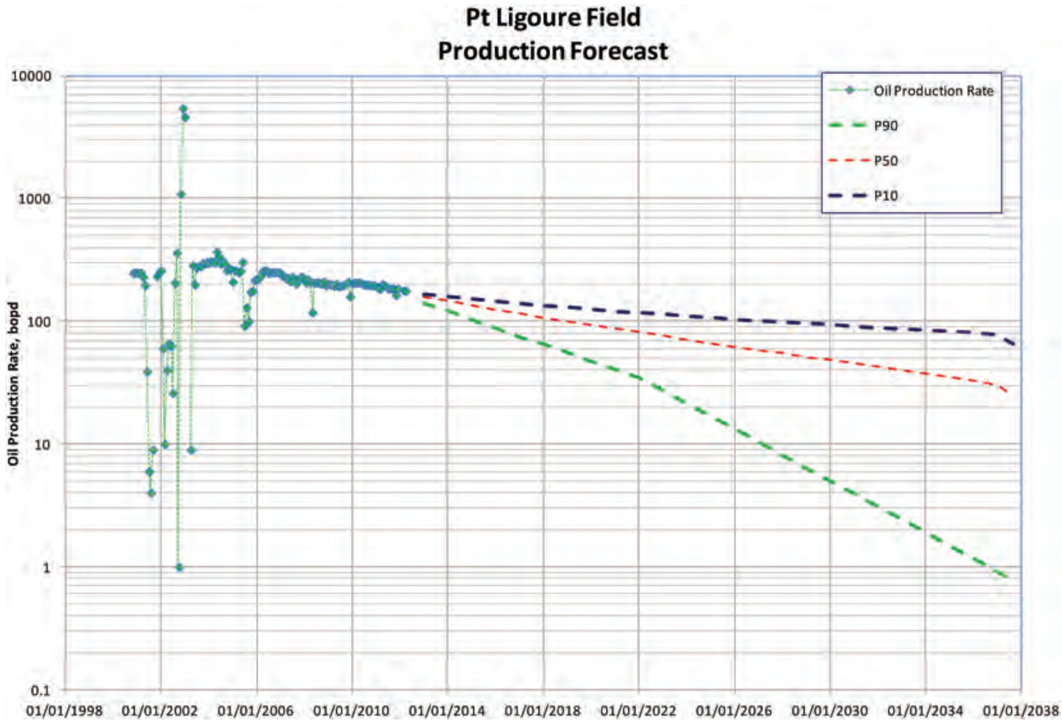

Figure 5-10: Point Ligoure Production Forecast

5.3 Contingent Resources

This section addresses volumes classified as Contingent. It includes estimated ultimate recoverable volume estimates and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5.

Trinity is planning to develop the middle and lower sheets within the North Area near well ALM-22. However, there is currently no firm commitment or field development plan so the resources are classified as Contingent Resources. RPS has estimated these resources by applying recovery factors of 5% (P90), 8.5% (P50) and 12% (P10) to the volumes calculated for this area (see section 5.2). These recovery factors were used by Trinity in their studies and RPS has accepted them as reasonable, considering the characteristics of the field and production mechanism, such as heavy oil (16^{o}API), mid to high viscosity, no aquifer support, no water injection, and weak gas solution drive. The expected remaining recovery for the block was estimated to be 64.9, 188.4 and 435.2 Mstb for the low, best and high case respectively, as shown in Table 5-4.

Based upon the performance of neighbouring wells in the area, RPS considers only one well is needed to produce these resources. The production forecast including these Contingent volumes is shown on Figure 5-11.

Gross Contingent Volumes[1]Point Ligoure Field

Low (Mstb)	Best (Mstb)	High (Mstb)
64.9	188.4	435.2

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 5-4: Point Ligoure Contingent Volumes

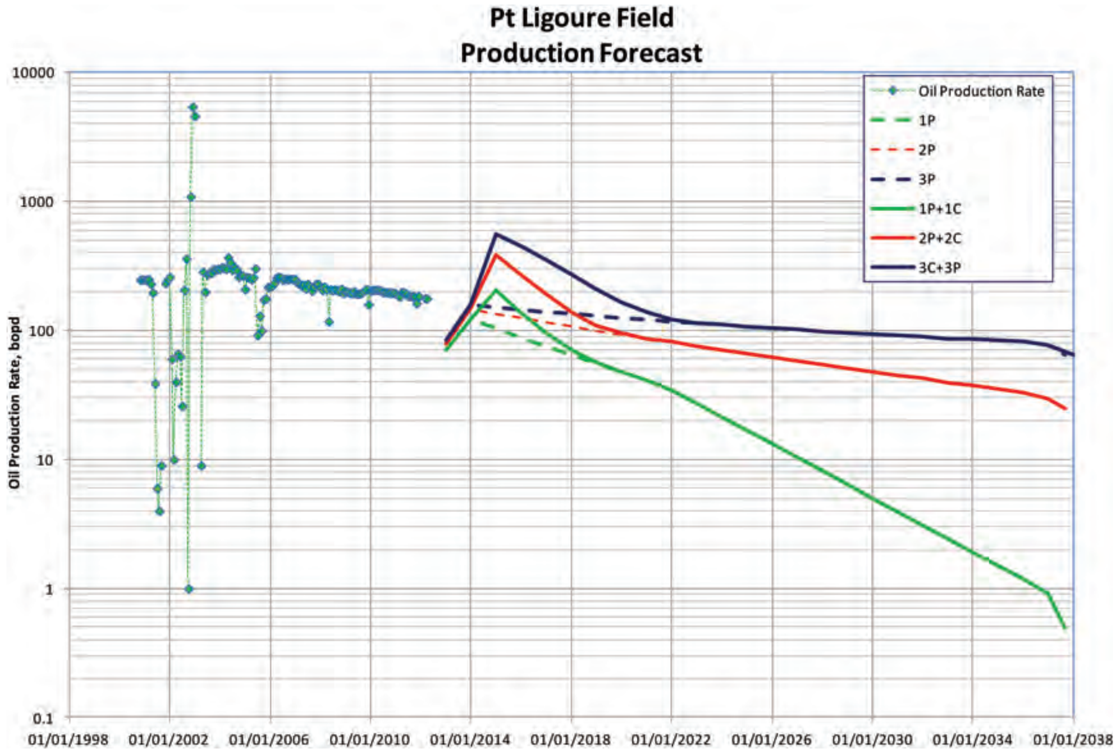

Figure 5-11: Point Ligoure Production Forecast including Contingent Volumes

6. ONSHORE LICENCES

The onshore producing fields leased to Trinity (Table 6-1) lie to the south of Trinidad in the Southern Sub-Basin, the main oil-producing region. This basin has a synclinal structure and is filled with younger Tertiary sediments. The formation and infilling of the petroleum rich southern basin is directly related to the tectonic evolution of the Caribbean-South American Plate boundary zone and its interaction with the Southerly Guyana craton from late Cretaceous to present times.

		Area	
Lease/Farmout	**Licence**	**Acres**	**Square Kilometres**
WD-2	Lennox Production Services Ltd	662	3.774
WD-5/6	Oilbelt Services Ltd	1230	5.77
WD-13	Antilles Resources	150	1.536
WD-14	Nakt Company	148.2	1.441
WD-16	Lennox Production Services Ltd	195	1.514
GU-1	Pioneer Petroleum Company Ltd	1360	6.494
FZ-2	Lennox Production Services Ltd	336	4.348
Tabaquite	Coastline International	8500	30.954

Table 6-1: Lease and Farmout Acreage operated by Trinity, onshore Trinidad

Five principal reservoir intervals ranging in depth from less than 150 to over 1800 metres have been developed from these eight blocks onshore Trinidad. The main producing reservoirs are Miocene-Pliocene age sands within the Cruse, Forest and Morne L'Enfer Formations (Figure 3-2) in the southern basin and the Oligo-Miocene age Nariva sands in Tabaquite.

The southern basin sands are predominately laminated, with grain sizes varying from fine to very fine grained. Sorting is variable, and in some instances, a high proportion of silt and clay has greatly reduced the effective porosity of the sands. Forest Reserve field produces from poorly lithified, immaturely sorted sands of the Forest and Cruse formations. The immature mineralogy of these sands indicates they were deposited close to their area of provenance. Sand porosities are generally high and vary inversely with depth of burial. Oil gravities (API) increase with formation age.

Permeability varies from 10 to 1495 md depending on the shaliness of the rock. Shallow formations exhibit high permeability of 0.5 to 1.5 Darcy's which generally decreases with depth and at Deep Cruse level averages 50 md.

The Tabaquite field lies towards the northern part of the southern basin along the Central Range trend and produces from Early Miocene-Oligocene age Nariva reservoirs. The main producing Nariva C basal sands (comprising of thin stringers) and the Blanket sand are extensive and appear to be distributed over the entire Block. The southwest to northeast trending depositional channel systems are interpreted to be turbidite fan deposits overlying hemipelagic shales.

The trapping mechanism in the southern basin is a combination of both stratigraphy and structure. Crestal as well as northern and southern flanks of the anticlinal structures contain hydrocarbons. Minor faults which are common in the field act as seals to reservoirs, since oil and gas are found downdip of faults below water levels of the same sand in adjacent blocks. In addition to the above trapping mechanisms, unconformities at the tops of Forest and Cruse Formations may act as seals, trapping oil and gas in the sand reservoirs below them.

Trinity has an aggressive programme to revitalise the onshore fields with a series of planned workovers, side-tracks, replacement and infill wells. Approximately eleven wells are planned onshore Trinidad in 2012, mainly in the WD-2 and WD-5/6 blocks.

6.1 Operator Contracts

6.1.1 Lease Operator Contracts

Lease Operatorships were awarded as part of a programme of cost cutting by the two former state-owned oil companies of Trinidad and Tobago, Trintoc and Trintopec. The programme was initiated in 1989. A number of peripheral assets were earmarked for disposal, the aim being that smaller, predominantly local companies would be able to invest the money and manpower to extract the last remaining reserves of oil from the fields.

The wells were separated into two classes. 'A' wells were considered to have high potential from minimal effort whereas 'B' wells required more demanding workovers. Originally, the Lease Operators only had the rights to the well bores and production was limited to the formation in which the well was perforated at the time it was leased to the operator. This was subsequently changed to include drilling of replacement and infill wells.

The majority of the fields were awarded between mid-1989 and January 1996. Since that time, a number of the licences have changed hands, two of the earliest being WD-13 and WD-14, both of which were purchased by Venture Production from Coastline International in September 1998, Coastline itself having purchased the blocks from the original Lease Operators, Antilles Resources and Nakt Company.

The leases operated by Trinity are:

- GU-1 (Pioneer Petroleum Company Ltd),
- FZ-2, WD-2 and 16 (Lennox Production Services Ltd),
- WD-5 and 6 (Oilbelt Services Ltd) and
- WD-13 and WD-14

6.1.2 Farm-Out Operatorships

The only farmout block operated by Trinity is located in Tabaquite (Figure 3-1) which lies in the central portion of Trinidad about ten miles north-east of San Fernando. The area is approximately 13.2 square miles (8,500 acres) and was farmed out by Petrotrin in 1994 to Coastline International.

The Block comprises of four field areas:

- Tabaquite Old Field
- Tabaquite New Field (inclusive of Tab 229 area)
- Tabaquite West (Piparo—Tab 236) area
- Johnson Road area

Coastline's interests were initially acquired in 1996 by Venture Production and subsequently by Trinity. Production of these assets continue with the exception of the Johnson Road acreage with the well JR1 being closed-in since May 2004.

6.2 Recoverable Resources

In order to build the notional production profiles for the planned recompletions and new wells RPS identified a number of analogue wells with sufficient production data which have been recently completed or drilled in the same formations. Then, notional profiles for planned recompletions and new wells were generated using the method described in section 2.4.2.

The expected remaining recovery associated with existing well completions, workovers and sanctioned new wells, after application of an economic cutoff, is classified as Reserves. Similarly, the expected remaining recovery associated with recompletions and unsanctioned new wells, after economic cutoff, is classified as Contingent Resources.

6.2.1 Fyzabad-2

6.2.1.1 Remaining Recoverable Volumes from Existing Wells

When generating notional profiles for recompletions in the Lower Forest Formation in fields WD-13, WD-14 and Fyzabad-2, it was realised that the number of wells recompleted recently in this formation on which to base the profiles is very limited, so data from these fields have been combined to generate a generic profile, for the recompletion cases. Thus, notional profiles for planned recompletions have been generated using the method described in Section 2.4.2 and the EUR and initial peak rate (IP) values shown in Table 6-2.

Probability	Expected Ultimate Recovery (Mstb)[1]	Initial Production Rate (bopd)	Decline Rate D (y^{-1})
P90	0.6	5.2	3.01
P50	3.8	17.6	1.65
P10	24.7	62.0	0.91

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-2: Estimated EUR and Initial Production Rate for Lower Forest Recompletion Wells in WD-13, WD-14 and Fyzabad-2

Expected Remaining Recovery estimated by DCA of existing wells (Developed Producing), and notional profiles for planned recompletion (Developed Non-Producing) in Fyzabad-2 Field are shown in Table 6-3 to Table 6-5, whilst forecast profiles are depicted in Figure 6-1. In this Figure, P90 Total, P50

Total and P10 Total refer to the profiles generated by adding the profiles for the planned workover to those from DCA of existing wells.

Gross Developed Producing, Expected Remaining Recovery[1] Fyzabad-2 Field

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
FZ-0028	0.38	1.74	3.12
FZ-0185	2.31	3.02	4.98
FZ-0195	1.5	2.33	4.36
FZ-0253	1.64	4.99	7.09
FZ-0277	5.1	5.35	5.6
FZ-0421	16	24.11	31.64
FZ-0424	0.26	0.65	1.67
FZ-0425	1.5	3.26	5.92
FZ-0432	32.78	40.48	43.25
FZ-0439	0.12	0.46	1.23
FZ-0449	0.76	1.48	5.2
FZ-0455	0.78	1.46	6.87
FZ-0477	9.33	9.99	10.4
FZ-0505	12.38	22.3	29.35
FZ-0660	3.37	6.09	6.25
FZ-0715	5.52	10.55	17.79
FZ-0732	8.63	10.42	19.5
FZ-0811	1.07	2.48	7.4
FZ-0833	1.39	1.99	4.57
FZ-1048	0	0.35	1.26
Swabbed Wells[2]	3.64	12.85	15.61
Arithmetic Total[3]	**108.5**	**166.4**	**233.1**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Swabbed wells: FZ-266, FZ-288, FZ-321, FZ-366, FZ-391, FZ-395, FZ-422, FZ- 498, FZ-600, FZ-639, FZ-687, FZ-746, FZ-749 and FZ-814

3 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-3: Fyzabad-2 Field—Expected Remaining Recovery by Well Existing Wells

Gross Developed Non-Producing Expected Remaining Recovery[1]

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
FZ-759	0.57	3.75	24.41

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-4: Fyzabad-2 Field—Expected Remaining Recovery from Planned Recompletion

Gross Arithmetic Total[1] Developed Producing and Developed Non-Producing Expected Remaining Recovery[2]

Low (Mstb)	Best (Mstb)	High (Mstb)
109.0	170.1	257.5

1 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

2 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-5: Fyzabad-2 Field—Gross Developed Producing and Developed Non-Producing Expected Remaining Recovery

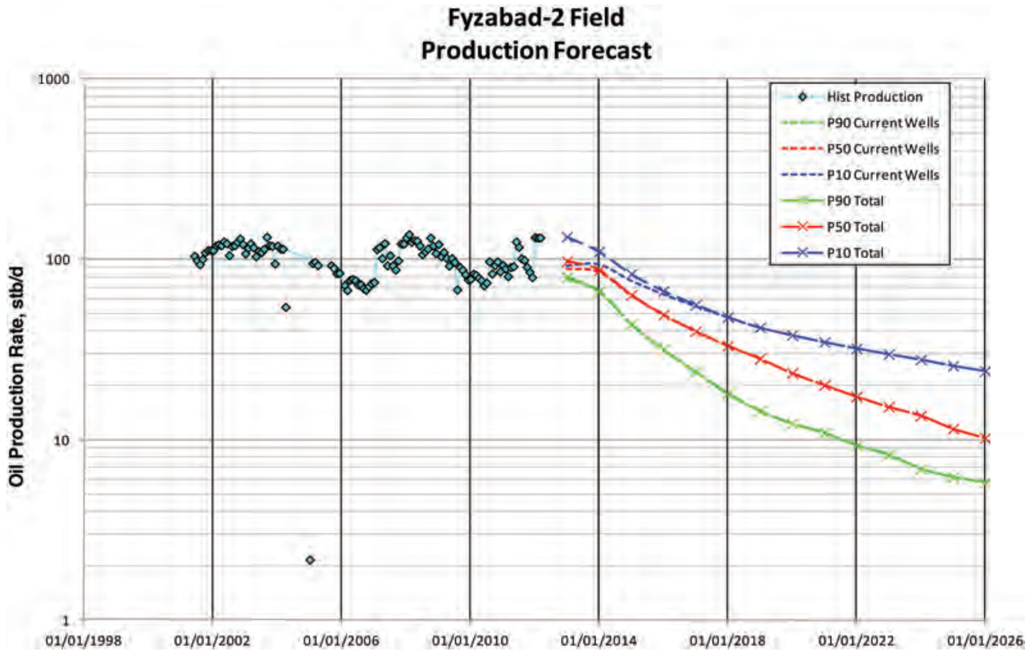

Figure 6-1: Fyzabad-2 Field Production Forecast

6.2.1.2 Contingent Resources

This section addresses volumes classified as Contingent. It includes estimated ultimate recoverable volume estimates and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5.

Three wells were identified as part of a recompletion campaign for Fyzabad-2 with a further six new well locations also indicated. Volumes associated with both are categorised as contingent.

A lack of complete or verifiable production data in the historical record makes it difficult to establish definitive statistics for new wells for the field. However, with only limited data that covered entire well-life histories, a probabilistic distribution was established, firstly by identifying wells that had complete histories, then defining a lognormal distribution for initial rate and EUR before generating notional profiles. The resulting values are shown in Table 6-6.

These profiles were then used for infill wells, whilst for recompletion cases the profiles were generated as described in Section 6.2.1.1. The recompletions are assumed to all be performed during 2015 with the infill wells staggered over three years.

The resulting contingent expected recovery is shown in Table 6-7, whilst Figure 6-2 depicts the production forecast for the field, including these volumes.

Probability	Expected Ultimate Recovery (Mstb)	Initial Production Rate (bopd)	Decline Rate D (y^{-1})
P90	9.0	4.5	0.16
P50	41.4	8.4	0.07
P10	107	16.5	0.05

Table 6-6: Estimated EUR and Initial Production Rate for New Wells in Fyzabad-2

Plan	Gross Contingent Expected Recovery[1] Low (Mstb)	Best (Mstb)	High (Mstb)
Recompletions	1.7	11.4	74.0
Drilling	48.1	129.7	271.8
Arithmetic Total[2]	**49.8**	**141.1**	**345.7**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (1C) may be very conservative and the arithmetic total P10 (3C) very optimistic.

Table 6-7: Fyzabad-2 Field Contingent Expected Recovery

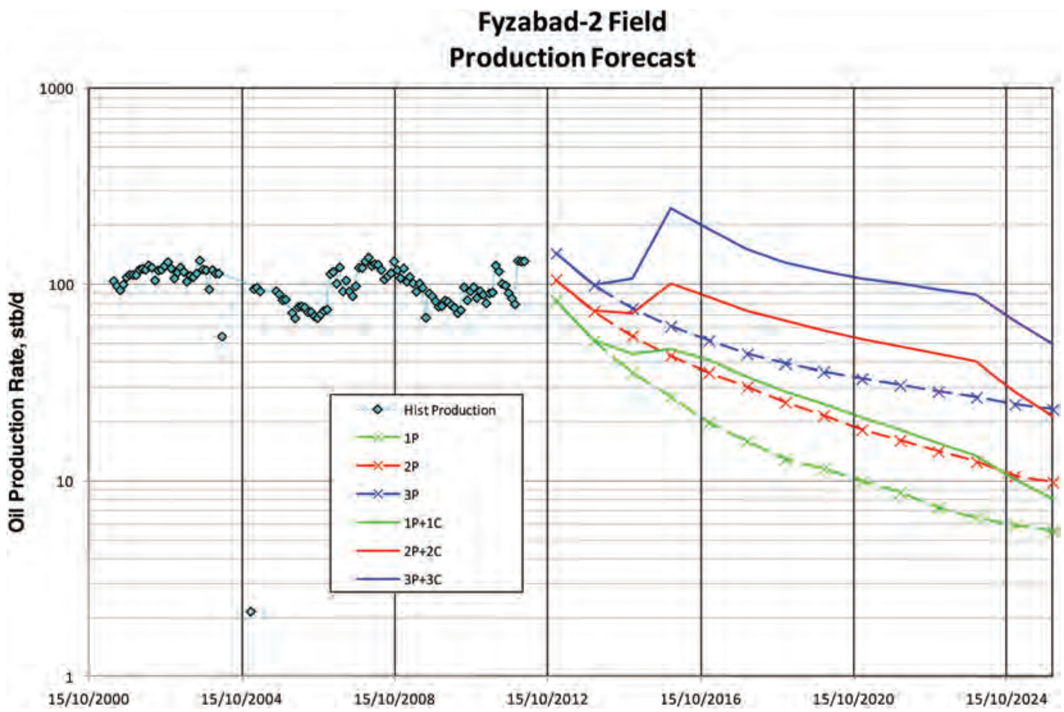

Figure 6-2: Fyzabad-2 Field Production Forecast including Contingent Volumes

6.2.2 Guapo-1

6.2.2.1 Remaining Recoverable Volumes from Existing Wells

Technical Remaining Resources estimated by DCA of existing wells in Guapo-1 Field are shown in Table 6-8. Forecast profiles are depicted in Figure 6-3.

Gross Developed Producing Expected Remaining Recovery[1] Guapo-1 Field

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
GUA 080	3.05	10.82	15.28
GUA 082	8.91	11.78	12.77
GUA 083	0.82	3.98	5.31
GUA 103	12.12	14.72	16.12
GUA 107	2.65	4.33	5.17
GUA 113	11.03	13.89	14.63
GUA 128	1.72	3.66	12.99
GUA 400	1.08	1.3	4.31
GUA 416	0.82	3.49	4.82
GUC 007	3.42	4.87	6.69
GUC 013	1.52	5.26	5.26
GUF 002	9.99	12.7	15.64
GUF 003	4.35	5.03	5.27
GUF 006	4.66	6.56	7.88
GUP 004	10.23	11.87	12.8
GUZ 012	1.06	2.31	3.19
GUZ 024	20.28	21.93	23.22
GUA 078	47.17	52.71	56.56
Swabbed Wells[2]	6.45	30.11	66.8
Arithmetic Total[3]	**151.3**	**221.3**	**294.7**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Swabbed wells: GUA-026, GUA-027, GUA-034, GUA-036, GUA-040, GUA-042, GUA-045, GUA-054, GUA-067, GUA-069, GUA-070, GUA-084, GUA-109, GUA-125, GUA-129, GUA-131, GUA-446, GUA-456, GUA-504, GUA-510, GUA-516, GUA-847, GUC-215, GUC-815, GUM-002, GUM-003 and GUM-004

3 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-8: Guapo-1 Developed Producing Expected Remaining Recovery by Well

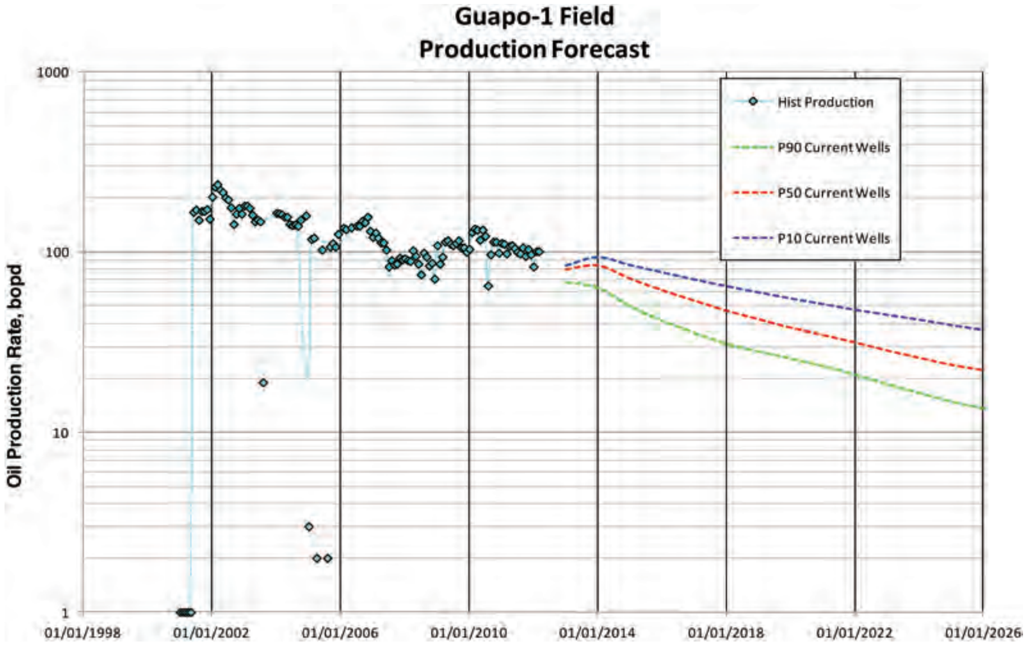

Figure 6-3: Guapo-1 Production Forecast

6.2.2.2 Contingent Resources

This section addresses volumes classified as Contingent. It includes estimated ultimate recoverable volume estimates and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5

Six wells were identified as part of a recompletion campaign for Guapo-1 with a further six new well locations also indicated. Both are categorised as contingent.

The methodology used to estimate resources for recompletions and new wells for this field was the same as used for Fyzabad-2. The values used in the generation of infill wells notional profiles are shown in Table 6-9. The contingent expected recovery is shown in Table 6-10 and the production profile including these volumes is presented in Figure 6-4.

Probability	Expected Ultimate Recovery[1] (Mstb)	Initial Production Rate (bopd)	Decline Rate D (y^{-1})
P90	4.1	2.4	0.17
P50	17.1	4.7	0.09
P10	43.37	9.27	0.07

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-9: Estimated EUR and Initial Production Rate for New Wells in Guapo-1

Gross Contingent Expected Recovery[1] Guapo-1 Field

Plan	Low (Mstb)	Best (Mstb)	High (Mstb)
Recompletions	3.4	22.8	148.1
Drilling	24.6	66.4	140.3
Arithmetic Total[2]	**28.0**	**89.2**	**288.3**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-10: Guapo-1 Contingent Expected Recovery

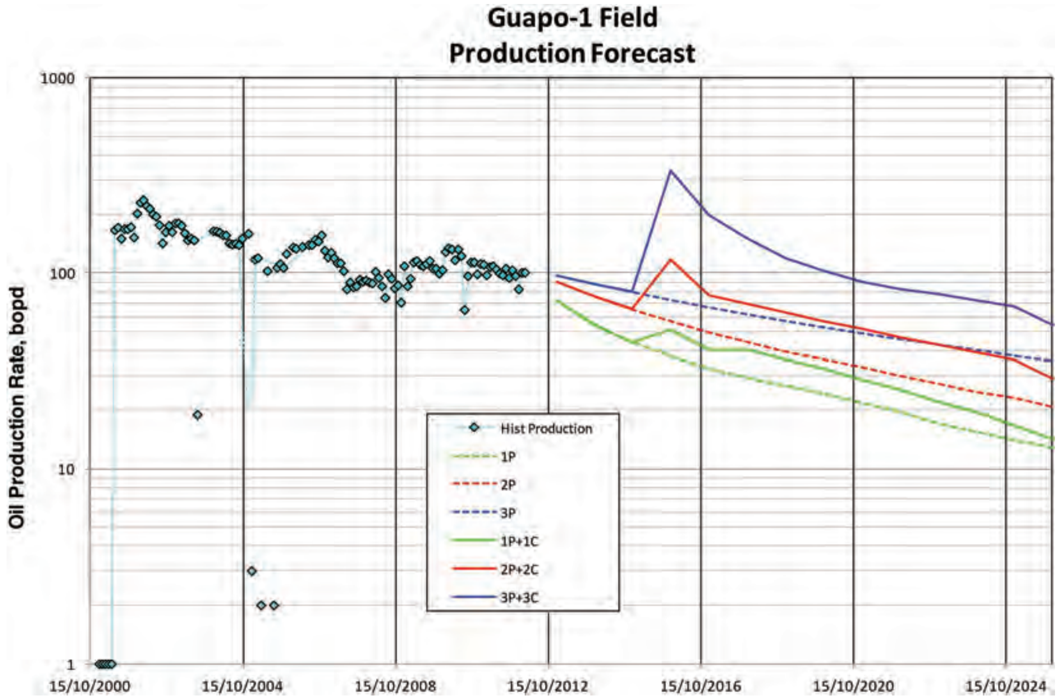

Figure 6-4: Guapo-1 Field Production Forecast including Contingent Volumes

6.2.3 Tabaquite

6.2.3.1 Remaining Recoverable Volumes from Existing Wells

Expected remaining recovery estimated by DCA of existing wells in Tabaquite Field are shown in Table 6-11, whilst forecast profiles are depicted in Figure 6-5.

Gross Developed Producing Remaining Expected Remaining Recovery[1] Tabaquite Field

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
TAB 0073	1.4	3.0	8.3
TAB 0225	1.2	22.2	30.1
TAB 0231	9.6	20.1	24.6
TAB 0235	0.7	4.1	10.5
TAB 0245	6.4	11.1	23.2
Swabbed Wells[2]	2.4	9.6	33.1
Arithmetic Total[3]	**21.7**	**70.1**	**129.8**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Swabbed wells: TAB0221, TAB0223, TAB0224, TAB0226, TAB0227, TAB0232, TAB0236, TAB0237 and TAB0238

3 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-11: Tabaquite Expected Remaining Recovery by Well

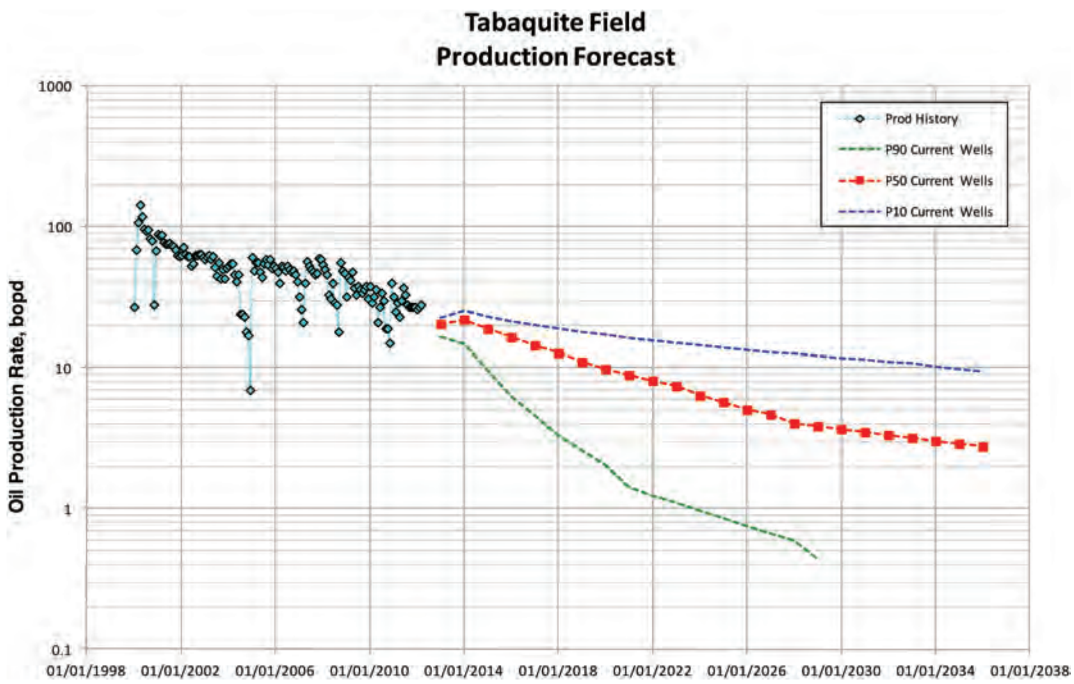

Figure 6-5: Tabaquite Field Production Forecast

6.2.3.2 Contingent Resources

This section addresses volumes classified as Contingent. It includes estimated ultimate recoverable volume estimates and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5

Five infill wells and five step-out wells targeted at the Nariva formation are under technical review by Trinity for the Tabaquite Field. It is assumed that these wells will be drilled at a rate of roughly three wells per year for three years. The contingent expected recovery has been estimated assuming three new wells are drilled per year for five years starting in 2015 (as part of the planned 20 lease operated wells per year over 5 years).

With the available data covering entire well-life histories, a probabilistic distribution was established. Firstly, wells that had complete histories were identified and the initial rate and EUR obtained from DCA assuming exponential decline. Lognormal distributions were then fitted to initial rate and EUR before generating corresponding notional profiles. The used values are shown in Table 6-12.

The resulting contingent expected recovery is shown in Table 6-13, whilst Figure 6-6 depicts the production forecast for the field, including contingent volumes.

Probability	Expected Ultimate Recovery (Mstb)	Initial Production Rate (bopd)	Decline Rate D (y^{-1})
P90	2.8	2.9	0.32
P50	9.0	7.3	0.28
P10	29.4	18.4	0.22

Table 6-12: Estimated EUR and Initial Production Rate for New Nariva Wells in the Tabaquite Field

Gross Contingent Expected Recovery[1] Tabaquite Field

Plan	Low (Mstb)	Best (Mstb)	High (Mstb)
Recompletions	—	—	—
Drilling	41.3	135.0	404.5
Arithmetic Total[2]	**41.3**	**135.0**	**404.5**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-13: Tabaquite Contingent Expected Recovery

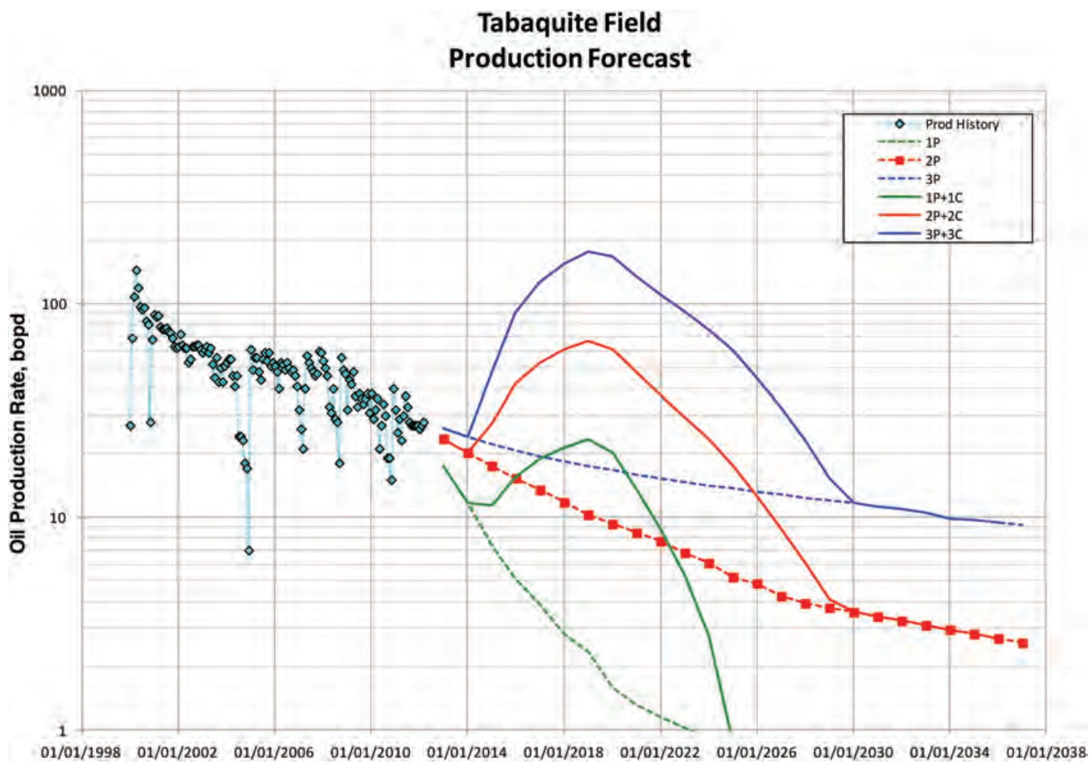

Figure 6-6: Tabaquite Field Production Forecast including Contingent Volumes

6.2.4 WD-2

6.2.4.1 Remaining Recoverable Volumes from New and Existing Wells

Notional profiles for sanctioned new wells have been generated using the method described in section 2.4.2 and the EUR and IP values shown in Table 6-14 and Table 6-15. Observing historic behaviour for this field it is reasonable to assume same profiles for both recompletion and infill drilling scenarios.

Probability	Expected Ultimate Recovery[1] (Mstb)	Initial Production Rate (bopd)	Decline Rate D (y^{-1})
P90	10	30	1.08
P50	38	43	0.40
P10	60	65	0.40

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-14: Estimated EUR and IP for Lower Forest Wells in WD-2

Probability	Expected Ultimate Recovery[1] (Mstb)	Initial Production Rate (bopd)	Decline Rate D (y^{-1})
P90	20	60	1.09
P50	51	96	0.68
P10	90	110	0.44

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-15: Estimated EUR and Initial Production Rate for Upper Forest Wells in WD-2

Expected Remaining Recovery estimated by DCA of existing wells (Developed Producing) and notional profiles for planned new wells (Undeveloped) in WD-2 Field are shown in Table 6-16 to Table 6-18. Figure 6-7 shows forecast profiles for the field. In this Figure, P90 Total, P50 Total and P10 All Wells refer to the profiles generated by adding the profiles for planned wells to those from DCA of existing wells.

The increments in production in years 2012 and 2013 are due to new wells being drilled during this period and coming into production.

Gross Developed Producing Expected Remaining Recovery[1]			
Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
ER041	1.0	3.1	6.0
ER104	3.0	7.0	19.5
PS056	2.3	4.0	5.5
PS-311	5.3	9.5	15.1
PS-319	0.5	4.8	6.6
PS-340	1.8	3.8	5.8
PS-343	5.9	7.3	8.9
PS-345	1.3	3.4	9.9
PS-366	0.0	0.1	0.3
PS-380	3.8	5.4	5.7
PS-386	8.0	9.5	12.3
PS-390	0.3	0.8	1.5
PS-541	4.3	7.6	11.7
PS-542	1.4	3.5	6.2
PS-543	24.6	34.8	43.2
PS-560	6.8	7.3	12.1
PS-561	2.2	2.6	3.9
PS-562	1.8	11.7	19.4
Swabbed[2]	11.8	22.0	34.1
Arithmetic Total[3]	**86.0**	**148.2**	**227.7**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Swabbed wells: ER-012, ER-038, ER-046, PS-307, PS-316, PS-324, PS-326, PS-334, PS-359, PS-363, PS-391, and PS-413

3 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-16: WD-2 Developed Producing Expected Remaining Recovery by Well

Gross Undeveloped
Expected Remaining Recovery[1]
WD-2 Field

Planned Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
PS329	9.5	37.4	59.0
PS343	9.5	37.4	59.0
PS345	9.5	37.4	59.0
PS366	9.5	37.4	59.0
PS372	19.1	49.7	88.3
PS333	19.1	49.7	88.3
PS377	9.5	37.4	59.0
PS305	9.5	37.4	59.0
Arithmetic Total[2]	**95.5**	**323.9**	**530.7**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-17: WD-2 field Undeveloped Expected Remaining Recovery

Gross Arithmetic Total[1]
Undeveloped and Developed Producing
Expected Remaining Recovery[2]
WD-2 Field

Low (Mstb)	Best (Mstb)	High (Mstb)
181.5	**472.1**	**758.4**

1 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

2 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-18: WD-2 Field Gross Undeveloped and Developed Producing Expected Remaining Recovery

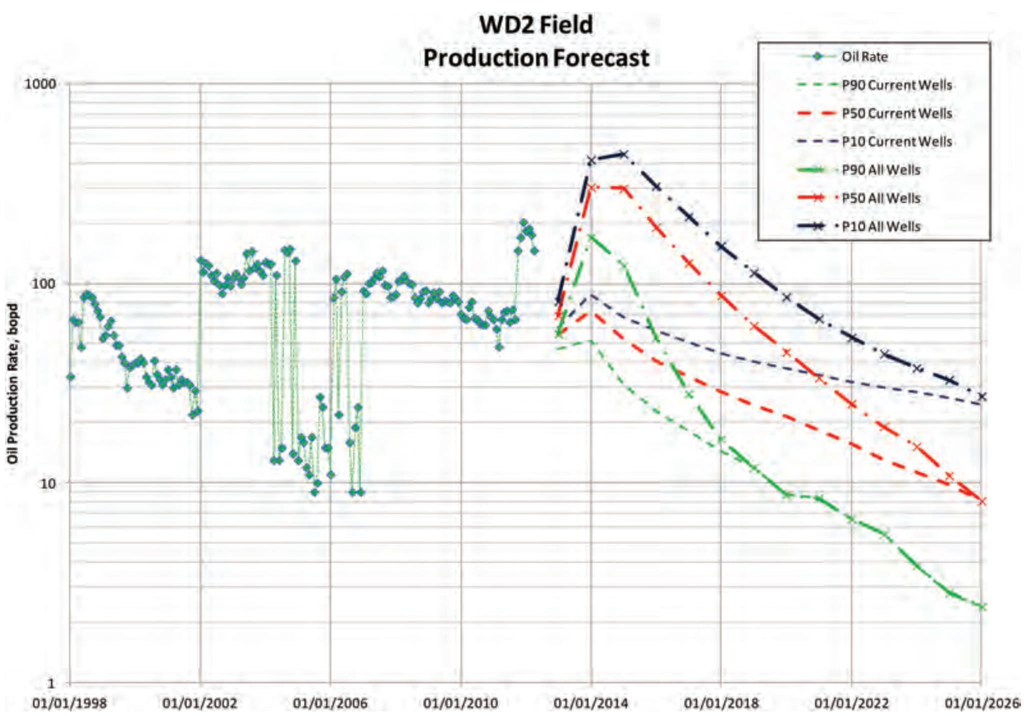

Figure 6-7: WD-2 Field Production Forecast

6.2.4.2 Contingent Resources

This section addresses volumes classified as Contingent. It includes estimated ultimate recoverable volume estimates and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5

A further six recompletions and ten new wells are under evaluation for further development of the field, and their forecasted resources are classified as contingent. In order to estimate the volumes for these new workovers and wells, the same profiles per well and formation estimated in section 5.2.4.1 were used. The total contingent expected recovery for these wells are shown in Table 6-19.

Gross Total Technical Contingent Resources[1]
WD-2 Field

Plan	Low (Mstb)	Best (Mstb)	High (Mstb)
Recompletions	18.1	55.7	81.3
Drilling	122.2	404.4	649.1
Arithmetic Total[2]	**140.3**	**460.1**	**730.4**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (1C) may be very conservative and the arithmetic total P10 (3C) very optimistic.

Table 6-19: WD-2 Field Contingent Expected Recovery

Figure 6-8 shows the production forecast for WD2 field including the contingent volumes.

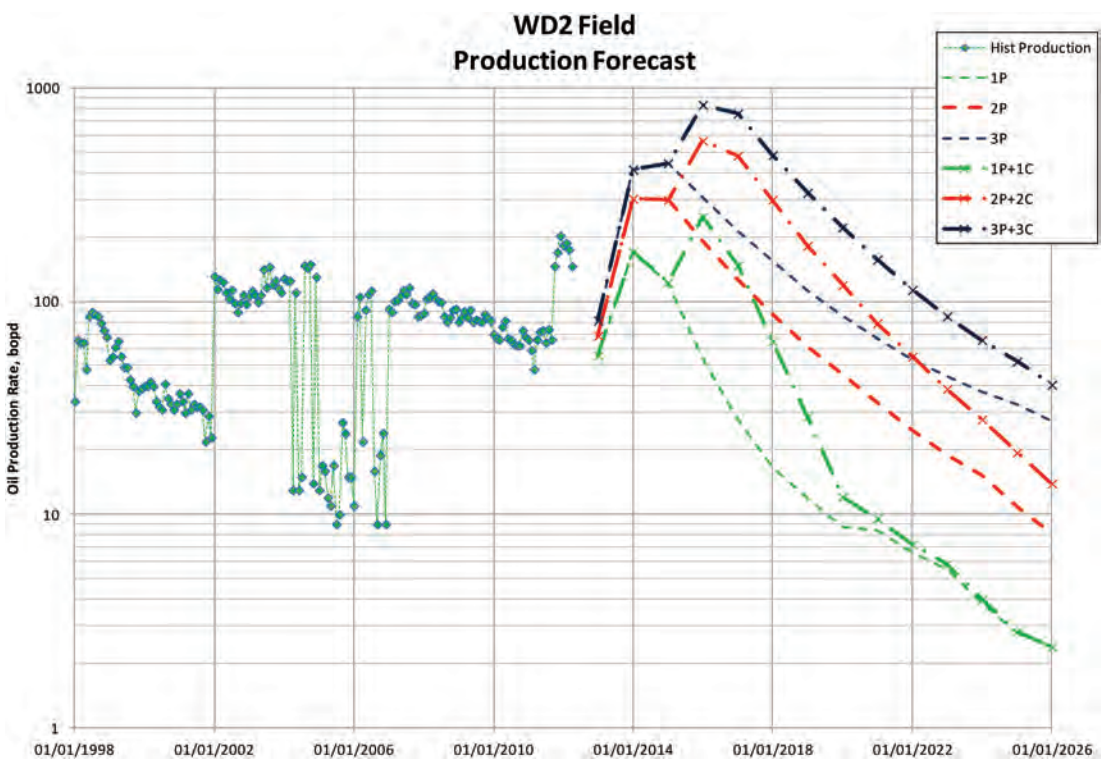

Figure 6-8: WD-2 Field Production Forecast including Contingent Volumes

6.2.5 WD-5/6

6.2.5.1 Remaining Recoverable Volumes from New and Existing Wells

Notional profiles for planned recompletions and sanctioned new wells have been generated using the method described in section 2.4.2 and the EUR and IP values shown in Table 6-20 and Table 6-21.

Probability	Expected Ultimate Recovery (Mstb)[1]	Initial Production Rate (bopd)	Decline Rate D (y^{-1})
P90	14	26	0.64
P50	43	55	0.47
P10	87	85	0.36

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-20: Estimated EUR and IP for Lower Forest Wells in WD-5/6

Probability	Expected Ultimate Recovery[1] (Mstb)	Initial Production Rate (bopd)	Decline Rate D (y^{-1})
P90	15	20	0.79
P50	26	47	0.65
P10	53	82	0.56

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-21: Estimated EUR and IP for Upper Forest Wells in WD-5/6

Expected Remaining Recovery estimated by DCA of existing wells (Developed Producing), notional profiles for planned workovers (Developed Non-producing) and new wells (Undeveloped) in the WD-5/6 Field are shown in Table 6-22 to Table 6-25. Figure 6-9 shows forecast profiles for the field. In this Figure, P90, P50 and P10 Totals refer to the profiles generated by adding the profiles for planned recompletions and new wells to those from DCA of existing wells.

Gross Developed Producing
Expected Remaining Recovery[1]
WD-5/6 Field

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
EN-011X	136.0	167.5	192.6
EN-015X	3.3	13.6	44.9
EN-017X	11.0	15.2	52.0
EN-0027	1.5	4.5	16.8
EN-0028	24.0	28.6	50.1
EN-0029	7.5	27.1	73.0
EN-0030	0.6	0.8	1.4
S-0064X	57.3	78.0	132.8
S-0065	0.9	17.0	23.1
S-0068X	16.4	31.5	64.2
S-0080X	93.8	110.1	141.2
S-0081X	27.6	41.6	95.8
S-0090X	31.8	39.2	44.4
S-0091RDX	0.0	4.0	12.9
S-0095XST	7.9	81.6	114.4
S-0123X	0.5	5.5	6.8
S-0127X	70.8	102.6	127.9
S-0133X	18.9	41.3	75.1
S-0153	4.3	24.7	43.9
S-0161X	58.4	139.9	208.6
S-0187X	3.0	11.3	43.3
S-0189X	25.6	82.7	92.3
S-0190XST	10.1	31.5	36.8
S-0194X	29.4	47.3	114.0
S-0213X	3.3	7.7	17.6
S-0270X	2.7	22.9	32.1
S-0274XST	35.7	44.1	55.5
S-0298	9.8	12.6	19.3
S-0355X	23.9	41.9	48.1
S-373	14.7	19.3	22.2
S-0383XST	3.6	11.9	15.4
GROUP 1[2]	252.0	369.0	1317.4
Swabbed Wells[3]	7.4	45.1	97.2
Arithmetic Total[4]	**993.7**	**1721.8**	**3433.1**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Group 1 represents the group of wells that did not have an individual forecast. List of wells: EN-030, PS-0064X, PS-0072XST, PS-0076X, PS-0080X, PS-0082X, PS-0106X, PS-0113X, PS-0187X, PS-0194X, PS-0199, PS-0202, PS-0214, PS-0229, PS-0240X, PS-0252X, PS-0264RD, PS-0283, PS-0294, PS-0302, PS-0353X, PS-0443RD, PS-0445, PS-0556, PS-0558 and PS-0559 (26 wells)

3 Swabbed wells: EN-006, EN-014, PS-0069ST, PS-0071, PS-0079, PS-0086, PS-0135, PS-0147, PS-0163, PS-0192, PS-0195, PS-0210, PS-0303, PS-0308, PS-0310, PS-0332, PS-0335, PS-0349, PS-0352, PS-0401, and PS-0422 (21 wells).

4 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-22: WD-5/6 Field Developed Producing Expected Remaining Recovery

Gross Developed Non-Producing
Expected Remaining Recovery[1]
WD-5/6 Field

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
PS79	13.4	40.7	61.8
PS63RD	14.1	42.0	85.0
PS302	14.2	25.6	33.3
Arithmetic Total[2]	**41.6**	**108.3**	**180.1**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-23: WD-5/6 field Developed Non-Producing Expected Remaining Recovery

Gross Undeveloped
Expected Remaining Recovery[1]
WD-5/6 Field

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
PS386	14.1	42.0	84.7
PS258	14.1	42.0	84.7
Arithmetic Total[2]	**28.1**	**84.0**	**169.5**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-24: WD-5/6 field Undeveloped Expected Remaining Recovery

Gross Arithmetic Total[1]
Undeveloped and Developed Non-Producing
Expected Remaining Recovery[2]
WD-5/6 Field

Low (Mstb)	Best (Mstb)	High (Mstb)
1063.4	1914.0	3782.7

1 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

2 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-25: WD-5/6 Field Gross Undeveloped and Developed Non-Producing Expected Remaining Recovery

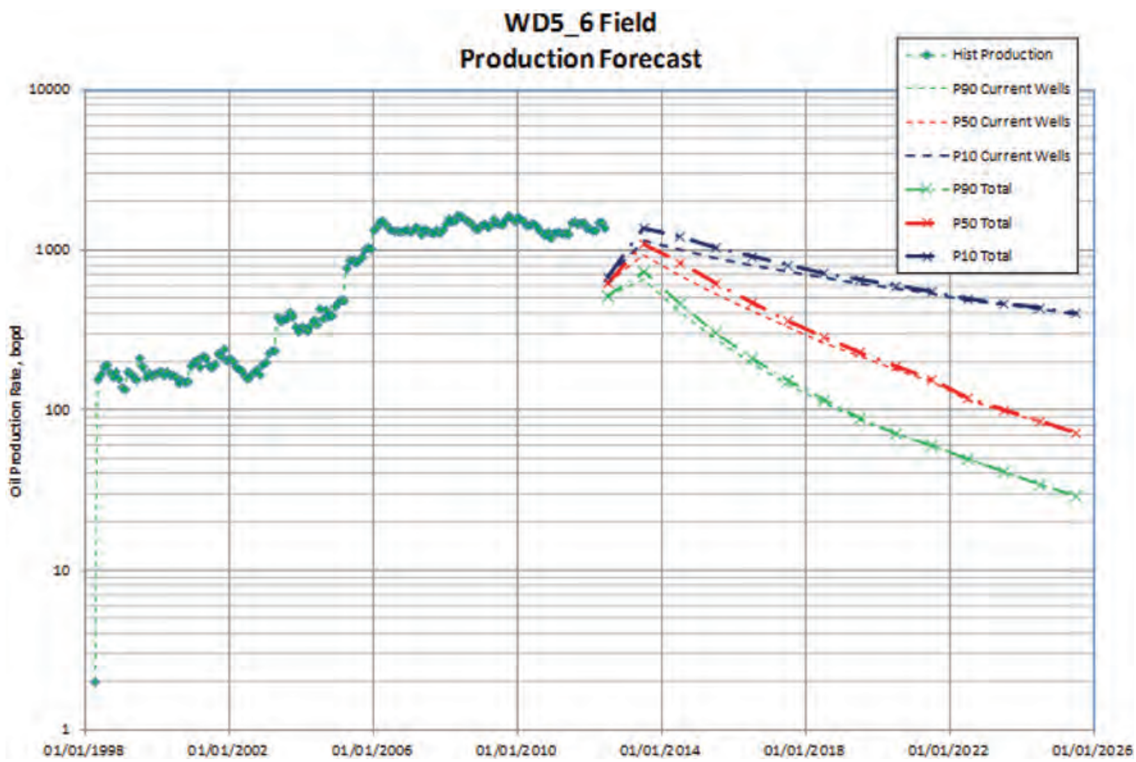

Figure 6-9: WD-5/6 Field Production Forecast

6.2.5.2 Contingent Resources

This section addresses volumes classified as Contingent. It includes estimated ultimate recoverable volume estimates and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5

Trinity is planning to drill a further seventeen wells and recomplete a further four wells in field WD5/6. The resources from this further development are classified as contingent. In order to estimate the volumes for these new workovers and wells, the same profiles per well and formation estimated in section 5.2.5.1 were used. The total contingent volumes for these plans are shown in Table 6-26, whilst Figure 6-10 depicts the forecasted profiles including the contingent cases.

Gross Contingent Expected Recovery[1] WD-5/6 Field

Plan	Low (Mstb)	Best (Mstb)	High (Mstb)
Recompletions	56.6	118.8	238.8
Drilling	236.0	668.0	1225.3
Arithmetic Total[2]	**292.5**	**786.8**	**1464.1**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (1 C) may be very conservative and the arithmetic total P10 (3C) very optimistic.

Table 6-26: WD-5/6 Field Contingent Expected Recovery

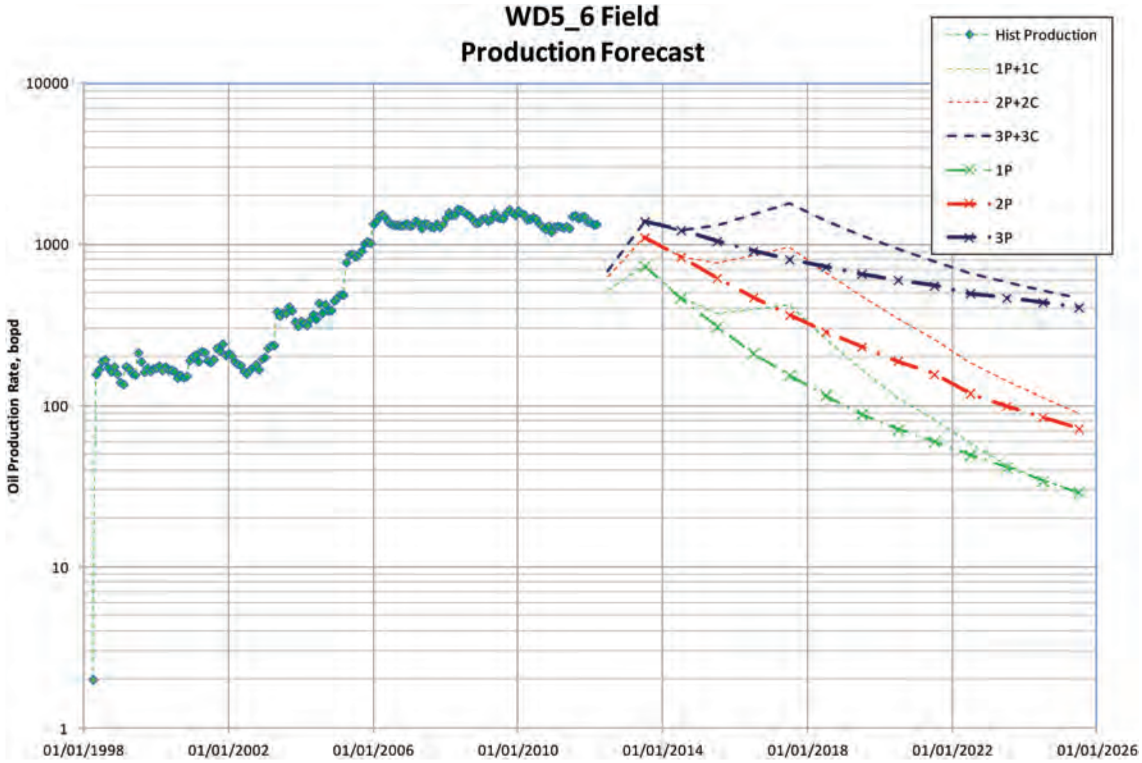

Figure 6-10: WD-5/6 Field Production Forecast including Contingent Volumes

6.2.6 WD-13

6.2.6.1 Remaining Recoverable Volumes from Existing Wells

Notional profiles for planned recompletions (Lower Forest) have been generated using the method described in Section 2.4.2 and the EUR and IP values shown in Table 6-2.

Expected Remaining Recovery estimated by DCA of existing wells (Developed Producing), and notional profiles for planned workovers (Developed Non-producing) in WD-13 Field are shown in Table 6-27 to Table 6-29, whilst forecast profiles are depicted in Figure 6-11. In this Figure, P90 Total, P50 Total and P10 Total refer to the profiles generated by adding the profiles for the planned recompletions to those from DCA of existing wells.

Gross Developed Producing Expected Remaining Recovery[1]			
Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
FR 1002	1.0	4.4	6.8
FR 0282	1.3	2.1	5.4
FR 1360	1.8	2.6	17.1
FR 1018	1.2	5.0	9.8
FR 1123	1.0	2.0	5.2
FR 1609	0.7	1.5	2.0
FR 1610	2.2	3.9	14.3
FR 1617	28.5	36.6	89.8
FR 1670	3.7	9.8	12.7
FR 1678	5.2	12.3	21.7
FR 1679	3.4	14.2	21.0
FR 1338	0.0	0.1	5.6
Swabbed Wells[2]	7.5	21.4	31.3
Arithmetic Total[3]	**57.5**	**115.9**	**242.6**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Swabbed wells: FR-639, FR-643, FR-837, FR-964, FR-1034, FR-1191, FR-1306, FR-1407 and FR-1606, FR-1608

3 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-27: WD-13 Developed Producing Expected Remaining Recovery by Well

Gross Developed Non-producing Expected Remaining Recovery[1]			
Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
FR 0697	0.6	3.8	24.7
FR 1169	0.6	3.8	24.7
FR 1191	0.6	3.8	24.7
FR 1009	0.6	3.8	24.7
FR 1074	0.6	3.8	24.7
Arithmetic Total[2]	**2.9**	**19.0**	**123.4**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-28: WD-13 Developed Non-Producing Expected Remaining Recovery by Well

Gross Arithmetic Total[1] Developed Producing and Non-Producing Expected Remaining Recovery[2]		
Low (Mstb)	Best (Mstb)	High (Mstb)
60.4	**134.9**	**366.0**

1 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case very optimistic.

2 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-29: WD-13 Field gross Developed Producing and Non-Producing Expected Remaining Recovery

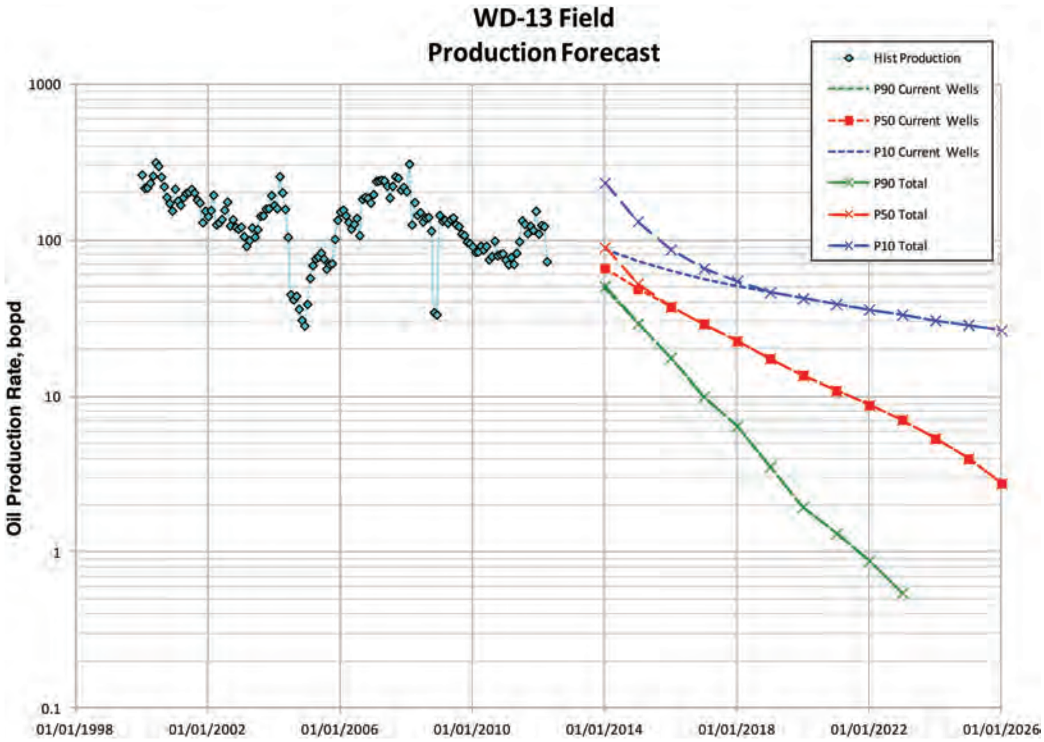

Figure 6-11: WD-13 Field Production Forecast

6.2.6.2 Contingent Resources

This section addresses volumes classified as Contingent. It includes estimated ultimate recoverable volume estimates and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5

Eleven new wells are identified as part of a drilling campaign for this field, whilst a further twelve recompletions are planned, with their associated resources classified as contingent.

Production data from WD-13, WD-14 and Fyzabad-2 was combined to generate notional profiles for wells recompleted in Lower Forest (see Table 6-2 and Section 6.2.1.1).

Due to the limited amount of data, the notional profiles for recompletions in zones other than the Lower Forest have been constructed based on the distribution of well performance of all recompletions. The distribution of new well performance has been based on the performance of recent WD-13 and WD-14 wells for which a complete production history is available. Notional profiles for recompletions and new wells have been generated using the method described in Section 2.4.2. The values of EUR and IP for recompletions in the Lower Forest are those shown in Table 6-2, whilst

for other formations are those shown in Table 6-30. In the case of new wells, values of EUR and IP used for estimating profiles are presented in Table 6-31.

The contingent expected recovery assumes two recompletions in the Lower Forest and ten recompletions in other formations in 2013.

It is assumed that a total of five new wells will be drilled per year in WD-13 and WD-14 starting in 2015 and continuing for a total of five years.

The resulting contingent volumes for this field are shown in Table 6-32, whilst Figure 6-12 depicts the production forecast for the field, including contingent expected recovery.

Probability	Expected Ultimate Recovery (Mstb)	Initial Production Rate (bopd)	Decline Rate D (y-1)
P90	3.4	6.8	0.68
P50	8.8	17.8	0.71
P10	22.9	46.1	0.73

Table 6-30: Estimated EUR and IP for Recompletions (excluding Lower Forest) in WD-13 and WD-14

Probability	Expected Ultimate Recovery (Mstb)	Initial Production Rate (bopd)	Decline Rate D (y-1)
P90	21.7	10.8	0.17
P50	43.3	22.9	0.19
P10	87.2	47.6	0.20

Table 6-31: Estimated EUR and IP for New Wells in WD-13 and WD-14

	Gross Contingent Expected Recovery[1]		
Plan	Low (Mstb)	Best (Mstb)	High (Mstb)
Recompletions	35.3	96.0	278.1
Drilling	198.5	399.9	808.6
Arithmetic Total[2]	**233.8**	**495.9**	**1086.7**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (1C) may be very conservative and the arithmetic total P10 (3C) very optimistic.

Table 6-32: WD-13 Field Contingent Expected Recovery

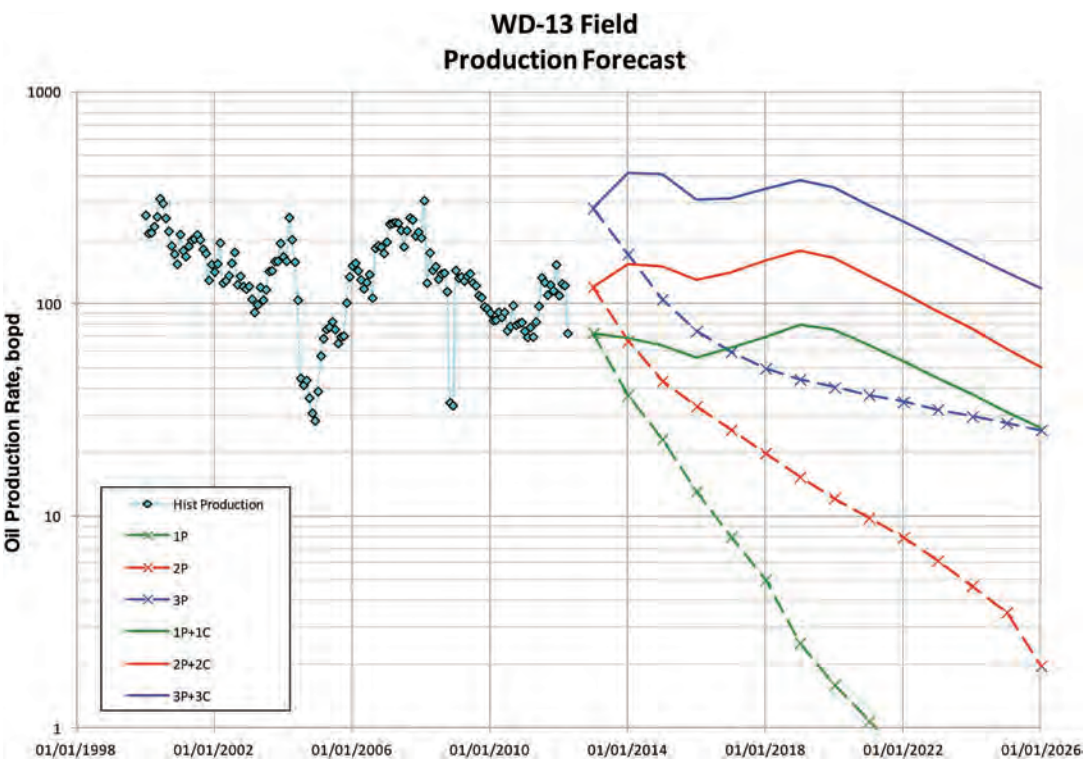

Figure 6-12: WD-13 Field Production Forecast including Contingent Volumes

6.2.7 WD-14

6.2.7.1 Remaining Recoverable Volumes from Existing Wells

Notional profiles for planned recompletions (Lower Forest) have been generated using the method described in Section 2.4.2 and the EUR and IP values shown in Table 6-2.

Expected Remaining Recovery estimated by DCA of existing wells (Developed Producing), and notional profiles for planned recompletion (Developed Non-producing) in WD-14 Field are shown in Table 6-33 to Table 6-35, whilst forecast profiles are displayed in Figure 6-13. In this Figure, P90 Total, P50 Total and P10 Total refer to the profiles generated by adding the profiles for the planned workovers to those from DCA of existing wells.

Gross Developed Producing Expected Remaining Recovery[1]

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
FR 1607	0.1	1.3	5.4
FR 1138	0.0	0.3	1.5
FR 1205	0.0	0.0	0.0
FR 0759	0.5	1.2	5.5
FR 1611	19.8	25.4	41.1
FR 1672	18.8	26.0	39.9
FR 1677	5.6	8.8	12.9
FR 0758	8.9	10.9	13.9
FR 0763	2.6	4.3	5.8
FR 0808	4.2	5.7	9.3
FR 0831	0.6	5.4	10.7
FR 1028	0.0	0.0	0.0
FR 1165	0.5	0.7	1.6
Swabbed Wells[2]	12.3	36.7	55.1
Arithmetic Total[3]	**73.9**	**126.7**	**202.8**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Swabbed wells: FR-260, FR-684, FR-820, FR-828, FR-1019, FR-1179

3 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

Table 6-33: WD-14 Developed Producing Expected Remaining Recovery by Well

Gross Developed Non-producing Expected Remaining Recovery[1]

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
FR 0757	0.6	3.8	24.7

1 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-34: WD-14 Developed Non-producing Expected Remaining Recovery

Gross arithmetic Total[1] Expected Remaining Recovery[2]

Low (Mstb)	Best (Mstb)	High (Mstb)
74.5	**130.5**	**227.5**

1 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (Low Case) may be very conservative and the arithmetic total P10 (High Case) very optimistic.

2 Without economic cutoff. See Section 9 for results of economic limit test

Table 6-35: WD-14 Field Gross Developed Producing and Non-Producing Expected Remaining Recovery

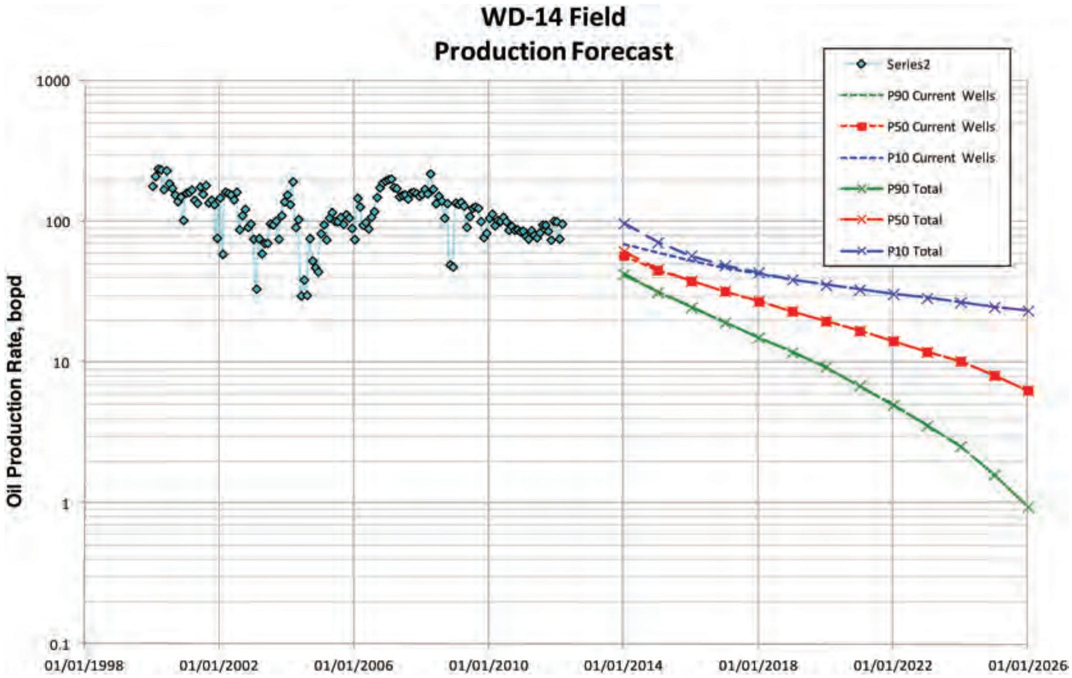

Figure 6-13: WD-14 Field Production Forecast

6.2.7.2 Contingent Resources

This section addresses volumes classified as Contingent. It includes estimated ultimate recoverable volume estimates and production forecasts before an economic limit test is applied. The economic limit test is discussed in Section 9.3 and resources post economic limit test are discussed in Section 9.5

Fourteen wells were identified as part of drilling campaign for this field, whilst further ten recompletions are planned, with their associated resources classified as contingent. The contingent expected recovery assumes eight recompletions in Lower Forest and two recompletions in other formations in 2013.

Notional profiles for planned new wells and recompletions are the same as generated for WD13 Field (Section 6.2.6.2, Table 6-2 (Lower Forest), Table 6-30 and Table 6-31). The resulting volumes are presented in Table 6-36, whilst Figure 6-14 shows the expected remaining recovery including contingent volumes.

Gross Contingent Expected Recovery[1]

Plan	Low (Mstb)	Best (Mstb)	High (Mstb)
Recompletions	11.4	48.1	243.2
Drilling	253.0	509.4	1030.2
Arithmetic Total[2]	**264.4**	**557.5**	**1273.4**

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the P90 (1C) may be very conservative and the arithmetic total P10 (3C) very optimistic.

Table 6-36: WD-14 Contingent Expected Recovery

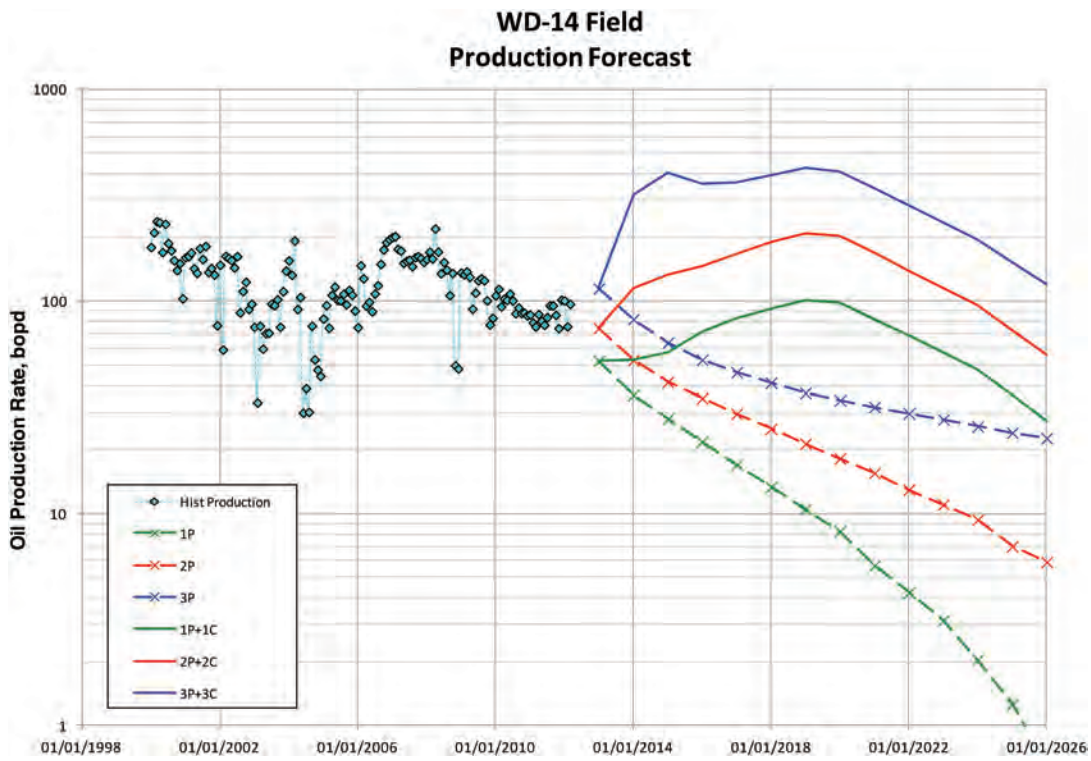

Figure 6-14: WD-14 Field Production Forecast including Contingent Volumes

6.2.8 WD-16

Technical Remaining Resources estimated by DCA of existing wells in WD-16 Field are shown in Table 6-37, whilst Figure 6-15 shows forecast profiles for the field. All wells in this field are produced by swabbing.

Gross Developed Producing Expected Remaining Recovery[1]

Well	P90 (Mstb)	P50 (Mstb)	P10 (Mstb)
Swabbed Wells[2]	9.9	14.8	17.5

1 Without economic cutoff. See Section 9 for results of economic limit test

2 Swabbed Wells: PS-563, PS-601, PS-878, PS-934, QU-142, QU-144, QU-146, QU-168, QU-169, QU-172, QU-173, QU-181, QU-191, QU-218, QU-250, QU-266, QU-284, QU-289.

Table 6-37: WD-16 Developed Producing Expected Remaining Recovery

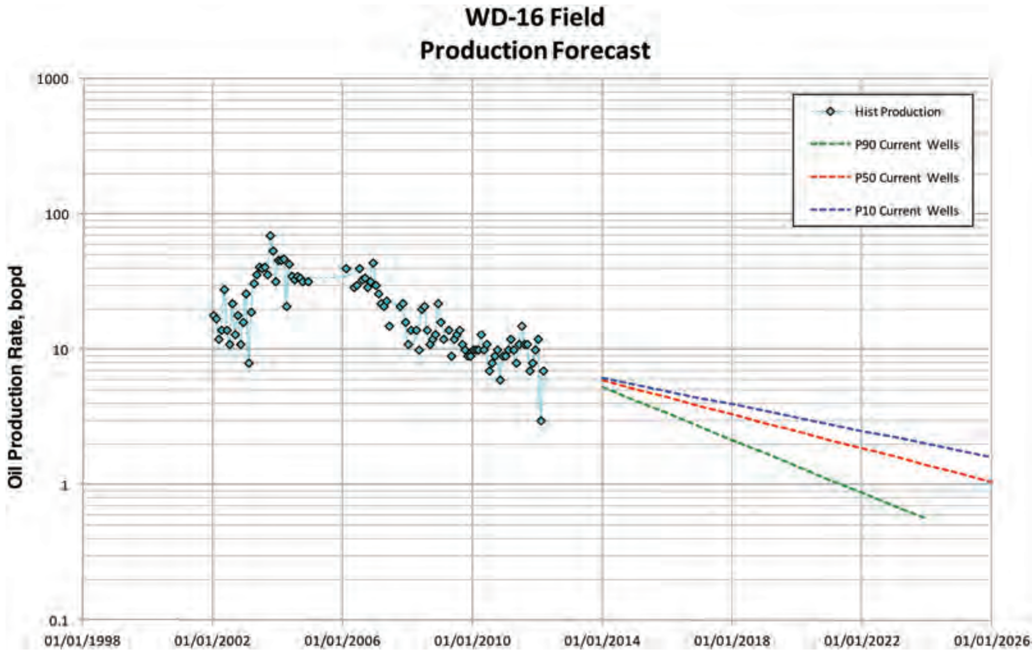

Figure 6-15: WD-16 Field Production Forecast

7. VOLUME SUMMARY

Expected Remaining Recovery (without an economic cut off) in the fields and discoveries as of July 1st 2012 that have been estimated by RPS are summarised in Table 7-1.

	Gross Oil Expected Remaining Recovery (Mstb)			Gross Oil Contingent Expected Recovery (Mstb)			Gross Oil Prospective Resources (Mstb)		
Field	**Low**	**Best**	**High**	**Low**	**Best**	**High**	**Low**	**Best**	**High**
Brighton	2428	4541	6916	3030	7616	17218	1663	6843	20700
Fyzabad-2	109	170	257	50	141	346	—	—	—
Guapo-1	151	221	295	28	89	288	—	—	—
Point Ligoure	302	670	1011	65	188	435	—	—	—
Tabaquite	22	70	130	41	135	404	—	—	—
WD-2	181	472	758	140	460	730	—	—	—
WD-5/6	1063	1914	3783	293	787	1464	—	—	—
WD-13	60	135	366	234	496	1087	—	—	—
WD-14	75	130	228	264	558	1273	—	—	—
WD-16	10	15	17	—	—	—	—	—	—
TOTAL (Mstb)	**4,402**	**8,339**	**13,762**	**4,145**	**10,470**	**23,246**	**1,663**	**6,843**	**20,700**

Table 7-1: Expected Remaining Recovery as of July 1st 2012

8. FACILITIES AND COSTS

8.1 Field Trip

RPS was invited by Trinity to visit the production facilities and observe the drilling activities currently being undertaken by the Operator. The visit took place over two days on the 9th and 10th of July, 2012. The RPS nominee was John C. Alcock (Principal Cost and Facilities Engineer) who has over 35 years experience in the industry.

The visit commenced at the Trinity SSL Building in San Fernando, South Trinidad for introductions followed by a short trip to the Brighton Compressor Station and office situated onshore, south of the Brighton Marine Offshore complex. An HSE induction took place followed by a visit by boat to the offshore MP-5, MP-8 and 9 production structures. The steel structures or decks were supported by concrete piles driven into the seabed. A series of 'dry trees' are manifolded into a small separator prior to offshore tank storage whereby periodic oil loading takes place offshore. Gas lift is provided by the compression facilities onshore.

It is recognised that some of the offshore facilities are over fifty years old and a recent survey by Xodus (Houston) indicates that the concrete pile supporting structures are in good order. However, the steel beam deck, on the MP- 8 platform, was observed to be in a state of considerable decay and subject to a planned replacement by a horseshoe type installation in two halves. Oily water was observed around some of the structures.

A tour of two drilling rigs (WS-152 and Rig 50) took place in the afternoon followed by a visit and presentation to Well Services. Both rigs are currently being re-furbished, prior to the imminent drilling campaign.

The second day was dedicated to the onshore facilities with a trip to the Fyzabad oil fields, and in particular to the WD-5/6 facilities. This was followed by a visit to the WD-2 rig, a workover rig and a well swabbing unit. The visit was concluded by presentations from 'Third Party Inspection' and 'IAL', both of which demonstrated local oil business participation.

8.2 Costs Associated with Reserves

The Brighton Marine drilling campaign associated with reserves requires six new wells, seven heavy workover interventions and eleven capillary coil gas lift implementations. Generally, base costs have been provided by Trinity and in the case of new wells they have estimated costs of $4.2MM per well. RPS has added a 15% contingency in line with oil industry practices to give an overall drilling cost of $28.98MM. Similarly, costs for workovers and implementations are put at $0.39MM and $0.04MM respectively. Total drilling related activities are estimated to be $32.15MM.

Tie-back costs for the six new wells are included at $1.725MM/well average and inclusive of a 15% contingency. Total costs for the tie-backs are estimated to be $10.35MM.

The structural steel beams on some of the platforms require extensive remedial work and even replacement. In the reserves evaluation we have allowed for one deck replacement (MP8) which involves the systematic removal and replacement of the deck in two halves and in a horseshoe fashion. Various estimates have been submitted and RPS has included $3.00MM for this undertaking of which $0.50MM could be expended in 2012.

Operating costs for the offshore facilities in Brighton Marine are based on Trinity data, but with a 10% contingency added. Fixed Opex for Brighton Marine is $2.75MM/annum together with a variable opex of $0.59/bbl.

Onshore costs are relative to the type of drilling activity. WD 2 is planned to have eight new wells and two for WD 5/6. For reserves a 15% contingency has been applied to the onshore well cost estimates provided by Trinity: costs per well for WD 2 range from $860,000 to $1,110,000; the two wells in WD 5/6 are estimated at $1,005,000 and $1,260,000.

Five recompletions are planned for WD 13, one for WD 14, three for WD 5/6 and one for Fyzabad. For reserves a 15% contingency has been applied to the onshore well recompletion cost estimates provided by Trinity: $65,000 per recompletion, and for WD 5/6 $40,000 or $60,000.

Operating costs for the Onshore Facilities are based on Trinity data, but with a 10% contingency added. Fixed Opex ranges from $0.1 to $5.1MM/annum and variable opex from of $0.6/bbl to $6.2/bbl

8.3 Costs Associated with Contingent Resources

The following activities were assumed to obtain contingent resources from the fields as follows:

	Re-Completions	New Wells
Brighton Marine	0	21
Fyzabad-2	3	6
Guapo-1	6	6
Tabaquite	0	15
WD-2	6	10
WD-5/6	4	17
WD-13	12	11
WD-14	10	14
Point Ligoure	0	1

New Infill well costs are included at $0.98MM/well and re-completions at $0.65MM. For each new well we are assuming associated production facilities costs of about $0.035MM/well. This is made up from flowline costs of about $6,000, tanks at $5,000, electrics at $3,500, pumps at $16,000 and a 15% contingency.

Fixed opex/annum per well for contingent resources varies from $130,000 for WD-16 to $5,102,000 for WD 5/6. Variable opex per well has been calculated internally and applied at about $35,000 for a majority of the fields and $98,000 for the larger WD 5/6 field.

9. ECONOMICS

9.1 Valuation Assumptions

9.1.1 General

The effective date of this report is 1st July 2012 and this has been used as the discount date for the valuation. All values are post-tax and have been expressed over a range of discount rates. An annual inflation rate of 2% has been assumed and is applied to both costs and revenues.

9.1.2 Oil Prices

The valuation has been based on the RPS long term forecast for West Texas Intermediate (WTI) crude (long term price of US$85/stb in REAL 2012$ from 2015 onwards) as shown in Table 9-1 and Figure 9-1. A Low Price Case ($70/stb in REAL 2012$) and High Price Case ($100/stb in REAL 2012$) are also shown in the Table in Money of the Day (MOD) and have been used for price sensitivity purposes. RPS Brent price forecasts have been included for reference only.

	Low WTI Price Case (US$/stb, MOD)	Base WTI Price Case (US$/stb, MOD)	High WTI Price Case (US$/stb, MOD)	Low Brent Price Case (US$/stb, MOD)	Base Brent Price Case (US$/stb, MOD)	High Brent Price Case (US$/stb, MOD)
2012 (6 months)	70.00	91.50	100.00	80.00	106.70	110.00
2013	71.40	90.00	102.00	81.60	99.00	112.20
2014	72.83	89.00	104.04	83.23	96.00	114.44
2015	74.28	90.20	106.12	84.90	95.51	116.73
2016	75.77	92.01	108.24	86.59	97.42	119.07
2017	77.29	93.85	110.41	88.33	99.37	121.45
2018	78.83	95.72	112.62	90.09	101.35	123.88
2019	80.41	97.64	114.87	91.89	103.38	126.36
2020	82.02	99.59	117.17	93.73	105.45	128.88
2021	83.66	101.58	119.51	95.61	107.56	131.46
2022	85.33	103.61	121.90	97.52	109.71	134.09
2023	87.04	105.69	124.34	99.47	111.90	136.77
2024	88.78	107.80	126.82	101.46	114.14	139.51
2025 onwards	+2% p.a.	+2% p.a.	+2% p.a.	+2% p.a.	+2% p.a.	+2% p.a.

Table 9-1: RPS Forecast Price Cases

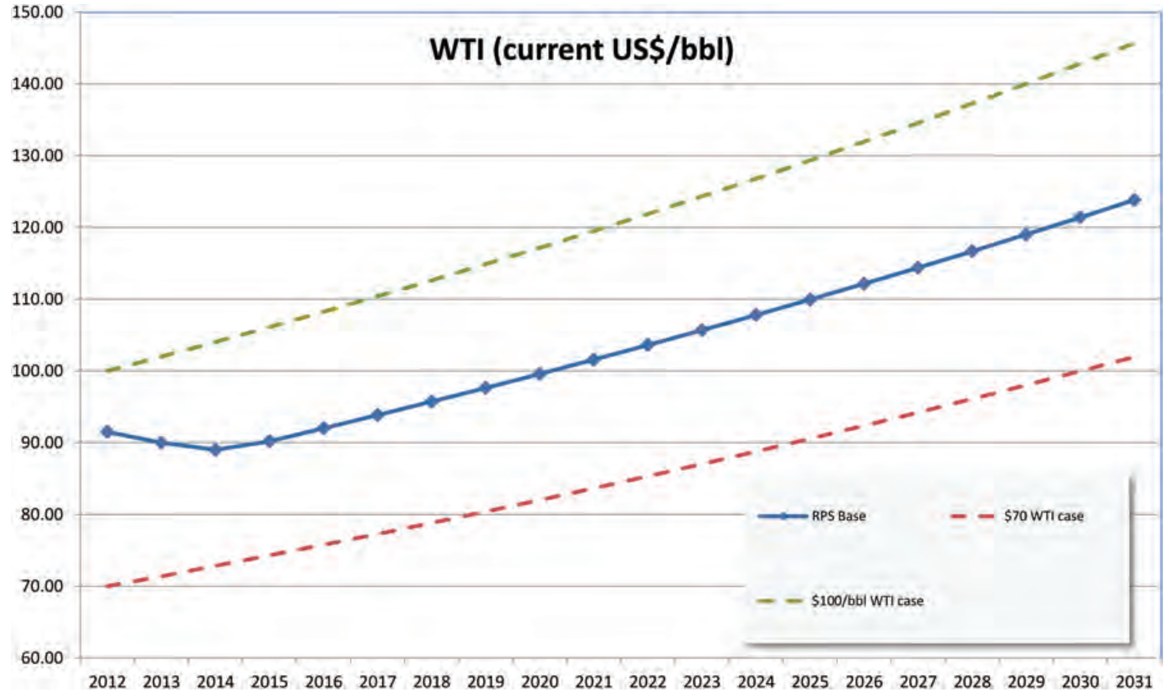

Figure 9-1: RPS Forecast Oil Prices

The valuations were based on the RPS forecast prices for WTI with local price differentials to WTI applied. The price differentials were derived from each field's observed realised sales prices relative to WTI prices during the period January 2011 to June 2012. The assumed price differentials per field are summarised in Table 9-2.

Field	Price Differential to WTI Crude
Brighton Marine	−1.0%
Fyzabad-2	−2.0%
Guapo-1	−7.0%
Tabaquite	0.0%
WD-2	−2.0%
WD-5/6	−2.0%
WD-13	−2.0%
WD-14	−2.0%
WD-16	−2.0%
Point Ligoure / Brighton	−2.0%

Table 9-2: Fields' Oil Price Differentials to WTI

9.2 Valuation Methodology

9.2.1 Reserves

1P, 2P and 3P reserves were valued using a spreadsheet-based discounted cashflow model. The model contains RPS's forecast of future production, prices and costs, and honours the applicable licence terms and Government taxes to provide post tax cashflows and valuations net to Trinity's share.

9.2.2 Contingent and Prospective Resources

Trinity Net Entitlement (1C, 2C and 3C) Contingent Resources were evaluated using the same spreadsheet-based cash flow model as the reserves valuations. Incremental cash flows to the 2P reserves cashflows from cases for 1C, 2C and 3C Contingent Resources have been calculated.

9.2.3 Trinity Valuation

Trinity's Reserves were valued separately by field on a stand-alone tax basis. In addition a corporate valuation was undertaken where Trinity's brought forward tax losses and depreciation pools and balances were included. Trinity's ownership of the fields is within 100% owned subsidiary companies, which are summarised in Table 9-3. The total tax losses at 31 December 2011 within these companies are $27.6 million, and the total capital cost depreciation balances sum to $15.7 million.

Subsidiary Company	Fields
Ten Degrees North Operating Company Ltd.	Brighton Marine Point Ligoure Guapo
Lennox Production Services Ltd.	WD2 WD16 Fyzabad-2
Pioneer Petroleum Co. Ltd.	Guapo-1
NAKT Co. Ltd.	WD14
Antilles Resources Ltd.	WD13
Coastline International Inc.	Tabaquite
Oilbelt Services Ltd.	WD 5/6

Table 9-3: Trinidad Fields by Trinity Subsidiary Company

The Trinity valuation does not include corporate overhead, but as the Trinidadian fields are Trinity's only assets, a proportion of the corporate overheads could be charged to the fields. Trinity's estimate of corporate overhead for 2012 is $9 million, of which Trinity estimate $3.1 million could be charged to operations.

9.3 Licences

The onshore fields Fyzabad-2, Guapo-1, WD-2, WD-5/6, WD-13, WD-14, WD-16 are licensed under lease operatorships. The onshore Tabaquite field was contractually arranged as a farm-out but this agreement expired and its continuance is currently under negotiation; we have assumed for the valuation that the current terms are extended (Table 9-4).

The offshore fields, Brighton Marine and Point Ligoure are arranged under Joint Ventures. The Point Ligoure JV has expired but Trinity expect a new JV agreement to be executed in November 2012, which will cover the offshore areas Point Ligoure, Guapo and Brighton Outer. Trinity has provided the proposed licence terms that will exist for this licence and we have used these in our valuation.

Field	Working Interest (%)	Current Agreement Expiry Date (d/m/y)	Renewal Option	Reserves Limit Date (d/m/y)
Brighton Marine (Inner)	100	06/10/2024	5 years	31/12/2029
Fyzabad-2	100	31/12/2020	5 years	31/12/2025
Guapo-1	100	31/12/2020	5 years	31/12/2025
Tabaquite[1]	100	01/09/2018	19 years	01/09/2037
WD-2	100	31/12/2020	5 years	31/12/2025
WD-5/6	100	31/12/2020	5 years	31/12/2025
WD-13	100	31/12/2020	5 years	31/12/2025
WD-14	100	31/12/2020	5 years	31/12/2025
WD-16	100	31/12/2020	5 years	31/12/2025
Point Ligoure[1] / Guapo / Brighton Outer	70	01/09/2018	19 years	01/09/2037

1 Point Ligoure, Guapo, Brighton Outer and Tabaquite agreements are currently expired. Trinity is in the final stages of reaching agreement on renewal of the Point Ligoure, Guapo and Brighton Outer licence (expected November 2012) for a further 6 years After the initial 6 years period there is a discretionary option for further 19 years. The Tabaquite licence terms are under discussion with agreement anticipated in early 2013. RPS has assumed all approvals are reasonably certain based on recent history

Table 9-4: Agreement and Reserves Limit Dates

Brighton Marine Reserves were assumed to be entirely within the Brighton Marine Inner Block. For valuation purposes it was assumed that 53% of the Contingent Resources in Brighton Marine were within the Brighton Marine Inner Block and 47% within the Point Ligoure / Guapo / Brighton Marine Outer Block, based on RPS volumetric estimates of STOIIP by area and by depth.

9.3.1 Petrotrin Overriding Royalties

With the exception of the Point Ligoure / Guapo / Brighton licence, Trinity has to pay an Over Riding Royalty (ORR) on oil production to Petrotrin that varies between licences.

The ORR rate is 18% in Tabaquite (and 12.5% for production in excess of 1,500 in a month, which production rate is not forecast).

The ORR rate for the onshore lease operatorships, and in Brighton Marine (Inner) from 01 July 2012, changes within oil price bands. Within the price bands there is a base ORR and an enhanced ORR depending on whether production is within the defined base production or in excess of the base production. For the lease operatorships, on forecast production, the base ORR rate mainly applies and depending on the RPS Base oil price forecast is generally either 33% or 35%, subject to reduced rates applicable to production from new wells. Production from new wells is exempt from ORR in the first year and attracts 50% of the ORR rate in the second year. This reduction does not apply to the Tabaquite field or the Brighton Marine (Inner) licence.

9.3.2 Licence Term and Economic Limit

RPS forecasts of production extend to the term of the licence plus one possible renewal, assuming that Government approval of any extension is not unreasonably withheld. An economic limit has been applied to the forecasts of field production in accordance with PRMS guidelines: "Economic limit is defined as the production rate beyond which the net operating cash flows (after royalties or share of production owing to others) from a project, which may be an individual well, lease, or entire field, are negative." The economic limit test for each field is therefore based on the operating cashflow calculated as follows:

Field Revenues less Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

Both Reserves and Contingent Resources have been cut off at the economic limit.

9.4 Fiscal Regime

The fiscal terms for Trinity's upstream operations exist within a tax and royalty regime. A Government Royalty applies to production and there is a Supplemental Petroleum Tax and a Petroleum Profit Tax, plus further small levies.

9.4.1 Royalty

Royalty for the Brighton Marine Licence is charged at 10% of gross revenues. For the other Trinity licences, the rate is 12.5%.

9.4.2 Supplemental Petroleum Tax

SPT is payable to the government on revenues after Government Royalty and the Petrotrin ORR have been deducted, at a rate that is dependent on whether the licence is offshore and onshore and that varies with oil price. The SPT rates are shown in Table 9-5.

Oil Price $/bbl	Offshore	Onshore
Price ≤ $50.00	0%	0%
$50.00 Price ≤ $90.00	33%	18%
$90.00 Price ≤ $200.00	33% + 0.2% (Price—$ 90.00)	18% + 0.2% (Price—$ 90.00)
Price >$200.00	55%	40%

Table 9-5: Supplemental Petroleum Tax Rates

An Investment Tax Credit of 20% of capex is allowable against the annual SPT charge, but this is not able to be carried forward if unused. Additional Sustainability Incentives are granted for mature marine and small marine oil fields, i.e. a 20% discount on SPT rates. A mature oil field is defined as a field that is 25 years or more from the date of first commercial production, while a small marine oil field is defined as one with production levels of 1,500 barrels of oil equivalent per day (boe/d) or less. It should be noted that companies will only be allowed to qualify for one of these discounts in respect of any particular field. Brighton Marine is eligible for the Sustainability Incentive. It was assumed that the Point Ligoure / Guapo / Brighton licence will qualify for the Sustainability Incentive as a small marine field licence.

9.4.3 Petroleum Production Levy

The Petroleum Production Levy (PPL) is applied at a rate of 4% of all gross oil revenues if company production is in excess of 3,500 barrels of oil per day. RPS's forecast of Trinity Reserves in each subsidiary company does not exceed this limit so no PPL is expected.

9.4.4 Green Fund Levy and Petroleum Impost

The Green Fund Levy (GFL) is calculated as a percentage (currently 0.1%) of total gross revenues, and these payments are not tax deductible.

Petroleum Impost is payable at TT$0.3233/bbl. An exchange rate of TT$: US$ of 6.4 constant has been assumed.

9.4.5 Petroleum Profits Tax

The Petroleum Profits Tax (PPT) is applicable to all oil and gas producers and is applied to the net profits from Trinity's operations at the current applicable tax rate of 50%. The net profit is derived by deducting from the gross income all royalties, taxes and levies with the exception of the GFL. Tax losses can be brought forward indefinitely. Balances at 31 December 2011 for each subsidiary company, provided by Trinity, have been used in the companies' post tax valuations.

The capital allowances for PPT are summarised in Table 9-6.

Capex Category	Allowance
Tangible	Initial allowance of 20%. Straight line depreciation for remaining balance over 5 years, commencing in year of expenditure
Intangible	Initial allowance of 10%. Declining balance depreciation for remaining balance at 20% p.a., commencing in year of expenditure
New wells assumed split	75% intangible, 25% tangible
Infrastructure capex	100% tangible

Table 9-6: Petroleum Profits Tax Capital Allowances

9.4.6 Unemployment Levy

The applicable rate is 5% of the net taxable income before loss relief.

9.5 Valuation Summary

9.5.1 Reserves

The post-tax Net Present Values (NPV) of Trinity's Reserves at a 10% discount rate in US$ MM Money of the Day (MoD), applying the Base Case price forecasts, are tabulated in Table 9-7.

Field	Post-Tax Net Present Value NPV_{10} (US$ Million, MoD)		
	1P	2P	3P
Brighton Marine	2.4	36.5	73.2
Fyzabad-2	0.0	0.2	0.7
Guapo-1	−0.2	0.1	0.3
Point Ligoure	2.5	4.9	6.9
Tabaquite	0.0	0.2	0.5
WD-2	−3.3	1.2	5.1
WD-5/6	1.2	6.9	18.3
WD-13	−0.1	0.4	2.8
WD-14	−0.1	0.1	0.7
WD-16	−0.1	−0.1	−0.1
Total Value from Fields	**2.3**	**50.3**	**108.5**
Consolidation Effects[1]	12.7	16.0	17.4
Total Value	**15.0**	**66.3**	**125.9**

1 Consolidation effects include benefits from consolidating Petroleum Profits Tax including tax losses and capital depreciation balances. No Corporate overhead has been included in the valuations.

Table 9-7: Post-Tax Valuation (Net Trinity's Share) of Trinity's Reserves in Trinidad (as of 01 July 2012)

Trinity's Reserves as of 01 July 2012 are summarised in Table 9-8.

Field	Gross Reserves (Mstb)[2]			Trinity Net WI Reserves (Mstb)[2]			Trinity Net Reserves Entitlement[2,3] (Mstb)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Brighton Marine	2,250	4,541	6,916	2,250	4,541	6,916	1,816	3,734	5,736
Fyzabad-2	39	74	147	39	74	147	21	41	81
Guapo-1	35	94	179	35	94	179	19	51	98
Point Ligoure	274	664	1011	192	465	708	168	407	619
Tabaquite	8	39	111	8	39	111	6	27	77
WD-2	147	415	687	147	415	687	107	292	481
WD-5/6	626	1,330	3,476	626	1,330	3,476	347	737	1,898
WD-13	34	77	295	34	77	295	19	43	177
WD-14	26	55	139	26	55	139	14	30	76
WD-16	1	1	1	1	1	1	1	1	1
ARITHMETIC TOTAL[1]	**3,442**	**7,289**	**12,964**	**3,360**	**7,090**	**12,661**	**2,518**	**5,361**	**9,245**

1 Individual 1P, 2P and 3P values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1P (Low Case) may be very conservative and the arithmetic total 3P (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

2 1P, 2P and 3P cases each include Developed Producing; Developed Non-producing and Undeveloped Reserves.

3 Trinity Net Reserves Entitlement is Trinity's WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty

Table 9-8: Reserves as of 01 July 2012

The post-tax Net Present Values (NPV) at a range of discount rates of Trinity's Reserves at in US$ MM Money of the Day (MoD), applying the Base Case price forecasts are shown in Table 9-9.

Discount Rate	Post-Tax Net Present Value (US$ Million, MOD) 0.0%	5.0%	7.5%	10.0%	15.0%
Proved Reserves (1P)	35.0	23.6	19.0	15.0	8.4
Proved plus Probable Reserves (2P)	110.6	84.3	74.5	66.3	53.4
Proved plus Probable plus Possible Reserves (3P)	209.2	158.6	140.6	125.9	103.2

Table 9-9: Trinity Post-Tax Valuation (Net Trinity's Share) of Trinity's Reserves at Different Discount Rates

9.5.1.1 Sensitivity to Oil Price

Sensitivity of the NPV10 of the future net revenue in Trinity's net Reserves to changes in oil price is shown in Table 9-10.

Price Case	Net Present Value10 of Future Net Revenue (US$ Million, MOD) 1P	2P	3P
Low Price ($70 REAL)	−2.3	44.4	92.5
Base Price	15.0	66.3	125.9
High Price ($100 REAL)	22.2	79.1	147.0

Table 9-10: Sensitivity to Oil Price of Post-Tax Valuation NPV 10 (Net Trinity's Share) of Trinity's Reserves

9.5.2 Contingent Resources

Trinity's Net Entitlement Contingent Resources as of 01 July 2012 are summarised in the following table.

	Contingent Resources (Mstb)								
	Gross Field			Trinity Working Interest			Trinity Net Entitlement[1]		
	1C	2C	3C	1C	2C	3C	1C	2C	3C
Brighton Inner[2]	1,386	3,316	7,686	1,386	3,316	7,686	1,165	2,785	6,456
Point Ligoure / Guapo / Brighton Outer[2]	1,447	3,747	8,479	1,013	2,623	5,935	886	2,295	5,193
WD-2	138	461	731	138	461	731	93	301	477
WD-13	262	545	1,128	262	545	1,128	146	326	712
WD-14	323	624	1,332	323	624	1,332	176	368	837
Fyzabad-2	63	139	423	63	139	423	33	74	241
Guapo-1	49	102	337	49	102	337	27	58	208
Tabaquite	52	150	428	52	150	428	44	128	353
WD-5/6	318	787	1,616	318	787	1,616	168	414	904
ARITHMETIC TOTAL[3]	**4,040**	**9,870**	**22,160**	**3,606**	**8,746**	**19,616**	**2,737**	**6,750**	**15,381**

Notes

1 Trinity's net entitlement is Trinity's WI share of Resources after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

2 Assuming 53% of the Contingent Resources in Brighton Marine are within the Brighton Marine Inner Block and 47% within the Brighton Marine Outer Block.

3 Individual 1C, 2C and 3C values correspond to P90, P50 and P10 probability levels, respectively. Arithmetic aggregation of P90, P50 or P10 values do not sum to equivalent probability values. The arithmetic total of the 1C (Low Case) may be very conservative and the arithmetic total 3C (High Case) very optimistic. PRMS recommends the use of arithmetic summation beyond field, property or project level.

Table 9-11: Contingent Resources as of 01 July 2012

10. CONCLUSIONS

RPS has undertaken a valuation of the assets of Trinity. These consist of four offshore blocks (Brighton Inner, Brighton Outer, Guapo and Point Ligoure) and nine onshore licences (Guapo-1, Fzyabad-2, Tabaquite, WD-2, WD-5, WD-6, WD-13, WD-14 and WD-16), Trinidad. The Brighton Inner and Pointe Ligoure licences are Joint Ventures; the former including the Brighton Marine field. The Guapo and Pointe Ligoure blocks are expected by Trinity to be combined with Brighton Outer block and converted into one licence in November 2012. RPS has assumed all approvals are reasonably certain based on recent history and has valued the assets based upon the interests shown in Table 1-1.

The Prospective Resources for key prospects are summarised in Table 1-4.

Contingent Resources as of 01 July 2012 that have been estimated by RPS are summarised in Table 1-3.

Trinity's Reserves as of 01 July 2012 are summarised in Table 9-8 and the post-tax Net Present Values (NPV) Trinity's Reserves are shown in Table 9-9.

Triinity's Reserves as of 01 July 2012 are summarised in Table 9-8

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
ERR	Expected Remaining Recovery (equals EUR minus past production)
ESD	emergency shut down
EUR	Expected Ultimate Recovery
Expected Recovery	Theoretically recoverable volumes, without consideration of economic factors
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
?	porosity
μ	viscosity
μ_{gb}	viscosity of gas
μ_{ob}	viscosity of oil
μ_{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.

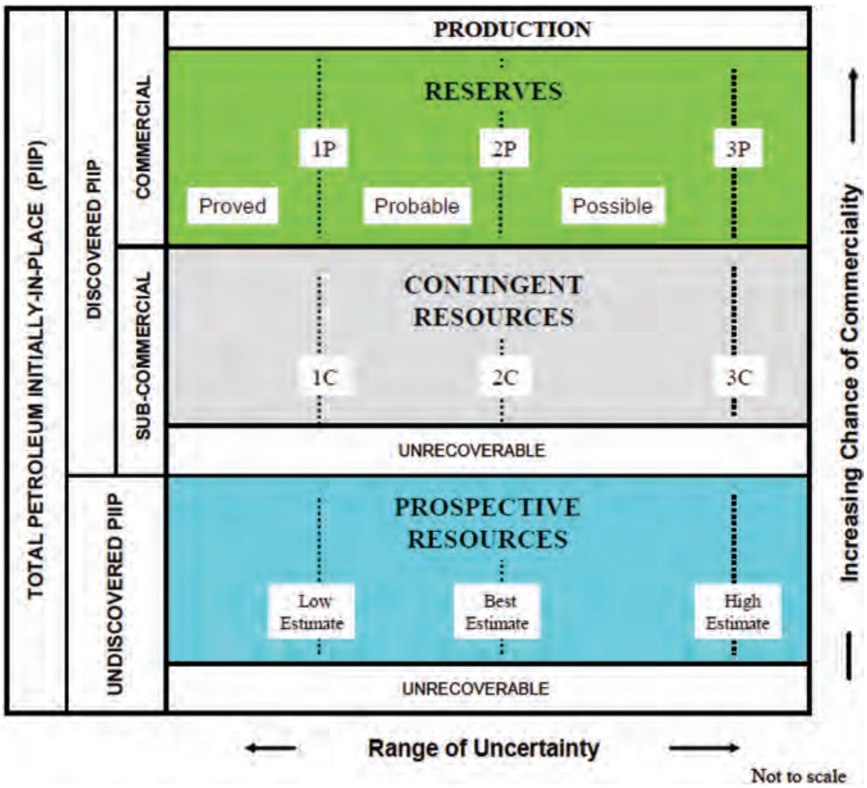

Figure 1-1: Resources Classification Framework.

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:

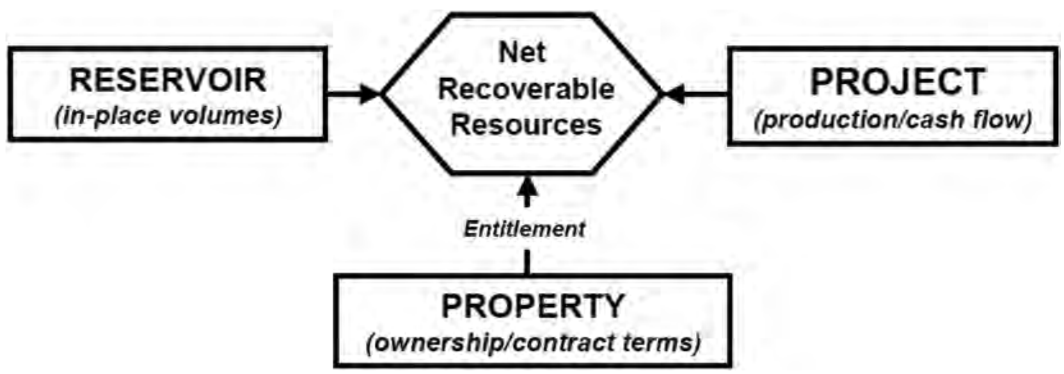

Figure 1-2: Resources Evaluation Data Sources

- 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.

PART VI

COMPETENT PERSON'S REPORT ON BAYFIELD

Gaffney, Cline & Associates

COMPETENT PERSON'S REPORT ON CERTAIN PETROLEUM ASSETS AS AT 30th JUNE, 2012

Prepared for

BAYFIELD ENERGY HOLDINGS PLC

25th JANUARY, 2013

www.gaffney-cline.com

Gaffney, Cline & Associates

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Gaffney, Cline & Associates

Gaffney, Cline & Associates Limited

Bentley Hall, Blacknest
Alton, Hampshire GU34 4PU, UK
Telephone: +44 (0)1420 525366

www.gaffney-cline.com

BCR/cxd/EE026693/0224 **25th January, 2013**

The Directors,
Bayfield Energy Holdings plc,
Burdett House,
15 – 16 Buckingham Street,
London,
WC2N 6DU

The Directors,
Seymour Pierce Limited,
20 Old Bailey,
London,
EC4M 7EN

The Directors,
RBC Europe Limited (trading as RBC Capital Markets),
Riverbank House,
2 Swan Lane,
London,
EC4R 3BF

The Directors,
Jefferies International Limited,
Vintners Place,
68 Upper Thames Street,
London,
EC4V 3BJ

The Directors,
First Energy Capital LLC,
85 London Wall,
London,
EC2N 7AD

Dear Sirs,

COMPETENT PERSON'S REPORT
ON THE PETROLEUM ASSETS OF BAYFIELD ENERGY HOLDINGS PLC

In accordance with the request made by Bayfield Energy Holdings plc ("Bayfield"), in September, 2012, Gaffney, Cline & Associates Ltd ("GCA") has reassessed petroleum interests owned by Bayfield in Trinidad and South Africa (Figures 0.1 and 0.2). These assets include the producing Trintes Field in the Galeota Block, offshore Trinidad together with planned further developments within the Trintes Field and peripheral areas, four discoveries and several Prospects in the Galeota Block with a seven-well committed exploration and appraisal drilling programme, of which there are five remaining, as well as exploration interests in the Inshore Block of the Pletmos Basin offshore South Africa. A further asset in Russia, the Karalatsky Block, is in the process of being disposed of, and has thus not been included in this report. The Effective Date of this assessment is 30th June, 2012.

On 15th October, 2012 it was announced that a merger had been agreed between Bayfield and Trinity Exploration & Production Limited (Trinity), subject to shareholder approval and various government consents. Trinity is a private oil and gas company with assets onshore and offshore Trinidad, The Merger constitutes a reverse takeover of Bayfield under the AIM Rules and is conditional, inter alia, upon Bayfield Shareholder approval and the consent of the Ministry and Petrotrin. As part of the process the enlarged listed entity will need to seek readmission on the AIM Market of the London Stock Exchange. This Competent Person's Report ("CPR") is intended to be included in the new Admission Document in connection with the submission to AIM.

This CPR has been prepared in accordance with the AIM Rules, specifically the ''Guidance Note for Mining, Oil and Gas Companies" dated June 2009 and the content requirements at Appendix 2 and the summaries set out in Appendices 1 and 3. Furthermore, GCA accepts responsibility for the updated CPR insofar as it is based on data provided by Bayfield, which GCA has relied on the accuracy and completeness thereof, and confirms that, to the best of its knowledge and belief having taken all reasonable care to ensure that such is the case, the information contained in the updated CPR is in accordance with the facts and contains no omission likely to affect its import for the purpose of paragraphs 1.1 and 1.2 of Annex I and paragraph 1.1 and 1.2 of Annex III of the AIM Rules.

GCA served as independent evaluator in the conduct of the analyses described and in the determination of the professional opinions expressed herein. GCA is an independent energy consultancy specialising in petroleum asset evaluation and economic analysis. In the preparation of this report, GCA has maintained, and continues to maintain, a strict consultant-client relationship with Bayfield. The management and staff of GCA have been, and continue to be, independent of Bayfield in the services they provide to the company including the provision of the opinion expressed in this assessment. Furthermore, the management and staff of GCA have no interest in any assets or share capital of Bayfield or in the promotion of the company.

Bayfield has made available to GCA a data set of technical information including geological, geophysical, petrophysical and engineering data, analyses and reports, together with financial data and other information pertaining to the fiscal and contractual terms applicable to the assets. In carrying out this assessment, GCA has accepted without independent verification, the accuracy and completeness of these data. This report represents GCA's best professional judgement based on accepted standards of professional investigation but should not be considered a guarantee or prediction of results.

GCA has no reason to believe that any material facts have been withheld from it, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

FIGURE 0.1

LOCATION MAP FOR THE GALEOTA BLOCK, TRINIDAD

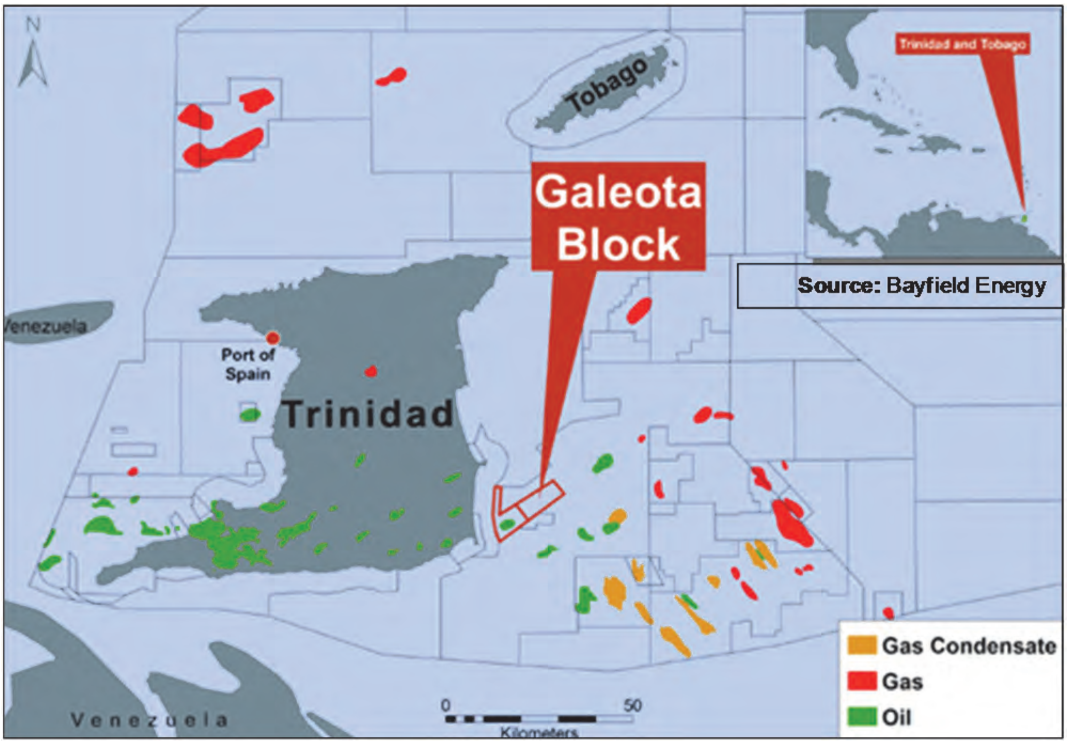
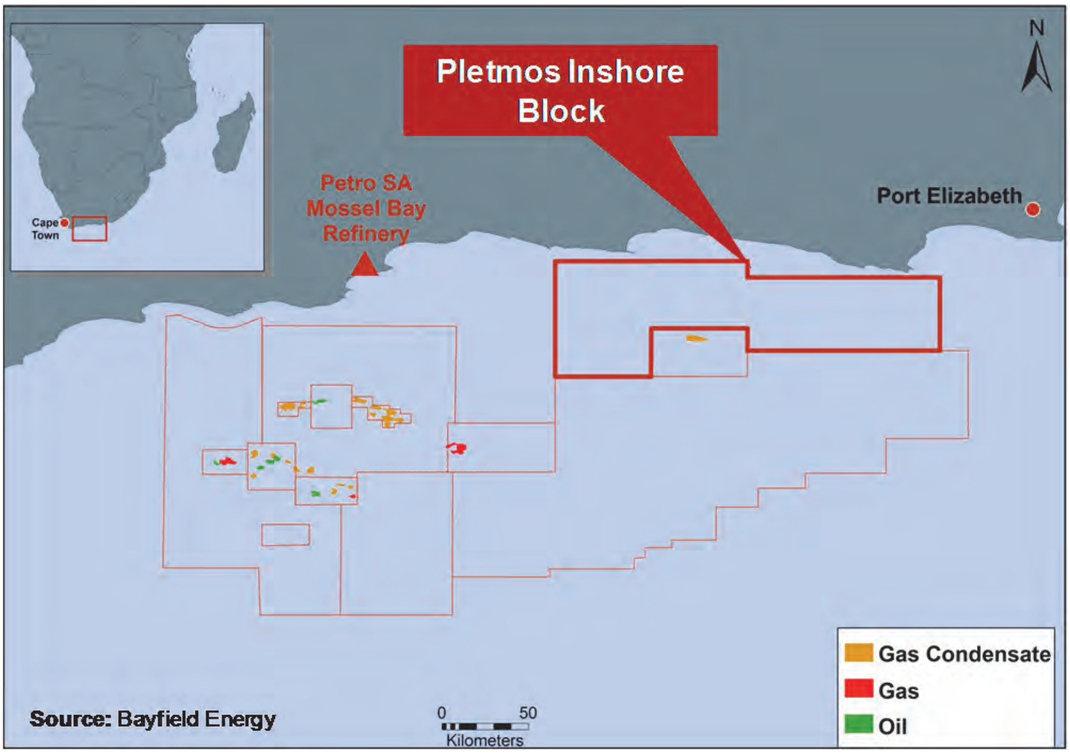


FIGURE 0.2

LOCATION MAP FOR THE PLETMOS INSHORE BLOCK, SOUTH AFRICA



The Resources reported herein are in accordance with the definitions of the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document (SPE PRMS), approved in March 2007 (see Appendix I for an abbreviated version).

Reserves are those quantities of petroleum that are 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 as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P) 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. All categories of Reserve volumes quoted herein have been determined within the context of an economic limit test (pre-tax and exclusive of accumulated depreciation amounts) assessment prior to any Net Present Value analysis.

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 evident 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 as 1C, 2C and 3C in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. It must be appreciated that the Contingent Resources reported herein are unrisked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

Prospective Resources are those quantities of petroleum that are 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 categorized as Low, Best and High estimates 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.

Prospective Resources include Prospects and Leads. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that they are considered drillable. Leads, on the other hand, are not sufficiently well defined to be drillable, and need further work and/or data. In general, Leads are significantly more risky than Prospects and therefore are not suitable for explicit quantification.

Prospective Resource volumes are presented as unrisked. The stated Geological Chance of Success (GCoS), a percentage which pertains to the probability of achieving the status of a Contingent Resource (where the Geological Chance of Success is unity) has not been applied to the volumes presented. This dimension of risk assessment does not incorporate the considerations of economic uncertainty and commerciality. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

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

Oil volumes appearing in this report have been quoted at stock tank conditions. Typically these volumes have been referred to in million barrel increments (MMBbl). Natural gas volumes have been quoted in billions of standard cubic feet (Bscf) and are volumes of sales gas. Standard conditions are defined as 14.73 psia and 60° Fahrenheit. Appendix II is a glossary of oilfield terms, some or all of which may be used in this report.

The NPVs for Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves were determined as part of this evaluation. The Reserves quoted in this report are based upon the future price scenario that has been prepared by GCA. It should be clearly understood that the NPV of future revenue potential of a petroleum property, such as those discussed in this report, does not represent a GCA opinion as to the market value of that property, nor any interest in it. In assessing a likely market value, it may be necessary to take into account a number of additional factors including: Reserves risk (i.e. that Proved and or Probable Reserves may not be realized within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk: potential upside, such as in this case exploitation of Reserves beyond the Proved and Probable level; other benefits, encumbrances or charges that may pertain to a particular interest and the competitive state of the market at the time. GCA has explicitly not taken such factors into account in deriving the NPVs presented herein.

Risked NPVs have been calculated for Contingent Resources as part of this evaluation. The risked NPVs reported herein are based on the 2C Contingent Resource volumes. A risk factor (Chance of Development) has been applied to NPV_{10} calculations to account for the chance that these volumes might not mature to Reserves class. The Chance of Development represents an indicative estimate of the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve. NPVs have been calculated by carrying out discounted cash flows using conceptual development plans, estimates of CAPEX and OPEX and associated production forecasts.

In 2011 GCA undertook a site visit to the Trintes Field facilities in the Galeota Block, offshore Trinidad as part of the due diligence in preparing the original CPR for the Bayfield IPO. GCA has not made a further site visit in preparing this CPR.

GCA confirms that, to the best of its knowledge, there has been no material change of circumstances than those stated herein.

This report has been prepared for Bayfield and should not be used for purposes other than those for which it is intended.

EXECUTIVE SUMMARY

Bayfield's primary asset is a 65% Working Interest in the Trintes Field in the Galeota Block offshore Trinidad to which Reserves are attributed. Five principal reservoir intervals ranging in depth from less than 150 mss to over 600 mss have been developed from four platforms with a total of 62 production wells. Production commenced in 1972 and the field is now mature, with production during the first half of 2012 averaging in the order of 1,317 bopd and watercut around 51%. The reservoirs comprise good quality shoreface, estuarine channel and fluvial sands. Bayfield acquired its interest and took over operatorship of the block from Petroleum Company of Trinidad and Tobago (Petrotrin) in April, 2009. Bayfield is actively pursuing an aggressive programme to revitalise the field with a series of planned work-overs, side-tracks, including extended reach drilling, and the installation of modern artificial lift methods. Historically, drilling from the four existing platforms had limited reach, and areas of the field remain untapped. Bayfield is in the process of developing the remainder of the field by means of extended reach drilling from existing platform centres. Reserves are attributed to the volumes that are expected to be recovered through implementation of these plans.

In addition, five wells drilled in the 1960s, 1970s and 1980s, and two more in 2012, in the Galeota Block intersected multiple stacked oil- and gas-bearing intervals, several of which were flow tested but never developed. Bayfield is formulating plans to develop these discoveries. It is likely that three of these discoveries, EG-3, EG-2/EG-8, and EG-4 will be developed with a total of four small platforms as a stand-alone cluster. The remaining discovery, GAL-21 updip, will likely be developed with a caisson structure and tied back to Trintes. There is a reasonably broad range in the potential recovery estimates from these assets, which is in part a consequence of the level of confidence in the sparse, old dataset. In 2012 Bayfield drilled the EG-7 and EG-8 wells in the northeast of the block. The EG-7 well was disappointing, however, 28° API oil was sampled by MDT at a depth of 536 m MD during a mini-DST which first flowed oil then water. Evaluation of the results of the EG-7, and its side-track EG-7ST1, has ruled out the viability of the EG-1 discovery. The EG-8 well discovered 10 stacked pay zones (1 oil- and 9 gas-bearing) when drilled to the east of, and across a fault from the EG-2 discovery well. Contingent Resources have been assigned to these assets by GCA. 1C Contingent Resources estimates are low, while significant upside potential is reflected in the larger volumes assigned as 3C. Through interpretation of 3D seismic data, Bayfield has identified a number of Prospects that are closely associated with the structures on which discoveries have already been made. Bayfield has also identified Prospects elsewhere in the Galeota Block. Bayfield has a committed seven-well exploration programme of which two wells have been drilled to date. Some of these wells will both narrow the range of uncertainty in the discoveries, possibly indicating non-viability (e.g. EG-7 and its impact on the EG-1 discovery), and test proximal Prospects. Development of the discoveries is contingent on the outcome of the appraisal and exploration programme, which may influence the selection of the field development concept. Development is also contingent on approval of the development plans by Bayfield's partner, Petrotrin.

Bayfield was awarded the exploration licence for the Pletmos Inshore Block on 17th April, 2012, in the Pletmos Basin immediately offshore the south coast of South Africa. The first exploration period consists of 3 years during which Bayfield has committed to undertake the reprocessing of 2,500 km of existing 2D data and the acquisition of additional 2,000 km of 2D data plus desktop geological studies.

The Pletmos Inshore block is located in the greater Outeniqua basin from which daily production of 140 MMscf gas and 7,500 Bbl of oil and condensate is currently processed at the Mossel Bay GTL plant which has spare capacity. The block is 200 km from the Mossel Bay plant.

No exploration activity has occurred in the Pletmos subbasin since 1990. Previous exploration efforts by Soekor (the then South Africa state oil company) between 1970 and 1990 had focused on syn-rift structures, and resulted in the discovery and appraisal of the Ga-A field, located immediately to the south of the Pletmos Inshore block, and a gas discovery in the Ga-V1 well, located in the south-west of the Pletmos Inshore block.

Bayfield plans to focus on two shallower (1,200-1,800 m) turbidite plays that have not been previously targeted in the block. High quality reservoir sands have been proven for these turbidites by wells drilled in the block that were targeting traps at deeper syn-rift levels.

Bayfield's Licences are summarised in Table 0.1.

TABLE 0.1

LICENCE SUMMARY

Country	Block / Permit	Operator	Bayfield W.I. (%)	Area (km^2)	Current Phase Expiration Date
Trinidad	Galeota	Bayfield	65	121.6	20th April, 2034
South Africa	Pletmos Inshore	Bayfield	90	10,800	16th April, 2015
Russia	Karalatsky	AGOC	74	1,500	

Notes:

1. Bayfield will pay 100% of costs in the Pletmos Inshore Block during the exploration phase. In the event of a commercial discovery being developed, the South African state Company, PetroSA, has 10% back-in right, paying only the forward costs. Bayfield's 90% Working Interest shown in this table is based on PetroSA exercising its back-in right. Note that an option exists for a further 10% to be taken by Historically Disadvantaged South Africans (HDSA), paying its equity of forward costs and of past costs.
2. Bayfield is in the process of surrendering the Karalatsky licence.

GCA's estimates of Gross Proved, Proved plus Probable and Proved plus Probable plus Possible oil and gas Reserves are summarised in Table 0.2. Table 0.2 also contains a summary of Bayfield's Net Entitlement Reserves based upon its Net Entitlement under the governing fiscal terms. GCA has calculated Net Present Values for the Reserves by carrying out discounted cash flows incorporating the fiscal terms governing each licence block. These are reported in Table 0.3. The economic evaluation was based on assumptions of forecast prices and escalating costs. The oil prices and escalation factors used were drawn from GCA's oil price scenario. Costs (capital and operating costs) were escalated at 2% per annum after mid-year 2013.

TABLE 0.2

SUMMARY OF GROSS FIELD OIL RESERVES AND BAYFIELD NET ENTITLEMENT OIL RESERVES AS AT 30th JUNE, 2012

Country	Field and Area / Reservoir	Gross Field Oil Reserves (MMBbl)			Bayfield Net Entitlement Oil Reserves (MMBbl)		
		Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible
Trinidad	Trintes Field Main	9.85	22.77	25.05	6.40	14.80	16.28
	Trintes NE extension M	-	6.63	10.10	-	4.31	6.56
	Trintes NE extension G	-	2.19	5.53		1.42	3.59
	Trintes SW extension M	-	1.70	4.49	-	1.11	2.92
	Trintes extension GAL-9 G and H	0.60	2.10	4.48	0.39	1.36	2.91
	Trintes extension GAL-12 H	0.38	1.72	2.03	0.25	1.12	1.32
Total		**10.83**	**37.11**	**51.68**	**7.04**	**24.12**	**33.58**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field after 30th June, 2012 onwards.
2. "Trintes Field Main" includes Reserves from continued production plus Bayfield's work-over and side-track programmes.
3. No gas Reserves are attributed to the Trintes Field.

TABLE 0.3

POST-TAX NET PRESENT VALUES AT 10% DISCOUNT NET TO BAYFIELD RESERVES AS AT 30th JUNE, 2012 (US$ MM)

Field	Proved	Proved plus Probable	Proved plus Probable plus Possible
Trintes Field Main	16.27	104.92	124.31
Trintes Field Extensions	5.27	96.81	206.42
Total	**21.54**	**201.73**	**330.73**

Notes:

1. The Net Present Values are calculated by carrying out discounted cash flows incorporating the fiscal terms governing each licence block.
2. The values shown in this table are Net to Bayfield according to the fiscal terms governing each licence block.
3. Economic calculations have been based on GCA's Third Quarter, 2012 Brent Pricing Scenario (Section 3.3).

GCA's estimates of 1C, 2C and 3C Gross Contingent Resources are summarised in Table 0.4. Bayfield's Net Entitlement Contingent Resources are summarised in Table 0.5. GCA has estimated Net Present Values for the 2C Contingent Resources by carrying out discounted cash flows incorporating the fiscal terms governing each licence block using conceptual development plans. A risk factor (Chance of Development) has been applied to NPV_{10} calculations to account for the chance that these volumes might not mature to Reserves class. The Chance of Development represents an indicative estimate of the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve. The risked NPVs for Contingent Resources are reported in Table 0.6.

TABLE 0.4

SUMMARY OF GROSS UNRISKED CONTINGENT RESOURCES AS AT 30th JUNE, 2012

Discovery	Gross Unrisked Contingent Resources					
	Oil (MMBbl)			Gas (Bscf)		
	1C	2C	3C	1C	2C	3C
EG-2 & EG-8	1.22	2.81	5.51	16.31	29.13	47.48
EG-3	1.92	3.26	5.09	3.15	4.65	6.58
EG-4	18.17	31.23	47.85	3.19	5.31	7.99
GAL-21 updip	0.44	0.96	1.65	0.66	0.84	1.05
Total	**21.75**	**38.26**	**60.10**	**23.31**	**39.93**	**63.10**

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the field without any economic cut-off being applied.
2. The volumes reported here are "Unrisked" in the sense that Chance of Development values have not been arithmetically applied to the designated volumes within this assessment. Chance of Development represents an indicative estimate of the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve.
3. The primary Contingent Resource volume reported here is the 2C, or 'Best Estimate', value.

TABLE 0.5

SUMMARY OF BAYFIELD NET ENTITLEMENT UNRISKED CONTINGENT RESOURCES AS AT 30th JUNE, 2012

Discovery	Bayfield Working Interest (%)	Net Bayfield Unrisked Contingent Resources					
		Oil (MMBbl)			Gas (Bscf)		
		1C	2C	3C	1C	2C	3C
EG-2 & EG-8	65	0.79	1.83	3.58	10.60	18.93	30.85
EG-3	65	1.25	2.12	3.31	2.05	3.02	4.28
EG-4	65	11.81	20.30	31.10	2.07	3.45	5.19
GAL-21 updip	65	0.29	0.64	1.07	0.43	0.55	0.68
Total		**14.14**	**24.89**	**39.06**	**15.15**	**25.95**	**41.00**

Notes:

1. The volumes reported here are Unrisked in the sense that Chance of Development values have not been arithmetically applied to the designated volumes within this assessment. Chance of Development represents an indicative estimate of the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve.
2. The primary Contingent Resource volume reported here is the 2C, or 'Best Estimate', value.

TABLE 0.6

SUMMARY OF RISKED NET BAYFIELD POST-TAX NET PRESENT VALUES FOR CONTINGENT RESOURCES AS AT 30th JUNE, 2012

Country	Block	Chance of Development (%)	Risked NPV_{10} (US$ MM)
Trinidad	Galeota	55	72.29

Notes:

1. A risk factor (Chance of Development) has been applied to NPV_{10} calculations of 2C Contingent Resources to account for the chance that these volumes might not mature to Reserves class. The Chance of Development represents an indicative estimate of the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve.
2. Economic calculations have been based on GCA's Third Quarter, 2012 Brent Pricing Scenario (Section 3.3).

GCA's Low, Best and High estimates of Gross Prospective Resources and Bayfield Net Entitlement Prospective Resources for Prospects are shown in Tables 0.7 and 0.8. Bayfield Net Entitlement Prospective Resources shown in this table are based on Bayfield's Working Interest.

It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Prospect/Lead and the potential dependencies between them. Similarly, it is inappropriate to sum Reserves with Contingent Resources and Prospective Resources or Contingent Resources with Prospective Resources. Each class of Resources is, therefore, reported separately.

TABLE 0.7

SUMMARY OF GROSS UNRISKED PROSPECTIVE RESOURCES (PROSPECTS) AS AT 30th JUNE, 2012

Country / Block	Prospect	Interval	Bayfield Working Interest (%)	Gross Unrisked Prospective Resources - Prospects						GCoS (%)
				Oil (MMBbl)			Gas (Bscf)			
				Low	Best	High	Low	Best	High	
Trinidad / Galeota	NE Trintes	H3	65	3.39	6.51	10.25	-	-	-	39
		M	65	7.04	12.96	24.13	-	-	-	41
		N	65	1.92	5.55	9.77	-	-	-	17
	EG-3	O1	65	3.34	5.82	9.04	-	-	-	18
		O2	65	2.31	4.03	6.26	-	-	-	32
		O3	65	1.57	2.74	4.23	-	-	-	32
		O4	65	3.72	6.43	10.02	-	-	-	31
		E	65	1.54	3.18	5.59	-	-	-	12
	Thais	O1	65	3.07	5.36	8.31	-	-	-	10
		O2	65	3.23	5.60	8.71	-	-	-	18
		O3	65	2.17	3.76	5.84	-	-	-	18
		O4	65	5.13	8.86	13.77	-	-	-	17
		B	65	-	-	-	3.19	4.81	6.82	17
		C	65	1.52	2.64	4.09	-	-	-	17
	South Trintes	F	65	1.23	2.41	4.00	-	-	-	7
		F1	65	0.76	1.48	2.48	-	-	-	7
		G	65	0.69	1.33	2.27	-	-	-	10
		H0	65	0.43	0.88	1.60	-	-	-	7
		M	65	5.58	10.96	18.94	-	-	-	8
	GAL21 Updip	A	65	1.70	8.04	17.51				25
		B	65	1.44	6.42	14.46				36
	EG-8	E	65	0.53	1.91	4.47	-	-	-	16
	EG-2	LaSv-N1	65	0.04	0.10	0.24	-	-	-	33
	Tatiana	LaSv-N1	65	0.24	1.78	5.33	-	-	-	30
		E	65	0.33	1.65	4.34	-	-	-	16
	Denise	LaSv-N1	65	0.67	3.01	7.66	-	-	-	30
		E	65	0.58	2.40	6.06	-	-	-	16
		H	65	-	-	-	4.24	14.19	29.82	25
		Denise Deep	65	-	-	-	0.68	2.98	7.76	14
		LaSv-Tbs	65	-	-	-	3.67	17.46	46.38	14
	Gaby	COS1-I	65	1.16	4.10	7.91	-	-	-	15
		COS1-L	65	0.97	2.82	5.00	-	-	-	13
		COS1-PA	65	1.40	3.01	4.64	-	-	-	13
		COS1-PB	65	0.70	1.42	2.19	-	-	-	13
		COS1-PC	65	3.82	9.76	16.21	-	-	-	15
South Africa / Pletmos Basin	1		90	-	-	-	11.9	234.5	447.7	18
	2		90	-	-	-	9.3	85.0	175.4	15
	3		90	-	-	-	35.4	184.5	415.8	13
	5		90	-	-	-	5.5	33.6	79.9	8
	9		90	-	-	-	43.0	169.5	370.4	6
	10		90	-	-	-	518.2	1,757.6	3,753.3	6
	GA-VI		90	-	-	-	63.4	240.1	518.4	10

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. Gross Unrisked Prospective Resources are 100% of the volumes estimated to be recoverable from the field.
3. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are “Unrisked”.
4. It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Prospect/Lead and the potential dependencies between them. Similarly, it is inappropriate to aggregate Prospective Resources with Reserves or Contingent Resources.

TABLE 0.8

SUMMARY OF BAYFIELD NET ENTITLEMENT UNRISKED PROSPECTIVE RESOURCES (PROSPECTS) AS AT 30th JUNE, 2012

Country / Block	Prospect	Interval	Bayfield Working Interest (%)	Net Bayfield Unrisked Prospective Resources - Prospects						GCoS (%)
				Oil (MMBbl)			Gas (Bscf)			
				Low	Best	High	Low	Best	High	
Trinidad / Galeota	NE Trintes	H3	65	2.20	4.23	6.66	-	-	-	39
		M	65	4.58	8.42	15.68	-	-	-	41
		N	65	1.25	3.61	6.35	-	-	-	17
	EG-3	O1	65	2.17	3.78	5.88	-	-	-	18
		O2	65	1.50	2.62	4.07	-	-	-	32
		O3	65	1.02	1.78	2.75	-	-	-	32
		O4	65	2.42	4.18	6.51	-	-	-	31
		E	65	1.00	2.07	3.63	-	-	-	12
	Thais	O1	65	2.00	3.48	5.40	-	-	-	10
		O2	65	2.10	3.64	5.66	-	-	-	18
		O3	65	1.41	2.44	3.80	-	-	-	18
		O4	65	3.33	5.76	8.95	-	-	-	17
		B	65	-	-	-	2.07	3.13	4.43	17
		C	65	0.99	1.72	2.66	-	-	-	17
	South Trintes	F	65	0.80	1.57	2.60	-	-	-	7
		F1	65	0.49	0.96	1.61	-	-	-	7
		G	65	0.45	0.86	1.48	-	-	-	10
		H0	65	0.28	0.57	1.04	-	-	-	7
		M	65	3.63	7.12	12.31	-	-	-	8
	GAL21 Updip	A	65	1.11	5.23	11.38	-	-	-	25
		B	65	0.94	4.17	9.40	-	-	-	36
	EG-8	E	65	0.34	1.24	2.91	-	-	-	16
	EG-2	LaSv-N1	65	0.03	0.07	0.16	-	-	-	33
	Tatiana	LaSv-N1	65	0.16	1.16	3.46	-	-	-	30
		E	65	0.21	1.07	2.82	-	-	-	16
	Denise	LaSv-N1	65	0.44	1.96	4.98	-	-	-	30
		E	65	0.38	1.56	3.94	-	-	-	16
		H	65	-	-	-	2.76	9.22	19.38	25
		Denise Deep	65	-	-	-	0.44	1.94	5.04	14
		LaSv-Tbs	65	-	-	-	2.39	11.35	30.15	14
	Gaby	COS1-I	65	0.75	2.67	5.14	-	-	-	15
		COS1-L	65	0.63	1.83	3.25	-	-	-	13
		COS1-PA	65	0.91	1.96	3.02	-	-	-	13
		COS1-PB	65	0.46	0.92	1.42	-	-	-	13
		COS1-PC	65	2.48	6.34	10.54	-	-	-	15
South Africa / Pletmos Basin	1		90	-	-	-	10.7	211.0	402.9	18
	2		90	-	-	-	8.4	76.5	157.9	15
	3		90	-	-	-	31.9	166.0	374.2	13
	5		90	-	-	-	4.9	30.2	71.9	8
	9		90	-	-	-	38.7	152.5	333.4	6
	10		90	-	-	-	466.4	1,581.8	3,378.0	6
	GA-VI		90	-	-	-	57.1	216.1	466.6	10

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked".
3. It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Prospect/Lead and the potential dependencies between them. Similarly, it is inappropriate to aggregate Prospective Resources with Reserves or Contingent Resources.

DISCUSSION

1. TRINIDAD GALEOTA BLOCK

1.1 Introduction

The Galeota Exploration and Production Licence area covers 121.6 km^2 in the shallow waters (17 m to 45 m) of the Columbus Basin off the east coast of Trinidad (Figure 0.1). Bayfield was awarded a 65% Working Interest in April, 2009 and took over operatorship from the state-owned Petroleum Company of Trinidad and Tobago (Petrotrin) who currently owns the remaining 35% Working Interest. Bayfield has committed to carry Petrotrin for four years in relation to operating costs and the committed programme of platform refurbishments and well work-overs on the producing Trintes Field. Bayfield has also undertaken to fund an exploration and appraisal programme of 3D seismic acquisition and seven new wells.

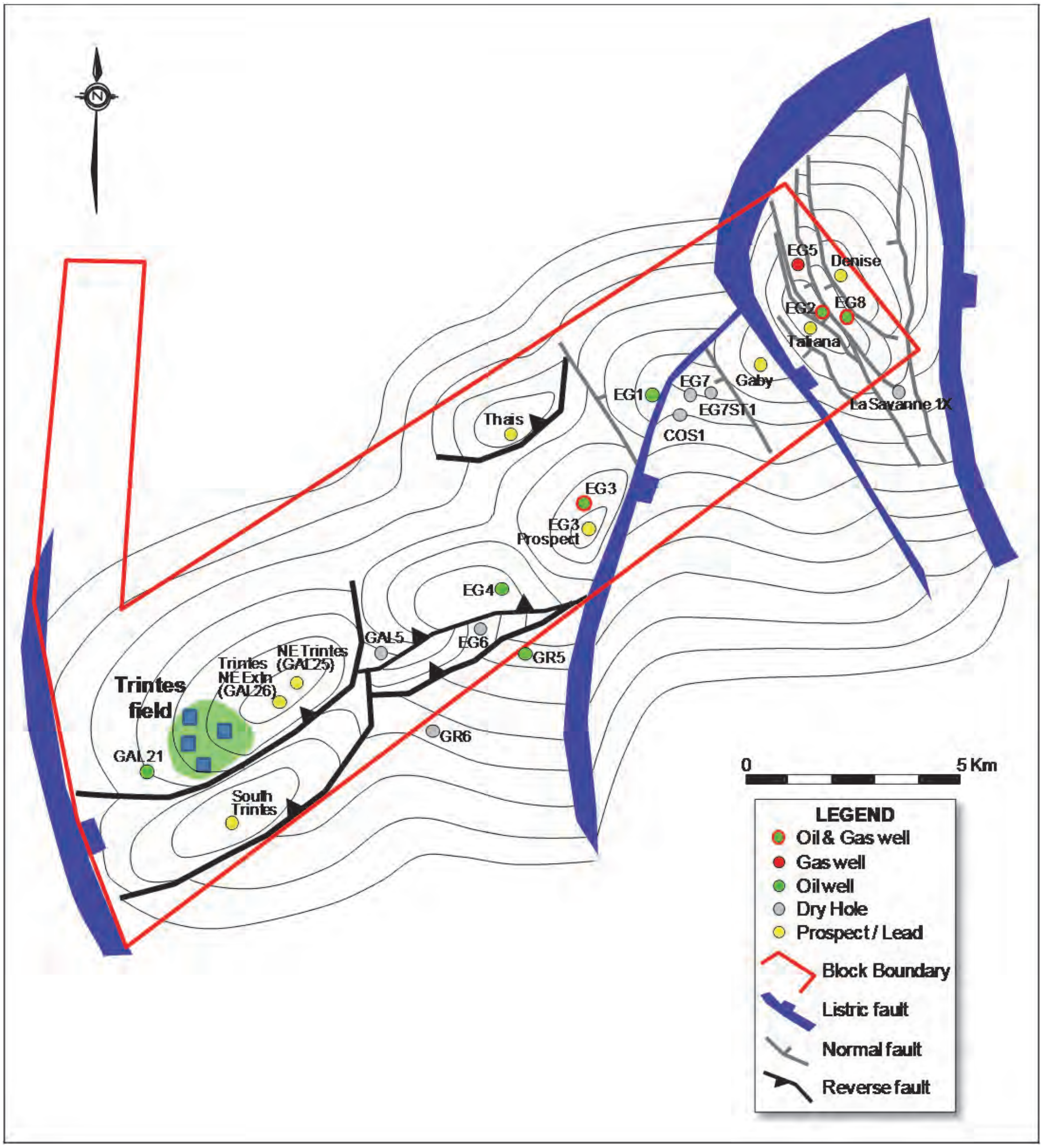
The Galeota Block is within the established oil play of the Columbus basin and is surrounded by mature oil fields. Exploration and development activity in the Galeota Block began in 1953 with the acquisition of seismic data, and the subsequent drilling of Galeota-1 exploration well in 1961. Over 90 wells (of which approximately two thirds are development wells) have since been drilled, targeting Pliocene and Pleistocene age reservoirs. Although several hydrocarbon discoveries have been made within the lease, only the Trintes Field, discovered in 1963, was considered to have encountered sufficient volumes to justify development at the time (Figure 1.1).

Since the Trintes Field came on stream in 1972, about 27.37 MMBbl of oil has been produced via four production platforms to 30th June, 2012. By the end of 1982, production had peaked at around 5,500 bopd. The Trintes Field is produced at a month average rate of 2,040 bopd in July 2012, and a continuing platform-based rig programme to work over the existing well inventory and to drill new side-track wells is targeted to increase production to over 4,000 bopd during 2013, and almost 8,000 bopd in 2016. Since the end of 2010 Bayfield has carried out some 66 work-overs and drilled 14 side-track wells almost doubling the field production rate compared to a year ago.

Besides the Trintes Field, five exploration wells drilled between 1964 and 1985 discovered hydrocarbons in multiple stacked reservoirs, and more recently two further exploration wells have been drilled by Bayfield as Operator in 2012. These earlier discoveries have not been fully appraised or developed to this time. A 3D seismic survey was acquired in 1999 but there was no further drilling until 2012. Bayfield's evaluation of these discoveries, based on the well data and the interpretation of the reprocessed 3D seismic data, has indicated the potential for development and Bayfield has devised conceptual field development plans for them. During 2010, Bayfield completed a new 3D seismic survey and also acquired 200 km of 2D data to support new drilling. Several exploration Prospects have been identified, some of which are closely associated with the discoveries. Development plans for the discoveries will be finalised following the outcome of the exploration and appraisal programme. GCA has judged the EG-1 discovery to be non-viable as a development since the drilling and evaluation of the EG-7 and its side-track EG-7ST1.

FIGURE 1.1

LOCATION OF THE TRINTES FIELD, HYDROCARBON DISCOVERIES AND PROSPECTS IN THE GALEOTA BLOCK, TRINIDAD



1.2 Geological Setting

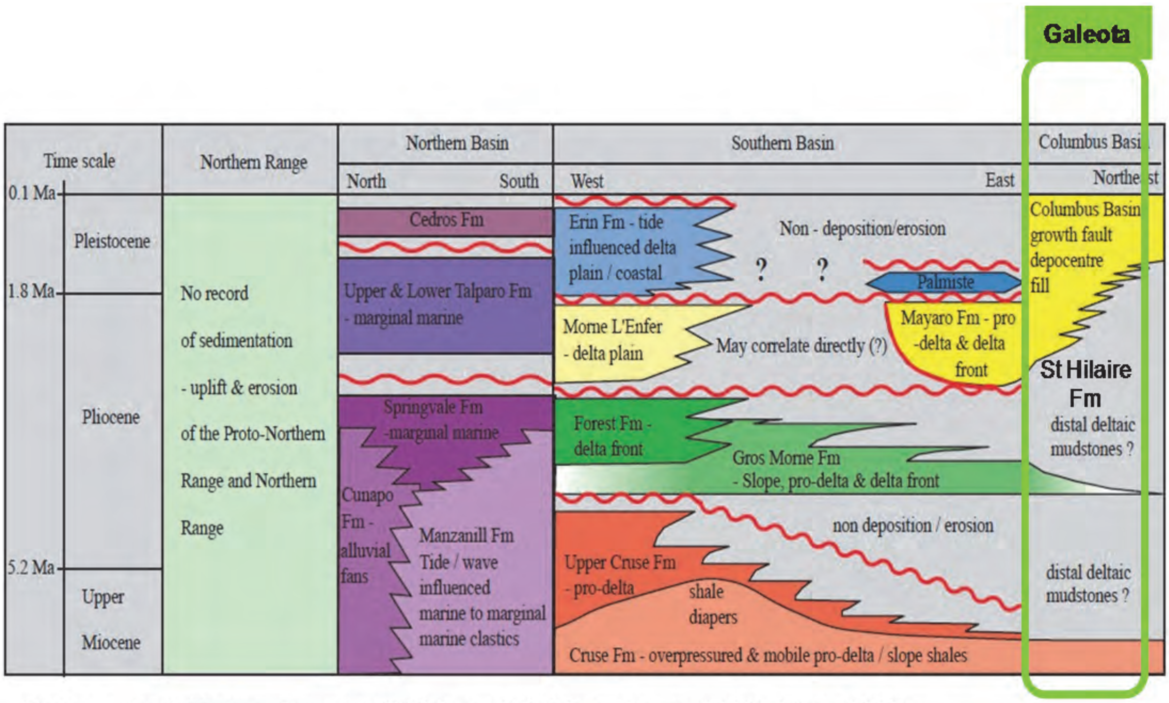
The Galeota Block is dominated by the Galeota Anticline, which is the offshore eastern continuation of the complex Southern Range Anticline. The anticline was likely formed in the Pleistocene during the most recent transpressive phase caused by the eastward movement of the Caribbean Plate relative to the South American Plate. It is a north-east to south-west trending anticline that plunges towards the north-east, until it disappears just east of the EG-2 / EG-5 area.

Prior to the Pleistocene compression, the structural features in the Galeota Block comprised down-to-the-east listric growth faults with their resultant broad roll-over structures typical of deltaic sedimentation. The listric growth faults were triggered by the active progradation of the proto-Orinoco Delta across Trinidad during the Pliocene and Pleistocene. The late stage compressive event during the Pleistocene which gave rise to the Galeota Anticline, folded the pre-existing sediments and growth faults, with the hydrocarbon accumulations thus located primarily in structural traps.

Thick deltaic sand and shale deposits of Pliocene and Pleistocene age underlie the lease (Figure 1.2). Sediment thicknesses of more than 12,000 m are estimated to have been deposited since the Pliocene in the deepest parts of the basin, and sand with excellent reservoir qualities (porosity up to 30%; permeability greater than one Darcy) is widespread. The sand units are subdivided lithologically in the West Galeota area into, from oldest to youngest, the Gros Morne W, V, T, S, P, O, N, and M Sands, and the St. Hilaire H, G, and F Sands. Figure 1.3 shows a typical stratigraphic sequence in the wireline logs of GAL-3, the Trintes Field discovery well.

FIGURE 1.2

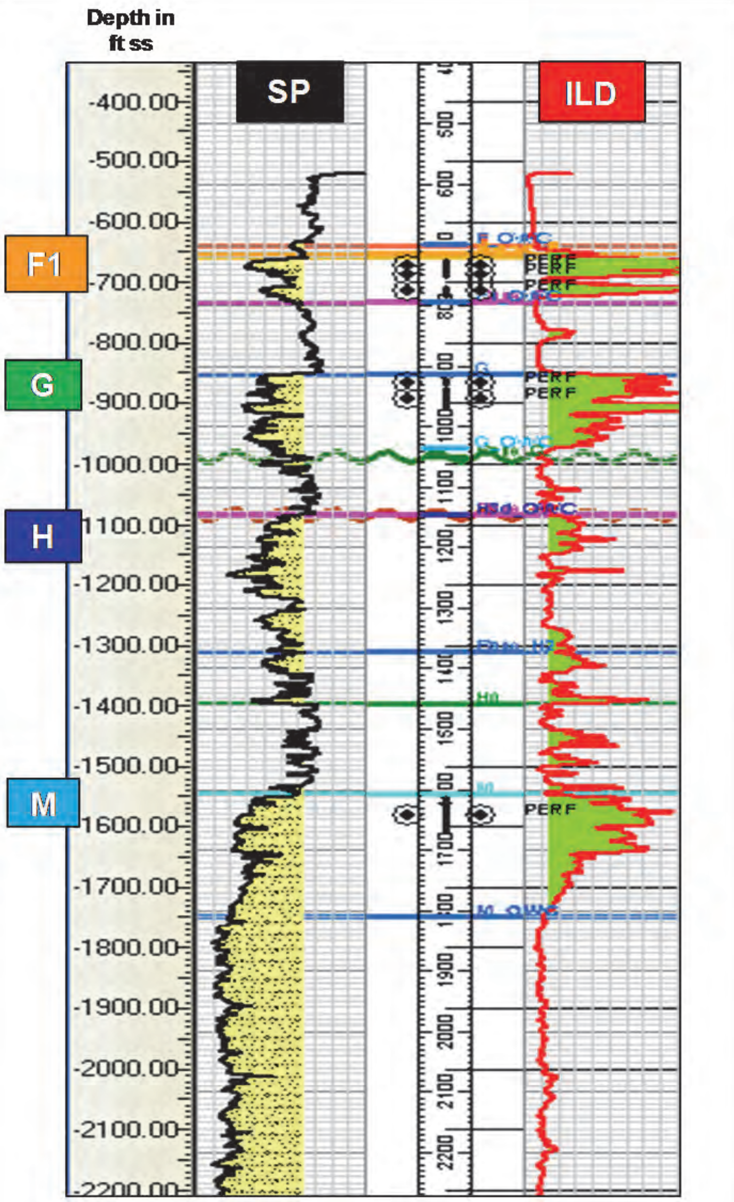
STRATIGRAPHIC COLUMN OF THE GALEOTA BLOCK, TRINIDAD



Source: Bayfield, from Bowman (2003), modified from Payne (1991), Algar (1998).

FIGURE 1.3

GAL-3 DISCOVERY WELL, TRINTES FIELD



Source: Bayfield Energy

Overall thickness of the sedimentary section varies throughout the block, due primarily to the effects of the synsedimentary growth faulting. For instance, well GAL-3 penetrated ca. 2,400 m of deltaic sediments while wells GAL-2 and GAL-1, located closer to one of the major growth faults, both penetrated at least 3,000 m of deltaic sediments. EG-3, which lies in East Galeota on the downthrown side of another growth fault, encountered 3,500 m of deltaic section within which the well was terminated. Growth fault activity, in the Galeota Trintes area in particular, appears to have been substantial during the Pliocene, resulting in thick aggradational deltaic sequences such as the Gros Morne M sand.

1.3 Trintes Field Reserves

Seven principal reservoir intervals developed in the Trintes Field, ranging in depth from less than 150 mss to over 600 mss, comprise good reservoir quality shoreface, estuarine channel and fluvial sand. The reservoir intervals, from shallowest to deepest, are called F, F1, G, H3, H2, H1 and M. Further, minor reservoir intervals: H0, N, O, OO and P have been intersected but have not contributed significantly to production. The current 2P development plan for the field includes recovering small volumes from a number of these minor reservoir intervals.

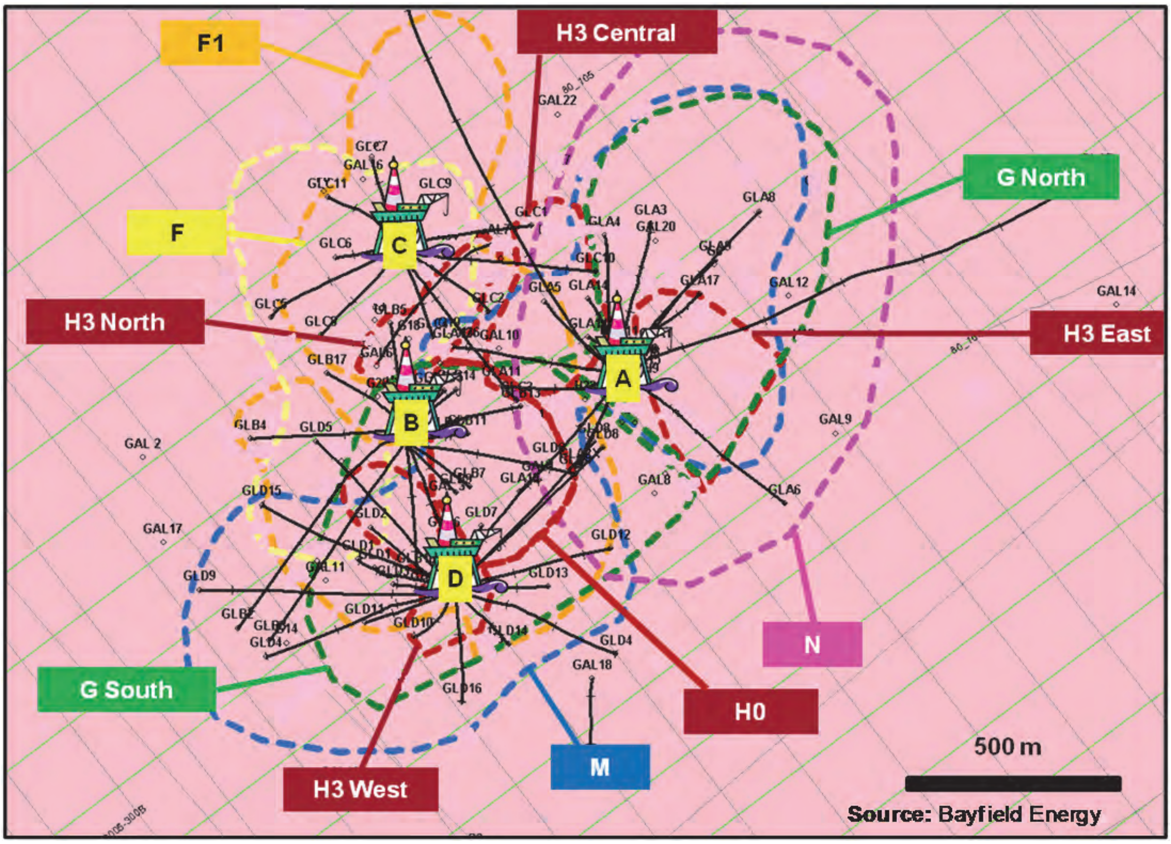
The field has been developed from four platforms, Alpha, Bravo, Charlie and Delta (also referred to as A, B, C and D) with a total of 62 production wells, which have collectively produced some 27.37 MMBbl to mid-2012 (Figure 1.4). Production commenced in 1972 and the field is now considered mature with production over the first half of 2012 averaging in the order of 1,317 bopd with an average watercut around 51%. The average rate during June 2012 was 1,708 bopd at a watercut of 49%. The July, 2012 field rate was in excess of 2,000 bopd. The field has demonstrated a rising production profile since March of this year, which reflects the high operational activity levels, particularly concerning the long side-track wells from the newly acquired Rig 2 able to target the inadequately drained reservoirs/pools in the field area, especially within the M and H sands since the end of 2011. In short, although the field is considered mature, Bayfield has embarked on field facilities upgrades, including improvements in well completions and artificial lift, to support further targeted drilling activity particularly focussed on extended reach side-track wells, to effectively drain areas of the reservoir sands comprising the field that have been poorly addressed and insufficiently developed until now.

Bayfield has provided GCA with historical monthly average oil and water production figures for each well, platform and reservoir. The historical production records are incomplete, and it is not known how much gas has been produced from any of the reservoirs as this has not been reported. GCA has relied on this information at face value. During 2009 and 2010, Bayfield undertook a campaign of pressure measurements using echo-sounding devices in individual wells, however, there has been no more recent pressure data acquisition. No PVT data are available and Bayfield has used industry standard fluid correlation methods to estimate fluid characteristics. Extensive historical appraisal and development drilling has resulted in a comprehensive database of formation depths, thicknesses and petrophysical properties throughout the Trintes area. This CPR has largely been based on a critical audit and review of all reservoir volumetrics and of a recent, detailed decline analysis study.

GCA has reviewed the dataset provided by Bayfield, including wireline logs, maps and seismic data together with production and well performance data and future development plans and associated costs.

FIGURE 1.4

TRINTES FIELD LAYOUT SHOWING RESERVOIRS, WELLS AND PLATFORMS



At some intervals (notably G and M), further extensions of the pay are more likely than not to extend beyond the confines of the developed part of the field to the north-east and, in the case of the M sand, probably to the south-west. These are areas of further development potential. Furthermore, two near field discoveries, the G and H sands intersected by Well GAL-9 and the H sand intersected by Well GAL-12, are to be developed, see Section 1.4.

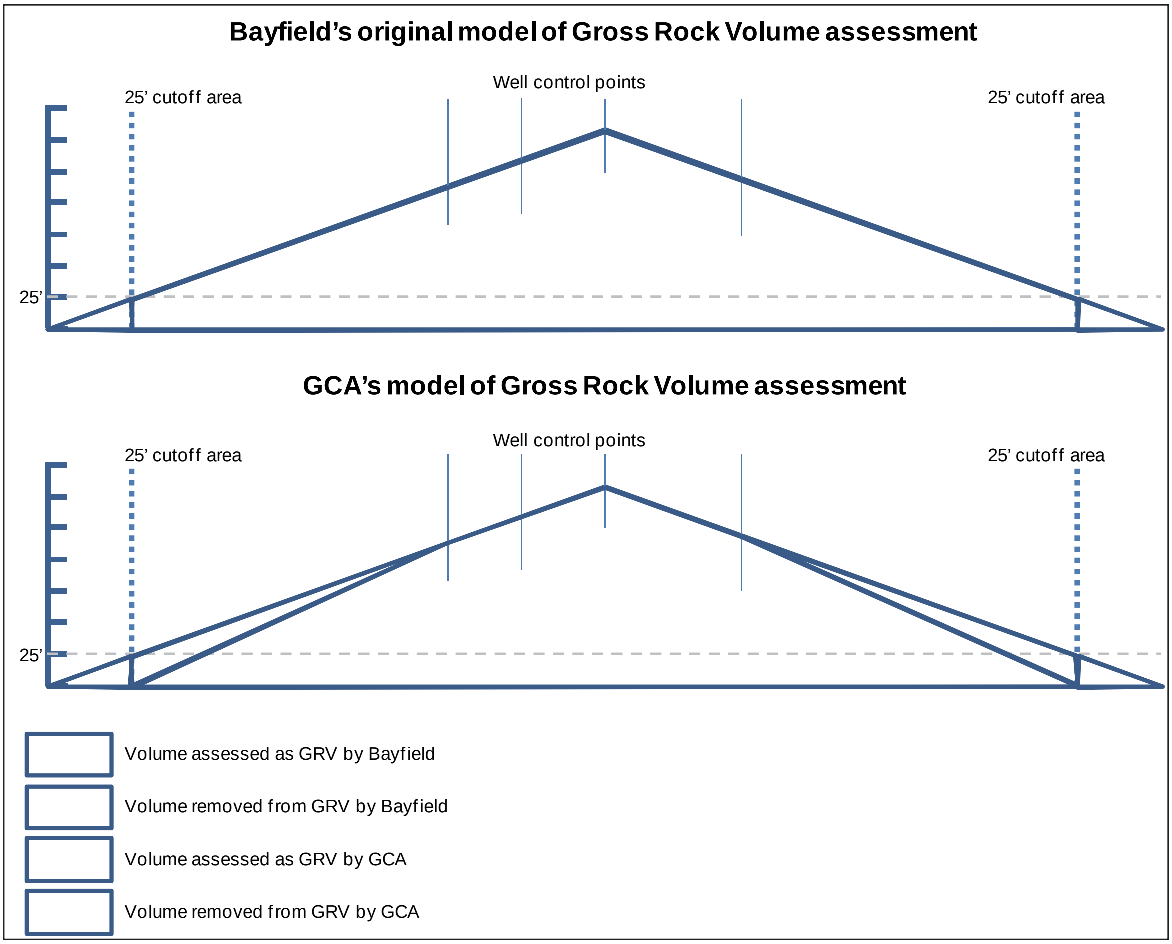
Since the 2011 GCA CPR, major updates have taken place to the interpretation of the H and M sands within the Trintes field. As part of the volumetric assessment undertaken by Bayfield, grids displaying Gross Pay were developed in Kingdom based on the thickness of Trintes sands in the wells across the field. Bayfield stipulated area cut-offs to these grids as away from the well data the volume of Gross sand becomes more uncertain. These cut-offs were often at either the 25 ft (7.6 m) or 50 ft (15.2 m) contour. After discussion with Bayfield it was established that this method does reflect an accurate representation of the Gross sands and therefore GCA implemented a volumetric methodology with Bayfield's agreement.

The areas that were originally used by Bayfield as their cut-off contours would still be used as the areal extent of the Gross Pay; however, rather than reflect 25 ft (7.6 m) or 50 ft (15.2 m) of pay at this contour it would reflect 0 ft of pay. With this model in place the grids were then recalculated using the well control points and the new 0 ft contour (Figure 1.5). This was implemented in the individual H sands as well as the M and N sands.

This model predominantly led to a reduction in Gross Rock Volume for the respective sands with only the H3 and H1a sands showing little change and the H0 sand increasing by 8% in volume. This was largely due a function of a large number of well control points with little area outside of those well control points, but within the cut-off contour, i.e. the increase was due to GRV being added by the gridding algorithm between the well control points.

FIGURE 1.5

TRINTES GROSS ROCK VOLUME ASSESSMENT; GCA MODEL



1.3.1 Trintes Main F and F1 Reservoirs

The F sand reaches a maximum gross pay thickness of over 45 m and a crestal depth of less than 200 mss in an area to the west of the Charlie platform (Figure 1.4). The F1 sand lies below the F sand and is separated from it by a shale interval in places, but is contiguous with it in other areas, forming a single reservoir unit. Gross pay of the F1 sand is best developed in two areas, to the west of Charlie platform and between the Bravo and Delta platforms where gross thickness of up to 32 m has been encountered. The F and F1 comprise upper to lower shoreface and estuarine channel sand of very good reservoir quality. The areal extents of the F and F1 sand bodies have been well defined by the large number of appraisal and development wells and there is little uncertainty in the range of in place volumes.

To date 19 wells have recovered some 4.45 MMBbl of oil and 1.52 MMBbl of water from the F sand. This amounts to a recovery factor of approximately 36% of the estimated STOIIP of 12.22 MMBbl. In the F1 sand 20 wells have recovered some 3.10 MMBbl of oil and 0.82 MMBbl of water to date, amounting to a recovery factor of approximately 33% of the estimated STOIIP of 9.52 MMBbl. Many wells are dual completed in the F and F1 sands and production allocation to the two reservoirs is approximate.

The reservoir pressure had declined from approximately 370 psia to just under 100 psia in the F sand and from approximately 350 psia to approximately 60 psia in the F1 sand in 2010. Water injection was implemented on a small scale between 1992 and 1995. The effect of water injection on production performance was inconclusive, although a clear positive response was observed in one well. It is likely that the reservoirs have experienced very slow water influx from a natural aquifer over many years, which has led to the high recovery factors achieved to date. Due to the absence of historical gas production records, it is not possible to determine the extent to which solution gas drive has contributed to oil recovery. The average combined production rate from the F and F1 sands over the first half of 2012 was 85 bopd, achieved from up to seven wells, some of which only produced intermittently.

Wells are all on artificial lift and potential exists to recover further volumes by improving field management practices and completions. Although the reservoir pressure is low, the wells have high productivity indices and a small reduction in the bottom hole flowing pressure of a well can yield reasonable gains in production rate. Bayfield has carried out a number of work-overs, and plans several more, where new replacement ESPs have been fitted to improve production. It is estimated that most likely volumes of 0.38 MMBbl and 0.25 MMBbl can be recovered from the F and F1 sands respectively from continued production and revitalisation, resulting in overall recovery factors of 40% and 35%. Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves have been attributed to the F and F1 sands.

1.3.2 Trintes Main G Reservoir

The G sandstone body is relatively extensive, with gross pay occurring below the Alpha, Bravo and Delta platforms (Figure 1.4). The edge of the sandstone body has not been intersected in the updip direction to the north-east and it is likely that further potential exists for development of this area. Gross pay is typically 30 m but varies considerably, reaching more than 50 m in some areas while being absent in other wells. The G sand comprises good reservoir quality fluvial and estuarine channel deposits.

To date 23 wells have recovered some 11.88 MMBbl of oil and 2.11 MMBbl of water from the G sand. This represents a recovery factor of approximately 35% of the estimated most likely STOIIP of 33.98 MMBbl within the confines of the developed part of the field. The reservoir pressure had declined from approximately 300 psia to less than 100 psia in the G reservoir in 2010. Water injection was implemented on a small scale between 1992 and 1995 but the volumes were considered too small to have had a noticeable effect on production. It is likely that the reservoirs have experienced very slow water influx from a natural aquifer over many years, which has led to the high recovery factors achieved to date. Due to the absence of historical gas production records, it is not possible to determine the extent to which solution gas drive has contributed to oil recovery. Up to eleven wells were on stream during the first half of 2012, flowing at a combined rate of approximately 329 bopd average over the half-year.

Wells are all on artificial lift and potential exists to recover further volumes by continuing to improve field management practices and completions. Although the reservoir pressure is low, the wells have high productivity indices and a small reduction in the bottom hole flowing pressure of a well can yield reasonable gains in production rate. Bayfield has carried out a number of work-overs, and plans several more, where replacement ESPs have been fitted to improve production, and one new side-track well has also been drilled from the D platform. A number of other side-track wells are planned to increase production from the G reservoir sands and it is estimated that a further most likely volume of 3.15 MMBbl can be recovered from the G sand by implementing Bayfield's plans, resulting in an overall recovery factors of 44%. Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves have been attributed to the G sand.

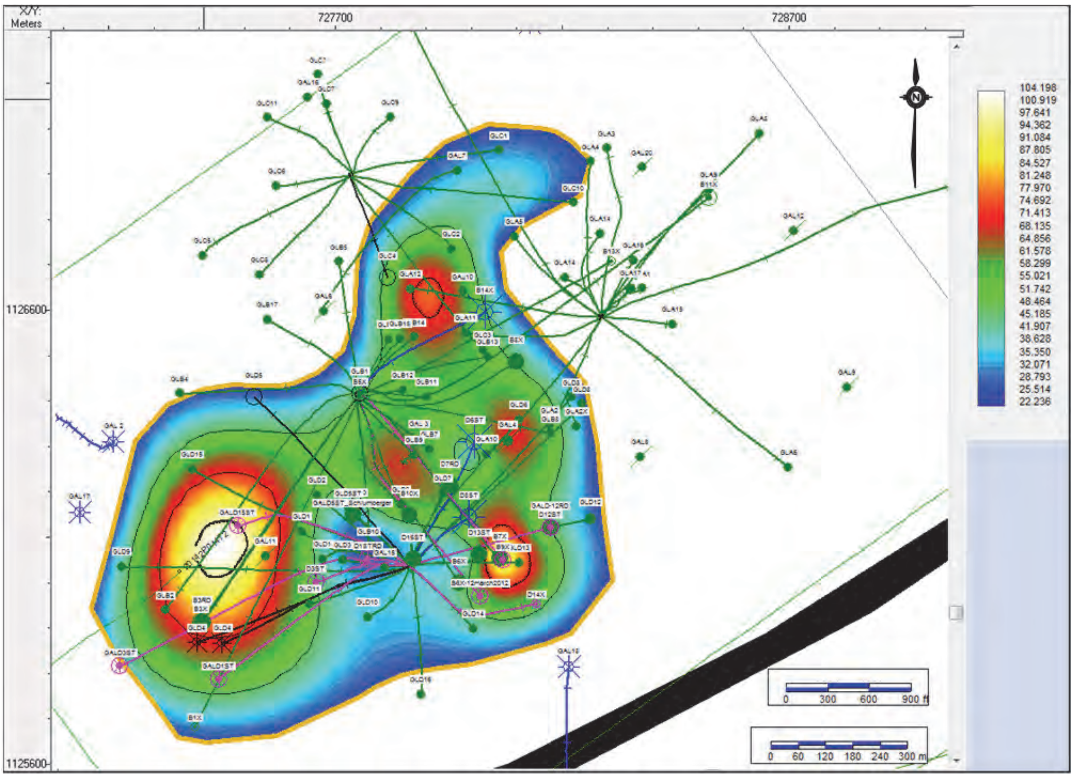
1.3.3 Trintes H Reservoir Group

The H0 sand has produced through two recent wells yielding 0.01 MMBbl of oil and 0.01 MMBbl of water. This represents a recovery factor of less than 1% of the estimated most likely STOIIP of 4.38 MMBbl within the confines of the developed part of the field. These two wells were on stream during the first half of 2012, flowing at an average rate of 36 bopd over the half-year.

The H0 sand has developed sand over 100 ft thick concentrated west of the Delta platform and occurs over an area of 226 acres (Figure 1.6).

FIGURE 1.6

TRINTES H0 NEW GRID



The H1 sand has produced through four recent wells yielding 0.02 MMBbl of oil and 0.03 MMBbl of water. This represents a recovery factor of less than 1% of the estimated most likely STOIIP of 3.79 MMBbl within the confines of the developed part of the field. These four wells were on stream during the first half of 2012, flowing at an average rate of 87 bopd over the half-year.

The H1 sand has been subdivided into two reservoir pay areas; H1a and H1b. To the southwest, the H1a area has developed Gross sand over 53 m thick concentrated west of the Delta platform and south of the Bravo platform (Figure 1.7). H1b to the northeast sees Gross sand thickness of over 45 m thick concentrated west of the Alpha platform and northeast of the Bravo platform (Figure 1.8). The Gross sand in H1a covers ~106 acres and in the H1b it covers ~33 acres.

FIGURE 1.7

TRINTES H1A NEW GRID

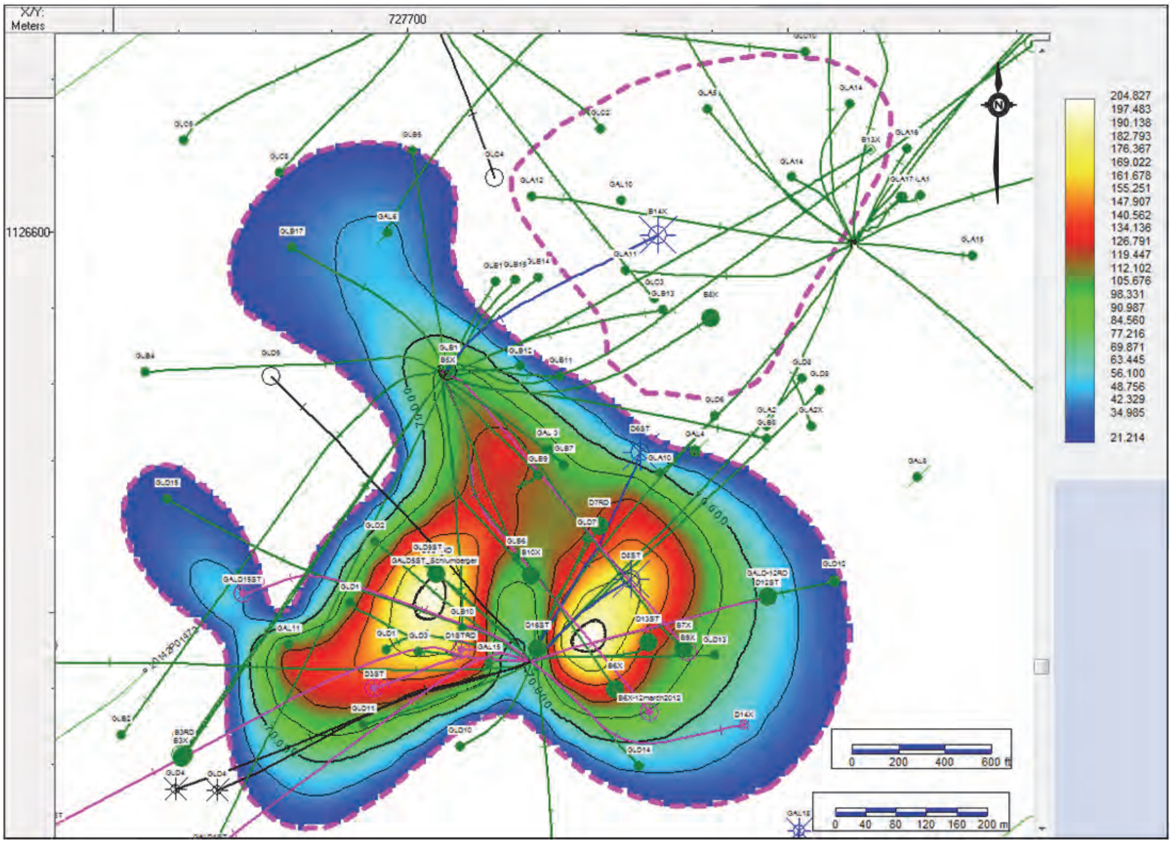
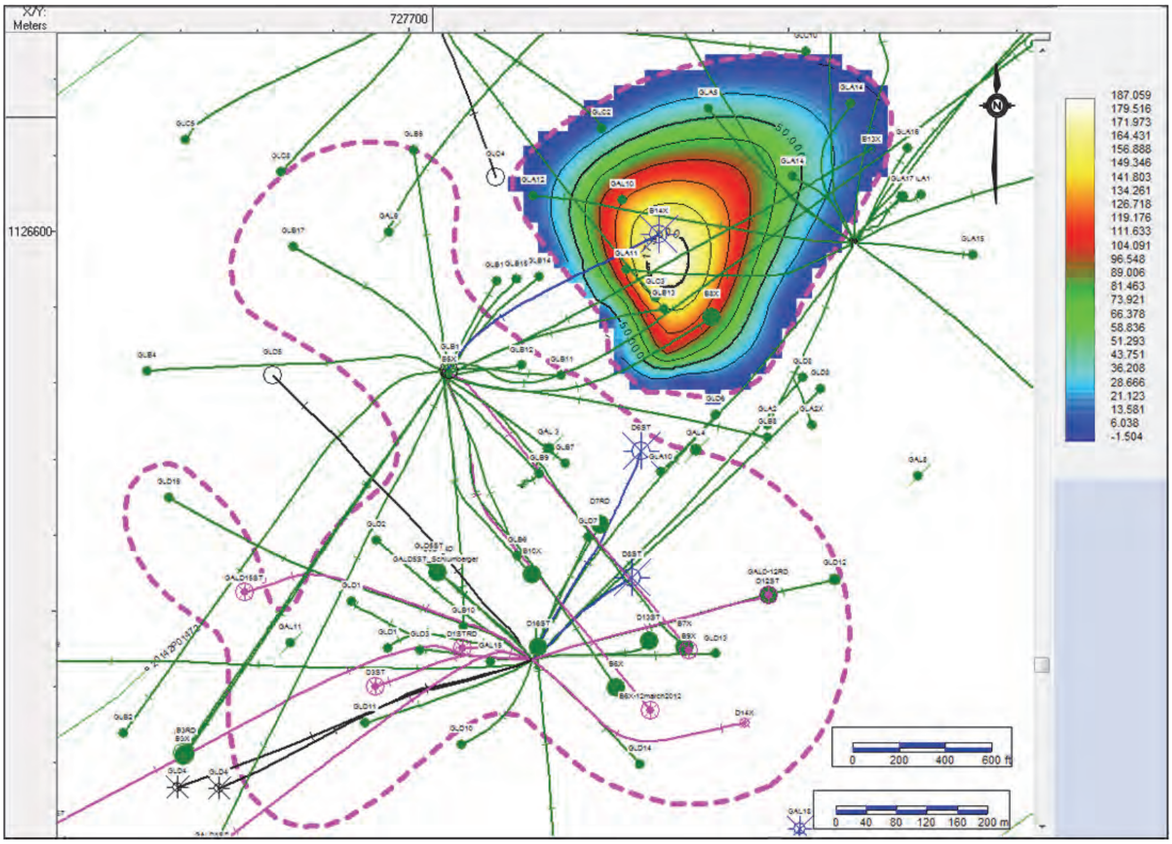


FIGURE 1.8

TRINTES H1B NEW GRID



The H2 sand is the main contributor currently to H sand production since three new side-track wells from the B and D platforms have been completed in this sand. Additionally the H1 sand has also been completed in these new wells, and a fourth B platform side-track well has been completed in the H1 sand and the H0 sand. The H3 sand is now a very minor contributor to production, but previously has been the principal focus of H sand development. Overall, the new H sand development has seen its contribution to total field production over the first half of 2012 increase to almost 22%.

The H2 sand sees over 45 m of gross sand covering an area of ~62 acres concentrated north of the Delta Platform and south of the Bravo platform (Figure 1.9).

The H3 sand has developed pay up to 35 m thick covering an area of ~278 acres concentrated west of the Alpha platform and below the Delta platform (Figure 1.10).

FIGURE 1.9

TRINTES H2 NEW GRID

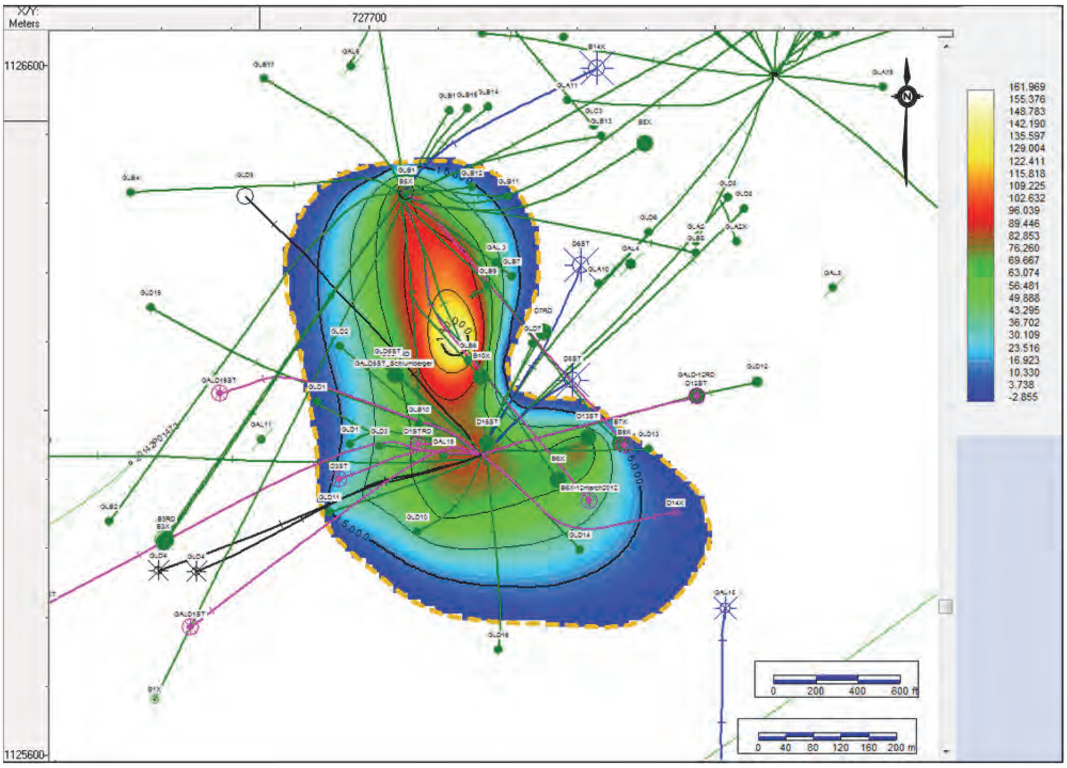
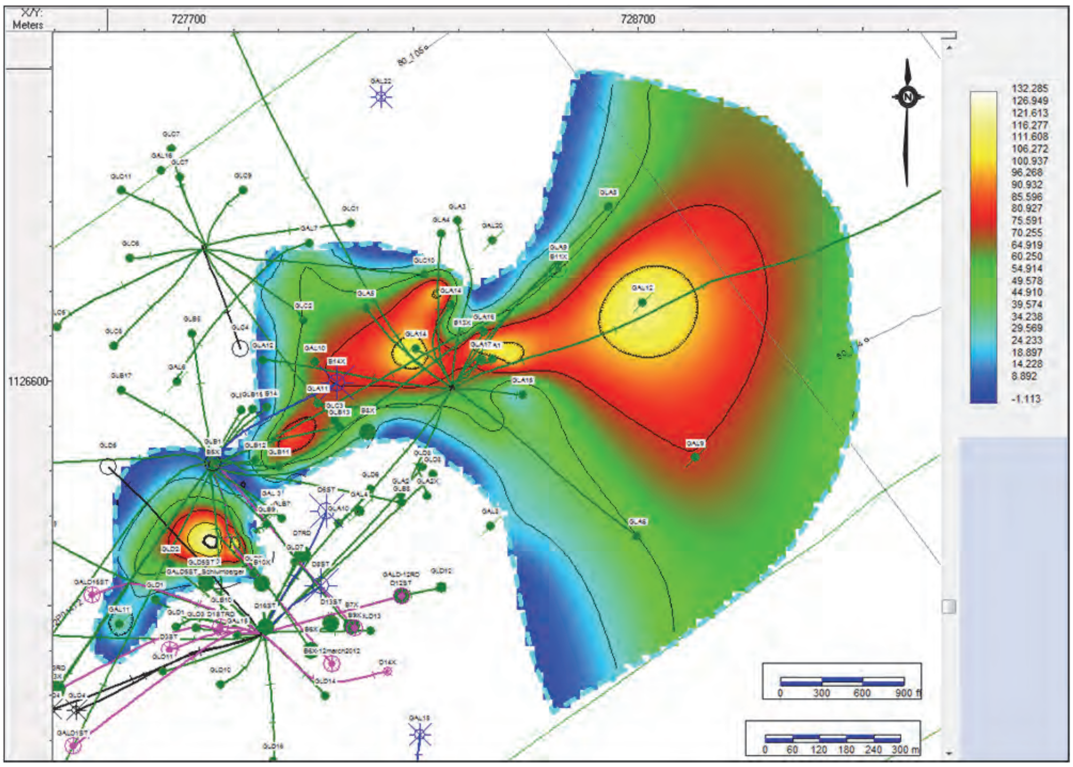


FIGURE 1.10

TRINTES H3 NEW GRID



To date seven wells have recovered some 0.83 MMBbl of oil and 0.66 MMBbl of water from the H3 sand. This represents a recovery factor of approximately 35% of the estimated most likely STOIIP of 2.34 MMBbl within the confines of the developed part of the field. The reservoir pressure had declined from above 300 psia to less than 70 psia in parts of the H3 sand in 2010, while in other areas the reservoir pressure is expected to be higher because of poor drainage. One well was on stream during the first half of 2012, flowing at an effective rate of just 2 bopd average over the half-year. Recovery from the H2 sand has been through three recent wells producing 0.03 MMBbl of oil and 0.029 MMBbl of water. This represents a recovery factor of approximately 2% of the estimated most likely STOIIP of 1.62 MMBbl within the confines of the developed part of the field. These three wells were on stream during the first half of 2012, flowing at an average rate of 158 bopd over the half-year.

Bayfield plans to further develop the H sands, which have demonstrated their continuing importance as part of the total field development with the encouraging results of the 4 recent side-track wells, and it is estimated that a further most likely volume of 2.16 MMBbl can be recovered from the H sands lying within the confines of the developed part of the field by implementing Bayfield's plans, resulting in an overall recovery factor of 25%. Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves have been attributed to the H sands.

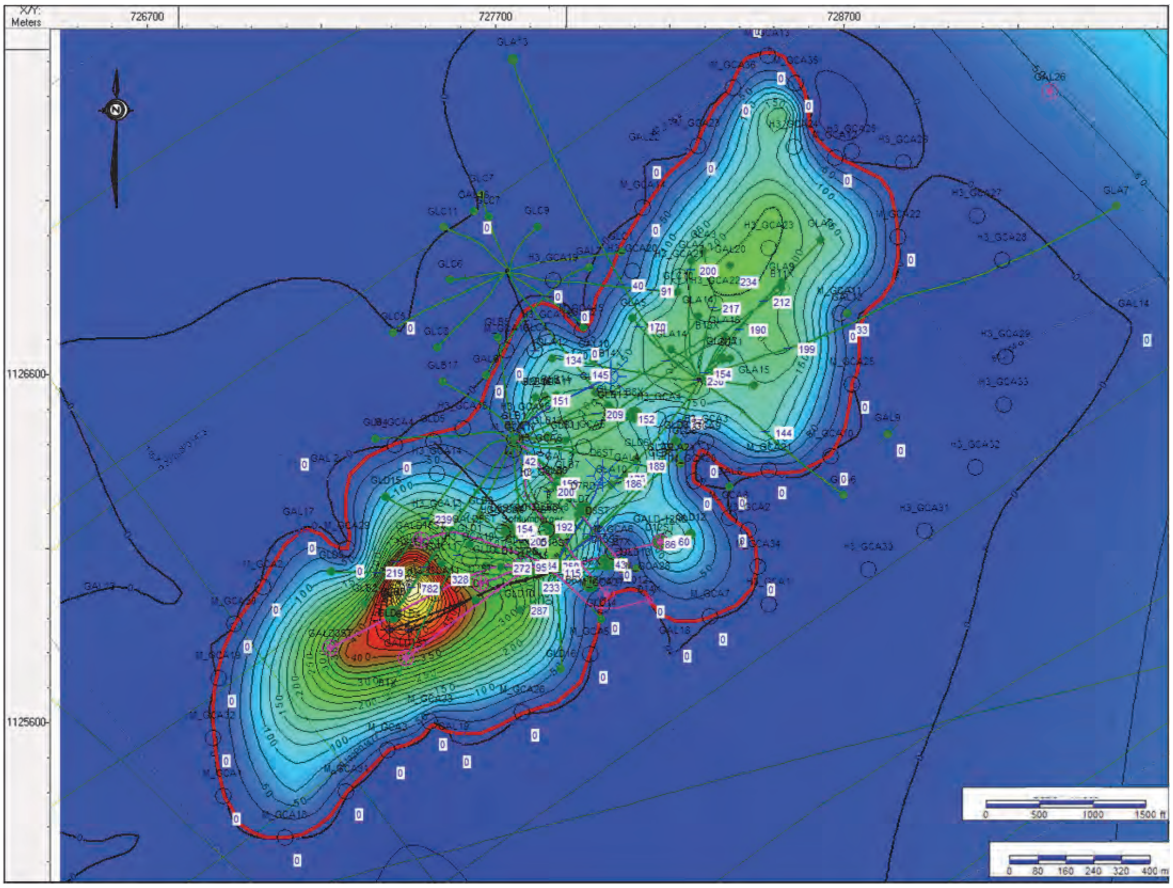
1.3.4 Trintes Main M Reservoir

The M reservoir is a thick extensive package, which has been intersected consistently by wells in and around the Trintes Field that have penetrated to that depth (Figure 1.4). The interval comprises fluvial and estuarine channels and upper shoreface deposits. The M sand comprises good quality reservoir, albeit not as good as the shallower F and G sands. The sandstone package with high NTG ratio extends to well over 400 m in thickness (see Figure 1.11). The structure is an anticline, dipping in a south-westerly direction from a depth of around 200 mss to approximately 600 mss. The Alpha and Delta platforms lie approximately on the axis of the anticline. Oil has been intersected all along the crest of the structure with the gross pay thickness diminishing down the flanks of the anticline as would be expected. However, an unusual feature is that the OWC appears to be tilted, roughly paralleling the dipping trend of the anticline. Along the axis of the anticline, the gross oil column is typically 60 m thick. The depth to the OWC changes by approximately 350 m over a distance of 2.5 km, giving an overall dip of more than 7°. No satisfactory explanation for this steeply dipping contact has been established.

To date 25 wells have recovered some 6.84 MMBbl of oil and 2.80 MMBbl of water from the M sand. This represents a recovery factor of approximately 12% of the estimated most likely STOIIP of 57.46 MMBbl within the confines of the developed part of the field. The reservoir pressure had declined by a relatively small amount from about 730 psia to about 550 psia in 2010. Relative to the other reservoirs in the Trintes Field, the M reservoir has by the far the largest STOIIP, has experienced the smallest pressure decline and has the lowest recovery factor to date. While the M sand is not the best quality reservoir in the field, it represents significant remaining reserves potential. During the first half of 2012, up to twelve wells were on stream, flowing at an average combined rate of 970 bopd (over 70% of the total field rate) over the half-year.

FIGURE 1.11

TRINTES FIELD M SANDS GROSS PAY



Bayfield has completed nine side-track wells from the B and D platforms since the fourth quarter 2010 and has a programme to carry out additional side-tracks to further develop the M sands. These will be completed with horizontal or highly deviated drain-holes improving drainage and well productivity. Additionally, work-overs have been performed to improve the completions and the artificial lift production performance of older wells. The M sand is well suited to horizontal drain-holes and is likely to benefit from some measure of basal water drive. Recent logs run in new well sections through the M sand interval support the interpretation of good water sweep and oil displacement. It is estimated that an additional most likely volume of 16.20 MMBbl can be recovered from the M sand by implementing Bayfield's plans, resulting in an overall recovery factors of 40%. Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves have been attributed to the M sand.

TABLE 1.1

TRINTES FIELD MAIN
STOIIP AND GROSS FIELD OIL RESERVES
AS AT 30th JUNE, 2012

Reservoir	STOIIP (MMBbl)			Oil produced to date (MMBbl)	Gross Field Reserves (MMBbl)		
	Proved	Proved plus Probable	Proved plus Probable plus Possible		Proved	Proved plus Probable	Proved plus Probable plus Possible
Trintes F	12.22	12.22	12.22	4.45	0.22	0.38	0.41
Trintes F1	9.52	9.52	9.52	3.10	0.09	0.25	0.28
Trintes G	30.37	33.98	37.37	11.88	1.84	3.15	3.47
Trintes H3	1.44	2.34	3.32	0.83	0.14	0.26	0.29
Trintes H2	1.02	1.62	2.25	0.03	0.28	0.72	0.79
Trintes H1	2.40	3.79	5.29	0.02	0.36	1.02	1.12
Trintes H0	2.78	4.38	6.13	0.01	0.03	0.16	0.18
Trintes M	36.94	57.46	73.40	6.84	6.74	16.20	17.80
Trintes N	4.91	7.64	10.55	0.07	0.09	0.36	0.40
Trintes O	6.27	10.44	12.76	0.10	0.06	0.30	0.33
Total	**107.87**	**143.39**	**172.81**	**27.33**	**9.85**	**22.77**	**25.05**

Note:

1. Reserves shown here are for continued economic operation of the Trintes Field plus Bayfield's work-over and side-track programme.

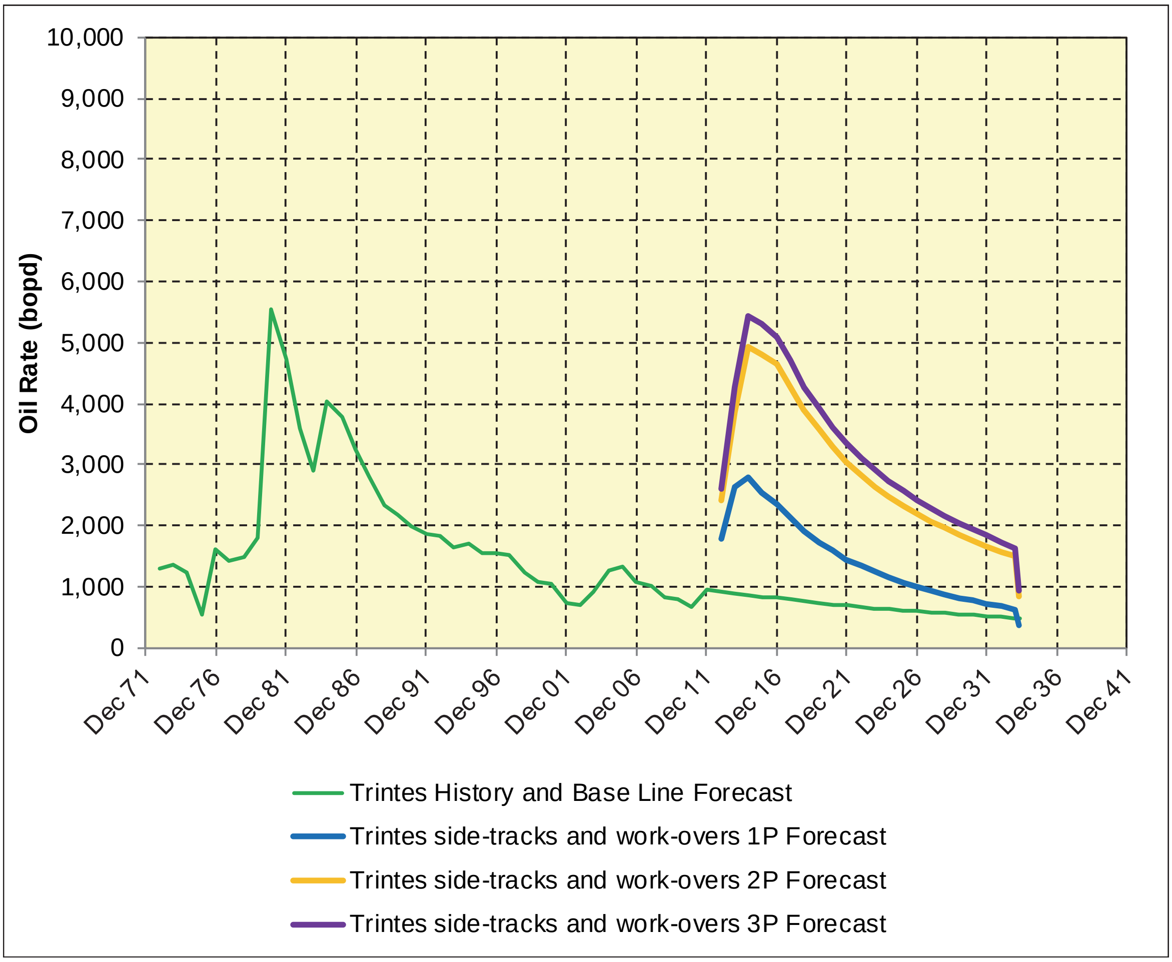
1.3.5 Facilities and Production Forecasts

It is estimated that the total remaining capital expenditure for the Trintes Field facilities upgrade is US$19.2 MM. Planned drilling expenditure, excluding extensions, but including all planned work-overs and side-tracks within the main field, is estimated to total US$38.6 MM post mid-2012.

Figure 1.12 illustrates the historical oil production rate from the Trintes Field since start-up in 1972, together with the end-2010 forecast of continued production without further developments. Also shown are the Proved, Proved plus Probable and Proved plus Probable plus Possible forecasts for the Trintes field, including planned work-overs and side-tracks.

FIGURE 1.12

TRINTES FIELD HISTORICAL PRODUCTION WITH FORECASTS FOR SIDE-TRACKS AND WORK-OVERS



GCA visited the existing Trintes facilities on 30th and 31st March, 2011 prior to the issuing of the original CPR in June 2011. Both the offshore facilities and onshore facilities were observed during the visit. The overall findings were that since taking over the facilities in April, 2009, Bayfield has:

- Implemented a structured programme of structural inspection and assessment;
- Conducted a rolling programme of maintenance aimed at recovering the previous backlog of neglect and improving reliability;
- Engaged the regulator in the maintenance programme;
- Cut operating costs; and,
- Pushed ahead with a programme to redevelop wells and improve artificial lift technology.

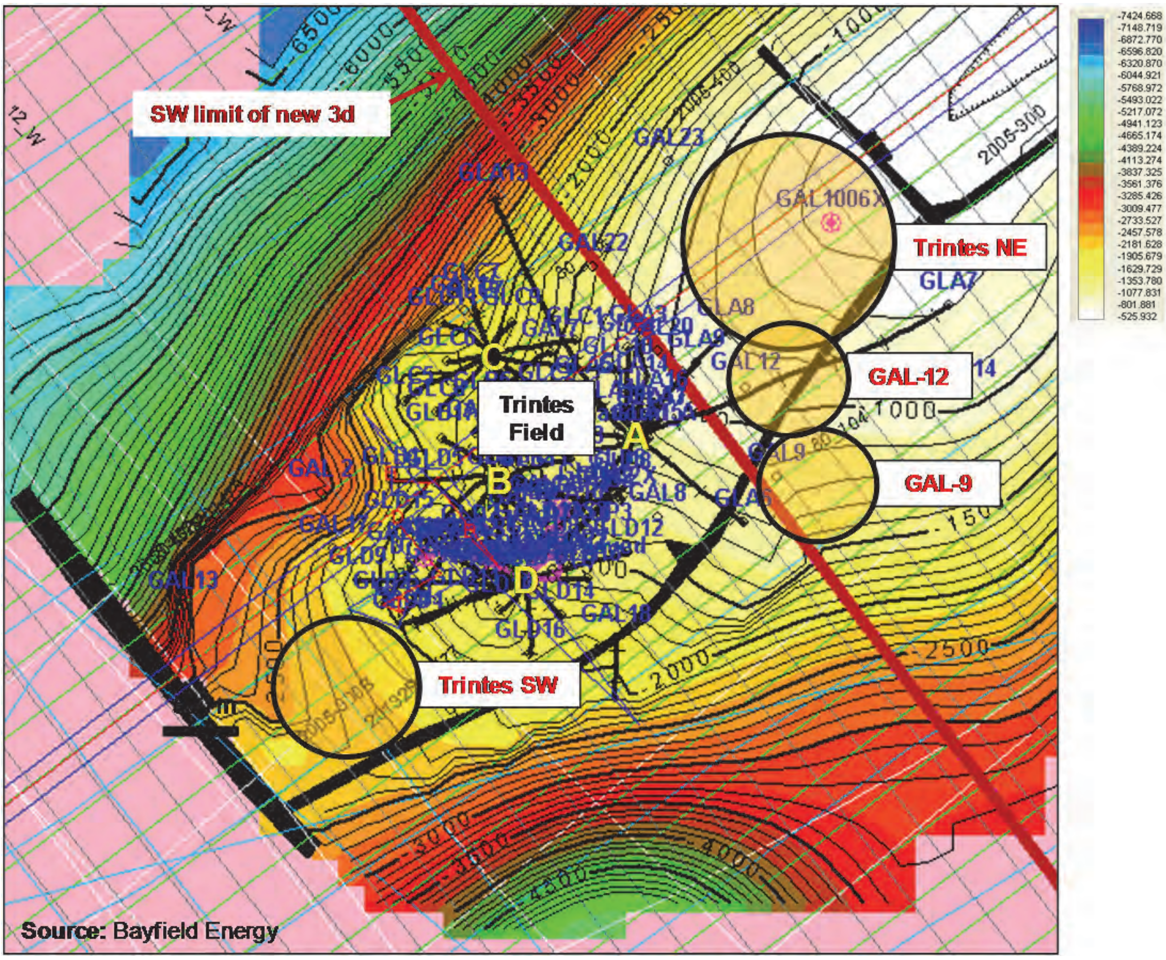
GCA was positively impressed with the individuals in the organisation as well as the co-operative culture of the company. Processes and procedures in place appeared to be comprehensive and fit for purpose. The budgets for maintenance appeared to be adequate to cover the anticipated work. Full field development was being conducted using a well-established project definition framework.

1.4 Trintes Field Extensions and Nearby Discoveries Reserves

Various extensions to the Trintes Field have been identified (Figure 1.13). These include the NE extension G and M sands, the SW extension M sand, the G and H sands intersected by GAL-9 and the H sand intersected by GAL-12.

FIGURE 1.13

TRINTES FIELD EXTENSIONS AND NEARBY DISCOVERIES



1.4.1 Trintes NE Extension G Reservoir

There is volumetric uncertainty in the in place volumes in the G sand caused by uncertainty in the limit of the reservoir in a north-easterly direction beyond the reaches of the existing Alpha platform wells. The appraisal well located furthest in a north-easterly direction, Well GAL-20, encountered 40 m of gross oil pay in the G sand. Bayfield's most recent plans to develop the G reservoir in this area, which is referred to as the NE extension (Figure 1.13), are based on extended reach drilling from the existing platform infrastructure, and two high angle Charlie platform wells are currently scheduled for drilling from April 2015 to June 2015. Proved plus Probable and Proved plus Probable plus Possible Reserves have been assigned to the planned development. No well has been drilled in this area and hence confidence in the mapped volumes is not sufficient to assign Proved Reserves. The area will be subject to further appraisal potential through the four wells planned for development of the M sand NE extension (see below), which is currently scheduled to be drilled first over the period from mid-2014 to January, 2015. Bayfield plans to bring the NE Extension G reservoir on stream in 2015.

1.4.2 Trintes NE Extension M Reservoir

There is considerable volumetric uncertainty in the in place volumes in the M sand due to uncertainty in the extent of the reservoir beyond the developed area, offering further development opportunities. Within the confines of the flanks of the anticline in a north-easterly updip direction, there is a high likelihood that oil-bearing reservoir is present beyond the reach of the Alpha platform wells. The appraisal well located furthest in a north-easterly direction, Well GAL-20, encountered 70 m of gross oil pay in the M sand, although there is the observed but not fully understood fact that the OWC becomes progressively shallower up-structure.

Bayfield's most recent plans to develop the M reservoir in this area, which again is referred to as the NE extension (Figure 1.13) are based on extended reach drilling from the Charlie platform involving four highly deviated wells scheduled over the period from June, 2014 to January, 2015. However, GCA believes it is possible that at least six wells will be required to adequately drain the structure if better than 2P determined reserves are encountered. As referenced above (Trintes NE Extension G Reservoir) the later scheduled G NE targeted wells may provide recompletion opportunities into the M reservoir in this area to enhance later life M sand recovery.

Proved plus Probable and Proved plus Probable plus Possible Reserves have been assigned to the planned development. No well has been drilled in this area and hence confidence in the volumes is not sufficient to assign Proved Reserves. It is estimated that the drilling expenditure for the development of both the M and G sands in the Trintes NE extension will amount to US$20.4 MM, comprising four extended reach wells from the Charlie platform. Bayfield plans to bring the M sand in the NE extension on stream in late 2014.

1.4.3 Trintes SW Extension M Reservoir

The limit of the M reservoir down-dip towards the south-west beyond the Delta platform has not been determined (Figure 1.13). The gross oil column in the M sand is greatest in the most south-westerly area reached by the Delta platform wells. It is likely that oil-bearing reservoir will be found in the M reservoir within the anticline in a down-dip direction. Bayfield refers to this as the SW extension. The volumetric uncertainty is brought about by the existence of the tilted OWC and the presence of oil-bearing formation in the SW extension relies on the continuation of the tilted contact in a down-dip direction. The very recent redrill of well B3 as B3RD to the M sand in the south-west of the field (June 2012) has indicated a deeper OWC than assumed previously, although mechanical problems prevented the well achieving the planned TD and penetrating the OWC. This has given rise to an improved STOIIP estimate for this sand.

Bayfield has assigned two of the four new vertical conductors planned for the Delta platform for new extended reach wells to the M sand in the SW extension area. Drilling is scheduled for September 2013 to November 2013. No plausible physical explanation has yet been put forward for the presence of the tilted contact, therefore, extrapolation of the tilted contact in a down-dip direction cannot be done with great confidence. Probable and Possible Reserves have been assigned, but no Proved Reserves. Drilling expenditure is estimated to be US$6.8 MM.

1.4.4 GAL-9 G and H Reservoirs

The GAL-9 well is located some 500 m ESE of the Alpha platform (Figure 1.13). Hydrocarbon-bearing G and H sands were intersected, but have not been developed up until now, due to the difficulty of reaching these shallow reservoirs from the platforms.

GAL-9 intersected excellent quality G sand at a depth of 162 mss. The gross interval of 24 m has a NTG ratio of 59%. The slightly deeper good quality H sand was intersected at a depth of 203 mss, with a gross interval of 17 m and NTG ratio of 89%. The well was not tested but by analogy to other Trintes wells, the G and H sands intersected by GAL-9 are expected to be oil productive. Proved, Probable and Possible Reserves have been attributed to this discovery. The areal extent of the accumulations is not well defined and is estimated to range between 0.04 km^2 and 0.3 km^2.

Bayfield's current plans to develop the G and H sands encountered in GAL-9 consist of the drilling of 2 extended reach wells from the Delta platform in late 2013 and early 2014. The drilling expenditure is estimated to be US$6.8 MM.

1.4.5 GAL-12 H Reservoir

GAL-12 is located some 430 m ENE of the Alpha platform (Figure 1.13). Good quality oil-bearing G sands encountered in this well have been developed. The H sand, intersected at a depth of 141 mss over a gross interval of 36 m with a NTG ratio of 89% has not been developed. The well was not tested but by analogy to other Trintes wells, the H sand intersected by GAL-12 is expected to be oil productive. Proved, Probable and Possible Reserves have been attributed to this discovery. The areal extent of the accumulation is not well defined and is estimated to range between 0.04 km^2 and 0.3 km^2.

Bayfield's current plans to develop the GAL-12 H sand comprise extended reach drilling of two wells from the Charlie platform over the period June 2015 to August 2015. The drilling expenditure is estimated to be US$6.8 MM.

TABLE 1.2

**TRINTES FIELD EXTENSIONS
STOIIP AND GROSS FIELD OIL RESERVES
AS AT 30th JUNE, 2012**

Reservoir	STOIIP (MMBbl)			Gross Field Reserves (MMBbl)		
	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible
Trintes NE extension M	-	19.68	30.38	-	6.63	10.10
Trintes NE extension G	-	6.49	14.84	-	2.19	5.53
Trintes SW extension M	-	4.81	13.13	-	1.70	4.49
GAL-9 G	2.38	3.57	6.75	0.38	1.22	2.90
GAL-9 H	1.44	2.35	3.32	0.23	0.88	1.58
GAL-12 H	2.88	4.69	6.64	0.38	1.72	2.03
Total	**6.70**	**41.59**	**75.06**	**0.99**	**14.34**	**26.63**

1.4.6 Facilities and Production Forecasts

Bayfield plans to meet its commitment to the work programme agreed with Petrotrin by continuing its programme of drilling extended reach side-track/high angle wells within the confines of the field. Studies performed on Bayfield's behalf have confirmed the ability to drill to all targets with identified reserves in the Trintes field area utilising modern ERD drilling technology.

The remaining facilities upgrade work scope includes:

- Charlie platform upgrades;
- Delta platform conductor installation;
- Cranes and platform process upgrades;
- Tank farm upgrades; and
- Workshop and overhauls of miscellaneous equipment.

The total remaining capital expenditure for these upgrades is US$19.2 MM.

Production forecasts are illustrated in Figure 1.14 (Proved), Figure 1.15 (Proved plus Probable) and Figure 1.16 (Proved plus Probable plus Possible). Each figure provides the relevant forecast for the Trintes field, which incorporates planned work-overs and side-tracks, together with the individual extensions and nearby discovery developments.

FIGURE 1.14

GROSS PRODUCTION FORECASTS FOR TRINTES FIELD WITH WORK-OVERS AND SIDE-TRACKS, AND DEVELOPMENT OF FIELD EXTENSIONS AND NEARBY DISCOVERIES – PROVED

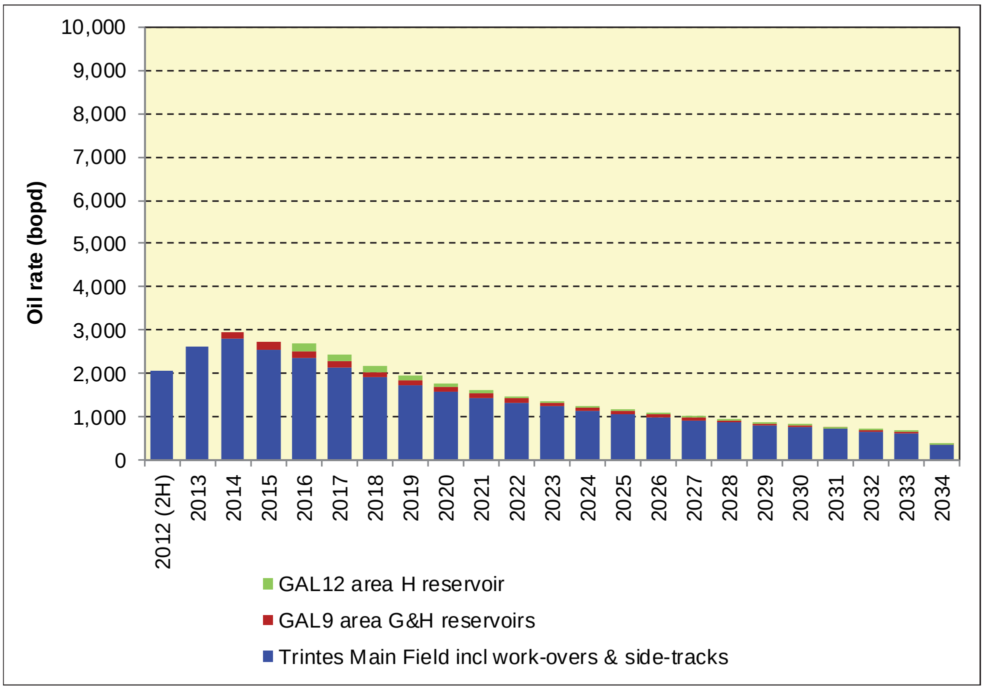


FIGURE 1.15

GROSS PRODUCTION FORECASTS FOR TRINTES FIELD WITH WORK-OVERS AND SIDE-TRACKS, AND DEVELOPMENT OF FIELD EXTENSIONS AND NEARBY DISCOVERIES – PROVED PLUS PROBABLE

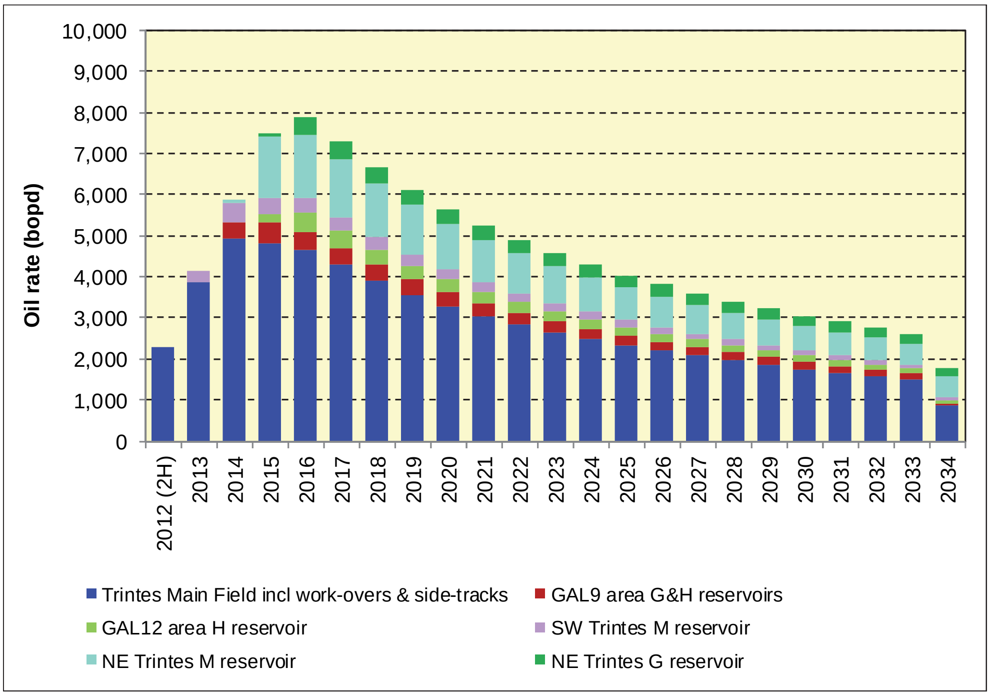
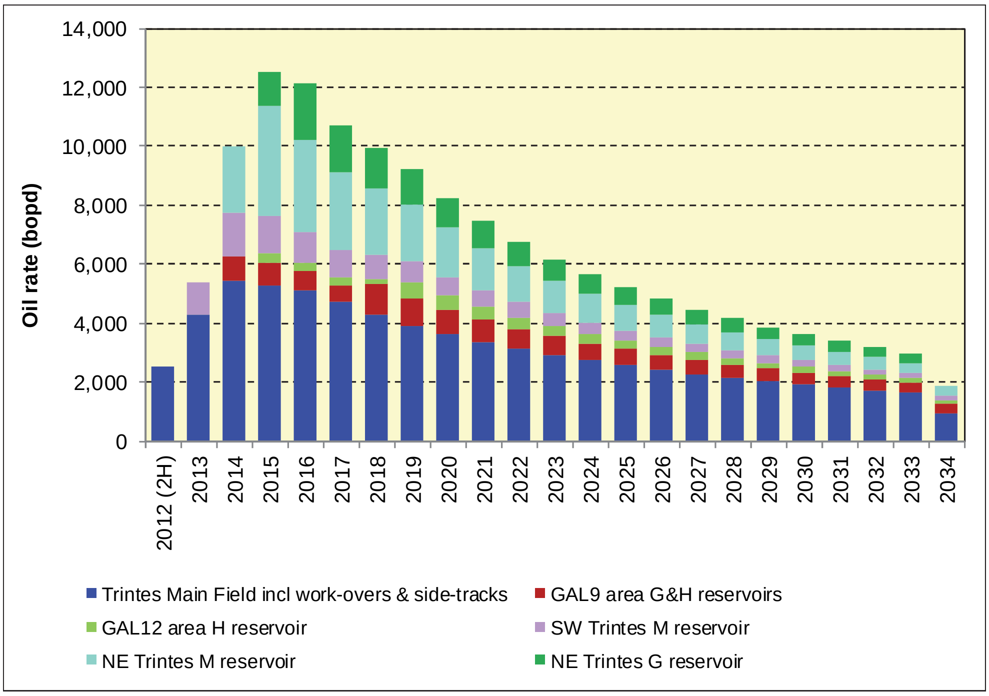


FIGURE 1.16

GROSS PRODUCTION FORECASTS FOR TRINTES FIELD WITH WORK-OVERS AND SIDE-TRACKS, AND DEVELOPMENT OF FIELD EXTENSIONS AND NEARBY DISCOVERIES – PROVED PLUS PROBABLE PLUS POSSIBLE



1.5 Galeota Contingent Resources

In the Galeota Block, six discovery wells, GAL-21, EG-1, -2, -3, -4 and -5 found stacked, oil- and gas-bearing, potential reservoir sands in separate Prospects, several of which were flow-tested, but not developed, during intermittent drilling campaigns in the 1960s to 80s. In pursuit of its plan to develop these discoveries, Bayfield began an appraisal drilling campaign in 2012, completing two wells, EG-7 (plus a side-track -7ST) and EG-8.

Well EG-7 was located in the presumed crestal area of the EG-1 discovery, but failed to find significant evidence of moveable hydrocarbons, thus removing the chance of a commercial development. Following the EG-7 well, the EG-1 Discovery has been remapped to be located in the footwall and to the north of an ENE-WSW extensional fault. This fault defines the northern trapping mechanism for the Gaby Prospect, which is dip-closed to the south.

Well EG-8 was an exploration well as it penetrated an adjacent fault block, NE of the EG-2 discovery and found additional gas, but reduced expectations oil resources compared to the pre-drill prognosis.

It is likely that the three discoveries EG-2/EG-8, EG-3 and EG-4 will be developed with four small platforms as a stand-alone cluster. The GAL-21 updip discovery is likely to be developed with a caisson structure tied back to the Trintes field.

Bayfield has based its Contingent and Prospective Resource expectations upon revised mapping of its 2010 3D seismic survey tied to recent wells EG-7, -7ST and EG-8. Discoveries and Prospects can be classified into two distinct structural styles:

- The Trintes field is located in the hanging wall of a south-verging thrust fault with additional stratigraphic trapping; the GAL-21 and EG-4 Discoveries and the South Trintes, GAL-26/25 and Thais Prospects appear to be similarly controlled.

- The EG-2/EG-8 Discovery and the Gaby, Tatiana and Denise Prospects are extensional features located in the footwalls and hanging walls of listric faults that are generally orthogonal to the south-verging thrusts.

Bayfield has several exploration and appraisal well commitments remaining in the Galeota Block, which is divided to reflect this drilling commitment into ‘Block A’ around the Trintes field and ‘Block B’ for the remainder of the block to the east. In Block A the two commitment exploration wells are likely to be drilled on the NE Trintes and South Trintes Prospects, with an expected appraisal commitment well on the former. In Block B the three exploration and appraisal well commitments are likely to be two exploration wells on the Denise (EG-9) and Gaby Prospects and an appraisal well on the EG-4 discovery.

The appraisal wells should reduce the range of uncertainty in the Discoveries, whilst the exploration wells will test compressional or extensional Prospects. Development of the discoveries is contingent on the outcome of the appraisal programme, which will influence the selection of the final field development concept. Development is also contingent on approval of the development plans by Bayfield’s partner, Petrotrin.

1.5.1 EG-2/EG-8 Contingent Resources

The EG-2 Discovery (see Figure 1.17) comprises a small, fault and dip closed high mapped at the EG2-E reservoir level, using the Oil-Down-To (ODT) of -1,094 m in the well to define the Low Case or 1C resource estimate, -1,189 m for the High Case or 3C and a mid-point contour at -1,128 m as the 2C case. The structure is a fault-bounded terrace with dip closure to the NNW at the 2C and 3C levels and dip closure to the west at the 1C level only.

The 1978 EG-2 well tested oil at 1,096 bopd in the lower half of the 38 m gross, E reservoir interval (top EG2-E mapped at 1,055 mss) and gas plus condensate in the F, G and H sand intervals within the underlying ca. 300 m thick section. Interpretation of the drill stem pressure data from the oil test is complicated by two-phase flow, which may indicate a retrograde condensate. A down-dip appraisal/exploration well, EG-5 drilled ca. 1 km to the NNW within the EG-2 fault block in 1985, intersected dry gas at the G reservoir level, but was otherwise wet.

The EG-2 fault block is the penultimate fault block in down-stepping terraces formed by antithetic faults to the major listric fault located to the south-west. The EG-8 fault-block is located adjacent and to the east of the EG-2 fault block and was penetrated by the EG-8 well which intersected up to nine potential gas sands and one potential oil sand reservoirs, some of which can be correlated with the -E, -G and -H sands in the EG-2 well. The tested oil sand in EG-2 is interpreted by Bayfield to be present in the EG-8 well albeit in overbank, non-reservoir facies. A shallower sand interpreted by Bayfield as LaSv-N1 (see Figures 1.18 and 1.19) is mapped at ca. 975 mss and following MDT sampling is interpreted to have the capacity to produce at ca. 1,000 bopd of undersaturated oil.

FIGURE 1.17

EG-E DEPTH MAP SHOWING THE EG-2 DISCOVERY

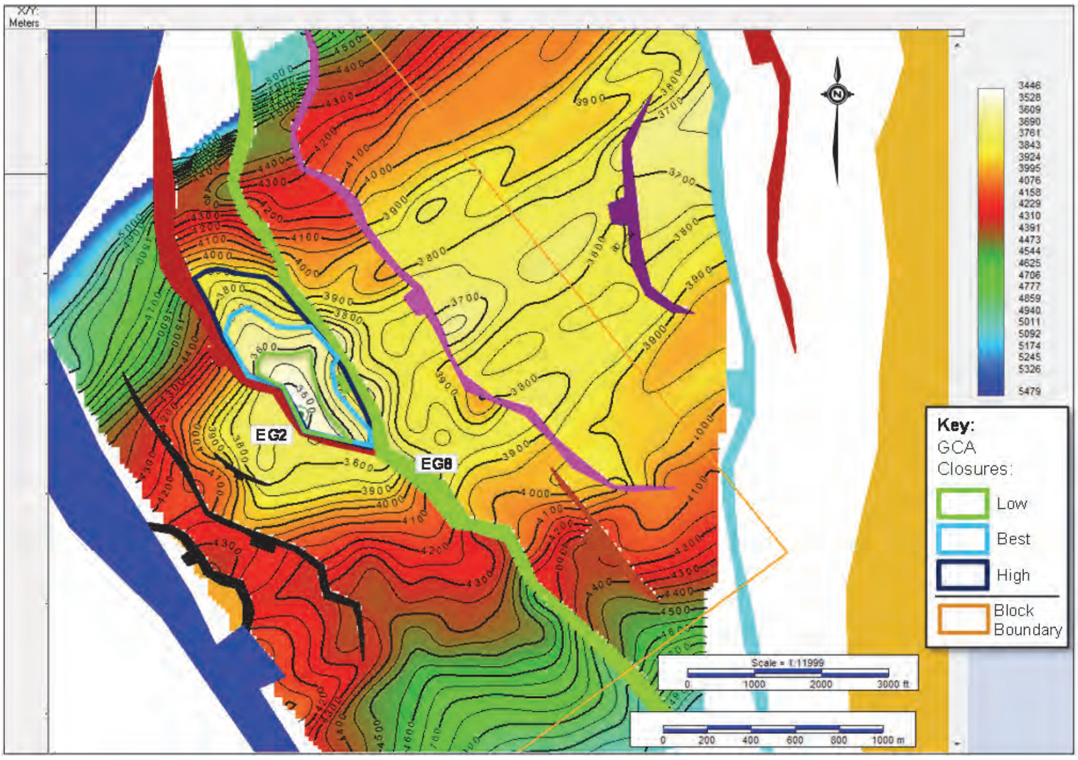


FIGURE 1.18

TOP LASV-N1 DEPTH STRUCTURE MAP WITH EG8 DISCOVERY

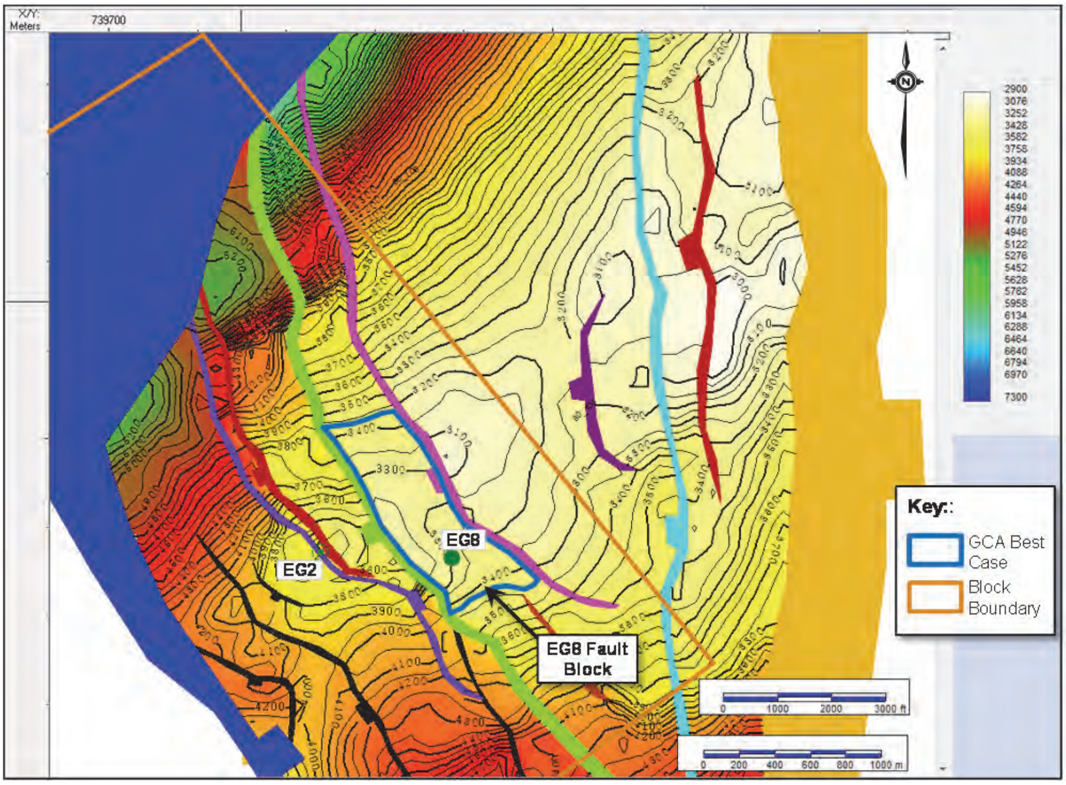
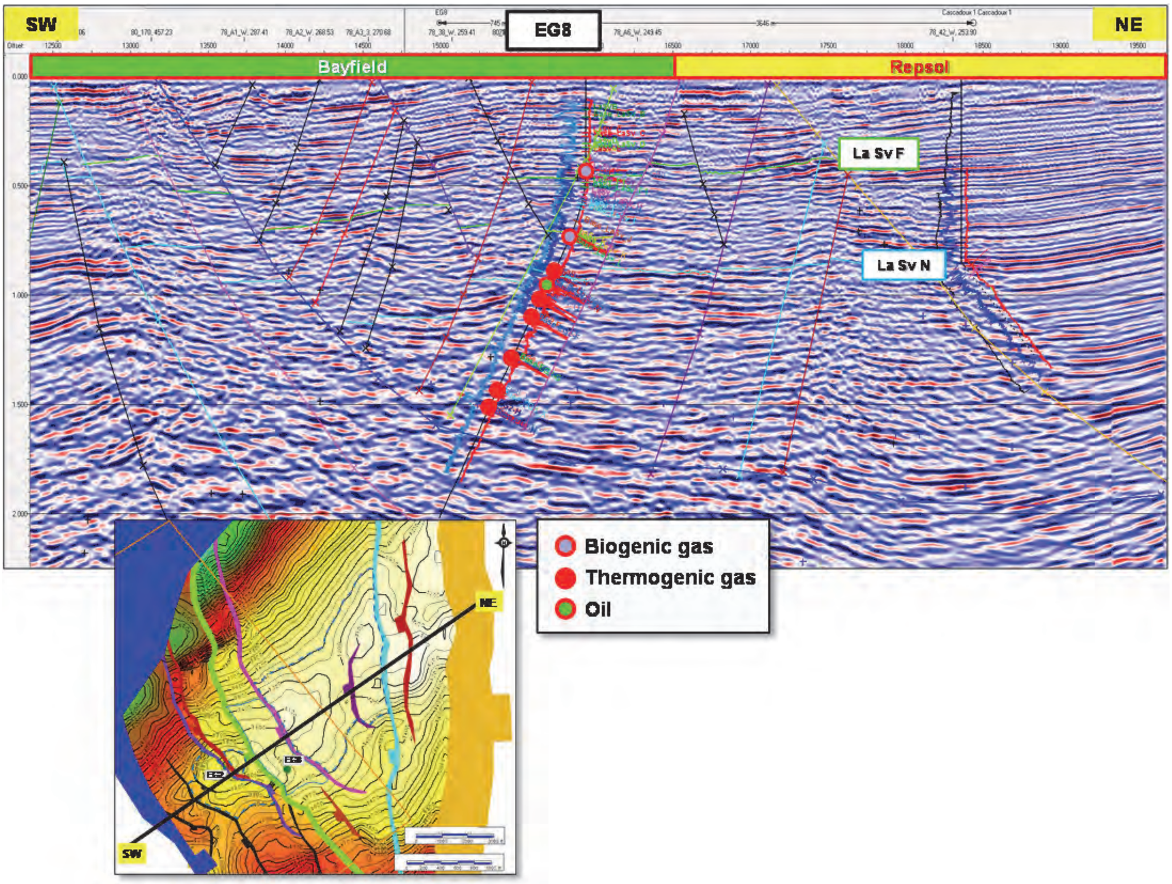


FIGURE 1.19

SEISMIC SECTION THROUGH THE EG-8 WELL



Oil and gas in place estimates have been made for eight of the nine gas sands in EG-8, one of the three gas sands in EG-2 and both of the separate oil sands in each well. There is not yet any unequivocal evidence for pressure communication between the two fault blocks, but Bayfield are understood to be considering a joint development. Tables 1.3 and 1.4 present the in place and recoverable hydrocarbon estimates for each sand.

TABLE 1.3

EAST GALEOTA DISCOVERY EG-2/EG-8
STOIIP AND GROSS FIELD OIL CONTINGENT RESOURCES
AS AT 30th JUNE, 2012

Reservoir	STOIIP (MMBbl)			Gross Field Contingent Resources (MMBbl)		
	Low	Best	High	1C	2C	3C
LaSv-N1	4.53	6.30	8.56	0.91	1.89	3.42
E	1.58	3.08	5.22	0.31	0.92	2.09
Total	**6.11**	**9.38**	**13.78**	**1.22**	**2.81**	**5.51**

TABLE 1.4

EAST GALEOTA DISCOVERY EG-2/EG-8
GIIP AND GROSS FIELD GAS CONTINGENT RESOURCES
AS AT 30th JUNE, 2012

Reservoir	GIIP (Bscf)			Gross Field Contingent Resources (Bscf)		
	Low	Best	High	1C	2C	3C
LaSv-F	0.36	0.50	0.66	0.22	0.35	0.53
LaSv-K & L	0.91	1.75	2.72	0.55	1.23	2.18
LaSv-N	0.50	0.72	0.99	0.30	0.50	0.79
LaSv-O	3.05	4.62	6.66	1.83	3.23	5.33
F	3.04	4.31	5.88	1.82	3.02	4.70
G	3.80	5.15	6.81	2.28	3.61	5.45
H	15.52	24.56	35.62	9.31	17.19	28.50
Total	**14.34**	**41.61**	**28.77**	**16.31**	**29.13**	**47.48**

1.5.2 EG-3 Contingent Resources

The 1978 discovery well EG-3, intersected three oil- and two gas-charged sands (A, B, C, D and E), but following remapping and reinterpretation of the DST data, only the B sand (12.2 MMscfd plus 38 bcpd) and C sand (1,770 bopd) are interpreted by Bayfield as having the potential for development. However, the C sand DST 3 is questionable as the bottom hole flowing pressure declined during the test, which could indicate depletion and thus restricted areal extent of the reservoir, although the formation may have been damaged by invasion of over-balanced drilling fluid.

The gas-bearing B sand was intersected at a depth of 1,406 mss over a gross interval of 9 m with a NTG ratio of 68% and permeability interpreted from the test of 33 mD.

The oil-bearing C sand was encountered at a depth of 1,452 mss with a NTG ratio of 85% and permeability interpreted from the test on the order of 450 mD. The water saturation at the top of the interval is approximately 40%, but increases toward the base. This could be interpreted as a transition zone above an OWC within a few metres of the base of the sand penetrated by the well.

Using the reprocessed 1999 3D survey, Bayfield originally interpreted the EG-3 structure as a fault-dip closure in the footwall of a NE-SW aligned, listric fault (Figure 1.20). However, the NW-SE seismic line from the better quality 2010 3D survey shows the Thais Prospect and EG-3 Discovery as ramping thrust folds, verging to the SE. A more plausible explanation of the greater EG-3 structure might be as a positive flower structure, especially as the orientation of the 'listric fault' is orthogonal to the regional transpression resulting from E-W, dextral wrenching.

Bayfield's structural mapping of the EG-3 C and B reservoir intervals is based upon a marker horizon at EG-3-O1 approximately 300 m shallower than the uppermost B reservoir horizon. The resultant 4-way dip closed EG-3 structure is used to estimate areal closure at the EG3-C (oil) and -B (gas) reservoir levels.

Tables 1.5 and 1.6 present the in place and recoverable hydrocarbon estimates for the B and C sands.

FIGURE 1.20

EG-3 DISCOVERY: THAIS A MARKER STRUCTURE MAP

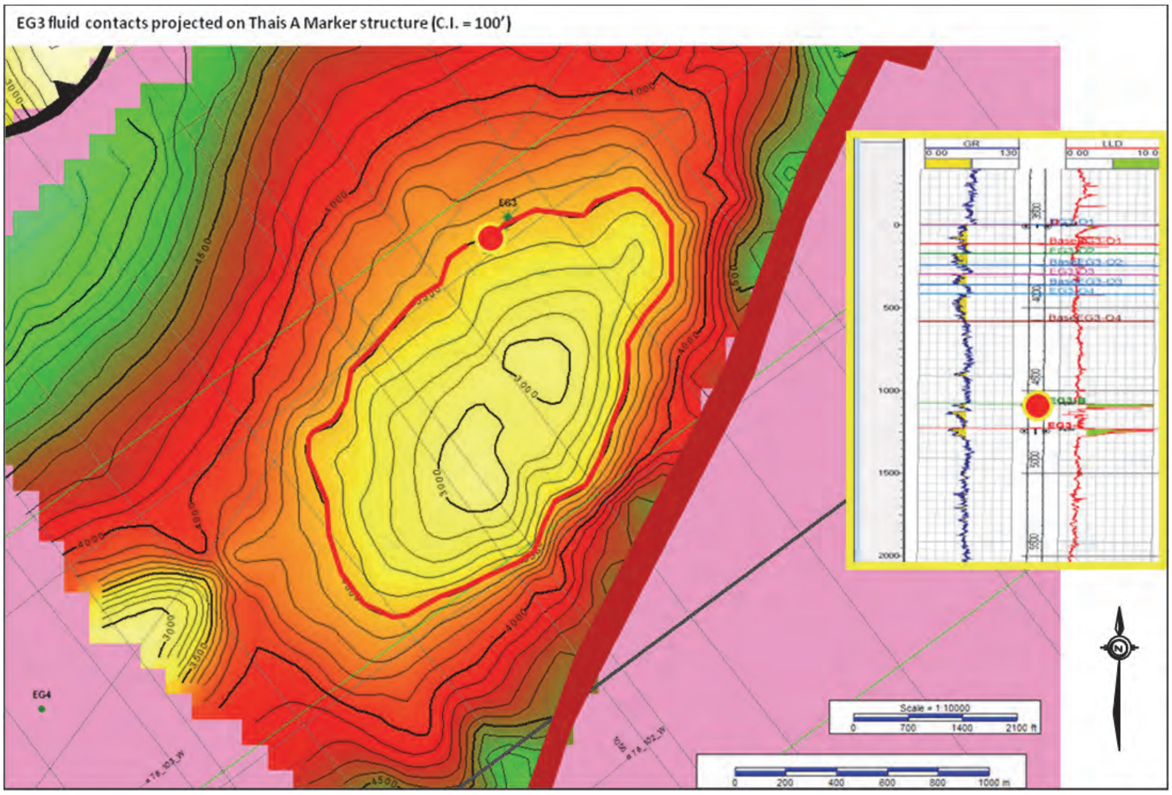


TABLE 1.5

EAST GALEOTA DISCOVERY EG-3
STOIIP AND GROSS FIELD OIL CONTINGENT RESOURCES
AS AT 30th JUNE, 2012

Reservoir	STOIIP (MMBbl)			Gross Field Contingent Resources (MMBbl)		
	Low	Best	High	1C	2C	3C
C	7.79	11.12	15.20	1.92	3.26	5.09
Total	**7.79**	**11.12**	**15.20**	**1.92**	**3.26**	**5.09**

TABLE 1.6

EAST GALEOTA DISCOVERY EG-3
GIIP AND GROSS FIELD GAS CONTINGENT RESOURCES
AS AT 30th JUNE, 2012

Reservoir	GIIP (Bscf)			Gross Field Contingent Resources (Bscf)		
	Low	Best	High	1C	2C	3C
B	4.68	6.69	9.18	3.15	4.65	6.58
Total	**4.68**	**6.69**	**9.18**	**3.15**	**4.65**	**6.58**

1.5.3 EG-4 Contingent Resources

The 1979 EG-4 discovery well is located in what is now interpreted as a down-dip location on the eastern flank of a thrust-fold anticline, which verges to the SE. This structural interpretation differs from an earlier version, which fault-closed the structure to the SW. The current structural interpretation now includes the old, 'wet' well GAL-5 within Bayfield's dip-closed area, as the GAL-5 well has been reinterpreted to include a 14 m gross hydrocarbon column at the base of the O sand, i.e. an ODT at -908 mss.

The Top O Structure map (Figure 1.21) has been used as the basis for areal closure estimation for the deeper reservoirs G and F. The overlying N mapping horizon has been used for defining top structure at the E sand level and to create isopach surfaces for the overlying D, C, B and A sands.

Well EG-4 penetrated a series of stacked, thin, poorly developed deltaic sands, each of 10 to 20 m gross thickness. Of the three drill-stem tests that were carried out, only the deepest sand 'G' produced at measurable rates. The overlying A, B, C, D and F sands are hydrocarbon-bearing, but were either not tested or had failed tests, consistent with low permeability sands.

The A sand, intersected at a depth of 208 mss, is present over a gross interval of 20 m with NTG ratio of 56%. The B sand, intersected at a depth of 278 mss, is present over a gross interval of 14 m with NTG ratio of 46%. The C sand, intersected at a depth of 378 mss, is present over a gross interval of 10 m with NTG ratio of 70%. None of these intervals was flow tested, but wireline logs and several sidewall cores in each sand interval indicate that the sands have reasonable porosity and permeability and are oil-bearing.

The D sand, intersected at a depth of 460 mss, is present over a gross interval of 15 m with NTG ratio of 76%. The interval was flow tested but only small volumes of gas were recorded at surface. Wireline logs and sidewall cores indicate the formation to be possibly oil-bearing, but with low permeability. The E sand was intersected at a depth of 506 mss. Wireline resistivity log character suggests that hydrocarbons are present. A single sidewall core shows traces of fluorescence. The F sand, intersected at a depth of 828 mss over a gross interval of 44 m with NTG ratio of 38%, was flow tested. A weak blow at surface was observed before the well loaded and died. Interpretation of the flow test data indicates a low permeability formation. Traces of oil were observed in reverse circulated cushion fluid.

The G sand was intersected at a depth of 886 mss. The total package has a gross interval of 67 m. An OWC was intersected at 908 m giving gross pay of 22 m with NTG ratio of around 80%. The interval was flow tested and flowed at a maximum rate of 200 bopd. Permeability from the test data is interpreted to be approximately 45 mD.

Low recovery factors of 10% (in the 1C case), 15% (in the 2C case) and 25% (in the 3C case) have been input to a probabilistic assessment of recoverable hydrocarbons from the reservoir sands to account for the generally poor quality reservoirs.

An appraisal well, informally named Carolina, will be drilled at a crestal location according to current mapping, approximately mid-way between EG-4 and GAL-5. Tables 1.7 and 1.8 present the in place and recoverable hydrocarbon estimates for each sand.

FIGURE 1.21

EG-4 DISCOVERY: TOP O STRUCTURE MAP

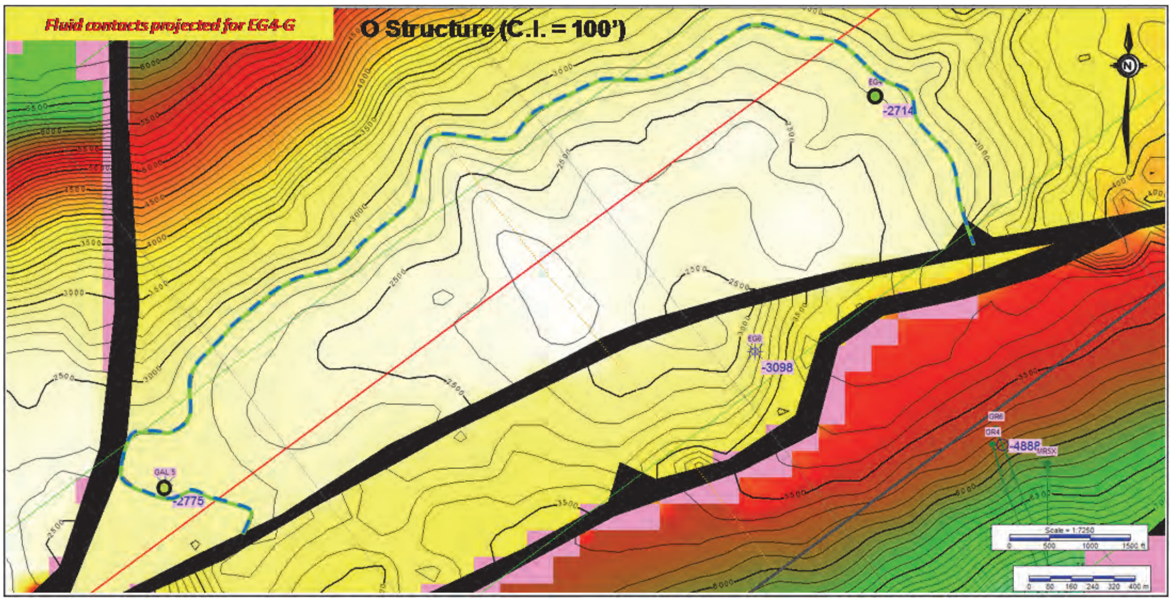


TABLE 1.7

**EAST GALEOTA DISCOVERY EG-4
STOIIP AND GROSS FIELD OIL CONTINGENT RESOURCES
AS AT 30th JUNE, 2012**

Reservoir	STOIIP (MMBbl)			Gross Field Contingent Resources (MMBbl)		
	Low	Best	High	1C	2C	3C
A	8.58	11.92	15.79	1.52	2.33	3.39
B	5.33	8.01	11.21	0.96	1.57	2.39
C	5.69	7.59	9.87	0.71	1.48	2.45
D	10.74	14.47	18.81	1.89	2.85	4.08
E	28.57	59.45	93.25	5.30	11.55	19.47
F	20.18	27.89	36.74	3.56	5.46	7.93
G	18.55	24.21	30.85	4.23	5.98	8.15
Total	**97.63**	**153.53**	**216.52**	**18.17**	**31.23**	**47.85**

TABLE 1.8

**EAST GALEOTA DISCOVERY EG-4
GIIP AND GROSS FIELD GAS CONTINGENT RESOURCES
AS AT 30th JUNE, 2012**

Reservoir	GIIP (Bscf)			Gross Field Contingent Resources (Bscf)		
	Low	Best	High	1C	2C	3C
A (solution gas)	-	-	-	0.08	0.12	0.17
B (solution gas)	-	-	-	0.07	0.12	0.18
C (solution gas)	-	-	-	0.07	0.15	0.25
D (solution gas)	-	-	-	0.25	0.37	0.53
E (solution gas)				0.76	1.66	2.80
F (solution gas)	-	-	-	0.90	1.38	2.00
G (solution gas)	-	-	-	1.07	1.51	2.05
Total	**-**	**-**	**-**	**3.19**	**5.31**	**7.99**

Note:

1. No GIIP volumes are reported for solution gas.

1.5.4 GAL-21 Contingent Resources

The 1976 GAL-21 discovery is located at the western end of the Galeota lease to the west of the Trintes field. The structure is a very steep, thrust-fold anticline, illustrated by four orthogonal seismic lines, which also show clear evidence of a gas chimney in the crestal area of what appears to be a positive flower structure. Bayfield's structural mapping (Figure 1.22) reflects the interpretation of a thrust-fold, bounded to the SW by the thrust, to the west by a listric fault and dip-closed to the NW and west.

GAL-21 encountered shows in sidewall cores from thin sands designated C and D, which have been interpreted by Bayfield as providing evidence for gas and oil, respectively, although neither interval was tested. The gamma ray and neutron-density logs indicate similar, fining-upward profiles and the induction logs are almost identical therefore not definitive with respect to hydrocarbon phase.

The C sand was intersected at a depth of 363 mss over a gross interval of 13 m, with NTG ratio of 60%. The underlying D sand was intersected at a depth of 403 mss over a gross interval of 8 m with a NTG ratio of 65%.

Appraisal well GAL-24, drilled 250 m updip of GAL-21 according to Bayfield's "Near Top GAL21-A Structure" mapping and within 100 m of the bounding thrust fault, experienced a three week gas blow-out at the projected depth of the C gas sand. No wireline logs were recovered from the GAL-24 well.

Gas and oil Contingent Resources have been assigned to the C and D sands respectively. The accumulations cover an area of approximately 1.0 km^2. Tables 1.5 and 1.6 present the in place and recoverable hydrocarbon estimates for the C and D sands.

FIGURE 1.22

GAL-21 DISCOVERY: NEAR TOP GAL21-A STRUCTURE MAP

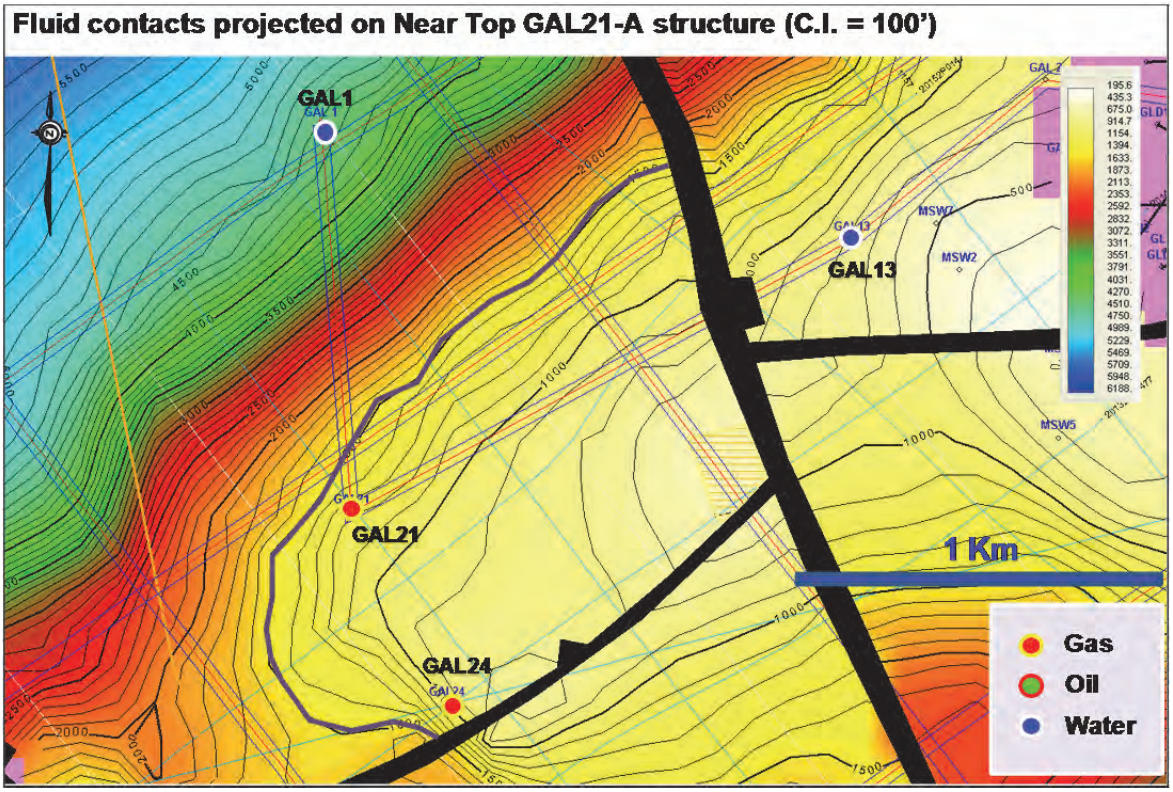


TABLE 1.9

**GAL-21 DISCOVERY
STOIIP AND GROSS FIELD OIL CONTINGENT RESOURCES
AS AT 30th JUNE, 2012**

Reservoir	STOIIP (MMBbl)			Gross Field Contingent Resources (MMBbl)		
	Low	Best	High	1C	2C	3C
D	4.39	4.95	5.51	0.44	0.96	1.65
Total	**4.39**	**4.95**	**5.51**	**0.44**	**0.96**	**1.65**

TABLE 1.10

**GAL-21 DISCOVERY
GIIP AND GROSS FIELD GAS CONTINGENT RESOURCES
AS AT 30th JUNE, 2012**

Reservoir	GIIP (Bscf)			Gross Field Contingent Resources (Bscf)		
	Low	Best	High	1C	2C	3C
C	1.10	1.21	1.32	0.66	0.85	1.05
Total	**1.10**	**1.21**	**1.32**	**0.66**	**0.84**	**1.05**

1.5.5 Conceptual Development Plan for Contingent Resources

Bayfield has drawn up a conceptual development plan for the discoveries in the Galeota Block (EG-3, EG-2/EG-8, EG-4 and GAL-21), which consists of five structures. These comprise:

- A 9-slot drilling and production platform for EG-3;
- The hub of the new developments: a 20-slot platform with a skid mounted drilling rig and processing facilities at EG-2/EG-8, where all production from the new developments will be processed and then exported through a new pipeline;
- Two 20-slot well head platforms for EG-4, each with a skid mounted drilling rig installed; and
- A 3-slot braced caisson connected back to the Trintes Delta platform for GAL-21 updip.

The GAL-21 updip planned wells will be drilled by a jack-up rig, the other platforms utilising installed skid mounted drilling rigs. The fluids produced from GAL-21 updip will be processed through, and exported from the Trintes facilities.

The development scheme is still provisional; however, the execution plan for the EG-3, EG-2/EG-8, EG-4 development is based around:

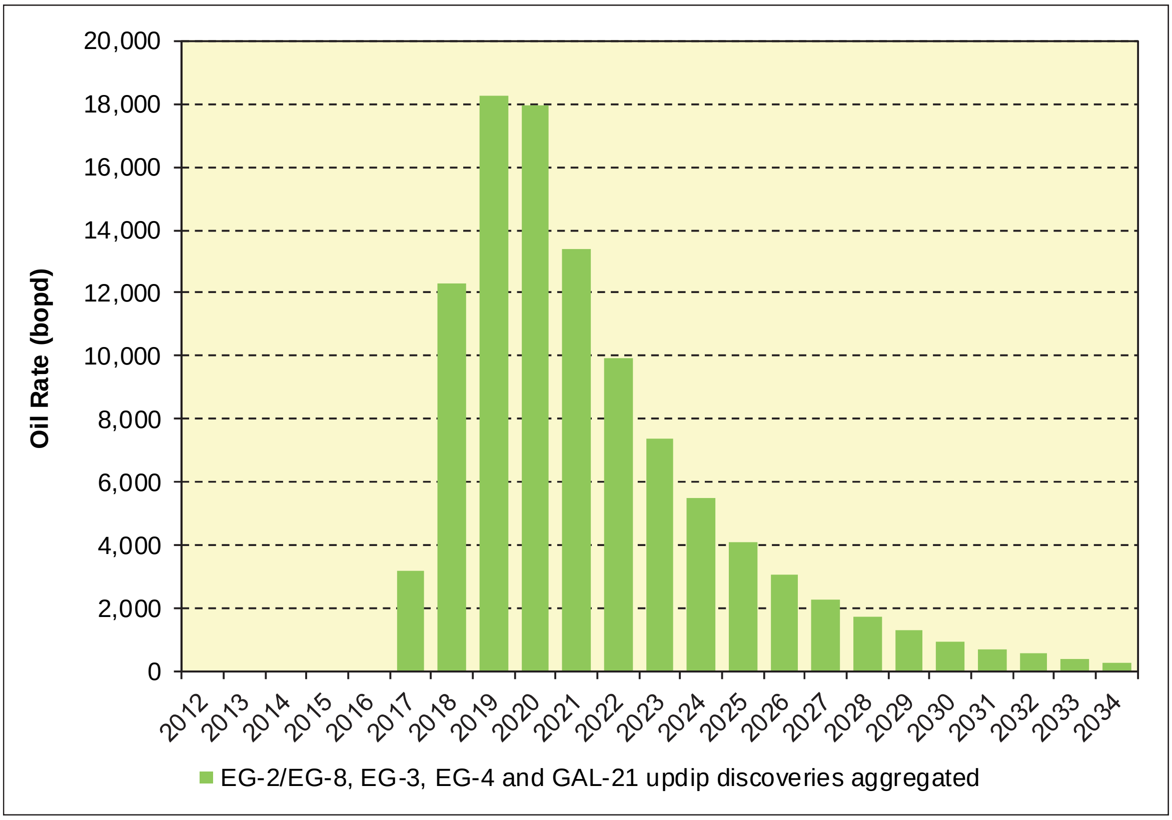
- All the platforms, pipelines, and subsea electric cables will be installed using a single mobilization of a derrick barge;
- Oil and gas export pipelines will be laid from the hub area, EG-2/EG-8;
- The maximum available throughput capacity will be 20,000 bopd;
- The trunk lines will be routed such that all platforms are within 3.5 km of the tees provided for tie-in;
- All oil producing wells will be artificially lifted by electric submersible pumps, the costs of which have been included in the drilling and completion cost estimates;
- A separate subsea electric cable will be installed from EG-2/EG-8 to each platform;
- A single mobilization of a lay barge to install the flow-line and electrical cables spread is planned;
- Electric cable will be installed at the same time as pipelines with hook-up by diving support vessel (DSV) included in the spread;
- All derrick and lay barge spreads will be mobilized from Gulf of Mexico; and
- All platform fabrication will be on US Gulf coast with barge and tug transport to Trinidad. However, the option of using fabrication yards in Trinidad will be considered to achieve the most cost effective development.

GCA has reviewed the conceptual development plan and associated costs, Class 5 estimates (+/- 50%). At this stage of the plan’s definition, GCA considers it to be fit-for-purpose for assessing Contingent Resources. While no detailed cost breakdowns were provided, GCA considers that the cost estimates fall within the range of outcome costs to be expected for the type of facilities planned. However, given that the costs have been prepared on the basis of studies, and that no firm quotations have been made available, GCA has included a contingency allowance of 20%, considered reasonable for early-stage cost estimates such as these. The total facilities expenditure for development of EG-2/EG-8, EG-3 EG-4 and GAL-21 updip is estimated to be US$219 MM excluding the 20% contingency, and drilling expenditure is estimated to be US$226 MM.

GCA has prepared a production forecast based on the conceptual development plan currently proposed by Bayfield. This forecast, which is presented at the 2C level only (Figure 1.23), includes development of all of the aforementioned areas (EG-3, EG-2/EG-8, EG-4 and GAL-21 updip) according to the currently scheduled drilling sequence. This forecast is presented on a gross and unrisked basis and thus takes no account of the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve.

FIGURE 1.23

GROSS UNRISKED PRODUCTION FORECAST FOR 2C CONTINGENT RESOURCES



1.6 Galeota Prospective Resources

Prospective Resources in the Galeota lease can be classified as (a) updip potential associated with wet reservoir intervals penetrated in down-dip wells, and (b), undrilled structures within the proven compression or extensional plays.

1.6.1 NE Trintes

Bayfield's structural interpretation of the North East Trintes Prospect is based upon the 2008 re-processed 3D survey, acquired by Petrotrin in 1999. NE Trintes appears to be the updip, crestal area of the same thrust-fold anticline that forms, along with stratigraphic elements, the trapping mechanism for the Trintes field.

The NE Trintes Prospect is the crestal anticlinal area up-structure and fault-separated from the Trintes platforms area (Figures 1.24 and 1.25). The main prospective reservoirs are the M and N sands as the younger reservoir sands in the Trintes Field have been eroded over the crest of the anticline. Over 600 m of good quality M and N reservoir sand has been penetrated in nearby wells, e.g. GAL-5. The effectiveness of top seal is the primary geological risk factor with this Prospect.

FIGURE 1.24

NE TRINTES PROSPECT: TOP O DEPTH STRUCTURE MAP

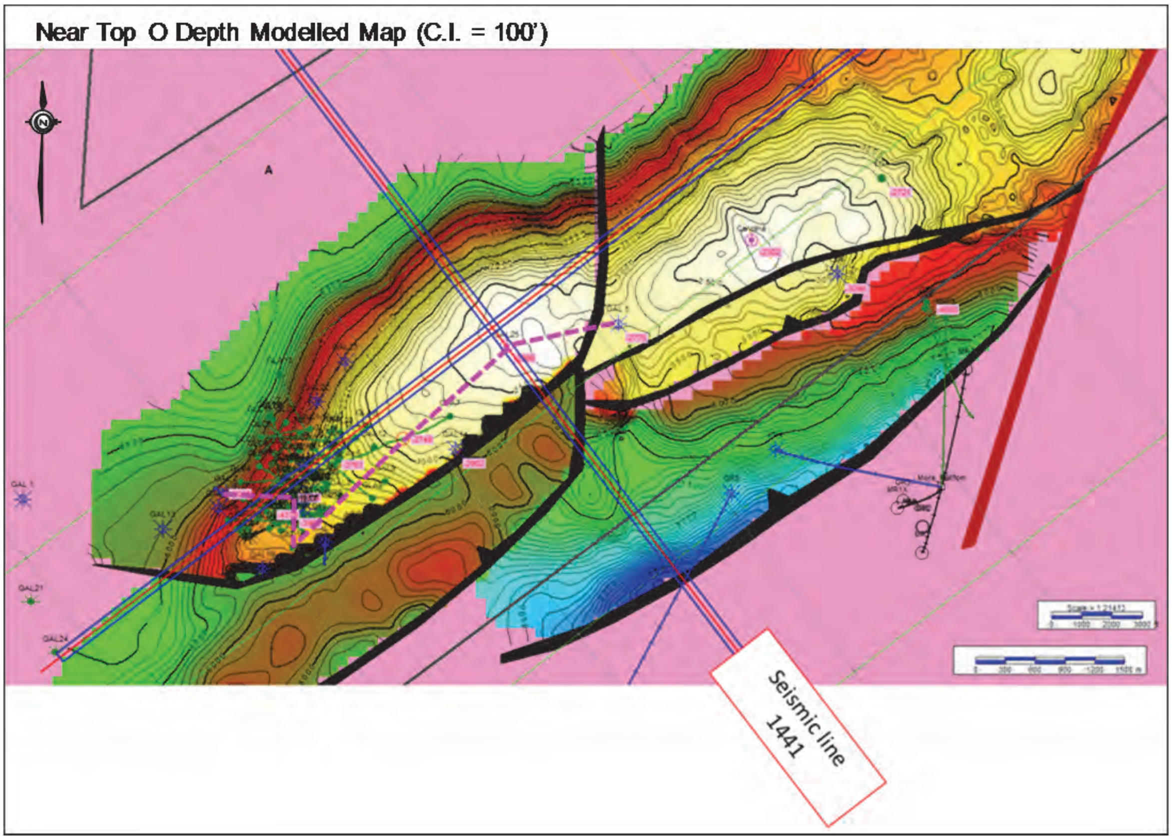


FIGURE 1.25

NE TRINTES SEISMIC LINE 1441

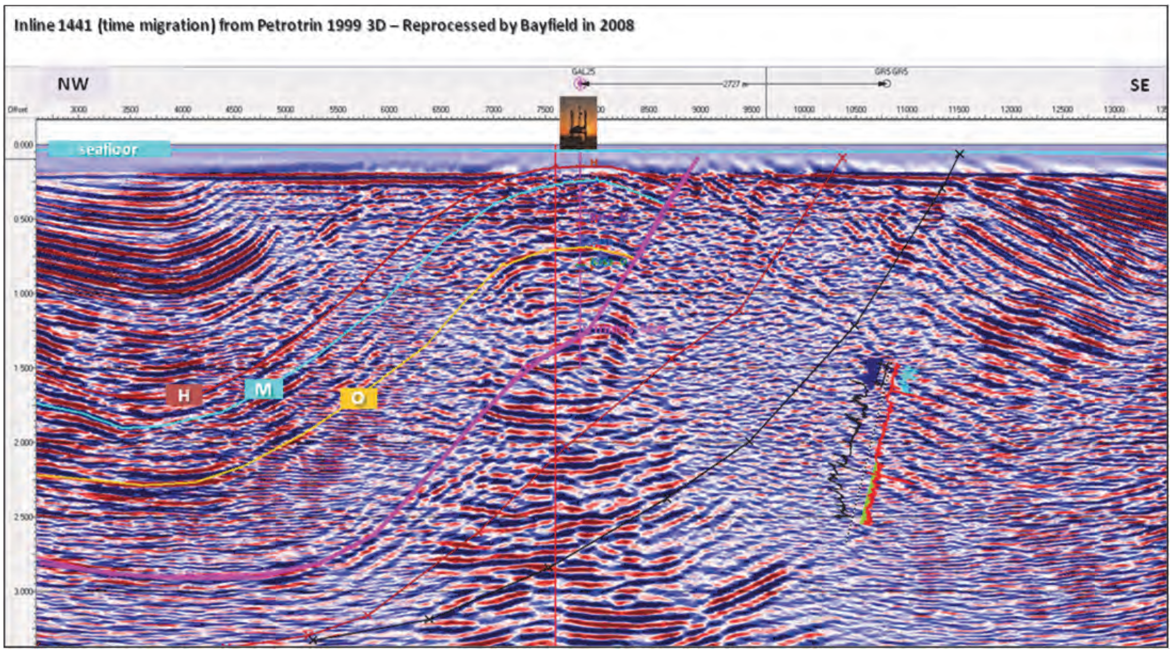


TABLE 1.11

NORTH EAST TRINTES
STOIIP AND GROSS FIELD OIL PROSPECTIVE RESOURCES
AS AT 30th JUNE, 2012

Prospect	Interval	STOIIP (MMBbl)			Gross Field Prospective Resources (MMBbl)			GCoS (%)
		Low	Best	High	Low	Best	High	
NE Trintes	H3	11.86	21.96	33.46	3.39	6.51	10.25	39
	M	23.56	66.26	111.72	7.04	12.96	24.13	41
	N	6.63	18.81	31.93	1.92	5.55	9.77	17

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked".

1.6.2 South Trintes Prospect

The South Trintes Prospect is located about 2 km to the SE of the main Trintes field (Figures 1.1 and 1.26) and comprises an anticline formed above a thrust fault probably resulting from late-stage compression during the Pleistocene (Figure 1.2). The South Trintes Prospect is located in the footwall of the main Trintes thrust fault, which controls the Trintes anticline, therefore, the prospective targets are considered to be deeper, repeat sections of the over-thrust Trintes field's F, F1, G, H0 and M sands (Figure 1.27). A stratigraphic trapping component is also noted, with an updip shale-out of the reservoir invoked in the F, F1 and H0 reservoirs.

As is often the case with compressional structures, the Prospect is poorly imaged by the seismic data and structural uncertainties remain; thus the primary risk factors for the South Trintes Prospect are trap and seal effectiveness. All of the target horizons have been analysed as oil-bearing, which is reasonable given the proximity of the Prospect to the Trintes field.

FIGURE 1.26

SOUTH TRINTES PROSPECT: M SAND STRUCTURE MAP

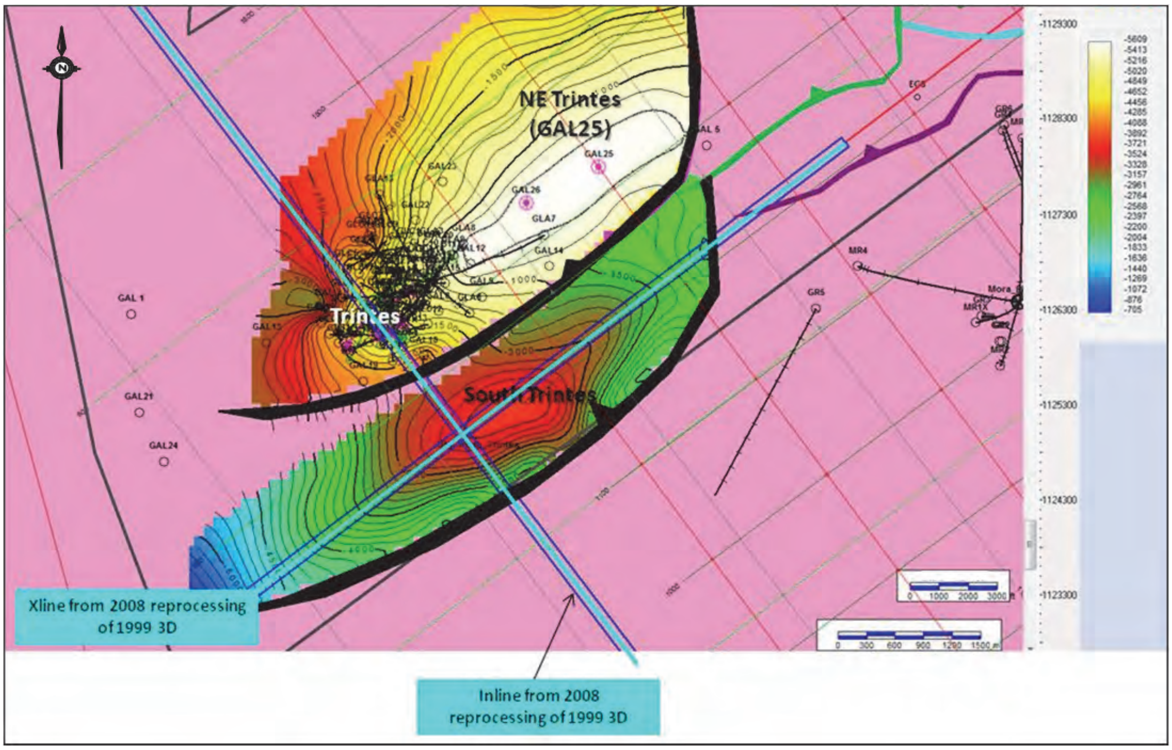


FIGURE 1.27

SOUTH TRINTES INLINE 1283

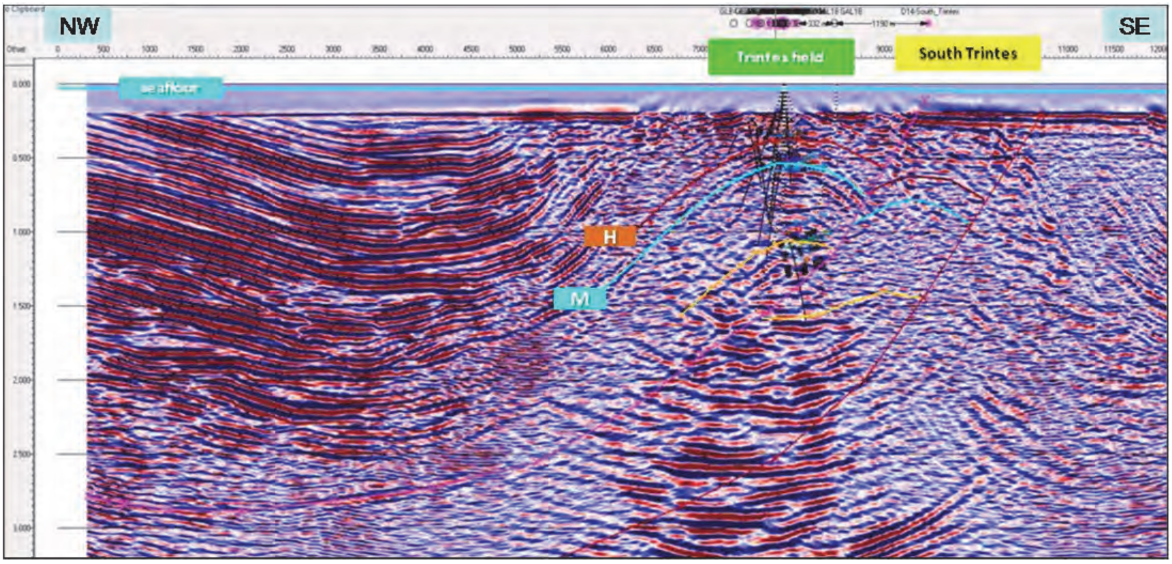


TABLE 1.12

SOUTH TRINTES
STOIIP AND GROSS FIELD OIL PROSPECTIVE RESOURCES
AS AT 30th JUNE, 2012

Prospect	Interval	STOIIP (MMBbl)			Gross Field Prospective Resources (MMBbl)			GCoS (%)
		Low	Best	High	Low	Best	High	
South Trintes	F	4.88	8.29	12.21	1.23	2.41	4.00	7
	F1	2.99	5.09	7.55	0.76	1.48	2.48	7
	G	2.76	4.61	6.89	0.69	1.33	2.27	10
	H0	1.70	3.06	4.96	0.43	0.88	1.60	7
	M	22.00	37.84	57.99	5.58	10.96	18.94	8

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are “Unrisked”.

1.6.3 GAL-21 Updip Prospect

Below the C and D hydrocarbon-bearing sands, GAL-21 encountered two very well-developed sand intervals, both water-bearing. Bayfield has labelled these B and A sands. Potential exists for significant volumes of hydrocarbons to be trapped updip against the bounding fault separating the GAL-21 area from the SW extremity of the Trintes Field (Figures 1.28 and 1.29). In GAL-21, the A sand was encountered at a depth of 492 mss with a potential gross sandstone package of several hundred metres. The B sand was encountered in GAL-21 at a depth of 954 mss also with a gross interval of 100 m or more. The prospective area lies updip of GAL-21 where the A and B sands could potentially be hydrocarbon-bearing over an estimated area ranging from 0.2 to 0.9 km^2.

The presence of reservoir, hydrocarbon source and timing are not considered to be significant geological risk factors. The greatest risk is that trap and seal may not be present or effective.

FIGURE 1.28

GAL-21 UPDIP PROSPECT: NEAR TOP GAL21-A STRUCTURE MAP

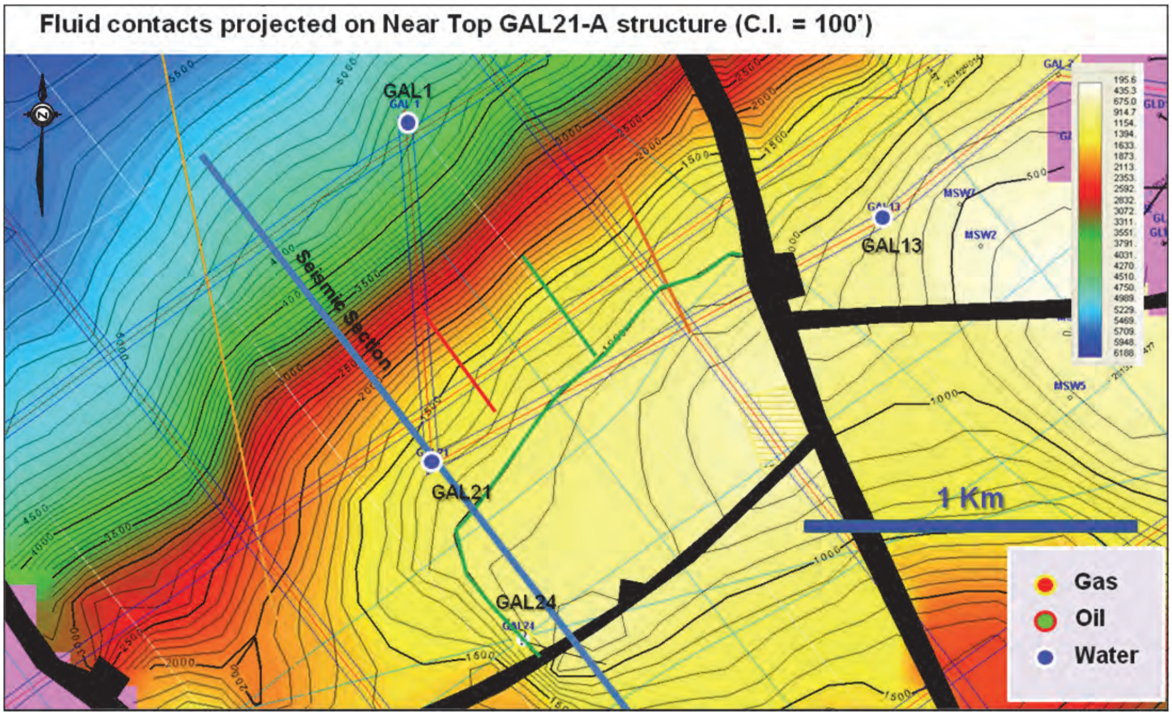
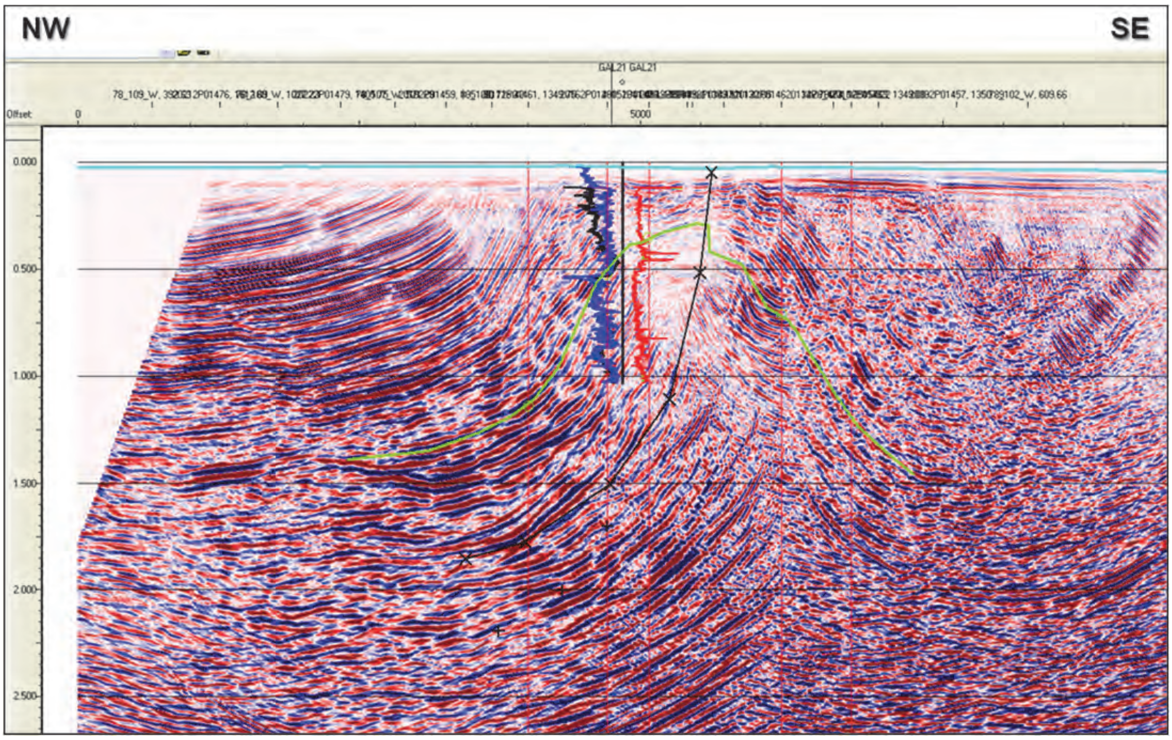


FIGURE 1.29

GAL-21 UPDIP SEISMIC SECTION



1.6.4 Thais Prospect

The Thais Prospect (formerly EG3 NW) is located about 5 km to the NW of well EG-3 (Figure 1.1) and comprises a thrust-fold anticline verging to the SE, thus fault-closed in this direction, dip-closed to the north and west with additional listric fault closure to the east (Figures 1.30 and 1.31).

The principal target reservoirs are the EG3 -O1, -O2, -O3, -O4, -C and -B sands. There is uncertainty as to the fluid type, albeit all except the EG3-B sand are expected to be oil- rather than gas-bearing.

FIGURE 1.30

THAIS PROSPECT: THAIS A SEISMIC MARKER MAP

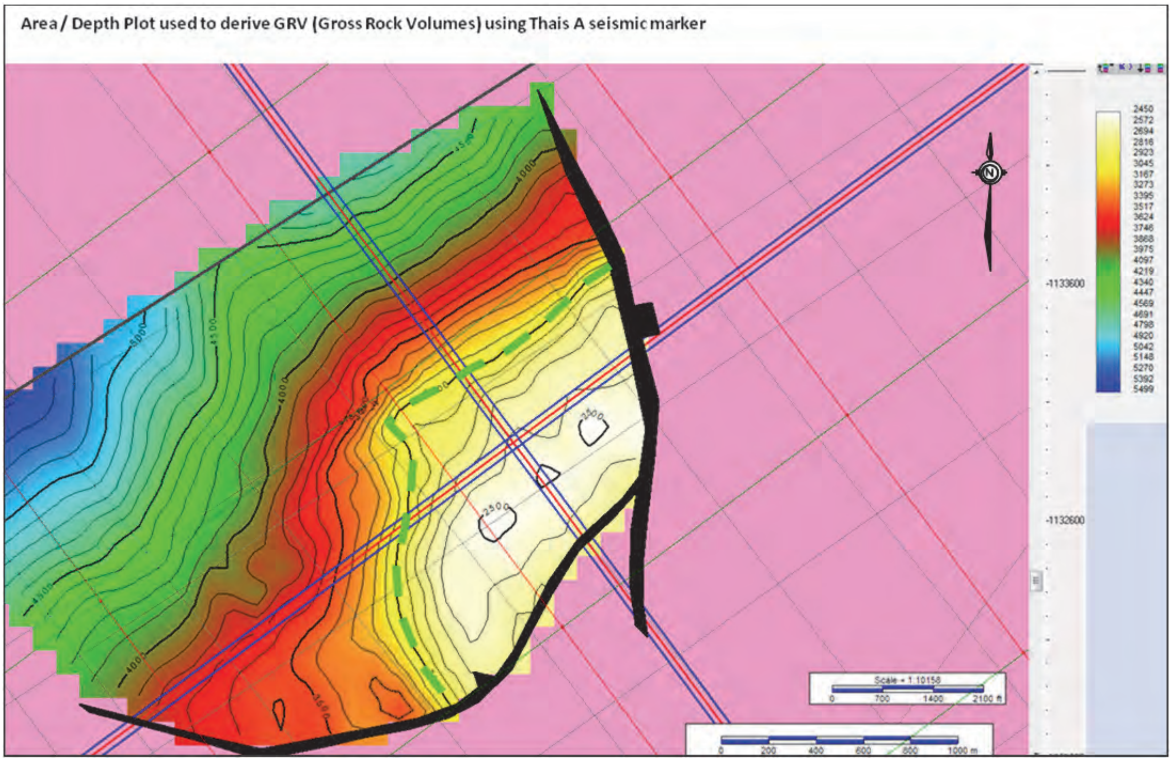


FIGURE 1.31

THAIS AND EG-3 SEISMIC SECTION

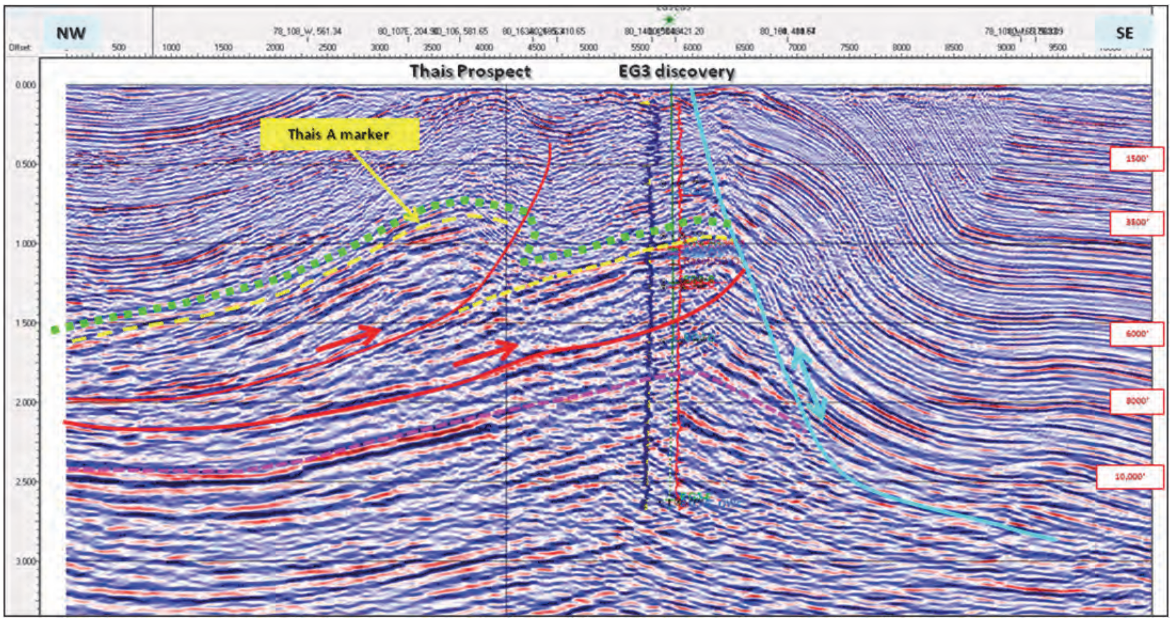


TABLE 1.13

THAIS (EG-3 NORTHWEST)
STOIIP AND GROSS FIELD OIL PROSPECTIVE RESOURCES
AS AT 30th JUNE, 2012

Prospect	Interval	STOIIP (MMBbl)			Gross Field Prospective Resources (MMBbl)			GCoS (%)
		Low	Best	High	Low	Best	High	
Thais	O1	12.51	18.26	24.80	3.07	5.36	8.31	10
	O2	13.19	19.16	25.84	3.23	5.60	8.71	18
	O3	8.85	12.90	17.44	2.17	3.76	5.84	18
	O4	20.83	30.39	41.11	5.13	8.86	13.77	17
	C	6.15	9.02	12.27	1.52	2.64	4.09	17

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked".

TABLE 1.14

THAIS (EG-3 NORTHWEST)
GIIP AND GROSS FIELD GAS PROSPECTIVE RESOURCES
AS AT 30th JUNE, 2012

Prospect	Interval	GIIP (Bscf)			Gross Field Prospective Resources (Bscf)			GCoS (%)
		Low	Best	High	Low	Best	High	
Thais	B	4.71	6.92	9.53	3.19	4.81	6.82	17

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked".

1.6.5 EG-3 Updip Prospect

Hydrocarbons were encountered in the E sand package which was intersected at a depth of 3,426 mss in EG-3. The gross interval is approximately 60 m thick, but very little if any net pay is evident. The interval was tested but mechanical problems were encountered.

Despite the mechanical problems, all indications are that the formation has extremely low permeability. Well EG-3 was not drilled at the crest of the structure so there is potential for hydrocarbon accumulation updip of the well.

The primary geological risk factor is the presence of satisfactory quality reservoir in the O1, O2, O3, O4 and EG-3E target sands. Figure 1.32 displays the EG-3 structure on the Thais A marker horizon.

FIGURE 1.32

EG-3 UPDIP PROSPECT: THAIS A MARKER STRUCTURE MAP

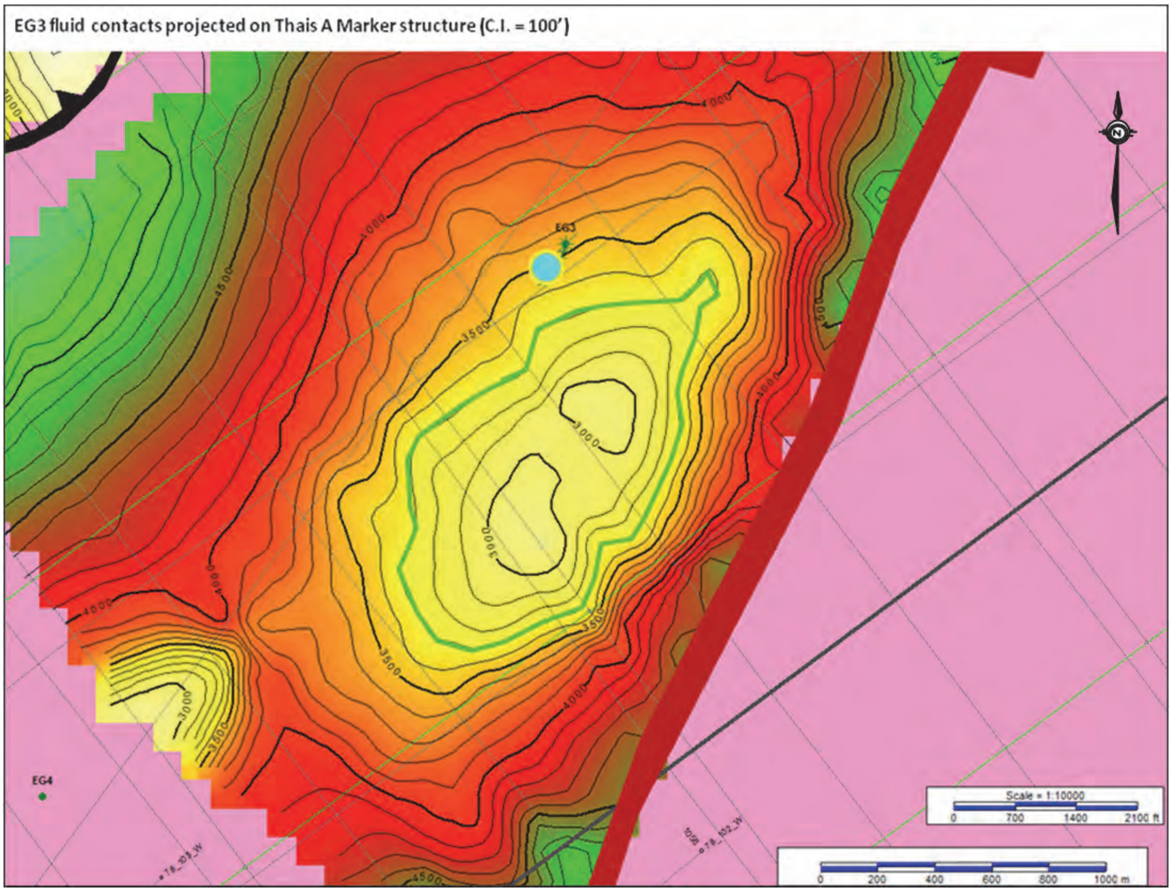


TABLE 1.15

EAST GALEOTA EG-3
STOIIP AND GROSS FIELD OIL PROSPECTIVE RESOURCES
AS AT 30th JUNE, 2012

Prospect	Interval	STOIIP (MMBbl)			Gross Field Prospective Resources (MMBbl)			GCoS (%)
		Low	Best	High	Low	Best	High	
EG-3	O1	13.59	19.86	27.03	3.34	5.82	9.04	18
	O2	9.51	13.85	18.64	2.31	4.03	6.26	32
	O3	6.42	9.34	12.61	1.57	2.74	4.23	32
	O4	15.12	22.03	29.77	3.72	6.43	10.02	31
	E	5.99	10.94	17.27	1.54	3.18	5.59	12

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are “Unrisked”.

1.6.6 EG-8 Prospect (EG-2-E Reservoir)

The EG-2-E channel sand reservoir intersected by the EG-2 well is interpreted by Bayfield to be present in EG-8, but in non-reservoir, overbank facies. Bayfield interprets a channel margin to the north of the EG-8 well and thus reservoir potential within the remainder of the EG-8 fault block; clearly reservoir presence is the most critical factor.

GCA has estimated Prospective Resources (Table 1.16) for the EG2-E reservoir. Figure 1.33 displays the EG-8 Prospect on the EG-E depth map.

FIGURE 1.33

EG-8 PROSPECT: EG-E DEPTH STRUCTURE MAP

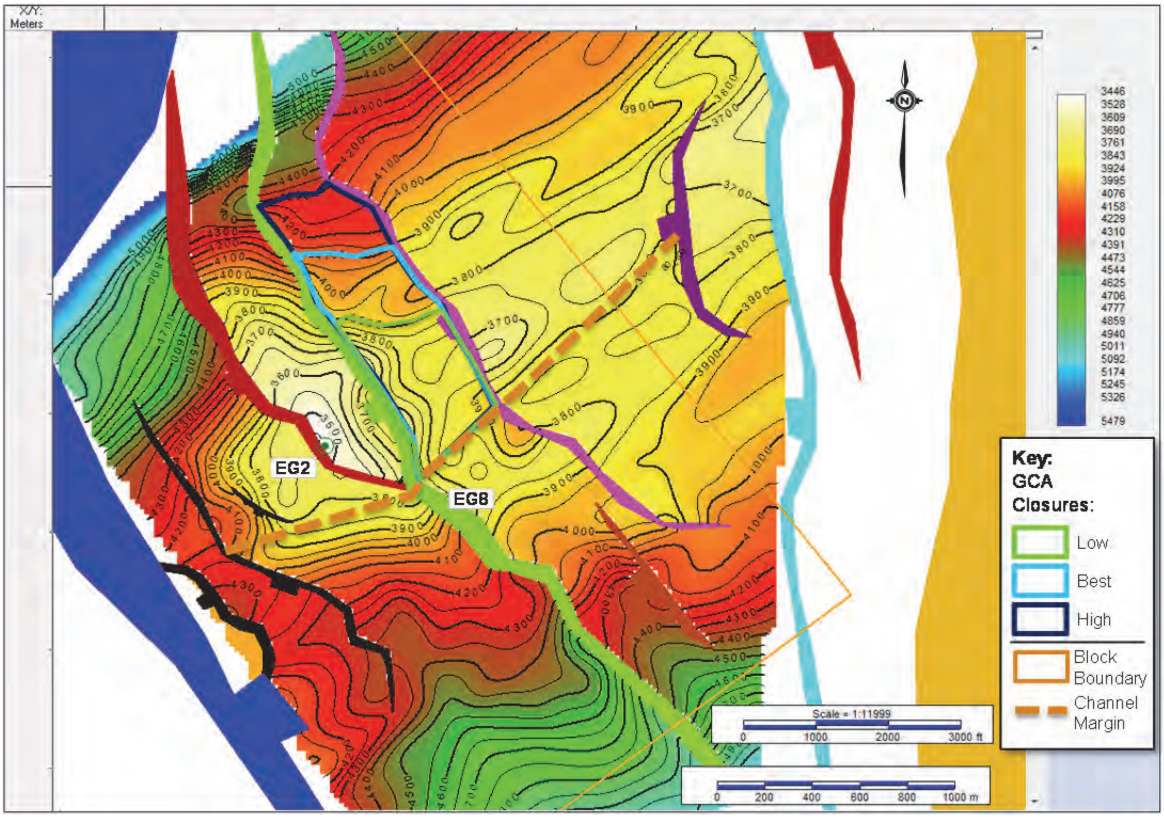


TABLE 1.16

EG8 PROSPECT, EG2-E RESERVOIR
STOIIP AND GROSS FIELD OIL PROSPECTIVE RESOURCES

Prospect	Interval	STOIIP (MMBbl)			Gross Field Prospective Resources (MMBbl)			GCoS (%)
		Low	Best	High	Low	Best	High	
EG-8	E	2.64	6.37	11.19	0.53	1.91	4.47	16

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are “Unrisked”.

1.6.7 EG-2 (LaSv-N1 Reservoir)

The oil-bearing LaSv-N1 reservoir which was intersected by the EG-8 well was not penetrated by the EG-2 well as the well crossed the block bounding fault (Figure 1.34). Bayfield, however, anticipate the reservoir to be present within the EG-2 fault block. GCA has estimated Prospective Resources (Table 1.17) for the LaSv-N1 reservoir.

TABLE 1.17

EG2 PROSPECT, LASV-N1 RESERVOIR
STOIIP AND GROSS FIELD OIL PROSPECTIVE RESOURCES

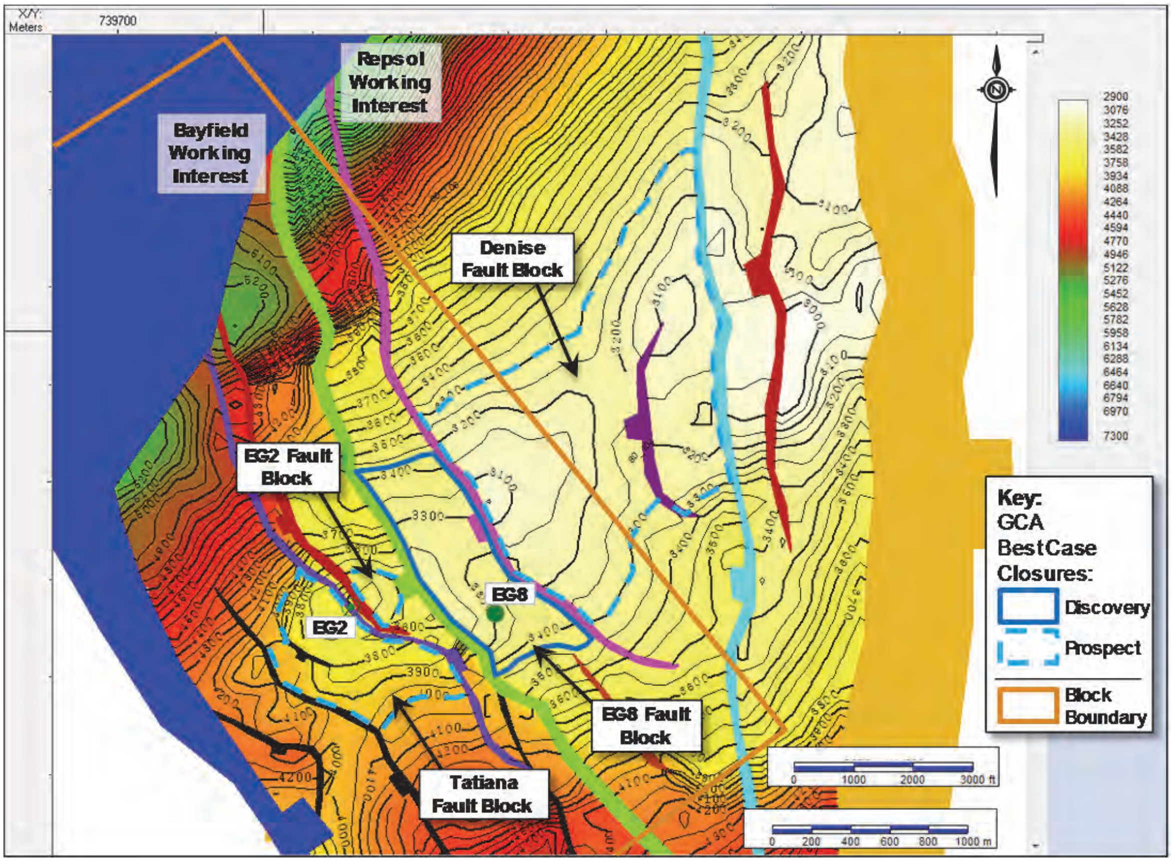
Prospect	Interval	STOIIP (MMBbl)			Gross Field Prospective Resources (MMBbl)			GCoS (%)
		Low	Best	High	Low	Best	High	
EG-2	LaSv-N1	0.18	0.35	0.61	0.04	0.10	0.24	33

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are “Unrisked”.

FIGURE 1.34

TOP LASV-N1 DEPTH STRUCTURE MAP WITH DISCOVERIES AND PROSPECTS IN THE EAST GALEOTA EG-2/EG-8 AREA



1.6.8 Tatiana Prospect

The Tatiana Prospect (Figure 1.34) is located to the west of, and adjacent to, the EG-2 fault block, within a terrace formed by antithetic faults to the major listric fault further west. Tatiana is mapped as a fault-dip closure at the shallower LaSv-N1 reservoir level, whilst at the underlying EG2-E reservoir level, an additional trapping component includes the inferred shale-out of the channel sand facies to the south. The presence of reservoir and an effective oil-prone charge carries a very low geological risk; slightly higher risk is again attached to trap and seal effectiveness due to possible cross-fault leakage updip. Table 1.18 presents GCA's estimate of Prospective Resources.

TABLE 1.18

TATIANA PROSPECT
STOIIP AND GROSS FIELD OIL PROSPECTIVE RESOURCES

Prospect	Interval	STOIIP (MMBbl)			Gross Field Prospective Resources (MMBbl)			GCoS (%)
		Low	Best	High	Low	Best	High	
Tatiana	LaSv-N1	1.20	5.95	13.33	0.24	1.78	5.33	30
	E	1.64	5.50	10.86	0.33	1.65	4.34	16

1.6.9 Denise Prospect (EG-9)

The Denise Prospect (Figure 1.34) comprises the fault-dip closure to the east of the EG-8 Discovery which extends beyond the Galeota Block boundary into adjacent acreage operated by Repsol. The Denise structure is mapped at the LaSv-N1 reservoir level as a broad terrace, dip-closed to the north and south with faulted, footwall closure to the west and hanging wall closure to the east. Prospective oil resources are estimated for the LaSv-N1 and underlying E sands (Table 1.19) with prospective gas resources estimated for the deeper H, Denise Deep and LaSv-Tbs potential reservoir levels (Table 1.20). Prospective Resources are estimated for the proportion of the Denise Prospect that is mapped within the Galeota Block and the most critical factor is trap integrity, particularly cross-fault sealing.

TABLE 1.19

DENISE PROSPECT
STOIIP AND GROSS FIELD OIL PROSPECTIVE RESOURCES

Prospect	Interval	STOIIP (MMBbl)			Gross Field Prospective Resources (MMBbl)			GCoS (%)
		Low	Best	High	Low	Best	High	
Denise	LaSv-N1	3.35	10.04	19.14	0.67	3.01	7.66	30
	E	2.90	7.99	15.15	0.58	2.40	6.06	16

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are “Unrisked”.

TABLE 1.20

DENISE PROSPECT
GIIP AND GROSS FIELD GAS PROSPECTIVE RESOURCES

Prospect	Interval	GIIP (Bscf)			Gross Field Prospective Resources (Bscf)			GCoS (%)
		Low	Best	High	Low	Best	High	
Denise	H	7.06	20.27	37.27	4.24	14.19	29.82	25
	Denise Deep	1.14	4.26	9.70	0.68	2.98	7.76	14
	LaSv-Tbs	6.12	24.94	57.97	3.67	17.46	46.38	14

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are “Unrisked”.

1.6.10 Gaby Prospect

The EG-7 and EG-7 side track were drilled in 2012 to appraise the EG-1 discovery but failed to find significant evidence of moveable hydrocarbons, effectively declassifying the EG-1 discovery as a dry hole. In light of this result, Bayfield has re-interpreted the 3D seismic survey in the EG-7 area establishing a new structural model. The new interpretation has identified the Gaby Prospect (Figures 1.35 and 1.36) in a fault bock adjacent to the EG-7 well. Five sand intervals; COS1-I, COS1-L, COS1-PA, COS1-PB and COS1-PC which were identified in both the EG-7 and COS-1 wells and interpreted as possible turbidite deposits are the target reservoirs for the Prospect.

GCA has calculated Prospective Resources (Table 1.21) for the Gaby Prospect. The main risk is trap integrity, which is believed to be the reason for lack of success in EG-7, and charge as the Prospect is located close to the EG-7 and COS-1 dry holes.

FIGURE 1.35

GABY PROSPECT: TOP COS1-I DEPTH STRUCTURE MAP

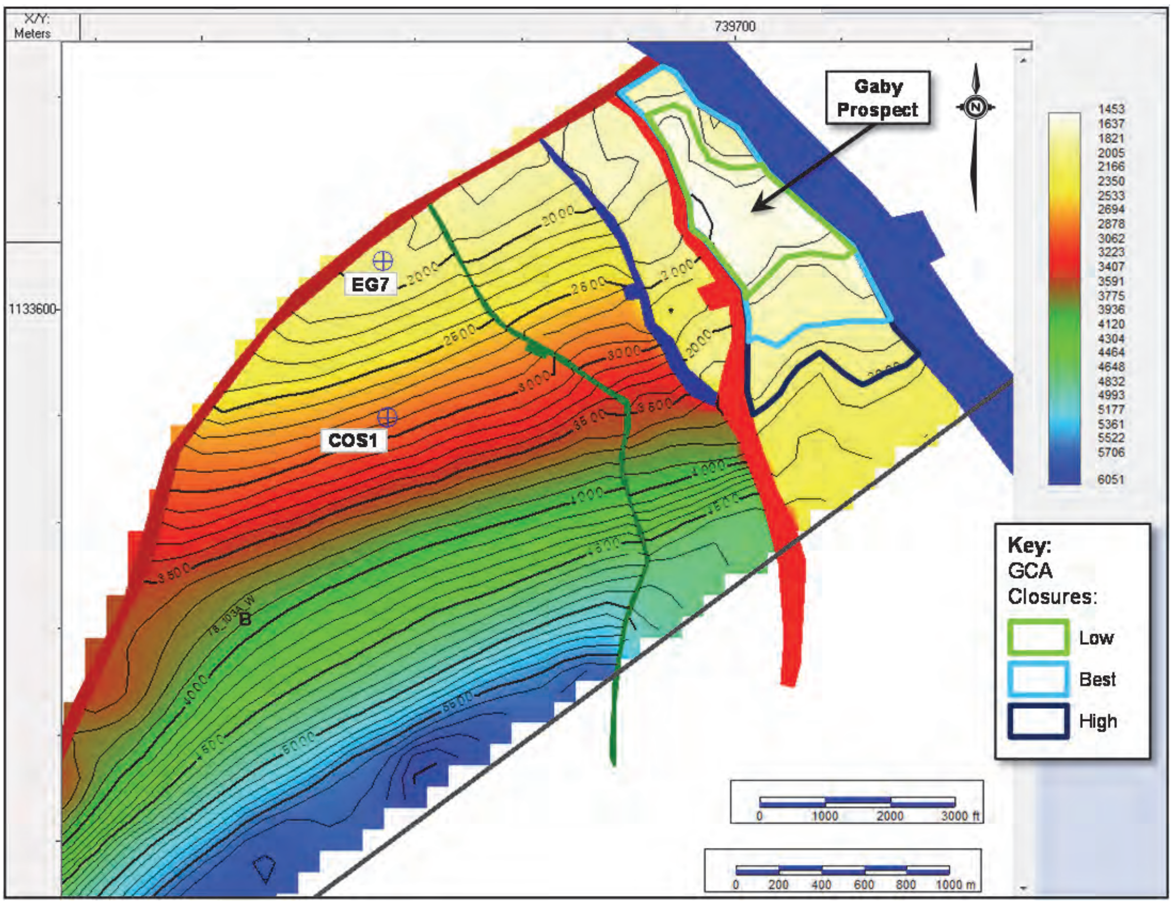


FIGURE 1.36

SEISMIC SECTION THROUGH THE EG-7 WELL AND GABY PROSPECT

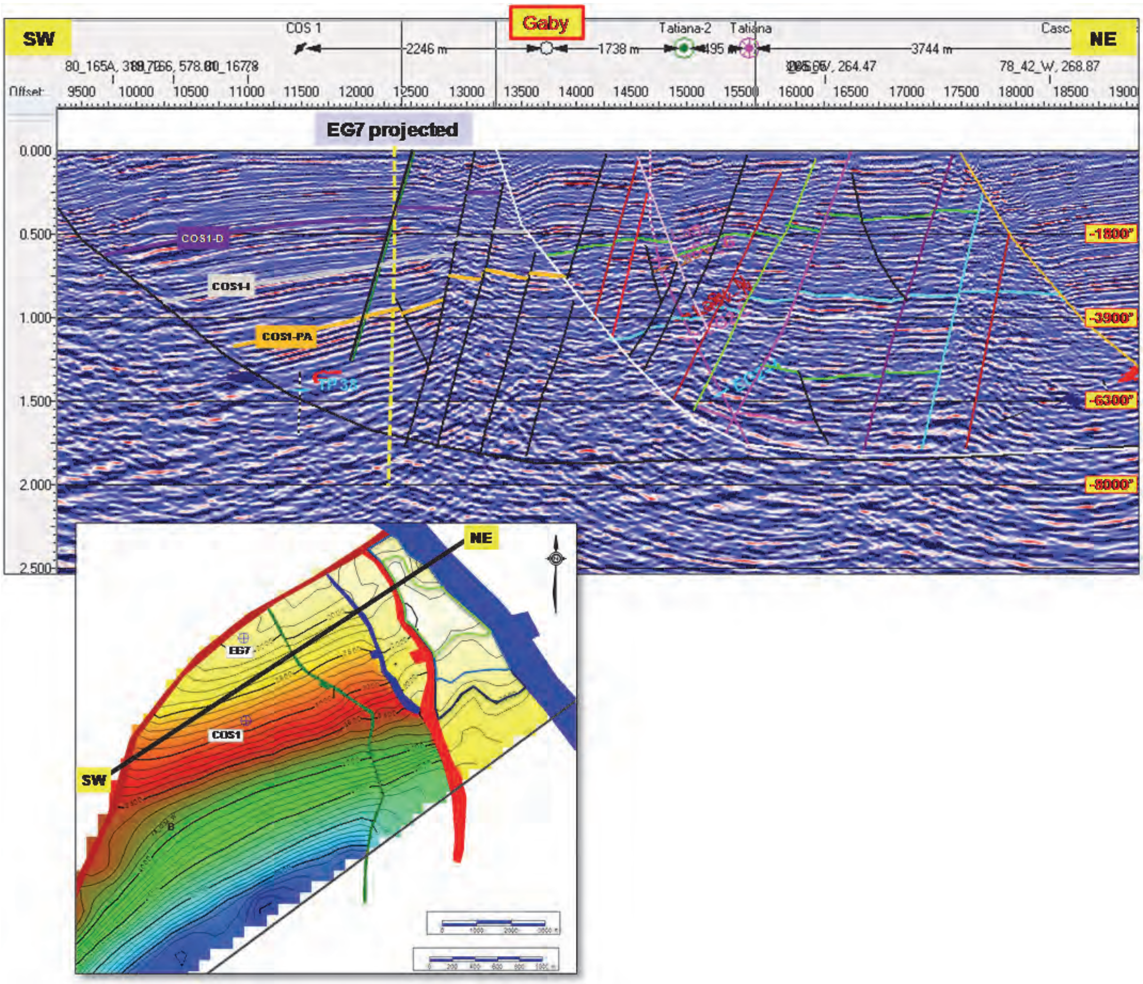


TABLE 1.21

GABY PROSPECT
STOIIP AND GROSS FIELD OIL PROSPECTIVE RESOURCES

Prospect	Interval	STOIIP (MMBbl)			Gross Field Prospective Resources (MMBbl)			GCoS (%)
		Low	Best	High	Low	Best	High	
Gaby	COS1-I	5.79	13.68	19.76	1.16	4.10	7.91	15
	COS1-L	4.87	9.39	12.50	0.97	2.82	5.00	13
	COS1-PA	7.01	10.02	11.61	1.40	3.01	4.64	13
	COS1-PB	3.49	4.74	5.47	0.70	1.42	2.19	13
	COS1-PC	19.11	32.55	40.52	3.82	9.76	16.21	15

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked".

2. SOUTH AFRICA PLETMOS BASIN INSHORE

2.1 Introduction

Bayfield was awarded the exploration licence for the Pletmos Inshore Block on 17th April, 2012, in the Pletmos Basin immediately offshore the south coast of South Africa. The first exploration period consists of 3 years during which Bayfield has committed to undertake the reprocessing of 2,500 km of existing 2D data and the acquisition of additional 2,000 km of 2D data plus desktop geological studies.

The Pletmos Inshore block is located in the greater Outeniqua basin from which daily production of 140 MMscf gas and 7,500 barrels of oil and condensate is currently processed at the Mossel Bay GTL plant which has spare capacity. The block is 200 km from the Mossel Bay plant, and the approximate licence area is 10,800 km^2.

No exploration activity has occurred in the Pletmos subbasin since 1990. Previous exploration efforts by Soekor (the then South Africa state oil company) between 1970 and 1990 had focused on syn-rift structures, and resulted in the discovery and appraisal of the Ga-A field, located immediately to the south of the Pletmos Inshore block, and a gas discovery in the Ga-V1 well, located in the south-west of the Pletmos Inshore block.

Bayfield plans to focus on two shallower (1,200-1,800 m) turbidite plays that have not been previously targeted in the block. High quality reservoir sands have been proven for these turbidites by wells drilled in the block that were targeting traps at deeper syn-rift levels.

Bayfield holds an initial 100% interest in the Pletmos Inshore Block during the exploration phase. In the event of a commercial discovery being developed, the South African state company, PetroSA, has 10% back-in right, paying only the forward costs. Additionally, there is provision for Historically Disadvantaged South Africans (HDSA) to take up to 10%, by paying its equity of forward costs and past costs. The first exploration period is 3 years and carries a commitment to reprocess 2,500 km of 2D seismic data and acquire 2,000 km of 2D seismic data. At the end of the first exploration period, Bayfield can either relinquish the block or extend the licence for another two year period, with additional commitment to be agreed at the time of applying for the extension. A total of three, 2-year extensions are possible with similar terms. The fiscal terms are governed by a tax royalty system.

The Pletmos Inshore Block is located in the north of the Pletmos sub-Basin, one of five in the Outeniqua basin off the south coast of South Africa (Figure 0.2). Of the five sub-basins, Bredasdorp to the west currently has oil and gas production. Within the Pletmos sub-Basin, 22 wells were drilled between 1970 and 1990, mostly by the South African state oil company of the time, Soekor, targeting synrift structures. However, only gas-bearing formations in low permeability shallow marine sand were encountered, which were considered non-commercial at the time. One such well, Ga-VI, is located in the south-west of Bayfield's Pletmos Inshore Block.

Bayfield is targeting a shallower, potentially high quality, base of slope turbidite channel play that is similar to the producing reservoirs in the nearby Bredasdorp sub-Basin. Bayfield is also targeting a basin boundary wedge play analogous to the recent Sea Lion oil discovery in the North Falkland basin. The Pletmos Inshore Block is located 200 km east of the Mossel Bay GTL plant, which has spare capacity because of the declining gas production from the fields in the Bredasdorp sub-Basin.

2.2 Geological Setting

The Pletmos sub-Basin was subjected to a history of strong strike-slip movement during the Late Jurassic-Early Cretaceous breakup of Gondwana and drift of the African and South American continental plates. The basin consists of a series of en echelon depocenters, each of which comprises a complex of rift half-grabens separated by horst structures and overlain by thick drift succession. The Pletmos sub-Basin itself was subdivided by a series of north-westerly striking faults (e.g., the Plettenberg, Superior, and Pletmos faults) into half-grabens (Figure 2.1).

The Northern Pletmos sub-Basin comprises two en echelon depocenters, the Plettenberg Graben and the Superior Graben, which are separated by a 4,000 m prominent transfer arch. Sediment thicknesses of up to 9,000 m have been mapped adjacent to basin-bounding faults. Truncation of the Tertiary and Upper Cretaceous successions by the seafloor is evident over the northern flank of the sub-basin parallel with the coastline, thus demonstrating that late tilting of the basin has occurred.

The two main reservoir targets are; i) Barremian deep-marine basin floor turbidite fan and channel sandstones and; ii) Barremian wedge of sandstone associated with the basin bounding Plettenberg fault. A third minor target comprises shallow marine sandstones of Late Valanginian age in which minor gas has been encountered in low permeability rock in well Ga-V1 within the Pletmos Lease and in the nearby Superior High gas discoveries.

The Barremian unconformity eroded an arenaceous shelf with a feeder point on the northern rim of the Pletmos sub-Basin. A massive sandstone penetrated in well Ga-B1has been interpreted to be a turbidite channel fill. This sinuous channel feature can be followed along its entire course from its feeder point on the shelf, arcuating down the slope and flattening out at base of slope. This is interpreted to be the major sediment source which resulted in the formation of the Barremian deep-marine basin floor fan and channel complex. Good but limited 2D seismic data reveal several bright anomalies overlying the Barremian unconformity. These are interpreted to represent channel and fan features in combined structural/stratigraphic traps and form the basis for Prospects 1, 2, 3, 5 and 9 (Figure 2.2).

An analogous but younger Albian-Aptian turbidite basin floor fan and channel complex has been proven to be oil- and gas-bearing in the Bredasdorp sub-Basin.

FIGURE 2.1

SCHEMATIC CROSS SECTION AND STRATIGRAPHY OF PLETMOS SUB-BASIN, SOUTH AFRICA

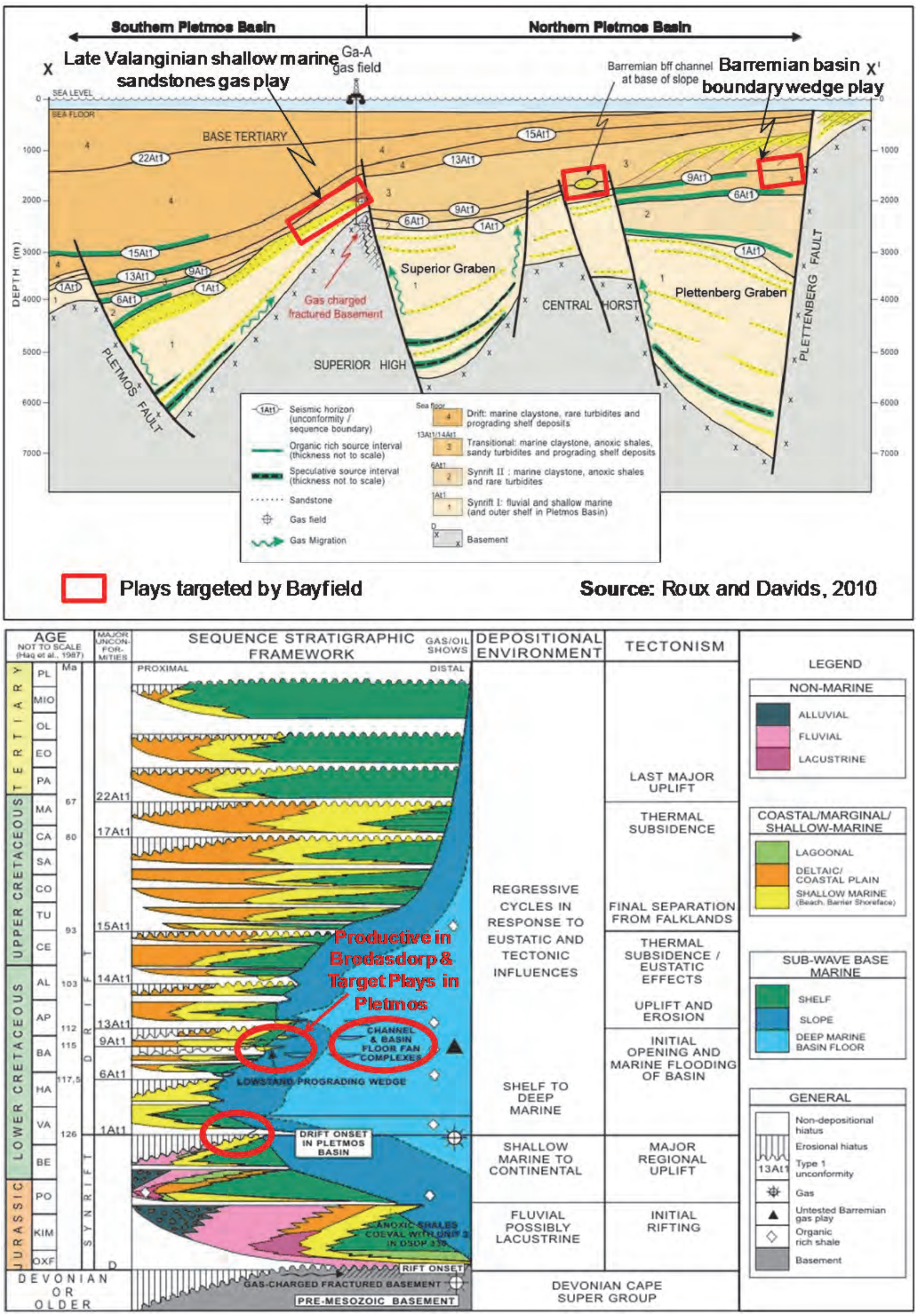
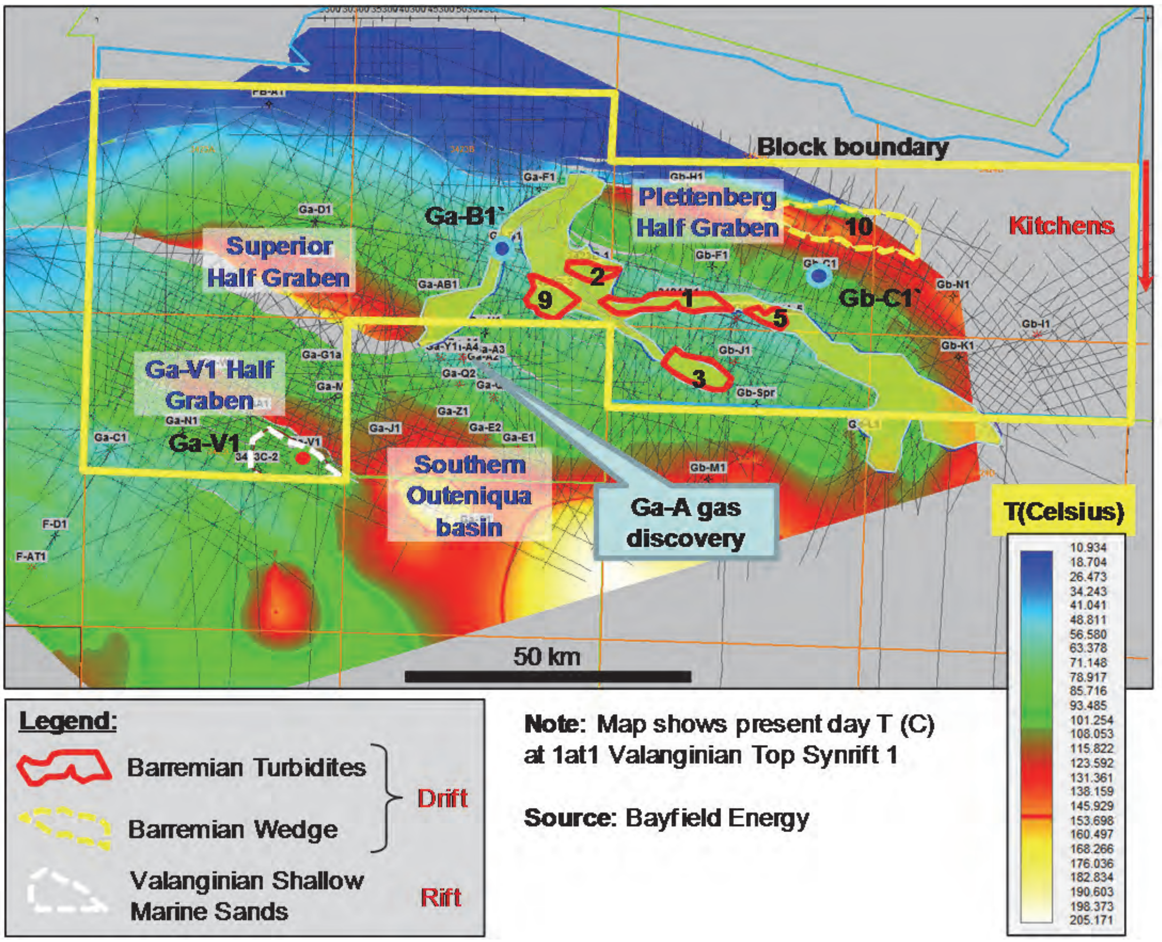


FIGURE 2.2

PLETMOS INSHORE BLOCK SHOWING PROSPECTS



The Barremian unconformity also eroded and deposited a thick wedge of basin floor fans and channels along the basin boundary Plettenberg Fault. This sediment wedge was intersected water-bearing in a structurally down-dip position by well Gb-C1, which penetrated a 210 m thick section of high NTG, massive sandstone with average porosities of 19%.

Late Valanginian syn-rift shallow marine sandstone is the reservoir target for the gas in the Ga-V1 area. Reservoir properties of the sandstone have degenerated severely due to diagenesis, with porosities averaging 10 to 12% and permeability averaging about 1.3 mD.

The structural and stratigraphic history of the Pletmos Lease provides analogous conditions for hydrocarbon trap development as in the nearby Bredasdorp sub-Basin. Six Prospects with potential for pooling commercial quantities of hydrocarbons have been identified, plus the Ga-V1 prospective area. Additional seismic data, the acquisition of which has already been planned by Bayfield, will be used to refine the Prospects.

2.3 Prospective Resources

2.3.1 Prospects 1, 2, 3, 5 and 9

The targets for these Prospects are the base of slope turbidite fan and channels that were penetrated in Well Ga-B1, but which lacked structural closure. These Prospects are interpreted to represent combined structural and stratigraphic traps and are characterized by bright seismic amplitudes on 2D lines, possibly an indication of hydrocarbons. Prospect 1 is illustrated in Figure 2.3.

Jurassic to Lower Cretaceous age deep marine organic rich claystones which are mature in the deeper parts of the Pletmos sub-Basin are considered to be the hydrocarbon source rocks for these Prospects. Reactivation of normal faults, resulting in late uplift of a central horst feature proximal to the transform fault during late Barremian times, could have provided potential conduits for gas migration into the channel sandstone. Recent tilting and uplift of the northern flank may have provided an added mechanism for gas in deep-seated reservoirs to breach seals and migrate to shallow targets. Presence of source, migration and gas charge into the Pletmos sub-Basin has been proven by the Superior High gas discoveries, for example, Ga-A (Figure 2.2).

The primary geological risk for these Prospects is seal which relies on lateral sealing capacity of reservoir shale-outs and closing faults. The second geological risk is reservoir which depends on the presence of an eastern branch of the Barremian basin-floor fan channel. The massive 28 m thick sandstone with porosity of 21 to 24% penetrated in well Ga-B1, which was water-bearing in Ga-B1 due to absence of structural closure to form a trap, is interpreted to be the western branch of the Barremian basin-floor fan channel system.

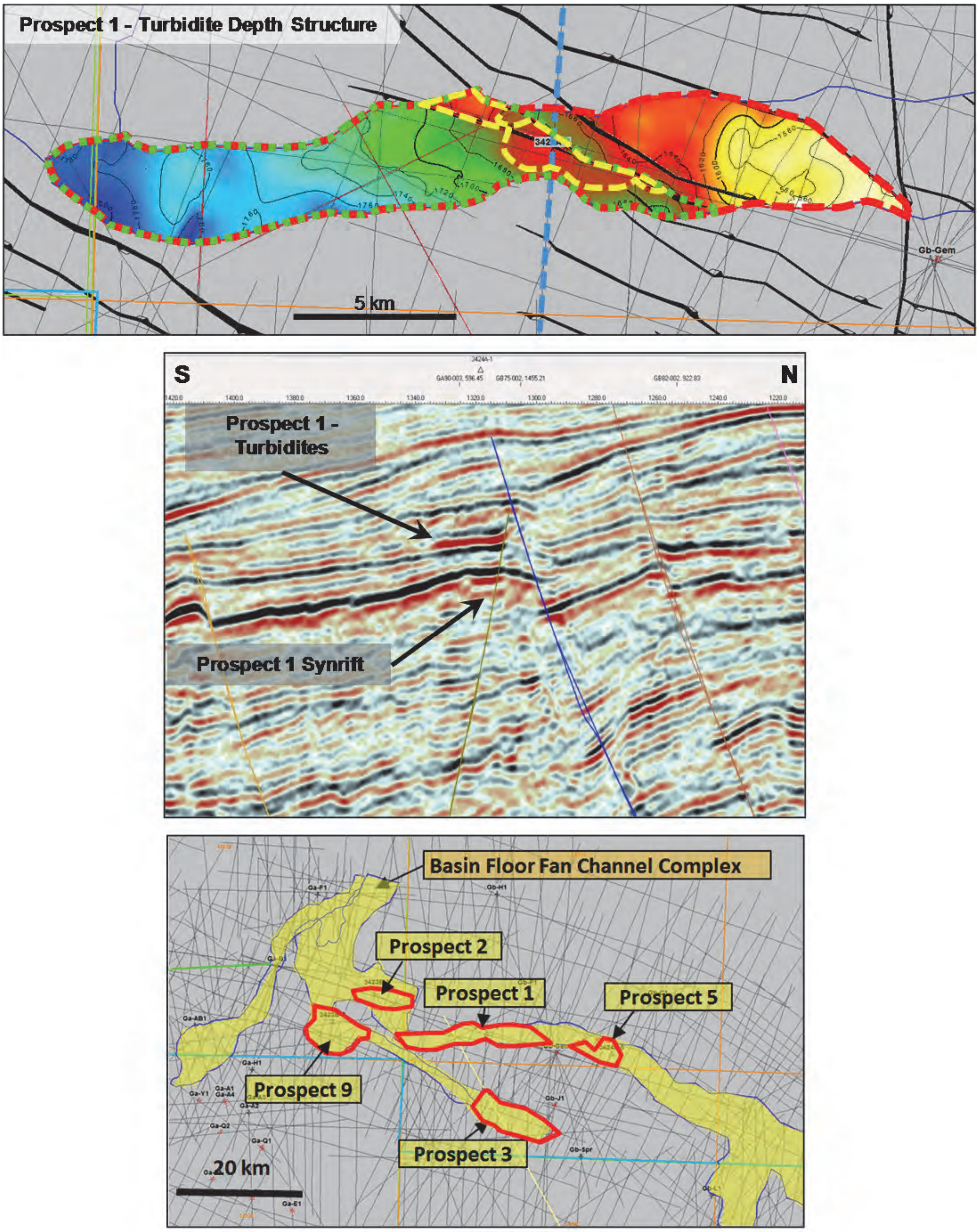
An analogous but slightly younger Albian-Aptian turbidite basin floor fan and channel complex has been proven to be oil- and gas-bearing in the adjacent Bredasdorp sub-basin, and includes the producing fields Oryx, Oribi and Sable Fields.

2.3.2 Prospect 10

Prospect 10 differs from Prospects 1, 2, 3, 5 and 9 in that the target is a massive turbidite wedge against the Plettenberg boundary fault. This has been penetrated in a down-dip location by well Gb-C1, but was found to be water-bearing (Figure 2.4). The main geological risk for Prospect 10 is considered to be lack of integrity of the top seal shales, as these might have been breached by faulting associated with late structuration and tilting of the basin. Hydrocarbon source, migration and charge risks are similar to those for Prospects 1, 2, 3, 5 and 9.

FIGURE 2.3

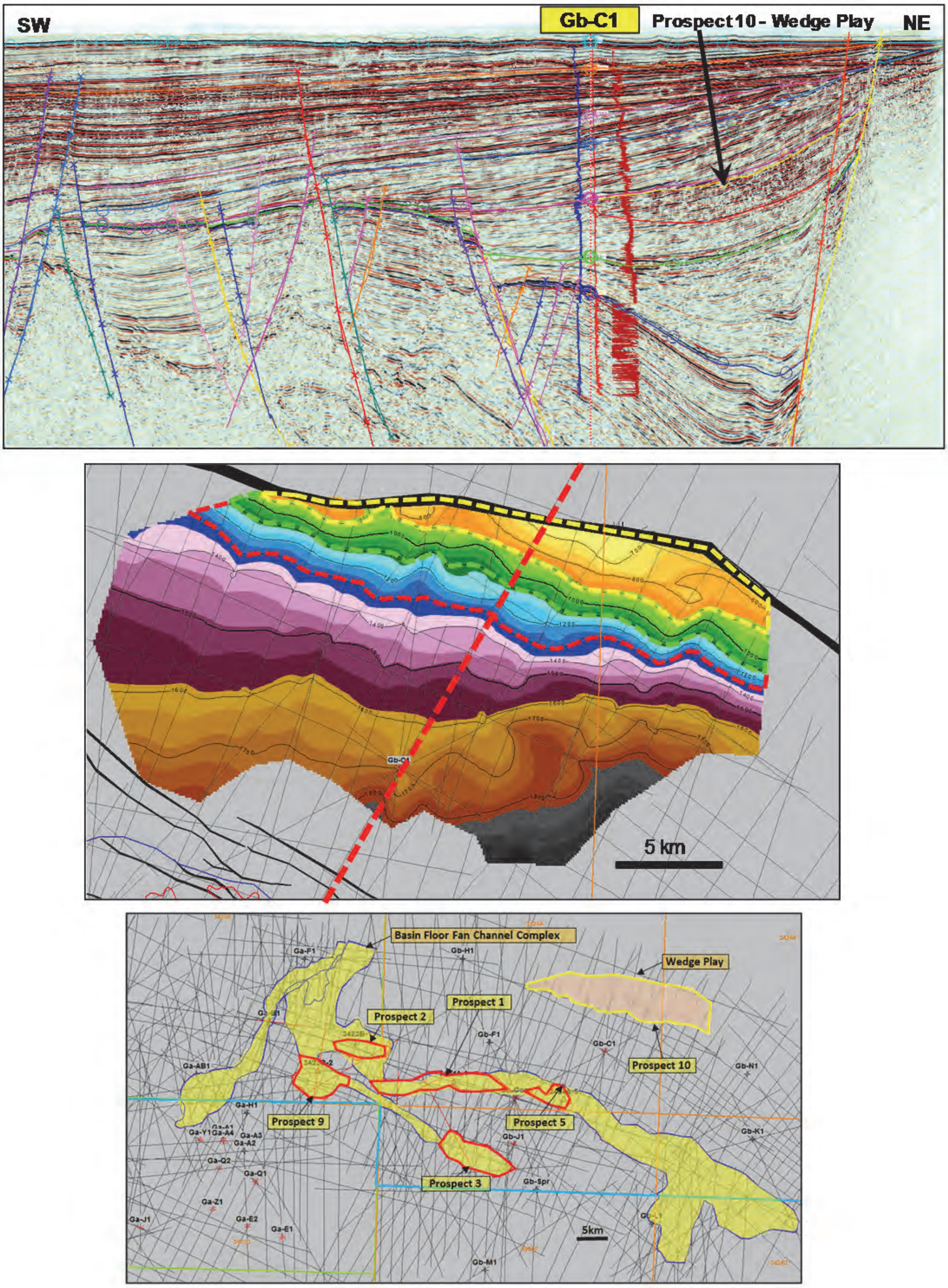
PROSPECT 1, TURBIDITE PLAY, PLETMOS INSHORE BLOCK



Source: Bayfield Energy

FIGURE 2.4

PROSPECT 10, TURBIDITE WEDGE PLAY, PLETMOS INSHORE BLOCK



Source: Bayfield Energy

2.3.3 Ga-V1 Gas Intersection

Well Ga-V1 penetrated 155 m gross, shallow marine sandstone with average porosity estimated to be 10.9%, but with extremely low permeability. The well was interpreted to contain only tight gas and was not tested. Many wells have been drilled since 1969 in the adjacent lease area targeting the same reservoir play. The main risk is the areal distribution of these shallow marine sandstone and more importantly, the preservation of good reservoir properties where the sandstones have not undergone severe diagenesis. Extensive good quality seismic data and additional drilling will be required to delineate and properly assess the potential of this play. Three wells have been reported by PetroSA to have tested at commercial gas rates in the Pletmos sub-Basin, but to date no field development has taken place. Due to the poor quality of the rock and absence of test data or indication of productivity, this gas intersection does not meet the criteria to be classified as a discovery under SPE PRMS and remains a Prospect. Reservoir quality formation is the only risk factor.

TABLE 2.1

PLETMOS BASIN
GIIP AND GROSS FIELD GAS PROSPECTIVE RESOURCES
AS AT 30th JUNE, 2012

Prospect	GIIP (Bscf)			Gross Field Prospective Resources (Bscf)			GCoS (%)
	Low	Best	High	Low	Best	High	
1	17.13	334.48	650.78	11.95	234.46	447.70	18
2	13.74	120.85	256.26	9.30	84.95	175.43	15
3	50.97	264.13	596.68	35.42	184.46	415.81	13
5	7.86	48.44	112.87	5.50	33.59	79.92	8
9	61.20	242.11	523.68	42.98	169.51	370.42	6
10	728.08	2,533.29	5,336.71	518.20	1,757.62	3,753.29	6
Ga-V1	128.09	487.54	1,023.43	63.36	240.13	518.42	10

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to be considered viable drilling targets.
2. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are “Unrisked”.

3. ECONOMIC EVALUATION

GCA has conducted economic evaluations and derived Net Present Values (NPV) for Reserves of the Trintes Field, including work-overs and side-tracks and of the five Extension Areas and Risked Net Present Values (NPV) for the Contingent Resources comprising four nearby discoveries, for the purpose of deriving a range of monetary values that could be attributed to future revenues from these fields.

In preparing its evaluation, GCA has modelled the applicable fiscal terms based on GCA's understanding of the fiscal and contractual terms governing the properties. The value of physical assets, i.e. plant and equipment, has not been attributed separately as their value has been implicitly included in the assessment of NPV as part of the petroleum property rights relating to Bayfield's interest in the Licence.

The NPVs of estimated after-tax cash flows (as at 30th June, 2012) attributable to a net economic interest in the Licence have been derived using the pricing and inflation assumptions described herein. No adjustments have been made for cash balances, inventories, indebtedness or other balance sheet effects, other than those stated herein.

It should be clearly noted that the Net Present Values (NPVs) of future revenue potential of a petroleum property, such as those discussed in this report, do not represent a GCA opinion as to the market value of that property, nor interest in it. In assessing a likely market value, it would be necessary to take into account a number of additional factors including; Reserves risk (i.e. that Proved and or Probable and or Possible Reserves may not be realised within the anticipated timeframe for their exploitation); potential upside, such as in this case exploitation of Reserves beyond the Proved, Probable and Possible levels; other benefits, encumbrances or charges that may pertain to a particular interest; and the competitive state of the market at the time. GCA has explicitly not taken such factors into account in deriving the NPVs referenced in this report.

3.1 Trinidad Fiscal Terms

The Trinidad and Tobago fiscal regime is a Royalty and Tax based system that features Royalty, Supplemental Petroleum Tax (SPT), and Production Levy (all based on the value of petroleum produced from the licence area) and Petroleum Profits Tax (PPT) and unemployment levy which are based on profits made from petroleum operations.

Pertinent fiscal and contractual terms applicable to Galeota Area Licence are summarised as follows:

- The term of the licence is 25 years with an expiry date of 20th April 2034;
- Bayfield carries Petrotrin for all costs related to the Trintes field until 2013;
- Royalty is payable at a rate of 12.5%;
- Contributions to abandonment funds amount to US$1.00/Bbl;
- Licence fees including production bonus payments and contributions to petroleum industry related training, research and development and scholarships amount to some US$300,000 per annum;
- Supplemental Petroleum Tax is charge at basic rates varying between 18% and 40% based on crude prices of between US$90/Bbl and US$200/Bbl. With effect from 1st January 2011, the Trintes field qualifies for a 20% reduction in the above rates as a mature oil field, having been in production for more than twenty five years as would any other small offshore fields with production of less than 1.5 Mbopd;

- Production Levy is charged at 4% of the value of production when production rates of 3.6 Mbopd or above are attained;
- Petroleum Profits Tax is chargeable at 50% of accessible profits; and
- Unemployment Levy is 5% of accessible profits (without relief of losses).

3.2 Cost Assumptions

Estimates of capital and operating expenses were provided by Bayfield. These were reviewed by GCA and are considered to be reasonable. The actual costs have been discussed previously in this report.

3.3 Oil and Gas Pricing Assumptions

In line with its standard practices, GCA has estimated the Reserves quoted herein by performing an Economic Limit Test (ELT) based on its third quarter, 2012 pricing scenario.

GCA PRICE SCENARIO

Year	Brent Price (US$/Bbl)
2H 2012	114.07
2013	110.48
2014	104.63
2015	98.96
2016	96.81
2017	98.85
Thereafter	+2.0% pa

Crude from the Galeota Block is sold to Petrotrin under an oil sales agreement which values the crude at a 9.5% discount to Brent less a further US$1.00/Bbl charge for transportation. Gas from the area is assumed to be sold at US$2.83/MMBtu (without escalation).

Other Base Case assumptions used for the economic assessment include:

- Opening Tax positions have been assumed to be zero;
- All cash flows are discounted on a nominal mid-year basis as at 1st July, 2012; and
- Costs are inflated at 2.0% per annum from 1st July, 2013.

3.4 Results of Economic Evaluation

The following table summarises the post-tax Net Present Values (NPV) at 10% discount for Bayfield's interests in the Trintes Field Main (including work-overs, side-tracks and infill drilling) and for the Trintes Field Extensions (including NE extension M and G sands, SW extension M sand, GAL-9 G and H sands and GAL-12 H sand) associated with the Proved, the Proved plus Probable, and the Proved plus Probable plus Possible Reserves, as at 30th June, 2012.

TABLE 3.1

POST-TAX NET PRESENT VALUES AT 10% DISCOUNT NET TO BAYFIELD RESERVES AS AT 30th JUNE, 2012 (US$ MM)

Field	Proved	Proved plus Probable	Proved plus Probable plus Possible
Trintes Field Main	16.27	104.92	124.31
Trintes Field Extensions	5.27	96.81	206.42
Total	**21.54**	**201.73**	**330.73**

Notes:

1. The Net Present Values are calculated by carrying out discounted cash flows incorporating the fiscal terms governing each licence block.
2. The values shown in this table are Net to Bayfield according to the fiscal terms governing each licence block.
3. Economic calculations have been based on GCA's Third Quarter, 2012 Brent Pricing Scenario (Section 3.3).

The following table summarises the risked post-tax Net Present Values (NPV) at 10% discount for Bayfield's interests in the proposed EG-3, EG-2/EG-8, and EG-4 cluster development and the proposed GAL-21 updip Trintes tie-back development comprising the 2C Contingent Resources, as at 30th June, 2012.

TABLE 3.2

SUMMARY OF NET BAYFIELD RISKED POST-TAX NET PRESENT VALUES FOR CONTINGENT RESOURCES AS AT 30th JUNE, 2012

Country	Block	Chance of Development (%)	Risked NPV_{10} (US$ MM)
Trinidad	Galeota	55	72.29

Notes:

1. A risk factor (Chance of Development) has been applied to NPV_{10} calculations to account for the chance that these volumes might not mature to Reserves class. The Chance of Development represents an indicative estimate of the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve.
2. Economic calculations have been based on GCA's Third Quarter, 2012 Brent Pricing Scenario (Section 3.3).

3.5 Sensitivities

GCA carried out a sensitivity analysis of the NPV pertaining to the 2P Reserves for the Trintes Field (the total field comprising the Main plus the Extensions). This analysis was performed considering GCA's view on the possible extent of variations pertaining to CAPEX and OPEX and to show the effects of fluctuations in oil price.

The results are given in the following table. This shows that the Trintes project is robust in terms of the outcomes, and costs seem to have little impact. However, the project appears to be quite sensitive to variations in oil price.

TABLE 3.3

NET PRESENT VALUE SENSITIVITY ANALYSIS
2P RESERVES – TRINTES FIELD
AS AT 30th JUNE, 2012

Case	Oil Price	NPV 10 (US$ MM)
Base case	GCA Brent Q3 2012	201.7
Base case + 20% Capex	GCA Brent Q3 2012	193.1
Base case - 20% Capex	GCA Brent Q3 2012	210.4
Base case +10% Opex	GCA Brent Q3 2012	195.6
Base case -10% Opex	GCA Brent Q3 2012	207.7
Base case	US$80 Flat	135.7
Base case	US$90 Flat	166.1
Base case	US$110 Flat	220.4

4. QUALIFICATIONS

GCA is an independent international energy advisory group of 50 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

The report is based on information compiled by professional staff members of GCA.

Staff who participated in the compilation of this report include Mr B. Rhodes, Mr M. A. Lucas, Mr J. R. Weston, Mr J. C. Chan, Mr D. J. Brown, Mr W. J. Askham and Mr A. V. Makhonin.

Mr Rhodes holds a B.Sc. (Hons) Geology, is a member of the Energy Institute, the Petroleum Exploration Society of Great Britain, the Society of Petroleum Engineers and the European Association of Geoscientists and Engineers; and has more than 38 years' industry experience. Mr Lucas holds an MBA in Business Studies, an M.Sc. Petroleum Engineering and a B.Sc. (Hons) Chemistry, is a member of the Society of Petroleum Engineers and has over 40 years' industry experience. Mr Weston holds a B.Sc. (Hons) Geology and M.Sc. Micropalaeontology, is a member of American Association of Petroleum Geologists, Petroleum Exploration Society of Great Britain, Geological Society, Society of Petroleum Engineers, Energy Institute; with 34 years' experience. Mr Chan holds an M.Sc. Soc. Economics, is a member of the Association of International Petroleum Negotiators and the International Association of Energy Economics; and has 17 years' experience. Mr Brown holds a B.Sc. (Hons) Geological Science, an M.Sc. Petroleum Geoscience, is a Fellow of the Geological Society and Petroleum Exploration Society of Great Britain member; with 5 years' experience. Mr Askham holds a B.Sc. (Hons) Geology, an M.Sc. Petroleum Geoscience, is a member of Petroleum Exploration Society of Great Britain, Geological Society, Society of Petroleum Engineer; with 5 years' experience. Mr Makhonin holds an M.Sc. Geology, and is a petrophysicist with 10 years' industry experience.

5. BASIS OF OPINION

This assessment has been conducted within the context of GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights including environmental and abandonment obligations, and any necessary licences and consents including planning permission, financial interest relationships or encumbrances thereon for any part of the appraised properties.

The opinions expressed herein represent GCA's informed judgment based upon accepted standards of professional investigation in its evaluation of the issues, the data that has been made available and the company's professional experience in the consideration of these matters but subject to the generally accepted uncertainties associated with the interpretation of geoscience and engineering data but should not be considered a guarantee or prediction of results. Any evaluation may be subject to significant variation over time as new information becomes available or perceptions of market conditions change.

Yours sincerely
GAFFNEY CLINE & ASSOCIATES

Brian Rhodes
Global Director – Corporate Advisory Services

APPENDIX I

Abbreviated Form of SPE PRMS

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers

Petroleum Resources Management System

Definitions and Guidelines ([1])

March 2007

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definition of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE PRMS document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.,

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that SPE PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE PRMS Definitions and Guidelines can be viewed at:
www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

1 These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

Approved for Development

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Justified for Development

Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

(1) the area delineated by drilling and defined by fluid contacts, if any, and

(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain**.** Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

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

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing,

(2) wells which were shut-in for market conditions or pipeline connections, or

(3) wells not capable of production for mechanical reasons.

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

(1) from new wells on undrilled acreage in known accumulations,

(2) from deepening existing wells to a different (but known) reservoir,

(3) from infill wells that will increase recovery, or

(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to

(a) recomplete an existing well or

(b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Development Pending

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to “On Hold” or “Not Viable” status. The project “decision gate” is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclarified or on Hold

A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to “Not Viable” status. The project “decision gate” is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project “decision gate” is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

PROSPECTIVE RESOURCES

Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

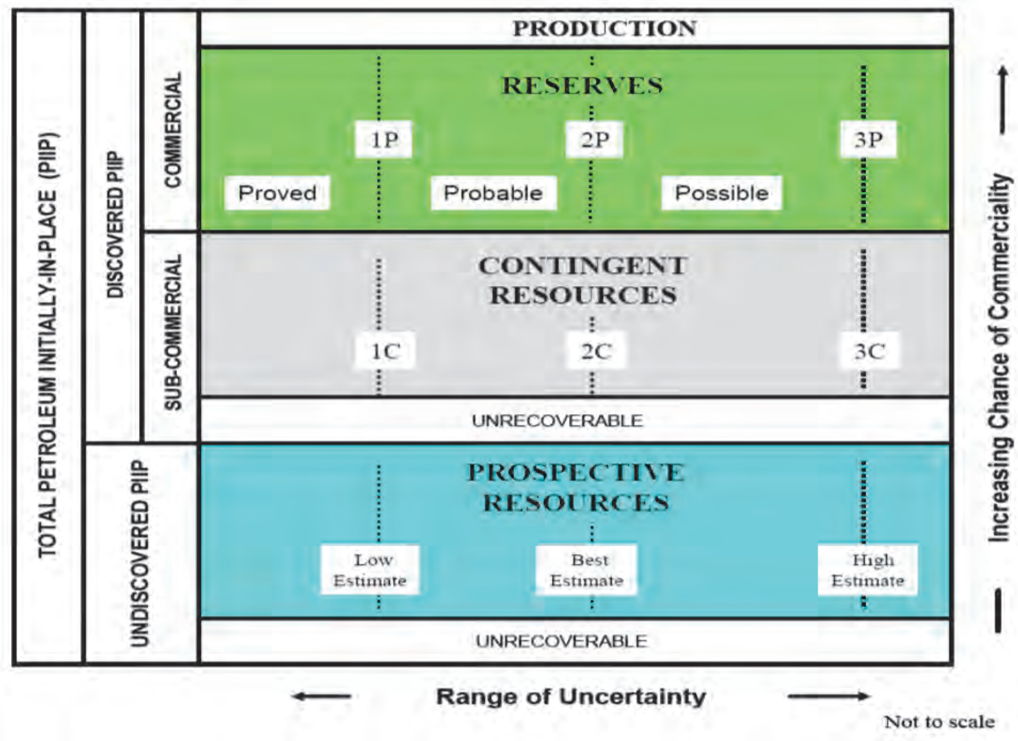
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

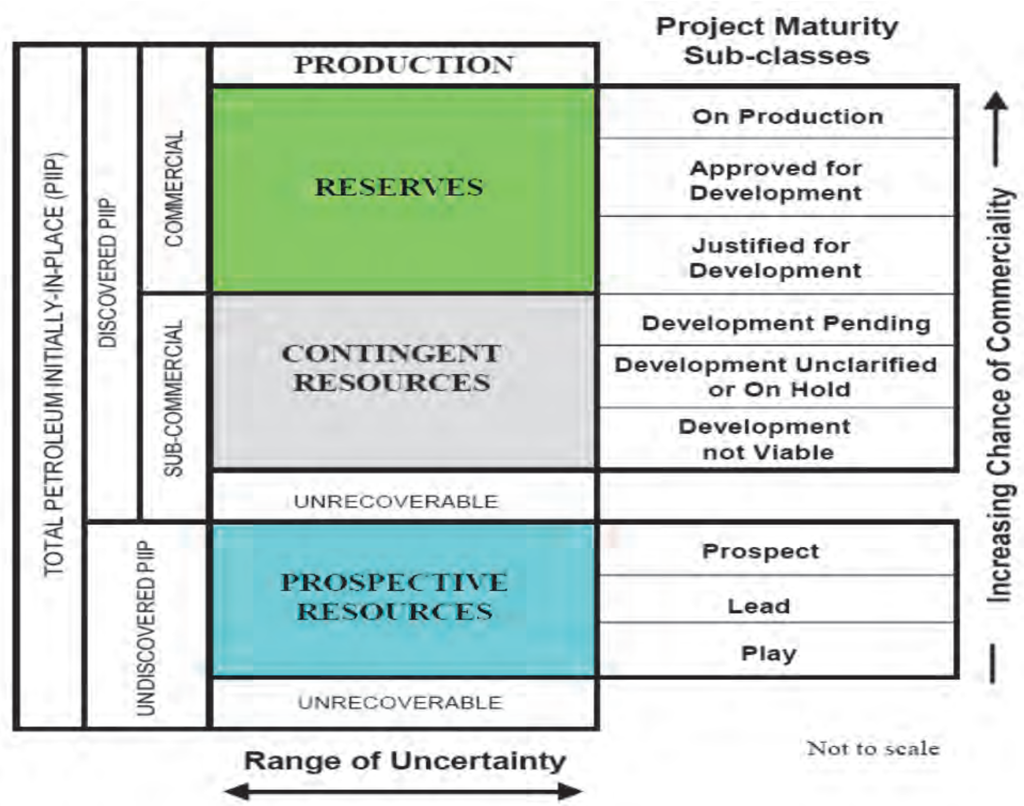
A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

RESOURCES CLASSIFICATION



PROJECT MATURITY



APPENDIX II

Glossary of Terms

GLOSSARY

List of Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
^{o}API	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A$	Australian Dollars
B	Billion (10^9)
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day
bpd	Barrels per day
boe	Barrels of oil equivalent @ xxx mcf/Bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/Bbl
BOP	Blow Out Preventer
bopd	Barrels oil per day
bwpd	Barrels of water per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels water per day
CBM	Coal Bed Methane
CO_2	Carbon Dioxide
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal
E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement Interest
EIA	Environmental Impact Assessment
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design
FPSO	Floating Production, Storage and Offloading
FSO	Floating Storage and Offloading
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre
gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs
GBP	Pounds Sterling

GDT	Gas Down to
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOR	Gas Oil Ratio
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H_2S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy) I kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km^2	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons
LKO	Lowest Known Oil
LNG	Liquefied Natural Gas
LoF	Life of Field
LPG	Liquefied Petroleum Gas
LTI	Lost Time Injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m^3d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrams per litre
MJ	Megajoules (One Million Joules)
Mm^3	Thousand Cubic metres
Mm^3d	Thousand Cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
mya	Million years ago
NGL	Natural Gas Liquids
N_2	Nitrogen
NPV	Net Present Value
OBM	Oil Based Mud
OCM	Operating Committee Meeting
ODT	Oil down to
OPEX	Operating Expenditure
OWC	Oil Water Contact

p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Producing
PI	Productivity Index
PJ	Petajoules (10^{15} Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved Undeveloped
PVT	Pressure volume temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
Rf	Recovery factor
RFT	Repeat Formation Tester
RT	Rotary Table
R_w	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
s_o	Oil Saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
ss	Subsea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
s_w	Water Saturation
T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
USGS	United States Geological Survey
US$	United States Dollar
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
1H05	First half (6 months) of 2005 (example of date)
2Q06	Second quarter (3 months) of 2006 (example of date)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
%	Percentage

PART VII

HISTORICAL FINANCIAL INFORMATION RELATING TO TRINITY AND OILBELT

SECTION 1: TRINITY

(A) UNAUDITED INTERIM FINANCIAL INFORMATION RELATING TO TRINITY

Independent review report to the directors of Trinity Exploration and Production Limited

Introduction

We have been engaged by management to review the non-statutory financial statements of Trinity Exploration and Production Limited (the 'Company') for the six month period ended 30 June 2012, which comprises the Condensed Consolidated Statement of Financial Position, Condensed Consolidated Statement of Comprehensive Income, Condensed Consolidated Statement of Changes in Equity, Condensed Consolidated Statement of Cash Flow and related notes. These non-statutory financial statements have been prepared on the basis of preparation and accounting policies in Note 1 to the non-statutory financial statements.

These non-statutory financial statements were prepared solely for management's own purposes and have not been prepared under section 394 of the Companies Act 2006 and are not the statutory financial statements of the business. The non-statutory financial statements do not disclose all the information or comply in all respects with applicable accounting standards which would be necessary for them to show a true and fair view.

Directors' responsibilities

The financial statements and other information contained in the financial statements is the responsibility of, and have been approved by, the directors. The directors are responsible for preparing the financial statements and other information contained in the financial statements in accordance with the basis of preparation and accounting policies in Note 1 to the non-statutory financial statements and for determining whether this basis of preparation is appropriate in the circumstances.

Our responsibility

Our responsibility is to express a conclusion on the financial statements based on our review. This report, including the conclusion, has been prepared for and only for the directors of the Company as a body for management purposes and for no other purpose. Our report may not be made available to any other party without our prior written consent. We do not, in producing this report, accept or assume responsibility for any other purpose or to any other person to whom this report is shown or into whose hands it may come save where expressly agreed by our prior consent in writing.

Scope of review

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

Conclusion

Based on our review, nothing has come to our attention that causes us to believe that the non-statutory financial statements for the 6 months ended 30 June 2012 are not prepared, in all material respects, in accordance with the basis of preparation and accounting policies in Note 1 to the non-statutory financial statements.

PricewaterhouseCoopers LLP
Chartered Accountants
25 January 2013
Aberdeen

Trinity Exploration and Production Limited

Consolidated Statement of Financial Position

for the period ended 30 June 2012

(Expressed in United States Dollars)

	Notes	As at 30 June 2012	As at 30 June 2011	As at 31 December 2011
		$'000 (unaudited)	$'000 (unaudited)	$'000 (audited)
ASSETS				
Non-current Assets				
Property, plant and equipment	2	54,583	14,270	56,248
Intangible assets—Goodwill		16,952	—	16,952
Deferred tax asset		12,597	—	12,882
		84,132	14,270	86,082
Current Assets				
Inventories		2,695	2,209	1,499
Trade and other receivables	3	13,809	5,735	10,892
Taxation recoverable		119	119	119
Short-term investments		37	37	37
Cash and cash equivalents		18,527	7,162	26,769
		35,187	15,262	39,316
Total Assets		**119,319**	**29,532**	**125,398**
EQUITY AND LIABILITIES				
Capital and Reserves Attributable to Owners of the Parent				
Share capital	4	34	21,720	33
Share premium		17,621	—	13,751
Share warrants		71	514	71
Merger reserves	5	53,172	—	53,172
Translation reserve		(81)	190	280
Accumulated deficit		(9,568)	(22,837)	(11,949)
Total Equity		**61,249**	**(413)**	**55,358**
Non-current Liabilities				
Convertible loan notes		6,837	9,337	6,837
Borrowings	6	6,139	—	8,460
Provision for decommissioning costs		6,580	2,040	6,402
Provision for employee retirement benefits		740	—	728
Deferred tax liability		18,204	54	19,504
		38,500	11,431	41,931
Current Liabilities				
Trade and other payables		10,075	9,979	14,677
Borrowings	6	4,268	5,027	6,251
Taxation payable		5,227	3,508	7,181
		19,570	18,514	28,109
Total Liabilities		**58,070**	**29,945**	**70,040**
Total Shareholders' Equity and Liabilities		**119,319**	**29,532**	**125,398**

Trinity Exploration and Production

Condensed Consolidated Statement of Comprehensive Income

(Expressed in United States Dollars)

	Notes	Six months to 30 June 2012	Six months to 30 June 2011	Year ended 31 December 2011
		$'000 (unaudited)	$'000 (unaudited)	$'000 (audited)
Operating Revenues				
Crude oil sales		40,499	15,870	53,167
Other income		218	344	723
		40,717	16,214	53,890
Operating Expenses				
Royalties		(14,818)	(4,983)	(18,366)
Production costs		(6,658)	(2,701)	(8,460)
Depreciation, depletion and amortisation	2	(3,553)	(738)	(3,611)
General and administrative expenses		(5,100)	(1,706)	(4,461)
		(30,129)	(10,128)	(34,898)
Operating Profit		**10,588**	**6,086**	**18,992**
Finance Income		54	3	206
Finance Costs		(941)	(602)	(5,768)
Finance Costs—Net		(887)	(599)	(5,562)
Profit Before Taxation		**9,701**	**5,487**	**13,430**
Taxation Charge	7	(7,320)	(3,547)	(652)
Profit		**2,381**	**1,940**	**12,778**
Other Comprehensive Income		**(361)**	**50**	**140**
Total Comprehensive Income		**2,742**	**1,990**	**12,918**
Earnings per share (expressed in dollars per share)	8			
Basic		71	89	510
Diluted		68	82	470

Trinity Exploration and Production Limited

Condensed Consolidated Statement of Changes in Equity

for the period ended 30 June 2012

(Expressed in United States Dollars)

	Share Capital	Share Premium	Share Warrant	Merger Reserve	Merger Difference	Translation Reserve	Accumulated Deficit	Total
	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
Year ended 31 December 2011								
At 1 January 2011	21,720	—	514	—	—	140	(24,727)	(2,353)
Comprehensive income for the period	—	—	—	—	—	50	1,890	1,940
Balance at 30 June 2011	**21,720**	**—**	**514**	**—**	**—**	**190**	**(22,837)**	**(413)**
Conversion of share warrant to shares	514	—	(514)	—	—	—	—	—
Issue of shares to satisfy Oilbelt consideration	7,479	—	—	—	—	—	—	7,479
Amalgamation of Ten Degrees North Energy Limited and Oilbelt Services Ltd—cancellation of existing shares	(29,713)	—	—	—	—	—	—	(29,713)
Amalgamation of Ten Degrees North Energy Limited and Oilbelt Services Ltd—issue of shares by the Company	30	—	—	124,943	(71,771)	—	—	53,202
Issue of shares for cash	3	14,200	—	—	—	—	—	14,203
Cost of share issue	—	(378)	—	—	—	—	—	(378)
Share warrant issued	—	(71)	71	—	—	—	—	—
Translation difference	—	—	—	—	—	90	—	90
Comprehensive income for the period	—	—	—	—	—	—	10,888	10,888
Balance at 31 December 2011	**33**	**13,751**	**71**	**124,943**	**(71,771)**	**280**	**(11,949)**	**55,358**
Conversion of financial liability to shares (note 4)	1	3,870	—	—	—	—	—	3,871
Translation difference	—	—	—	—	—	(361)	—	(361)
Comprehensive income for the period	—	—	—	—	—	—	2,381	2,381
Balance at 30 June 2012	**34**	**17,621**	**71**	**124,943**	**(71,771)**	**(81)**	**(9,568)**	**61,249**

Trinity Exploration and Production Limited

Statement of Cash Flows

(Expressed in United States Dollars)

	Six months to 30 June 2012	Six months to 30 June 2011	Year ended 31 December 2011
	$'000 (unaudited)	$'000 (unaudited)	$'000 (audited)
Cash Flows from Operating Activities			
Profit before taxation	9,701	5,487	13,430
Adjustments for:			
Profit on disposal of property, plant and equipment (PPE)	—	—	(110)
Interest paid on loans	706	467	1,142
Finance cost—change in fair value of financial liability	—	—	3,822
Finance cost—decommissioning provision	236	135	273
Interest received	(54)	(3)	(206)
Depreciation, depletion and amortisation	3,553	738	3,611
	14,142	**6,824**	**21,962**
Changes In Working Capital			
(Increase)/decrease in inventory	(1,196)	(330)	458
(Increase)/decrease in trade and other receivables	(2,916)	13	(5,144)
(Decrease)/increase in trade and other payables	(779)	(335)	1,050
	9,251	**6,172**	**18,326**
Taxation paid	(10,289)	(1,245)	(7,359)
Net Cash (Used)/Generated From Operating Activities	**(1,038)**	**4,927**	**10,967**
Cash Flow from Investing Activities			
Interest received	54	3	206
Acquisition of subsidiary	—	—	(1,402)
Purchase of PPE	(2,455)	(1,566)	(7,320)
Disposal of PPE	—	194	311
Net Cash (Used) in Investing Activities	**(2,401)**	**(1,369)**	**(8,205)**
Cash Flows from Financing Activities			
Proceeds from Issuance of shares (net of costs)	—	—	12,164
Repayment of convertible shareholder loan notes	—	—	(2,500)
Interest paid on loans	(706)	(467)	(1,142)
Repayment of borrowings	(4,303)	(1,097)	(6,163)
Proceeds from new borrowings	—	—	16,500
Net Cash (Used)/Generated From Financing Activities	**(5,009)**	**(1,564)**	**18,859**
Net (Decrease)/Increase in Cash and Cash Equivalents	**(8,448)**	**1,994**	**21,621**
Cash And Cash Equivalents at Beginning of Period	26,769	5,148	5,148
Exchange Gains and Losses on Cash and Cash Equivalents	206	20	—
Cash and Cash Equivalents at End of Period	**18,527**	**7,162**	**26,769**

Trinity Exploration and Production Limited

Notes to the Condensed Consolidated Financial Statements

1 Accounting Policies

Basis of Preparation

These condensed interim financial statements for the six months ended 30 June 2012 have been prepared in accordance with IAS 34, 'Interim financial reporting', as adopted by the European Union. The condensed interim financial statements should be read in conjunction with the annual financial statements for the year ended 31 December 2011, which have been prepared in accordance with IFRSs as adopted by the European Union.

The results for the six months ended 30 June 2012 and 30 June 2011 are unaudited and do not comprise statutory accounts within the meaning of section 434 of the Companies Act 2006. Statutory accounts for the year ended 31 December 2011 were approved by the board of directors and delivered to the Registrar of Companies. The report of the auditors on those accounts was unqualified, did not contain an emphasis of matter paragraph and did not contain any statement under section 498 of the Companies Act 2006.

Background

Trinity Exploration and Production Limited ("Trinity UK") was incorporated and registered on 4 April 2011. On 30 November 2011, a new UK parent company structure became effective by way of a share for share exchange ("amalgamation") between the shareholders of Ten Degrees North Energy Limited (the previous parent company) and Trinity UK (the new parent company) and the Group became Trinity Exploration and Production Limited. As a consequence of the amalgamation the results of the Group for the year ended 31 December 2011 and period ended 30 June 2012 comprise the results of Ten Degrees North Energy Limited consolidated with those of Trinity UK. The comparative figures for the period ended 30 June 2011 are those of the Group headed by Ten Degrees North Energy Limited.

Accounting policies

The accounting policies adopted are consistent with those of the previous financial year.

Estimates

The preparation of interim financial statements requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets and liabilities, income and expense. Actual results may differ from these estimates.

In preparing these condensed interim financial statements, the significant judgements made by management in applying the group's accounting policies and the key sources of estimation uncertainty were the same as those that applied to the consolidated financial statements for the year ended 31 December 2011.

Entities under common control

Business combinations involving entities under common control are excluded from the scope of IFRS 3 and have been accounted for using predecessor accounting. The principles of predecessor accounting are:

- no assets or liabilities are restated to their fair values;
- no goodwill arises; and
- the acquired Group's results and balance sheet are incorporated into the new Group as if both entities had always been combined.

2 Property, Plant and Equipment

	Plant & Equipment $'000	Land & Buildings $'000	Oil & Gas Property $'000	Other $'000	Total $'000
Period ended 30 June 2012					
Opening net book amount	897	1,158	54,012	181	56,248
Translation difference	(8)	(10)	(548)	(1)	(567)
Additions	855	319	1,581	—	2,455
Depreciation, depletion and amortisation charge for period	(142)	(82)	(3,329)	(9)	(3,553)
Closing net book amount	**1,301**	**1,385**	**51,725**	**171**	**54,583**
At 31 December 2011					
Cost	6,015	1,567	120,525	495	128,602
Accumulated depreciation, depletion, amortisation and impairment	(4,705)	(172)	(68,252)	(323)	(73,452)
Translation Difference	(8)	(10)	(148)	(1)	(567)
Closing net book amount	**1,302**	**1,385**	**51,725**	**171**	**54,583**

	Plant & Equipment $'000	Land & Buildings $'000	Oil & Gas Property $'000	Other $'000	Total $'000
Period ended 30 June 2011					
Opening net book amount	857	288	12,402	172	13,659
Translation difference	(3)	(11)	(17)	(2)	(23)
Additions	170	—	1,396	—	1,566
Disposals	(194)	—	—	—	(194)
Depreciation, depletion and amortisation charge for period	(119)	(27)	(583)	(9)	(738)
Closing net book amount	**711**	**250**	**13,198**	**161**	**14,270**
At 31 December 2011					
Cost	6,788	301	69,014	466	76,569
Accumulated depreciation, depletion, amortisation and impairment	(6,074)	(100)	(55,799)	(303)	(62,276)
Translation Difference	(3)	(1)	(17)	(2)	(23)
Closing net book amount	**711**	**200**	**11,192**	**161**	**24,270**

2 Property, Plant and Equipment (Continued)

	Plant & Equipment	Land & Buildings	Oil & Gas Property	Other	Total
	$'000	$'000	$'000	$'000	$'000
Year ended 31 December 2011					
Opening net book amount	857	228	12,402	172	13,659
Additions—Oilbelt Services	203	95	37,460	29	37,787
Additions	297	3	6,026	—	6,326
Disposals	(201)	—	—	—	(201)
Work in progress	—	849	145	—	994
Adjustment to decommissioning estimate	—	—	1,294	—	1,294
Depreciation, depletion and amortisation charge for year	(259)	(17)	(3,315)	(20)	(3,611)
Closing net book amount	**897**	**1,158**	**54,012**	**181**	**56,248**
At 31 December 2011					
Cost	5,460	1,248	118,944	495	126,147
Accumulated depreciation, depletion, amortisation and impairment	(4,563)	(90)	(64,932)	(314)	(69,899)
Closing net book amount	**897**	**1,158**	**54,012**	**181**	**56,248**

3 Due from related party

An amount of $0.9 million is receivable from the previous shareholders of Oilbelt Services Limited for petroleum profits tax paid by Trinity Exploration and Production Limited on Oilbelts' behalf for the period January—July 2011. This amount is included within Trade and Other Receivables.

4 Issue of share capital

On 25 April 2012, the company issued 925 ordinary shares (nominal value $1) at $4,185 per share to a former member of the management team. These shares were issued in full settlement of a financial liability which existed at 31 December 2011, which amounted to $3.9 million. The financial liability was presented within trade and other payables prior to being settled.

5 Merger reserves

Merger reserves were formed on the amalgamation of Ten Degrees North Energy Limited and Oilbelt Services Ltd. Merger reserves are analysed further in the Condensed Consolidated Statement of Changes in Equity.

6 Borrowings and Loans

	30 June 2012	30 June 2011	31 December 2011
	$'000	$'000	$'000
Non Current	6,139	—	8,460
Current	4,268	5,027	6,251
	10,407	**5,027**	**14,711**

6 Borrowings and Loans (Continued)

Movements in borrowings are analysed as follows:

	$'000
Six months ended 30 June 2012	
Opening amount as at 1 January 2012	14,711
Repayment of borrowings	(4,303)
Foreign exchange movement	(4)
Closing amount as at 30 June 2012	**10,407**
Six months ended 30 June 2011	
Opening amount as at 1 January 2011	6,124
Repayment of borrowings	(1,097)
Closing balance as at 30 June 2011	**5,027**
Year ended 31 December 2011	
Opening amount as at 01 January 2011	
Repayment of borrowings	(6,163)
Proceeds from new borrowings	16,500
Non cash movement	(1,661)
Foreign exchange	(89)
Closing balance at 31 December 2011	**14,711**

7 Taxation

	30 June 2012	30 June 2011	31 December 2011
	$'000	$'000	$'000
Current tax			
—Current period			
Petroleum profits tax	3,419	904	4,350
Supplemental petroleum tax	4,916	2,643	7,359
Deferred tax			
—Current period			
Movement in asset due to tax losses	285	—	(12,472)
Movement in liability due to (unwinding)/accelerated tax depreciation	(1,300)	—	1,415
Tax charge	**7,320**	**3,547**	**652**

7 Taxation (Continued)

The Group parent company is domiciled in the UK. All production activities take place in Trinidad and Tobago. The Group's effective tax rate varies from the statutory rate for petroleum companies in Trinidad and Tobago of 55% as a result of the differences shown below:

	30 June 2012	30 June 2011	31 December 2011
	$'000	$'000	$'000
Profit before taxation	**9,701**	**5,487**	**13,430**
Tax charge at expected rate of 55% (Jun 2011: 55%), (Dec 2011: 55%)	5,336	3,018	7,387
Effects of:			
Disallowable expenses	12	—	3,819
Deferred tax asset/(liability) not recognized	242	(425)	(1,061)
Tax loss generated not recognized	370	—	587
Tax losses utilized but not previously recognized	(831)	—	(54)
Tax claimed on workover cost capitalized	—	(150)	(247)
Prior year tax losses recognized in current period	—	—	(12,902)
Supplemental petroleum tax	2,256	1,189	3,311
Other differences	(65)	(85)	(188)
Tax charge	**7,320**	**3,547**	**652**

8 Earnings Per Share

Basic earnings per share is calculated by dividing the earnings attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the period. Diluted earnings per share

8 Earnings Per Share (Continued)

is calculated using the weighted average number of ordinary shares adjusted to assume the conversion of all dilutive potential ordinary shares.

	Earnings—Total Comprehensive (Loss)/Income For The Period	Weighted Average Number Of Shares	Earnings Per Share
	$'000		$
Period ended 30 June 2011			
Basic	**1,940**	**21,870**	**89**
Impact of dilutive ordinary shares:			
Bovaro Warrants	—	514	—
Centrica Convertible Loan Notes	—	1,195	—
Diluted	**1,940**	**23,579**	**82**
Year ended 31 December 2011			
Basic	**12,778**	**25,046**	**510**
Impact of dilutive ordinary shares:			
Centrica Convertible Loan Notes	—	1,195	—
Oriel Warrants	—	17	—
Settlement of Financial Liability	—	925	—
Diluted	**12,778**	**27,183**	**470**
Period ended 30 June 2012			
Basic	**2,381**	**33,594**	**71**
Impact of dilutive ordinary shares:			
Centrica Convertible Loan Notes	—	1,195	—
Oriel Warrants	—	17	—
Diluted	**2,381**	**34,806**	**68**

The earnings per share figures for the period ended 30 June 2011 are presented based upon the Group and capital structure before the insertion of Trinity Exploration and Production Limited as the new top company. As a result, the comparative figures are based upon the capital structure of the previous Ten Degrees North Energy Limited Group.

9 Contingent liabilities

(i) A subsidiary Company is a defendant in certain legal proceedings. A claim was made against the subsidiary by Mora Ven Holdings limited. The claim being made was that the subsidiary bought the shares of Ligo Ven Resources Limited, a fellow subsidiary, at gross under-value. Management, after taking appropriate professional advice, is of the view that no material liabilities will crystallize and accordingly no provision has been made in the financial statements for any potential liabilities.

(ii) The group has performance bonds in respect of its lease operatorship agreements and licences amounting to approximately $334,000.

(B) ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION RELATING TO TRINITY

The Directors and Proposed Directors
Bayfield Energy Holdings plc
Burdett House
Fourth Floor
15 – 16 Buckingham Street
London
WC2N 6DU

Seymour Pierce Limited (the "**Nominated Adviser**")
20 Old Bailey
London
EC4M 7EN

25 January 2013

Dear Sirs

Trinity Exploration and Production Limited

We report on the financial information set out in Section C of this Part VII (the "**Target Group Financial Information Table**"). The Target Group Financial Information Table has been prepared for inclusion in the admission document dated 25 January 2013 (the "**Admission Document**") of Bayfield Energy Holdings plc (the "**Company**") on the basis of the accounting policies set out in Note 2 of the Target Group Financial Information Table. This report is required by Schedule Two of the AIM rules for Companies published by the London Stock Exchange plc (the "**AIM Rules**") and is given for the purpose of complying with that Schedule and for no other purpose.

Responsibilities

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

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

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and for any responsibility arising under paragraph (a) of Schedule Two of the AIM Rules to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and

PricewaterhouseCoopers LLP, 32 Albyn Place, Aberdeen AB10 1YL
T: +44 (0) 1224 210100, F: +44 (0) 1224 253318, www.pwc.co.uk

given solely for the purposes of complying with Schedule Two to the AIM Rules, consenting to its inclusion in the Admission Document.

Basis of opinion

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

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

Opinion

In our opinion, the Target Group Financial Information Table gives, for the purposes of the Admission Document dated 25 January 2013, a true and fair view of the state of affairs of Trinity Exploration and Production Limited as at the dates stated and of its profits/losses, cash flows and changes in equity/recognised income and expense for the periods then ended in accordance with International Financial Reporting Standards as adopted by the European Union.

Declaration

For the purposes of paragraph (a) of Schedule Two of the AIM Rules we are responsible for this report as part of the Admission Document and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the Admission Document in compliance with paragraph (a) of Schedule Two to the AIM Rules.

Yours faithfully

PricewaterhouseCoopers LLP
Chartered Accountants

(C) HISTORICAL FINANCIAL INFORMATION RELATING TO TRINITY

Trinity Exploration and Production Limited
Consolidated Statement of Financial Position
for the 3 years ended 31 December 2011
(Expressed in United States Dollars)

	Notes	Restated 2009	Restated 2010	2011
		$'000	$'000	$'000
ASSETS				
Non-current Assets				
Property, plant and equipment	5	14,443	13,659	56,248
Intangible assets	6	—	—	16,952
Investments	7	10,000	—	—
Deferred tax asset	19	—	—	12,882
		24,443	13,659	86,082
Current Assets				
Inventories	8	1,964	1,879	1,499
Trade and other receivables	9	4,964	5,748	10,892
Taxation recoverable	10	124	325	119
Short-term investments	11	37	37	37
Cash and cash equivalents	26	4,518	5,148	26,769
		11,607	13,137	39,316
Total Assets		**36,050**	**26,796**	**125,398**
EQUITY AND LIABILITIES				
Capital and Reserves Attributable to Equity Holders of the Company				
Share capital	12	23,070	21,720	33
Share premium	12	—	—	13,751
Share warrants	13	514	514	71
Merger reserve	14	—	—	53,172
Translation reserve		(98)	140	280
Accumulated losses		(23,657)	(24,727)	(11,949)
Total Equity		**(171)**	**(2,353)**	**55,358**
Non-current Liabilities				
Convertible loan notes	15	10,000	9,337	6,837
Borrowings	16	10,000	—	8,460
Decommissioning provision	17	1,754	1,908	6,402
Provision for employee retirement benefits	18	—	—	728
Deferred tax liability	19	98	54	19,504
		21,852	11,299	41,931
Current Liabilities				
Trade and other payables	20	10,153	10,314	14,677
Borrowings	16	2,730	6,124	6,251
Taxation payable	10	1,486	1,412	7,181
		14,369	17,850	28,109
Total Liabilities		**36,221**	**29,149**	**70,040**
Total Shareholders' Equity and Liabilities		**36,050**	**26,796**	**125,398**

Trinity Exploration and Production Limited

Consolidated Statement of Comprehensive Income

for the 3 years ended 31 December 2011

(Expressed in United States Dollars)

By function of expense	Notes	Restated 2009	Restated 2010	2011
		$'000	$'000	$'000
Operating Revenues				
Crude oil sales		22,434	26,023	53,167
Other income		271	672	723
		22,705	26,695	53,890
Operating Expenses				
Royalties		(7,157)	(8,018)	(18,366)
Production costs		(5,877)	(8,106)	(8,460)
Depreciation, depletion and amortisation		(2,415)	(1,699)	(3,611)
General and administrative expenses		(2,502)	(2,788)	(4,461)
		(17,951)	(20,611)	(34,898)
Operating Profit	21	4,754	6,084	18,992
Impairment of Property, Plant and Equipment	5	(3,015)	—	—
Finance Income		1,296	969	206
Finance Costs	22	(2,452)	(3,347)	(5,768)
Finance Costs—Net		(1,156)	(2,378)	(5,562)
Profit before Taxation		**583**	**3,706**	**13,430**
Taxation Charge	23	(3,696)	(4,776)	(652)
(Loss)/Profit for the Year		**(3,113)**	**(1,070)**	**12,778**
(Loss)/Profit Attributable to:				
Owners of the parent		(3,113)	(1,070)	12,778
Earnings per share (expressed in dollars per share)				
Basic	24	(135)	(48)	510
Diluted	24	(126)	(45)	470
(Loss)/Profit for the Year		**(3,113)**	**(1,070)**	**12,778**
Other Comprehensive Income		**(98)**	**238**	**140**
Total Comprehensive (Loss)/Income for the Year		**(3,211)**	**(832)**	**12,918**
Attributable to:				
Owners of the parent		(3,211)	(832)	12,918

Trinity Exploration and Production Limited

Consolidated Statement of Changes in Equity

for the 3 years ended 31 December 2011

(Expressed in United States Dollars)

	Share Capital	Share Premium	Share Warrant	Merger reserve	Merger difference	Translation Reserve	Accumulated Losses	Total
	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
Year ended 31 December 2009— Restated								
Balance at beginning of year	23,070	—	514	—	—	—	(20,544)	3,040
Translation difference	—	—	—	—	—	(98)	—	(98)
Comprehensive loss for the year	—	—	—	—	—	—	(3,113)	(3,113)
Balance at end of year	**23,070**	**—**	**514**	**—**	**—**	**(98)**	**(23,657)**	**(171)**
Year ended 31 December 2010— Restated								
Balance at beginning of year	23,070	—	514	—	—	(98)	(23,657)	(171)
Repurchase of shares	(1,200)	—	—	—	—		—	(1,200)
Translation difference	(150)	—	—	—	—	238	—	88
Comprehensive loss for the year	—	—	—	—	—	—	(1,070)	(1,070)
Balance at end of year	**21,720**	**—**	**514**	**—**	**—**	**140**	**(24,727)**	**(2,353)**

Trinity Exploration and Production Limited

Consolidated Statement of Changes in Equity

for the 3 years ended 31 December 2011

(Expressed in United States Dollars)

	Share Capital	Share Premium	Share Warrant	Merger reserve	Merger difference	Translation Reserve	Accumulated Losses	Total
	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
Year ended 31 December 2011								
Balance at beginning of year	21,720	—	514	—	—	140	(24,727)	(2,353)
Conversion of share warrant to shares (note 13)	514	—	(514)	—	—	—	—	—
Issue of shares to satisfy Oilbelt consideration (note 30)	7,479	—	—	—	—	—	—	7,479
Amalgamation of Ten Degrees North Energy Limited and Oilbelt Services Ltd—cancellation of existing shares	(29,713)	—	—	—	—	—	—	(29,713)
Amalgamation of Ten Degrees North Energy Limited and Oilbelt Services Ltd—issue of shares by the Company	30	—	—	124,943	(71,771)	—	—	53,202
Issue of shares for cash (note 12)	3	14,200	—	—	—	—	—	14,203
Cost of share issue (note 12)	—	(378)	—	—	—	—	—	(378)
Share warrant issued (note 13)	—	(71)	71	—	—	—	—	—
Translation difference	—	—	—	—	—	140	—	140
Comprehensive income for the year	—	—	—	—	—	—	12,778	12,778
Balance at end of year	**33**	**13,751**	**71**	**124,943**	**(71,771)**	**280**	**(11,949)**	**55,358**

The balances disclosed as at 31 December 2009 and 31 December 2010 represent the equity position for the predecessor Group, Ten Degrees North Energy Limited (now Trinity Exploration and Production (Trinidad & Tobago) Limited).

The Company was incorporated on 4 April 2011 through the issue of 1 share at a nominal value of $1. Through an amalgamation with Ten Degrees North Energy Limited (now Trinity Exploration and Production (Trinidad & Tobago) Limited), the Company became the new parent company of the Group and therefore the share capital of Ten Degrees North Energy Limited was replaced by that of Trinity Exploration and Production Limited. The insertion of the new parent company qualified for merger relief under s.612 of the UK Companies Act 2006, which resulted in the creation of a merger reserve and merger difference as described in note 14.

Trinity Exploration and Production Limited

Consolidated Statement of Cash Flows

for the 3 years ended 31 December 2011

(Expressed in United States Dollars)

	Notes	Restated 2009	Restated 2010	2011
		$'000	$'000	$'000
Cash Flows from Operating Activities				
Profit before taxation		583	3,706	13,430
Adjustments for:				
Profit on disposal of property, plant and equipment (PPE)		(21)	(66)	(110)
Interest paid on loans		2,178	2,338	1,142
Finance cost—change in fair value of financial liability		—	—	3,822
Finance cost—decommissioning provision		274	170	273
Interest received		(1,296)	(969)	(206)
Impairment of producing assets		3,015	—	—
Depreciation depletion and amortisation		2,415	1,699	3,611
		7,148	**6,878**	**21,962**
Changes In Working Capital				
Decrease/(increase) in inventory		216	(73)	458
(Increase) in trade and other receivables		(1,985)	(813)	(5,144)
Increase in trade and other payables		6,691	320	1,050
		12,070	**6,312**	**18,326**
Taxation paid		(3,900)	(5,073)	(7,359)
Net Cash Generated from Operating Activities		**8,170**	**1,239**	**10,967**
Cash Flows from Investing Activities				
Interest received		1,296	969	206
Acquisition of subsidiary		—	—	(1,402)
Purchase of PPE		(7,093)	(1,000)	(7,320)
Proceeds from sale of PPE		32	145	311
Proceeds from sale of short-term investment		6,121	—	—
Well abandonment		(41)	—	—
Net Cash Generated/(Used) in Investing Activities		**315**	**114**	**(8,205)**
Cash Flows from Financing Activities				
Repurchase of shares		—	(1,192)	—
Proceeds from issuance of shares (net of costs)		—	—	12,164
Repayment of convertible shareholder loan notes		—	(658)	(2,500)
Interest paid on loans		(2,178)	(2,338)	(1,142)
Repayment of borrowings		(6,267)	(2,659)	(6,163)
Proceeds from new borrowings		—	6,124	16,500
Net Cash (Used)/Generated from Financing Activities		**(8,445)**	**(723)**	**18,859**
Net Increase in Cash and Cash Equivalents		**40**	**630**	**21,621**
Cash and Cash Equivalents at Beginning of Year		4,478	4,518	5,148
Cash and Cash Equivalents at End of Year		**4,518**	**5,148**	**26,769**

Trinity Exploration and Production Limited
Notes to the Consolidated Financial Information

1 Incorporation and Principal Activities

Trinity Exploration and Production Limited is incorporated in Scotland with its registered office c/o McGrigors LLC, 52-54 Rose Street, Aberdeen, AB10 1UD, United Kingdom. It is the ultimate parent Company of the Group with a 100% interest in Trinity Exploration and Production (Barbados) Limited. The Group comprises the entities as described below:

Trinity Exploration and Production (Barbados) Limited was incorporated on June 10, 2011 under the Companies Act Cap 308 of the Laws of Barbados with its registered office located at Worthing Corporate Centre, Worthing Corporate Centre, Worthing, Christ Church BB 15008, Barbados. It has a 100% interest in Trinity Exploration and Production (Trinidad & Tobago) Limited.

Trinity Exploration and Production (Trinidad & Tobago) Limited is incorporated in the Republic of Trinidad and Tobago with its registered office located at 88-90 Lady Hailes Avenue San Fernando, Trinidad, West Indies. Its wholly owned subsidiaries are Ten Degrees North Operating Company Limited (formerly Venture Production Trinidad Limited), Oilbelt Services Limited and Tabaquite Exploration and Development Company Limited. Ten Degrees North Operating Company Limited's wholly owned subsidiaries are NAKT Company Limited, Antilles Resources Limited, Coastline International Inc, Lennox Production Services Limited, Pioneer Petroleum Company Limited, Ligo Ven Resources Limited, Ten Degrees North Services Limited (formerly Antilles Drilling and Workover Company Limited). All of the subsidiaries are incorporated in the Republic of Trinidad and Tobago with the exception of Coastline International Inc. which is incorporated in the United States of America but resident in Trinidad and Tobago.

The principal activities occur at the Trinity Trinidad level, which are the exploration, development, production and sale of crude oil and natural gas under exploration & production, farmout and lease operatorship agreements with Petroleum Company of Trinidad and Tobago Limited (Petrotrin). Ten Degrees North Services Limited provides administrative, drilling and workover services to all companies in the Group and is not engaged in exploration and production activities. Under the lease operatorship and farmout agreements, the Group companies are authorised to perform petroleum operations as follows:

Ten Degrees North Operating Company Limited (formerly Venture Production Trinidad Limited)

Ten Degrees North Operating Company Limited (TDNOCL) has two main areas of operation:

i) Point Ligoure field

TDNOCL is part of a Joint Venture Consortium for the Point Ligoure field, located offshore Trinidad. It has a 25% interest in the field, with Ligo Ven Resources Limited (a 100% subsidiary of TDNOCL) holding a 17.5% interest, Krishna Persad & Associates Limited a 7.5% interest and Petroleum Company of Trinidad and Tobago Limited (Petrotrin) the remaining 50%.

The main agreements governing this arrangement are:

1) The Exploration & Production licence for the block which is dated 7 October 1999 for a period of thirty years from 1 July 1980. At the date of issue of the consolidated financial information this licence has expired but operations continue normally and the licence is in the process of being renewed.
2) A farmout agreement dated in 2000 for a period of five years or until the consortium fulfils its minimum work obligations. Minimum work obligations were fulfilled and certified by Petrotrin on 1 July 2003.
3) The Joint Operating Agreement which was valid until expiry of the licence.

ii) Brighton Marine Block

This block located offshore Trinidad comprises sub-areas 'A' and 'B'. There are no commercial operations in sub-area 'A'. The interests in sub-area 'A' are: TDNOCL (65%) and Petrotrin (35%). The original interests in sub-area 'B' were—TDNOCL (55%) and Petrotrin (45%). Effective 1 July 2002 TDNOCL's interest in sub-area 'B' increased to 100%. This was achieved via

1 Incorporation and Principal Activities (Continued)

conversion of Petrotrin's 45% interest into an overriding royalty (ORR) which is governed by an ORR Agreement. TDNOCL is the designated operator of the Block as stated in the Joint Operating Agreement. In November 2005 TDNOCL relinquished its interest in sub-area "A". The Brighton Marine Block now only consists of sub-area "B".

There are four agreements governing this block, they are:

1) Exploration & Production licence dated 7 October 1999, effective for a period of six years from this date and subsequently renewed for a term not exceeding twenty-five years.

2) A Farmout agreement dated 7 October 1999 effective for a period of six years. All minimum work obligations were met.

3) Joint Operating Agreement dated 7 October 1999 effective until expiry of the Exploration & Production licence as noted above.

4) ORR agreement with a conversion date of 1 July 2002. The agreement came into force on the conversion date and shall endure a period of ten years.

Antilles Resources Limited

Antilles Resources Limited has a lease operatorship with Petrotrin for the WD 13 Block located at Forest Reserve. The lease operatorship agreement was renewed in 2011 with a lease term of 10 years expiring 31 December 2020.

NAKT Company Limited

NAKT Company Limited has a lease operatorship with Petrotrin for the WD 14 Block located at Forest Reserve. The lease operatorship agreement was renewed in 2011 with a lease term of 10 years expiring 31 December 2020.

Ligo Ven Resources Limited

Ligo Ven Resources Limited is a 100% subsidiary of TDNOCL. Ligo Ven is part of the Joint Venture Consortium for the Point Ligoure field as noted above. At the date of issue of the consolidated financial information the licence for this field has expired but operations continue normally and the licence is in the process of being renewed.

Coastline International Inc.

Coastline International Inc. has an Exploration & Production sub licence (Farmout) with Petrotrin for the Tabaquite block. The agreement dated 4 January 1995 has various renewal options.

There was a subsequent agreement dated 1 March 2000 with various renewal options which expired on 28 February 2010.

The terms of the renewed agreement have been agreed with Petrotrin but the agreement has not been executed pending renewal of the exploration and production head licence between Petrotrin and the Government of Trinidad and Tobago.

Lennox Production Services Limited

Lennox Production Services Limited has lease operatorship agreements with Petrotrin for the FZ 2, WD 2 and WD 16 Blocks located at Forest Reserve. The lease operatorship agreement was renewed in 2011 with a lease term of 10 years expiring 31 December 2020.

1 Incorporation and Principal Activities (Continued)

Pioneer Petroleum Company Limited

Pioneer Petroleum Company Limited has a lease operatorship agreement with Petrotrin for the Guapo 1 (GU1) Block located at Guapo. The lease operatorship agreement was renewed in 2011 with a lease term of 10 years expiring 31 December 2020.

Ten Degrees North Services Limited (formerly Antilles Drilling and Workover Company Limited)

Ten Degrees North Services Limited is a limited liability Company incorporated in Trinidad and Tobago under the Companies Act 1995. Its principal business activity is the provision of drilling and workover services.

Oilbelt Services Limited

Oilbelt Services Limited has a lease operatorship agreement with Petrotrin for the WD5/6 Block located at Forest Reserve. This Company was recently acquired through a business combination agreement effective 1 August 2011. The lease operatorship agreement was renewed in 2011 with a lease term of 10 years expiring 31 December 2020.

Tabaquite Exploration & Development Company Limited

This company is incorporated in Trinidad and Tobago under the Companies Act 1995 and currently has no trading activities. The intention is when the licence for the Tabaquite block is renewed it will be renewed under this entity. (see Coastline International Inc on previous page)

2 Summary of Significant Accounting Policies

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

2.1 Basis of preparation

This consolidated financial information has been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU, the IFRIC interpretations and Companies Act 2006. This consolidated financial information has been prepared under the historical cost convention.

The preparation of the consolidated financial information in conformity with IFRS requires the use of certain critical accounting estimates. It also requires management to exercise its judgement in the process of applying the Group's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial information are disclosed in note 4.

Trinity Exploration and Production Limited ("Trinity UK") was incorporated in England and Wales on 4 April 2011. On 30 November 2011, a new UK parent company structure became effective by way of a share for share exchange ("amalgamation") between the shareholders of Ten Degrees North Energy Limited (the previous parent company) and Trinity UK (the new parent company) and the Group became Trinity Exploration and Production Limited. As a consequence of the amalgamation the results of the Group for the year ended 31 December 2011 comprise the results of Ten Degrees North Energy Limited consolidated with those of Trinity UK. The comparative figures for the years ended 31 December 2009 and 31 December 2010 are those of the Group headed by Ten Degrees North Energy Limited. The acquisition was accounted as a business combination for entities under common control. The control of the Group remained the same before and after the transaction. As a result, this consolidated financial information adopts predecessor accounting whereby:

- no assets or liabilities are restated to their fair values;
- no goodwill arises; and

2 Summary of Significant Accounting Policies (Continued)

- the acquired Group's results and balance sheet are incorporated into the new Group as if both entities had always been combined.

The following standards and amendments to existing standards have been published and are mandatory for the first time for the financial year beginning 1 January 2011 but had no significant impact on the Group:

- The amendments to IFRS 1 relating to (a) accounting policy changes in year of adoption, (b) revaluation as deemed cost and of deemed cost for operations subject to rate regulation (c) additional exemptions for first time adopters, and (d) limited exemption from comparative IFRS 7 disclosure for first-time adopters.
- IFRS 7—clarification of disclosures. The amendments emphasise the interaction between quantitative and qualitative disclosures about the nature and extent of risks associated with financial instruments.
- IAS 1—clarification of the Statement of Changes in Equity ('SOCE'). The amendments clarify that an entity will present an analysis of other comprehensive income for each component of equity, either in the statement of changes in equity or in the notes to the consolidated financial information.
- IAS 24—Related Party Disclosures—Revised definition of related parties. The IAS is applicable for periods beginning on or after 1 January 2011. It clarifies and simplifies the definition of a related party.
- IAS 27—describing the transition for amendments resulting from IAS 27 (2008).
- IAS 32—Financial Instruments: Presentation—Amendments relating to classification of rights issues. The IAS addresses the accounting for rights issues that are denominated in a currency other than the functional currency of the issuer.
- IFRIC 14—prepayments of a minimum funding requirement. The amendments are effective for periods beginning on or after 1 January 2011.
- IFRIC 19—Extinguishing liabilities with equity instruments. The IFRIC is applicable for periods beginning on or after 1 July 2010. The interpretation clarifies the accounting by an entity when the terms of a financial liability are renegotiated and result in the entity issuing equity instruments to a creditor of the entity to extinguish all or part of the financial liability.

The following new standards, amendments to standards and interpretations have been issued, but are not effective (and in some cases had not yet been adopted by the EU) for the financial year beginning 1 January 2011 and have not been early adopted.

- IFRS 7—clarification of disclosures. For accounts beginning on or after 1 July 2011 amendments require additional disclosure on transfer transactions of financial assets, including the possible effects of any residual risks that the transferring entity retains. The amendments also require additional disclosures if a disproportionate amount of transfer transactions are undertaken around the end of a reporting period.
- IFRS 9—Financial Instruments—Classification and Measurement. The standard is applicable for periods beginning on or after 1 January 2013 and introduces new requirements for classifying and measuring financial assets.
- IFRS 10—The new standard, effective from 1 January 2013, will establish principles for the presentation and preparation of consolidated financial statements.
- IFRS 11—Joint Arrangements—IFRS 11 is a more realistic reflection of joint arrangements by focusing on the rights and obligations of the arrangement rather than its legal form. There are two types of joint arrangement: joint operations and joint ventures. Proportional consolidation of joint ventures is no longer allowed. The standard is applicable for periods beginning on or after 1 January 2013.

2 Summary of Significant Accounting Policies (Continued)

- IFRS 12—Interests in Other Entities—IFRS 12 includes the disclosure requirements for all forms of interests in other entities, including joint arrangements, associates, special purpose vehicles and other off balance sheet vehicles. The standard is applicable for periods beginning on or after 1 January 2013.
- IFRS 13—Fair Value Measurement—IFRS 13 aims to improve consistency and reduce complexity by providing a precise definition of fair value and a single source of fair value measurement and disclosure requirements for use across IFRSs. The standard is applicable for periods beginning on or after 1 January 2013.

The Group is yet to assess the full impact of these new standards and amendments but does not expect them to have a material impact on the consolidated financial information.

The consolidated financial information incorporates the financial information of the Company and entities controlled by the Company (its subsidiaries) made up to 31 December each year. Control is achieved where the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities.

The results of subsidiaries acquired or disposed of during the year are included in the consolidated statement of comprehensive income from the effective date of acquisition and up to the effective date of disposal, as appropriate.

The acquisition method of accounting is used to account for the acquisition of subsidiaries by the Group. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date, irrespective of the extent of any minority interest. The excess of the cost of acquisition over the fair value of the Group's share of the identifiable net assets acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognised directly in the statement of comprehensive income (note 2.8).

Uniform accounting policies have been adopted across the Group. All intra-Group transactions, balances, income and expenses are eliminated on consolidation.

2.3 Business combination

The acquisition of subsidiaries is accounted for using the purchase method. For each business combination, the cost of the acquisition is measured at the aggregate of the fair values, at the date of exchange, of assets given, liabilities incurred or assumed, and equity instruments issued by the Group in exchange for control of the acquiree, plus any costs directly attributable to the business combination. The acquiree's identifiable assets, liabilities and contingent liabilities that meet the conditions for recognition under IFRS 3 are recognised at their fair value at the acquisition date. Where the Group has acquired assets held in a subsidiary undertaking that do not meet the definition of a business combination, purchase consideration is allocated to the net assets acquired and the interests of non-controlling shareholders are initially measured at their proportionate share of the acquiree's net assets.

2.4 Revenue recognition

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for the sale of crude oil and services provided in the ordinary course of business, net of discounts and sales related taxes. Revenue is recognised when goods are delivered and title has passed.

Interest income is accrued on a time basis, by reference to the principal outstanding and the interest rate applicable, unless collectability is in doubt.

2 Summary of Significant Accounting Policies (Continued)

2.5 Share-based payments

The Group operates a number of equity-settled, share-based compensation plans (warrants/options) as consideration for services the entity receives, under which the entity receives services from employees. The fair value of the services received in exchange for the grant of options/warrants is recognised as an expense. The total amount to be expensed is determined by reference to the fair value of the options granted:

– including any market performance conditions (for example, an entity's share price);

– excluding the impact of any service and non-market performance vesting conditions and

– including the impact of any non-vesting conditions

Non-market performance and service conditions are included in assumptions about the number of options/warrants that are expected to vest. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied

At the end of each reporting period, the Group revises its estimates of the number of options that are expected to vest based on the non-market vesting conditions. It recognises the impact of the revision to original estimates, if any, in the statement of comprehensive income, with a corresponding adjustment to equity. When the options are exercised, the Group issues new shares. The proceeds received net of any directly attributable transaction costs are credited to share capital (nominal value) and share premium.

Where the services provided relate solely to the issue of share capital, the expense will be charged to equity within the share premium account.

2.6 Foreign currency translation

i) Functional and presentation currency

The functional currency of the Group operating entity is Trinidad & Tobago dollars as this is the currency of the primary economic environment in which the entities operate. This financial information is presented in United States Dollars which is the Group's presentation currency. The Statement of Financial Position is translated at the closing rate and Statement of Comprehensive Income is translated at the average rate. The following exchange rates have been used in the preparation of these accounts:

	2009	2010	2011
Average rate TTD=USD	6.286	6.340	6.400
Closing rate TTD=USD	6.290	6.329	6.343

ii) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year-end exchange rates of monetary assets and liabilities denominated in foreign currencies, and recognised in the statement of comprehensive income.

2.7 Property, plant and equipment

a) Oil and gas assets

Exploration and Evaluation Assets—Capitalisation

Oil and natural gas exploration and evaluation expenditures are accounted for using the successful efforts method of accounting. Under this method, costs are accumulated on a field-by-field basis and capitalised within property, plant and equipment upon discovery of commercially viable mineral reserves. If the commercial viability is not achieved or achievable, such costs are charged to expense.

2 Summary of Significant Accounting Policies (Continued)

Costs incurred in the exploration and evaluation of assets includes:

License and property acquisition costs

Exploration and property leasehold acquisition costs are capitalised until determination of commercially viable mineral reserves. If commercial viability is not obtained these costs are written off.

Exploration and evaluation expenditure

Capitalisation is made within property, plant and equipment. Costs directly associated with an exploration well are capitalised until the determination of commercial reserves is evaluated. Such costs include topographical, geological, geochemical and geophysical studies, exploratory drilling costs, trenching, sampling and activities in relation to evaluating the technical feasibility and commercial viability of extracting mineral resources. If commercial reserves are found the costs continue to be carried as an asset. If commercial reserves are not found, exploration and evaluation expenditures are written off as a dry hole when that determination is made.

Once commercial reserves are found, exploration and evaluation assets are tested for impairment. No depreciation and/or amortisation are charged during the exploration and evaluation phase. Capitalised geological and geophysical costs are depreciated over the remaining period of the underlying exploration and production licences.

Exploration and Evaluation Assets—Impairment

Exploration and evaluation assets are tested for impairment (in accordance with the criteria set out in IFRS 6: Exploration for and Evaluation of Mineral Resources) whenever facts and circumstances indicate impairment. An impairment loss is recognised for the amount by which the exploration and evaluation assets' carrying amount exceed their recoverable amount. The recoverable amount is the higher of the exploration and evaluations assets' fair value less costs to sell and their value in use. For the purposes of assessing impairment, the exploration and evaluation assets subject to testing are grouped with existing cash generating units (CGUs) of related production fields located in the same geographical region. The geographical region is the same as that used for reserves reporting purposes.

The following indicators are evaluated to determine whether these assets should be tested for impairment:

- The period for which the Group has the right to explore in the specific area.
- Whether substantive expenditure on further exploration and evaluation in the specific area is budgeted or planned.
- Whether exploration and evaluation in the specific area have not led to the discovery of commercially viable quantities and the Company has decided to discontinue such activities in the specific area.
- Whether sufficient data exist to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the exploration and evaluation asset is unlikely to be recovered in full from successful development or by sale.

Development and Production Assets—Capitalisation

Acquisitions of oil and gas properties are accounted for under the purchase method where the transaction meets the definition of a business combination.

Transactions involving the purchases of an individual field interest, or a group of field interests, that do not qualify as a business combination are treated as asset purchases, irrespective of whether the specific transactions involve the transfer of the field interests directly, or the transfer of an incorporated entity. Accordingly, the consideration is allocated to the assets and liabilities purchased on a relative fair value basis.

2 Summary of Significant Accounting Policies (Continued)

Proceeds on disposal are applied to the carrying amount of the specific asset or development and production assets disposed of. Any excess is recorded as a gain on disposal in the statement of comprehensive income and any shortfall between the proceeds and the carrying amount is recorded as a loss on disposal in the statement of comprehensive income.

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development commercially proven wells is capitalised according to its nature. When development is completed on a specific field it is transferred to Production Assets. No depreciation and/or amortisation are charged during the development phase.

Expenditure on Geological and Geophysical (G&G) surveys used to locate and identify properties with the potential to produce commercial quantities of oil and gas as well as to determine the optimal location for development wells are capitalised.

Development and Production Assets—Impairment

An impairment test is performed whenever events and circumstances arising during the development or production phase indicate that the carrying value of a development or production asset may exceed its recoverable amount.

The carrying value is compared against the expected recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and the value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels (its cash generating unit) for which there are separately identifiable cash flows. The cash generating unit applied for impairment test purposes is generally the field. These fields are the same as that used for reserves reporting purposes.

Production Assets—Depreciation, depletion and amortisation

The provision for depreciation, depletion and amortisation of proved oil and gas properties is calculated using the unit-of-production method. With respect to the producing assets, the basis used is to write off the book cost of each field in line with the depletion of proved developed reserves.

Capitalised G&G costs are depreciated using the unit of production method, over proved developed and proved undeveloped reserves.

Oil and gas properties are depreciated generally on a field-by-field basis using the unit-of-production method. Unit-of-production rates are based on production and proved reserves, which are oil, gas and other mineral reserves estimated to be recovered from existing wells with existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the field storage tank.

Producing assets are generally grouped into cash generating units with other assets that are dedicated to serving the same reserves for depreciation purposes, but are depreciated separately from producing assets that serve other reserves. The main categories of producing assets are producing wells and production facilities. Wells are depleted over proved developed producing reserves. The facilities are depleted over proved developed and proved undeveloped reserves. The cash generating unit applied for depreciation purposes is generally the field, except that a number of field interests may be grouped as a single cash generating unit where the cash flows of each field are inter-dependent.

Decommissioning

Provision for decommissioning is recognised in full at the commencement of oil and gas production. The amount recognised is the net present value of the estimated cost of decommissioning at the end of the economic producing lives of the wells and the end of the useful lives of refinery and storage units. Such costs include removal of equipment, restoration of land or seabed. The unwinding of the discount on the provision is included in the statement of comprehensive income within finance costs.

2 Summary of Significant Accounting Policies (Continued)

A corresponding asset is also created at an amount equal to the provision. This is subsequently depleted as part of the capital costs of the production assets. Any change in the present value of the estimated expenditure or discount rates are reflected as an adjustment to the provision and the asset and dealt with prospectively.

b) Non-oil and gas assets

All property, plant and equipment are recorded at historical cost less accumulated depreciation and any impairment losses. Historical cost includes the original purchase price of the asset and expenditure that is directly attributable to bringing the asset to its working condition for its intended use. Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably.

The provision for depreciation with respect to operations other than oil and gas producing activities is computed using the straight-line method based on estimated useful lives as follows:

Buildings	5%
Computer and office equipment	25%
Plant and equipment	25%
Vehicles and machinery	25%

Spares are not depreciated.

The assets' residual values and useful lives are reviewed, and adjusted if appropriate at each statement of financial position date. An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount.

Gains and losses on disposals are determined by comparing proceeds with carrying amounts and are included in the statement of comprehensive income.

Repairs and maintenance are charged to the statement of comprehensive income during the financial period in which they are incurred. The cost of major renovations is included in the carrying amount of the asset when it is probable that future economic benefits in excess of the originally assessed standard of performance of the existing assets will flow to the Group. Major renovations are depreciated over the remaining useful life of the related asset.

2.8 Intangible Assets

Goodwill

Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognised for non-controlling interest over the net identifiable assets acquired and liabilities assumed. If this consideration is lower than the fair value of the net assets of the subsidiary acquired, the difference is recognised in profit or loss.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Company's cash-generating units that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

2.9 Impairment of non-financial assets

At each balance sheet date, assets that have an indefinite useful life, for example, goodwill, are not subject to amortisation and are tested for impairment. Assets that are subject to amortisation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value, less costs to sell and

2 Summary of Significant Accounting Policies (Continued)

value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units). Non-financial assets other than goodwill that suffered impairment are reviewed for possible reversal of the impairment at each reporting date.

2.10 Inventories

Crude oil is stated at the lower of cost and net realisable value. Cost is determined by the first in first out (FIFO) method. Net realisable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

Spares are stated at lower of cost and net realisable value. Cost is determined using the average cost (AVCO) method.

2.11 Cash and cash equivalents

Cash and cash equivalents comprises cash in hand, deposits held at call with banks and other short-term highly liquid investments with original maturities of three months or less.

2.12 Trade receivables

Trade receivables are amounts due from customers for crude oil sold in the ordinary course of business. If collection is expected in one year or less (or in the normal operating cycle of the business if longer), they are classified as current assets. If not, they are presented as non-current assets.

Trade receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method less provision for impairment. Appropriate provisions for estimated irrecoverable amounts are recognised in the statement of comprehensive income when there is objective evidence that the Group will not be able to collect all amounts due according to the original terms of sale.

2.13 Trade payables

Trade payables are initially recognised at fair value and subsequently measure at amortised cost using the effective interest method.

2.14 Current and deferred income taxes

The tax expense for the period comprises current and deferred tax. Tax is recognised in the statement of comprehensive income, except to the extent that it relates to items recognised in equity. In this case the tax is also recognised directly in equity.

The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the statement of financial position date in the countries where the Company's subsidiaries and associates operate and generate taxable income. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. It establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred income tax is recognised, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial information. However, the deferred income tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the statement of financial position date and are expected to apply when the related deferred income tax asset is realised or the deferred income tax liability is settled.

Deferred income tax assets are recognised only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilised.

2 Summary of Significant Accounting Policies (Continued)

Deferred income tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets against current tax liabilities and when the deferred income taxes assets and liabilities relate to income taxes levied by the same taxation authority and the Company intends to settle the balances on a net basis.

2.15 Borrowings

Borrowings are recognised initially at fair value net of transaction costs incurred. Borrowings are subsequently stated at amortised cost; any differences between proceeds (net of transaction costs) and the redemption value is recognised in the statement of comprehensive income over the period of the borrowings using the effective interest method.

Borrowings are classified as current liabilities unless the Group has an unconditional right to defer settlement of the liability for at least 12 months after the statement of financial position date.

General and specific borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale.

All other borrowing costs are recognised in comprehensive income in the period in which they are incurred.

2.16 Provisions

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events, where it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made. Provisions are not recognised for future operating losses.

Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a pre tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to passage of time is recognised as expense finance cost.

2.17 Employee retirement benefits

The Group provides retirement benefits for certain employees in the form of individual annuity policies. These are defined contribution instruments.

For defined contribution plans, the Group pays contributions to publicly or privately administered pension insurance plans on a mandatory, contractual or voluntary basis. The Group has no further payment obligations once contributions have been paid. The contributions are recognised as employee benefit expenses when they are due.

In respect of the employees of a subsidiary, retirement benefits are provided for in accordance with the terms of a Union Agreement with severance and length of service payments being payable to employees under this agreement. A liability is provided based upon certain criteria, including the length of service of current employees, likelihood of reaching retirement age while continuing in employment with the Group and average pay over the employees’ length of service.

2 Summary of Significant Accounting Policies

2.18 Convertible loan note

Convertible loan notes are accounted for as borrowings (see note 2.15) in accordance with contractual terms. If loan notes are converted to shares the carrying amount is reduced with a corresponding increase in equity. Convertible loan notes are classified as a liability except where the settlement of the loan will be in shares and the number of shares to be issued upon conversion is fixed, in which case the loan notes will be classified within equity.

2.19 Share capital

Ordinary shares are classified as equity. The nominal value of any shares issued is recognised in share capital with the excess above the nominal amount paid being shown within share premium.

Incremental costs directly attributable to the issue of new ordinary shares are shown in equity. Where, on issuing shares, share premium has been recognised, the expenses of issuing those shares and any commission paid on the issue of those shares have been written off against the share premium account.

Where any Group Company purchases the Company's equity share capital (treasury shares), the consideration paid, including any directly attributable incremental costs (net of income taxes) is deducted from equity attributable to the Company's equity holders until the shares are cancelled or reissued. Where such ordinary shares are subsequently reissued, any consideration received, net of any directly attributable incremental transaction costs and the related income tax effects, and is included in equity attributable to the Company's equity holders.

2.20 Dividends

Dividend distribution is recognised as a liability in the Group's consolidated financial information when it becomes a legally binding obligation of the Company and in the case of a final dividend when the members pass a written resolution.

2.21 Comparatives

Comparatives have been restated for changes in the presentation currency in the current year. The comparatives are presented using the rate in note 2.6.

2.22 Segmental reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision-maker. The chief operating decision-maker ("CODM"), who is responsible for allocating resources and assessing performance of the operating segments, has been identified as the executive board that makes strategic decisions. The CODM considers all segment information on an entity wide basis for the Group's only reportable operating segment, being oil and gas exploration and production through the Group's Trinidadian assets. Therefore, no separate segmental reporting disclosures have been provided in this consolidated financial information and all entity-wide disclosures are provided in the notes to the consolidated financial information.

3 Financial Risk Management

3.1 Financial risk factors

The Group's activities expose it to a variety of financial risks. The Group's overall risk management programme seeks to minimise potential adverse effects on the Group's financial performance.

Risk management is carried out by management. Management identifies and evaluates financial risks.

3 Financial Risk Management (Continued)

a) Market risk

(i) Foreign exchange risk

The Group is exposed to foreign exchange risk primarily with respect to the United States dollar. Foreign exchange risk arises from future commercial transactions and recognised assets and liabilities which are denominated in a currency that is not the entity's functional currency.

At 31 December 2011, if the functional currency had weakened/strengthened by 10% against the US dollar with all other variables held constant, post-tax profit/(loss) for the year would have been $0.3m (2010: $0.6m)(2009: $0.1m)lower/higher, mainly as a result of foreign exchange gains/losses on translation of US dollar-denominated borrowings and sales.

(ii) Price risk

The Group is exposed to commodity price risk regarding its sales of crude oil which is an internationally traded commodity.

(iii) Interest rate risk

The Group's interest rate risk arises from borrowings. Borrowings issued at variable rates expose the Group to cash flow interest rate risk.

At 31 December 2011, if interest rates on currency-denominated borrowings had been 1% higher/lower with all other variables held constant, post-tax profit/(loss) for the year would have been $0.2m (2010: $0.2m) (2009: $0.5m) lower/higher, mainly as a result of higher/lower interest expense on floating rate borrowings.

Credit risk

Credit risk arises from cash and cash equivalents, deposits with banks and financial institutions, as well as credit exposures to customers, including outstanding receivables and committed transactions. For banks and financial institutions, management determines the placement of funds based on its judgement and experience and only independently rated parties with a minimum credit rating of A are accepted.

All sales are made to a state-owned entity—Petroleum Company of Trinidad and Tobago Limited (Petrotrin).

c) Liquidity risk

Prudent liquidity risk management implies maintaining sufficient cash and short-term funds and the availability of funding through an adequate amount of committed credit facilities. Management maintains flexibility in funding.

3 Financial Risk Management (Continued)

The table below analyses the Group's financial liabilities into relevant maturity Groupings based on the remaining period at the statement of financial position to the contractual maturity date. The amounts disclosed are the contractual undiscounted cash flows.

	Less than 1 year	Between 2 and 5 years	Over 5 years
	$'000	$'000	$'000
At 31 December 2011			
Borrowings	7,324	8,819	—
Trade and other payables	14,677	—	—
At 31 December 2010—Restated			
Borrowings	6,568	—	—
Trade and other payables	10,314	—	—
At 31 December 2009—Restated			
Borrowings	4,337	10,303	1,540
Trade and other payables	10,153	—	—

3.2 Capital risk management

The Group's objectives when managing capital are to safeguard the Group's ability to continue as a going concern in order to provide returns for shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital.

In order to maintain or adjust the capital structure, the Group may adjust the amount of dividends paid to shareholders, issue new shares or sell assets to reduce debt.

Consistent with others in the industry, the Group monitors capital on the basis of the gearing ratio. This ratio is calculated as net debt divided by total capital. Net debt is calculated as total borrowings (including 'current and non-current borrowings' as shown in the consolidated statement of financial position) less cash and cash equivalents. Total capital is calculated as 'equity' as shown in the consolidated statement of financial position plus net debt.

The gearing ratios at 31 December 2009, 2010 and 2011 were as follows:

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Total borrowings (Includes convertible loan)	22,730	15,461	21,548
Less: cash and cash equivalents	(4,518)	(5,148)	(26,769)
Net debt/(funds)	18,212	10,313	(5,221)
Total equity	(76)	(2,353)	55,358
Total capital	18,136	7,960	50,137
Gearing ratio	100%	130%	—

3.3 Fair value estimation

The carrying values of trade receivables (less impairment provision) and payables are assumed to approximate their fair values. The fair value of financial liabilities for disclosure purposes is estimated by discounting the future contractual cash flows at the current market interest rate that is available to the Group for similar financial instruments.

4 Critical Accounting Estimates and Judgments

Estimates and judgements are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

Critical accounting estimates and judgments

Management makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below:

a) Income taxes

Some judgement is required in determining the provision for income taxes. There are many transactions and calculations for which the ultimate tax determination is uncertain. Management recognises liabilities for anticipated tax audit issues based on estimates of whether additional taxes will be due. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the income tax and deferred tax provisions in the period in which such determination is made.

b) Provision for decommissioning costs

This provision is significantly affected by changes in technology, laws and regulations which may affect the actual cost of decommissioning to be incurred at a future date. The estimate is also impacted by the discount rates used in the provisioning calculations. The discount rates used are the Group's risk-free rate and the core inflation rate applicable to the local oil and gas industry. The provision has been estimated using a discount rate of 8% (2010: 9.75%) (2009: 9.75%) and a core inflation rate of 4% (2010: 5%) (2009: 5%). The impact of a 1% change in these variables is as follows:

	Statement of Financial Position Obligation			Statement of Comprehensive Income		
	2009	2010	2011	2009	2010	2011
	$'000	$'000	$'000	$'000	$'000	$'000
Discount rate						
1% increase in assumed rate	1,466	1,578	963	107	56	13
1% decrease in assumed rate	(1,725)	(1,840)	(1,150)	(102)	(48)	(10)
Inflation rate						
1% increase in assumed rate	(1,903)	(2,034)	(1,259)	(319)	(182)	(49)
1% decrease in assumed rate	1,621	1,752	1,058	271	157	42

c) Estimation of reserves

The Group estimated its reserves using internal expertise. All reserve estimates involve some degree of uncertainty, which depends chiefly on the amount of reliable geological and engineering data available at the time of the estimate. Generally, reserve estimates are revised as additional data become available. Reserves are evaluated periodically by independent external reserve evaluators. The last independent external reserve evaluation was performed for reserves as at 31 December 2009 for all reserves, except those of Oilbelt Services Limited, which was acquired during the year. All the Group's reserves are currently being evaluated but the evaluation has not been completed as at the date of issue of the consolidated financial information.

Reserve quantities impact on the following:

– Amounts charged for depreciation, depletion and amortisation

– Goodwill impairment testing

4 Critical Accounting Estimates and Judgments (Continued)

d) Farm outs and lease operatorship agreements

The Group accounts for its farmout and lease operatorship agreements on the basis that they will be renewed upon expiry. If any of these farmout or lease operatorship agreements are not renewed or renewed on disadvantageous terms this may severely impact the profitability and ongoing operations of the Group.

e) Estimated impairment of goodwill

The Group tests annually whether goodwill has suffered any impairment, in accordance with the policy stated in note 2.9. The recoverable amounts of cash-generating units have been determined based on value-in-use calculations. Should the actual amounts recovered differ significantly from these estimates the carrying value of the goodwill may be impaired.

5 Property, Plant and Equipment

	Plant & Equipment $'000	Land & Buildings $'000	Oil & Gas Property $'000	Other $'000	Total $'000
At 1 January 2009—Restated					
Cost	6,271	290	61,442	791	68,794
Exchange rate differences	(10)	(1)	(85)	(2)	(98)
Accumulated depreciation, depletion, amortisation and impairment	(4,196)	(44)	(50,474)	(235)	(54,949)
Net book amount	**2,065**	**245**	**10,883**	**554**	**13,747**
Year ended 31 December 2009—Restated					
Opening net book amount	2,065	245	10,883	554	13,747
Additions	139	13	6,911	30	7,093
Disposal	—	—	(1)	(10)	(11)
Work in progress	—	—	5	—	5
Adjustment to decommissioning estimate (note 17)	—	—	(961)	—	(961)
Impairment charge (note 5.1)	—	—	(2,769)	(246)	(3,015)
Depreciation, depletion and amortisation charge for year	(950)	(15)	(1,358)	(92)	(2,415)
Closing net book amount	**1,254**	**243**	**12,710**	**236**	**14,443**
At 31 December 2009—Restated					
Cost	6,400	302	67,311	809	74,822
Accumulated depreciation, depletion, amortisation and impairment	(5,146)	(59)	(54,601)	(573)	(60,379)
Closing net book amount	**1,254**	**243**	**12,710**	**236**	**14,443**
Year ended 31 December 2010—Restated					
Opening net book amount	1,254	243	12,710	236	14,443
Additions	266	—	685	49	1,000
Disposals	(13)	—	—	(66)	(79)
Adjustment to decommissioning estimate (note 17)	—	—	(6)	—	(6)
Depreciation, depletion and amortisation charge for year	(650)	(15)	(987)	(47)	(1,699)
Closing net book amount	**857**	**228**	**12,402**	**172**	**13,659**
At 31 December 2010—Restated					
Cost	6,618	301	67,618	466	75,003
Accumulated depreciation, depletion, amortisation and impairment	(5,761)	(73)	(55,216)	(294)	(61,344)
Closing net book amount	**857**	**228**	**12,402**	**172**	**13,659**

5 Property, Plant and Equipment (Continued)

	Plant & Equipment	Land & Buildings	Oil & Gas Property	Other	Total0
	$'000	$'000	$'000	$'000	$'000
Year ended 31 December 2011					
Opening net book amount	857	228	12,402	172	13,659
Additions—Oilbelt Services (note 30)	203	95	37,460	29	37,787
Additions	297	3	6,026	—	6,326
Disposals	(201)	—	—	—	(201)
Work in progress	—	849	145	—	994
Adjustment to decommissioning estimate (note 17)	—	—	1,294	—	1,294
Depreciation, depletion and amortisation charge for year	(259)	(17)	(3,315)	(20)	(3,611)
Closing net book amount	**897**	**1,158**	**54,012**	**181**	**56,248**
At 31 December 2011					
Cost	5460	1,248	118,944	495	126,147
Accumulated depreciation, depletion, amortisation and impairment	(4563)	(90)	(64,932)	(314)	(69,899)
Closing net book amount	**897**	**1,158**	**54,012**	**181**	**56,248**

5.1 This charge relates to four wells located at Tabaquite under the subsidiary, Coastline International Inc. Management has considered the production levels and economic costs and benefits of these wells and has concluded that the carrying costs are impaired

6 Intangible Assets

The carrying amounts and changes in the year are as follows:

	Goodwill	Other Intangible Assets	Total
	$'000	$'000	$'000
Years ended 31 December 2009 and 31 December 2010—Restated			
Opening and closing net book amount	**—**	**—**	**—**
Year ended 31 December 2011			
Opening net book amount	—	—	—
Additions	16,952	—	16,952
Closing net book amount	**16,952**	**—**	**16,952**
At 31 December 2011			
Cost	16,952	—	16,952
Accumulated amortisation and impairment	—	—	—
Closing net book amount	**16,952**	**—**	**16,952**

Goodwill arose on the business combination of Oilbelt Services Limited and represents the excess of the purchase price over the fair value of the net assets. (See Note 30)

After initial recognition, goodwill on acquisition is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash-generating units that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units. The entire goodwill balance has been allocated to the WD 5⁄6 Block which is considered to be one cash-generating unit.

6 Intangible Assets (Continued)

During the five months following the business combination there were no indicators of impairment such as a change in circumstances or fundamental changes in the key assumptions and cash flows relating to this particular Cash Generating Unit (CGU). Going forward a full impairment review will be performed in 2012.

7 Investments

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Certificate of Participation	**10,000**	**—**	**—**

This investment held with First Global Trinidad and Tobago Limited (previously ONE Financial Limited), originated on 30 June 2008 and comprises a certificate of participation in US$1.5m variable rate, unsecured, oil producing receipts, which matures on 31 March 2015. The rate of interest on the certificate was 11.00% per annum (2008—10.50% per annum). This investment was liquidated in 2010.

8 Inventories

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Crude oil	67	132	189
Materials and supplies	1,897	1,747	1,310
	1,964	**1,879**	**1,499**

9 Trade and Other Receivables

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Trade receivables	1,803	1,725	6,243
Prepayments	350	314	337
VAT recoverable	1,956	2,624	2,210
Other receivables	855	1,085	1,942
Receivables from related parties (note 25)	—	—	160
	4,964	**5,748**	**10,892**

The fair value of trade and other receivables approximate their carrying amounts.

As at 31 December 2011, trade receivables of $6.2m (2010—$1.7m) (2009—$1.8m) were fully performing. Trade receivables that are less than three months past due are not considered impaired. As of 31 December 2011, trade receivables of $nil (2010: $nil) (2009: $nil) were past due but not impaired. These relate to the Group's only customer, Petrotrin, for whom there is no recent history of default.

As at 31 December 2011, no trade receivables (2010—$nil) (2009—$nil) were impaired and provided for.

Ageing analysis of these trade receivables is as follows:

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Up to 3 months	1,803	1,725	6,243
	1,803	**1,725**	**6,243**

9 Trade and Other Receivables (Continued)

The carrying amount of the Group's trade and other receivables are denominated in the following currencies:

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
US Dollar	1,163	1,156	1,601
Trinidad& Tobago Dollar	3,801	4,592	9,291
	4,964	**5,748**	**10,892**

Included in other receivables in 2009 is an amount of approximately $4.8m due from Krishna Persad and Associates Limited which has been fully provided for. This relates to costs incurred by the group on behalf of Krishna Persad and Associates Limited regarding fulfilment of minimum work obligations in the Point Ligore Block (Note 1). Movements on the group's provision for impairment of the receivables due from Krishna Persad and Associates Limited as follows:

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Beginning of year	4,771	—	—
Provision for receivables impairment	—	—	—
Release of provision	(4,771)	—	—
End of year	**—**	**—**	**—**

The other classes within trade and other receivables do not contain impaired assets.

The maximum exposure to credit risk at the reporting date is the value of each class of receivable as shown above. The group does not hold any collateral as security.

10 Taxation Recoverable/(Payable)

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Taxation recoverable			
Production Petroleum tax (PPT)/Unemployment Levy (UL)	124	325	119
Taxation payable			
Production Petroleum tax (PPT)/Unemployment Levy (UL)	(51)	—	(4,064)
Supplemental petroleum tax (SPT)	(1,435)	(1,412)	(3,117)
	(1,486)	**(1,412)**	**(7,181)**

11 Short-term Investments

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Guardian Asset Management Limited	3	3	3
RBC Royal Bank (Trinidad and Tobago) Limited	34	34	34
	37	**37**	**37**

12 Share Capital and Share Premium

Authorised, issued and fully paid	Number of shares	Share capital	Share premium
		$'000	$'000
Description			
As at 1 January 2009	23,070	23,070	—
As at 31 December 2009—Restated	**23,070**	**23,070**	**—**
As at 1 January 2010	23,070	23,070	—
Repurchase of shares	(1,200)	(1,350)	—
As at 31 December 2010—Restated	**21,870**	**21,720**	**—**
As at 1 January 2011	21,870	21,720	—
Conversion of share warrant to shares (note 13)	514	514	—
Issue of shares to satisfy Oilbelt consideration (note 30)	7,479	7,479	—
Amalgamation of Ten Degrees North Energy Limited and Oilbelt Services Ltd—cancellation of existing shares	(29,863)	(29,713)	—
Amalgamation of Ten Degrees North Energy Limited and Oilbelt Services Ltd—issue of shares by the Company	29,863	30	—
Issue of new shares for cash	3,394	3	14,200
Cost of raising equity	—-	—	(378)
Share warrant issued (note 13)	—	—	(71)
As at 31 December 2011	**33,257**	**33**	**13,751**

The balances disclosed as at 31 December 2009 and 31 December 2010 represent the equity position for the predecessor Group, Ten Degrees North Energy Limited (now Trinity Exploration and Production (Trinidad & Tobago) Limited).

The Company was incorporated on 4 April 2011 with 1 share at a nominal value of $1 in issue. As part of the amalgamation of Ten Degrees North Energy Limited (now Trinity Exploration and Production (Trinidad & Tobago) Limited) and Oilbelt Services Ltd, the Company issued shares to the shareholders of these entities, thereby becoming the new parent company of the Group ("the Amalgamation"). Therefore from a Group consolidated perspective the share capital of Ten Degrees North Energy Limited was replaced by that of the Company. The issue of shares by the Company as part of the Amalgamation met the criteria of merger relief under s.612 of the UK Companies Act 2006 such that no share premium was recorded, but which resulted in the recognition of a merger reserve as described in note 14. These new shares have a nominal value of $1,000 per share.

On 30 November 2011 the Company issued 3,394 shares to new shareholders as part of an equity raise.

13 Warrant Shares

The Group's policy with respect to equity-settled share-based payment transactions is to measure the value of the good or service received with the corresponding increase in equity at the fair value of the services received. If the Group cannot estimate reliably the fair value of the good or services received it then shall measure their value and the corresponding increase in equity indirectly by reference to the fair value of the equity instrument.

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Issued			
Bovaro Capital LLC	514	514	—
Oriel Securities Limited	—	—	71
	514	**514**	**71**

13 Warrant Shares (Continued)

Bovaro Capital LLC warrants

Bovaro Capital LLC and Trinity Exploration and Production (Trinidad & Tobago) Limited, formerly known as Ten Degrees North Energy Limited entered into a Warrant and Purchase Agreement dated December 20, 2005. The agreement permits that in exchange for good and valuable consideration, Bovaro Capital LLC is entitled to purchase from Trinity Exploration and Production (Trinidad & Tobago) Limited (formerly known as Ten Degrees North Energy Limited), at any time during the Exercisable Period, up to 514 Warrant Shares. In the event of an exercise, Bovaro Capital LLC shall surrender the Warrants accompanied by the respective payment set out in the agreement. The warrants are non-transferable.

Key terms of the Agreement:

- Issue Date—20th December, 2005;
- Exercisable Period—Earlier of (i) 24 months following the Issue Date or (ii) Liquidity Event and ending on the Expiration Date;
- Liquidity Event—(i) Initial public offering of the Company's Common Stock. (ii) any transaction in which the Company sells, conveys or transfers a majority of the Company's Common Stock or assets to another party or (iii) the Company begins paying dividends to the shareholders of the Company's Common Stock;
- Exercise Price—TT$0.01 per share (subject to adjustment pursuant to one of the clauses of the agreement);
- Expiration Date—20th December, 2015.

The warrants were exercised in 2011 prior to the Amalgamation, with 514 shares issued by Trinity Exploration and Production (Trinidad & Tobago) Limited (formerly known as Ten Degrees North Energy Limited) with a value of $1,000 per share.

Oriel Securities Limited warrants

Oriel Securities Limited ('Oriel'') was appointed to assist Trinity Exploration and Production Limited ('Trinity') in introducing potential subscribers for private placing of new ordinary shares. In consideration for the services under the engagement, and subject to receipt of the gross proceeds as a result of the placing, Trinity and Oriel agreed a fee in cash to the value of $150,000.

In addition to the fees above, Oriel was granted an option by the Company over shares equivalent in value to 0.25% (one quarter of one per cent) of the value of the Company following the Placing, such option to be exercisable at the share price at which the new funds are raised in the Placing. The option can be exercised between the 1^{st} and 5^{th} anniversary of the option being granted or if later on the 1^{st} anniversary of any flotation.

The Group recognised the warrants in the financial year by estimating the services received at fair value at the date of the transaction. In arriving at the fair value of the services received an estimate was received from Oriel indicating that the cost of the service had no warrant been included would have been 1.5% of the Placing. As the cost is associated with the raising of capital, this expense has been recognised as a deduction from share premium (see note 12).

14 Other reserves

	Merger reserve	Merger difference	Total
	$'000	$'000	$'000
As at 1 January 2009, 31 December 2009, and 31 December 2010— Restated	—	—	—
Amalgamation with Ten Degrees North Energy Limited	124,943	(71,771)	53,172
As at 31 December 2011	**124,943**	**(71,771)**	**53,172**

As described in note 12, the issue of shares by the Company as part of the Amalgamation met the criteria for merger relief such that no share premium was recorded. As allowed under the UK Companies Act 2006 and required by IAS 27 ("Consolidated and separate financial statements"), a merger reserve equal to the difference between the fair value of the shares acquired by the Company and the aggregation of the nominal value of the shares issued by the Company has been recorded.

The insertion of the Company as the new parent to the Group has been accounted for using predecessor accounting as described in note 2.1. The merger difference recorded in the consolidated financial information represents the difference between the net assets of the consolidated accounts of Ten Degrees North Energy Limited immediately prior to the Amalgamation and the aggregate of the share capital and merger reserve recorded by the Company as part of the Amalgamation.

15 Convertible Loan Notes

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Centrica Loan note	**10,000**	**9,337**	**6,837**

Trinity Exploration and Production (Trinidad & Tobago) Limited (formerly known as Ten Degrees North Energy Limited) created $15 million of Unsecured Convertible Subordinated Loan Notes due 2010-2014 by virtue of a Converted Loan Note instrument dated 16th December 2005. Trinity Exploration and Production (Trinidad & Tobago) Limited (formerly known as Ten Degrees North Energy Limited) issued $10 million of Unsecured Convertible Subordinated Loan Notes 2010-2014 created by the Loan Note Instrument to CENTRICA UPSTREAM INVESTMENT LIMITED (Centrica) (formerly named Venture Investment Holdings Limited ("Venture")) on 16th December 2005 which was transferred to them by way of a Deed of Transfer dated 26th June 2007.

During 2010, Trinity Exploration and Production (Trinidad & Tobago) Limited (formerly known as Ten Degrees North Energy Limited) repaid $1,500,000 of the original Notes issued to Centrica leaving $8,500,000 in principal amount of the Notes outstanding. However, the Loan Note Instrument was amended by virtue of an Amendment Instrument between Centrica and Trinity Exploration and Production (Trinidad & Tobago) Limited (formerly known as Ten Degrees North Energy Limited) resulting in the issuing of a new principal amount of $9,337,346, which included the $8,500,000 principal plus a further $837,246 of interest which was satisfied through the issue of new convertible loan notes.

A further restatement was made on the 18th November 2011 on the "Restated and Amended Loan Note Instrument" moving the Loan Note from Trinity Exploration and Production (Trinidad & Tobago) Limited (formerly known as Ten Degrees North Energy Limited) to the new ultimate parent company Trinity Exploration and Production Company Limited. Thus, Trinity Exploration and Production Limited is now accepting liability for repayment of the Notes. Centrica have agreed not to exercise its Repayment Right and have further agreed to permit Trinity Exploration and Production (Trinidad & Tobago) Limited to transfer all of its obligations and rights under the Loan Note Instrument and the Amendment to Trinity Exploration and Production Limited, which Trinity has agreed to accept. As part of this Agreement, the principal sum of $2,500,000 was applied towards repayment of the facility, resulting in a balance of $6,837,246 at 31 December 2011.

15 Convertible Loan Notes (Continued)

The key elements of the Agreement are as follows:

- The loan note is redeemable in equal quarterly instalments of $320,000 on the following dates: 31 March, 30 June, 30 September and 31 December in each of the years 2012 to 2016 inclusive with the first redemption date being December 31, 2012;

i. 31 March, 30 June, 30 September and 31 December in each of the years 2012 to 2016 inclusive;

ii. In the period to 31 December 2013, LIBOR plus 3% per annum;

iii. In the period from 1 January 2014 to 31 December 2015, LIBOR plus 5% per annum; and

iv. In the period from 1 January 2016 onwards, LIBOR plus 7% per annum; and

- If the Convertible Notes have not been previously redeemed in full then on a Conversion Event the Noteholder may convert up to $5,000,000 nominal amount of the Convertible Notes into Shares in accordance with the provisions stipulated in the agreement. The equity element of the convertible loan is not recognised separately as conversion is dependent upon certain contingent settlement provisions and therefore the entire loan is recognised as a financial liability.

16 Borrowings

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Non-current portion:			
First Global Trinidad and Tobago Limited	10,000	—	—
Citibank (Trinidad and Tobago) Limited	—	—	8,460
Current portion:			
Citibank(Trinidad and Tobago) Limited	2,730	4,124	4,251
Promissory note (Jonathan Murphy) (see note 25 (f))	—	2,000	—
David & Christina Segel Living Trust loan note (see note 25 (f))	—	—	2,000
	12,730	**6,124**	**14,711**

First Global Trinidad and Tobago Limited

The non-current portion comprises US$10,000,000 in variable interest rate notes from First Global Trinidad and Tobago Limited (previously One Financial Limited). These loan notes originated in 2008 and bear interest at the rate of 11.00% and mature in 2015. The loan notes are repayable in twenty consecutive monthly instalments of US$500,000 commencing 1.75 years after drawdown. Interest is payable monthly in arrears. These notes were liquidated in 2010.

Citibank (Trinidad & Tobago) Limited Loan

The key terms of the loan are as follows:

- Principal amount $13,000,000
- Maturity date 30 September 2014
- Interest rate three month US Libor plus 575 basis points per annum, to be reset quarterly
- Debenture over the fixed and floating assets of Trinity Exploration and Production (Trinidad & Tobago) Limited and its subsidiaries.
- Principal Repayment in thirty six equal monthly instalments commencing in December
- Interest payable monthly in arrears on last day of each month

16 Borrowings (Continued)

- Financial covenants:
- Minimum debt service coverage 1.4:1
- Maximum total debt to EBITDA 3:1
- Minimum EBITDA to Interest Expense 1.5:1
- Average interest rate 6.187% (2010: 9.85%)

The comparative current portion was due to Citibank (Trinidad & Tobago) Limited and was repaid in the financial year ended 31 December 2011. The carrying value is not materially different from the fair value.

The comparative promissory note payable to Jonathan Murphy was settled through the issue of shares during the financial year ended 31 December 2011.

David & Christina Segel Living Trust Promissory note

Key terms of the loan note are as follows:

- Issue Date—8th March 2011
- Interest Rate—Fixed 10% per annum (30/360 day basis)
- Principal sum—$2,000,000
- Maturity date—31st December, 2011
- Interest and principal will be repaid on the Maturity Date
- Rollover Provision—The Issuer may request that some or the entire outstanding principal of the note be rolled-over following conditions disclosed in the agreement.
- Average interest paid 2011—$171,111

The rollover provision was exercised at the end of the financial period with the loan note balances rolled over to 2012, whereby a new agreement was issued.

Analysis of net debt

	At 1 January 2009	Cashflow	Non-cash movements	Exchange movements	At 31 December 2009
	$m	$m	$m	$m	$m
Cash and cash equivalents	4,478	40	—	—	4,518
Financial liabilities—borrowings current	(9,000)	6,267	—	3	(2,730)
Financial liabilities—borrowings non-current	(20,000)	—	—	—	(20,000)
	(24,522)	**6,307**	**—**	**3**	**(18,212)**

16 Borrowings (Continued)

Analysis of net debt

	At 1 January 2010	Cashflow	Non-cash movements	Exchange movements	At 31 December 2010
	$m	$m	$m	$m	$m
Cash and cash equivalents	4,518	662	—	(32)	5,148
Financial liabilities—borrowings current	(2,730)	(3,432)	—	38	(6,124)
Financial liabilities—borrowings non-current	(10,000)	—	10,000	—	—
	(8,212)	**(2,770)**	**10,000**	**6**	**(976)**

	At 1 January 2011	Cashflow	Non-cash movements	Exchange movements	At 31 December 2011
	$m	$m	$m	$m	$m
Cash and cash equivalents	5,148	21,621	—	—	26,769
Financial liabilities—borrowings current	(6,124)	(1,877)	1,661	89	(6,251)
Financial liabilities—borrowings non-current	—	(8,460)	—	—	(8,460)
	(976)	**11,284**	**1,661**	**89**	**12,058**

17 Decommissioning provision

This represents an estimate of the amounts required for abandonment of the Group's wells and facilities. The amounts are calculated based on the provisions of existing contractual agreements with Petrotrin. Furthermore, liabilities for decommissioning costs are recognised when the Group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reasonable estimate of that liability can be made. An obligation for decommissioning may also crystallize during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. A corresponding item of property, plant and equipment of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the capital costs of the facility or item of plant. Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment. Some of the key assumptions made in the present value decommissioning calculation include the following:

a. Core inflation rate—4% (2010; 5%) (2009; 5%)

b. Risk free rate—8% (2010; 9.75%) (2009; 9.75%)

c. Estimated market value/decommissioning cost for both onshore $0.1m (2010; $0.08m) (2009; $0.5m) and offshore $0.3m (2010; $0.1m) (2009; $0.8m) wells

d. Estimated life of each asset

See note 4(b) for the rates used and sensitivity analysis.

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Opening provision	2,482	1,744	1,908
Adjustment to estimates	(961)	(6)	1,294
Decommissioning recorded on acquisition	—	—	2,927
Actual abandonment payment	(41)	—	—
Unwinding of discount (note 22)	274	170	273
Closing provision	**1,754**	**1,908**	**6,402**

17 Decommissioning provision (Continued)

In 2009 and 2011 there was a significant movement in the provision mainly on account of the estimation assumptions used in determining the estimated cost to decommission the Group's oil and gas facilities. There has been a corresponding reduction in the carrying amount of property plant and equipment (note 5).

18 Provision For Employee Retirement Benefits

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Provision for employee benefits	**—**	**—**	**728**

Upon the acquisition of Oilbelt Services Limited, the Group assumed a legal obligation based on an agreement between Oilbelt Services Limited and the Oilfield Workers Trade Union which entitles members to service benefits. The final level of benefit is not defined and can vary based upon certain criteria, such as the length of service.

19 Deferred Taxation

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
At beginning of year	413	98	54
Deferred tax assumed on acquisition	—	—	4,750
Deferred tax on fair value uplift arising from acquisition	—	—	12,875
(Credit) for the year	(315)	(44)	(11,057)
Net deferred tax liability	**98**	**54**	**6,622**

19 Deferred Taxation (Continued)

Deferred tax assets and liabilities are only offset where there is a legally enforceable right of offset and there is an intention to settle the balances net. The deferred tax balances are analysed below:

	Restated 2009	Movement	Restated 2010	Movement	2011
	$'000		$'000		$'000
Deferred tax assets					
Acquisition	—	—	—	(410)	(410)
Tax losses recognised	—	—	—	(12,472)	(12,472)
	—	**—**	**—**	**(12,882)**	**(12,882)**
To be recovered after more than 12 months					
To be recovered within 12 months					
	—		**—**		**(12,882)**

	Restated 2009	Movement	Restated 2010	Movement	2011
	$'000		$'000		$'000
Deferred tax liabilities					
Accelerated tax depreciation	98	(44)	54	1,415	1,469
Acquisition	—	—	—	5,160	5,160
Fair value uplift	—	—	—	12,875	12,875
	98	**(44)**	**54**	**19,450**	**19,504**
To be recovered after more than 12 months					
To be recovered within 12 months					
Net deferred tax liabilities	**98**		**54**		**6,622**

Tax losses were recognised in 2011. These losses relate to Ten Degrees North Operating Company and were previously not recognised because there was no definitive plan of how they would be utilised in the future. However, following revisions to the Company's development plan, projected taxable profits has increased and therefore the losses are expected to be utilised in the future.

20 Trade and other payables

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Trade payables	6,777	4,188	2,641
Advances from Petrotrin	1,048	1,057	1,063
Accrued expenses	2,059	2,017	4,223
VAT payable	73	70	376
Financial liability	—	—	3,822
Other payables	196	2,982	2,095
Amounts due to related parties (note 25 (e))	—	—	457
	10,153	**10,314**	**14,677**

Financial liability

On April 14 2010 the Group reached a settlement agreement ("the Settlement Agreement") with an ex-member of management who was also a shareholder (the 'Seller'). The agreement required Ten Degrees North Energy Limited, (the 'Buyer') to repurchase 1,200 shares from the seller at $1,000 each. In 2010 this transaction was executed and the Buyer purchased 1,200 shares from the Seller. In addition to the

20 Trade and other payables (Continued)

1,200 shares at $1,000 each there was an 'additional purchase price' payable by the Buyer to the Seller upon the occurrence of certain circumstances which included any restructuring of the Company's share capital (Liquidation event). The amount payable is the difference between the unit price payable by a third party for a common share of the Company less the sum of $1,000 multiplied by 1,200 shares.

A Liquidation event occurred in 2011 after the issue of share capital to new shareholders which were executed at $4,185 per share. As such a financial liability has been recognized at 31 December 2011 for the fair value of the settlement, being $4,185 less the sum of $1,000 multiplied by 1,200 shares. The financial liability is categorised as a liability measured at fair value through the comprehensive income. Therefore, the change in the fair value since the settlement agreement was reached in 2010 is recognized within finance cost in comprehensive income, see note 22.

A supplementary agreement was signed in 2012, which states that in lieu of settlement by the Buyer, the Company agreed to settle the liability by issuing the Seller the equivalent of 925 new shares in the Company at the execution price reached upon the occurrence of the Liquidation event. As the conditions of the settlement did not exist at 31 December 2011, this is a non-adjusting post balance sheet event and the shares shall be recorded in 2012.

21 Operating Profit

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Operating profit is stated after taking the following items into account:			
Depreciation of property, plant and equipment	2,415	1,699	3,611
Profit on disposal of property, plant and equipment	21	66	110
Employee costs (note 29)	2,650	3,400	4,734
Operating lease rentals	14	128	259
Inventory recognised as expense	402	146	529
Auditors' remuneration:			
—Fees payable to the Company's auditors for the audit of the Company accounts	—	—	50
—Fees payable to the Company's auditors for the audit of the Group accounts	77	63	110

22 Finance Income and Costs

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Interest expense:			
—Unwinding of discount on decommissioning provision (note 17)	274	170	273
—Loans	2,178	2,338	1,142
—Accounts payable	—	839	531
Change in fair value of financial liability (note 20)	—	—	3,822
Finance costs	**2,452**	**3,347**	**5,768**
Finance income:			
—Interest income on short-term bank deposits	1,296	969	206
	1,296	**969**	**206**

23 Taxation

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Current tax			
Petroleum profits tax	126	54	4,350
Supplemental petroleum tax	3,744	4,766	7,359
Adjustments in respect of prior years	141	—	—
Deferred tax			
Movement in asset due to tax losses	—	—	(12,472)
Movement in liability due to accelerated tax depreciation	(315)	(44)	1,415
Tax charge	**3,696**	**4,776**	**652**

The Group's effective tax rate varies from the statutory rate for petroleum companies of 55% as a result of the differences shown below:

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Profit before taxation	**583**	**3,706**	**13,430**
Tax charge at expected rate of 55% (2010: 55%) (2009:55%)	321	2,038	7,387
Effects of:			
Tax on subsidiary at 25%	42	(258)	—
Disallowable expenses	1,580	(574)	3,819
Prior year under provision	141	—	—
Deferred tax asset not recognised	—	—	(1,061)
Tax loss generated not recognised	1,581	1,005	587
Tax losses utilised but not previously recognised	(1,445)	—	(54)
Tax claimed on workover cost capitalised	—	—	(247)
Prior year tax losses recognized in current year	—	—	(12,902)
Supplemental petroleum tax	1,685	2,145	3,311
Other differences	(209)	420	(188)
Tax charge	**3,696**	**4,776**	**652**

In 2009 tax losses for certain entities were fully utilised.

24 (Loss)/Earnings Per Share

Basic (loss)/earnings per share is calculated by dividing the (loss)/earnings attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. Diluted

24 (Loss)/Earnings Per Share (Continued)

(loss)/earnings per share is calculated using the weighted average number of ordinary shares adjusted to assume the conversion of all dilutive potential ordinary shares.

	(Loss)/Earnings— Total Comprehensive (Loss)/Income For The Year	Weighted Average Number Of Shares	(Loss)/ Earnings Per Share $
	$'000		
Year ended 31 December 2009			
Basic	**(3,113)**	**23,070**	**(135)**
Impact of dilutive ordinary shares:			
Bovaro Warrants	—	514	—
Centrica Convertible Loan Notes	—	1,195	—
Diluted	**(3,113)**	**24,779**	**(126)**
Year ended 31 December 2010			
Basic	**(1,070)**	**22,212**	**(48)**
Impact of dilutive ordinary shares:			
Bovaro Warrants	—	514	—
Centrica Convertible Loan Notes	—	1,195	—
Diluted	**(1,070)**	**23,921**	**(45)**
Year ended 31 December 2011			
Basic	**12,778**	**25,046**	**510**
Impact of dilutive ordinary shares:			
Centrica Convertible Loan Notes	—	1,195	—
Oriel Warrants	—	17	—
Settlement of Financial Liability	—	925	—
Diluted	**12,778**	**27,183**	**470**

The loss per share figures for the years ended 31 December 2009 and 31 December 2010 are presented based upon the Group and capital structure before the insertion of Trinity Exploration and Production Limited as the new top company. As a result, the comparative figures are based upon the capital structure of the previous Ten Degrees North Energy Limited Group.

25 Related Party Transactions

The following are the major transactions and balances with related parties:

(a) Sales of services

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Well Services Petroleum Company Limited	—	—	277
	—	**—**	**277**

25 Related Party Transactions (Continued)

(b) Purchases of services

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Purchases of services:			
Blanket Securities Limited	—	—	347
Rigtech Services Limited	—	—	256
Well Services Petroleum Company Limited	7	24	857
IAM Consulting Limited	—	—	420
Dingwall Energy Advisors Ltd	150	149	151
	157	**173**	**2,031**

(c) Key management compensation

Aggregate compensation for key management, being the directors and members of the Executive Committee, was as follows:

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Salaries and other short-term employee benefits	564	569	936
Post-employment benefits	—	6	7
	564	**575**	**943**

(d) Directors

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Aggregate emoluments	366	555	528
Company contributions to money purchase pension scheme	—	6	7
	366	**561**	**535**

(e) Year-end balances arising from sales/purchases of goods/services

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Receivables from related parties:			
Well Services Petroleum Company Limited	—	—	160
	—	**—**	**160**
Payables to related parties:			
Blanket Securities Limited	—	—	5
Rigtech Services Limited	—	—	367
Well Services Petroleum Company Limited	—	—	11
Dingwall Energy Advisors Ltd	—	—	50
IAM Consulting Limited	—	—	24
	—	**—**	**457**

The receivables from related parties arise mainly from sale transactions and are due two months after the date of sales. The receivables are unsecured and bear no interest. No provisions are held against receivables from related parties (2010: nil) (2009: nil).

25 Related Party Transactions (Continued)

The payables to related parties arise mainly from purchase transactions and are due two months after the date of purchase. The payables bear no interest.

(f) Loans from related parties

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
At 1 January			
Promissory note (Jonathan Murphy) (note 16)	—	2,000	—
David & Christina Segel Living Trust loan note (note 16)	—	—	2,000
At 31 December	**—**	**2,000**	**2,000**

26 Financial Instruments By Category

The accounting policies for financial instruments have been applied to the line items below:

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Trade and other receivables (note 8)	4,964	5,748	10,892
Short-term investments (note 11)	37	37	37
Cash and cash equivalents	4,518	5,148	26,769
	9,519	**10,933**	**37,698**

The only category of financial assets held by the Group is loans and receivables. There are no assets held at fair value through profit or loss, derivatives used for hedging and available-for-sale financial instruments.

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Borrowings (note 16)	12,730	6,124	14,711
Trade and other payables (note 20)	10,153	10,314	14,677
	22,883	**16,438**	**29,388**

The only category of financial liabilities held by the Group is liabilities at amortised cost. There are no liabilities held at fair value through profit or loss and derivatives used for hedging.

27 Credit Quality Of Financial Assets

The credit quality of the financial assets that are neither past due nor impaired can be assessed by reference to historical information about the counterparty default rates:

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Trade receivables			
Counterparties without external credit rating:			
Existing customers (more than 6 months) with no defaults in the past	**1,803**	**1,725**	**6,243**

All trade receivables are with the Group's only customer, Petrotrin.

	Restated 2009	Restated 2010	2011
Cash and cash equivalents and short-term investments			
Trinidad and Tobago based banking institutions:			
Short-term investments	37	37	37
Cash at bank	4,518	5,148	26,769
	4,555	**5,185**	**26,806**

28 Commitments and Contingencies

Commitments

There are commitments for abandonment costs of the wells and facilities under the Group's farmout agreements with Petrotrin, which have been provided for as described in note 17.

There are commitments for operating leases as follows:

	Restated 2009	Restated 2010	2011
	$'000	$'000	$'000
Not later than 1 year	14	129	261
Later than 1 year and no later than 5 years	435	333	467
	449	**462**	**728**

Contingent Liabilities

i) As part of the consideration for the 25% Participating Interest in Point Ligoure, the Group covenanted to pay:

$450,000 on the anniversary of the first million barrels of Petroleum, inclusive of barrels of petroleum equivalent to gas sold from the contract Area by the parties from the commencement date.

The cumulative sales from the commencement date to 31 December 2011 were 914,186 barrels. The annual sales for 2011 were 68,186 barrels. However, it is management's view that there is currently no certainty that an obligation will arise and therefore no liability has been recognised.

ii) One of the subsidiaries has received an assessment from the Board of Inland Revenue (BIR) in respect of Petroleum Profits Tax. The subsidiary has filed a notice of objection with the BIR and until the matters are determined, the assessments raised are not considered final. No material unrecorded liabilities are expected to crystallise.

iii) A subsidiary Company is a defendant in certain legal proceedings. A claim was made against the subsidiary by Mora Ven Holdings limited. The claim being made was that the subsidiary bought the shares of Ligo Ven Resources Limited, a fellow subsidiary, at gross under-value. Management, after taking appropriate professional advice, is of the view that no material liabilities will crystallize and accordingly no provision has been made in the consolidated financial information for any potential liabilities.

28 Commitments and Contingencies (Continued)

iv) As described in Note 1 the farmout agreement for the Tabaquite block (Coastline International Inc.) has expired. There may be additional liabilities arising when the agreement is finalised, but these cannot be presently quantified and hence the consolidated financial information does not include any estimates of such liabilities.

v) The Group received a claim from Petrotrin regarding abandonment liabilities for the Point Ligoure field. The directors, after obtaining legal advice, are of the view that no provision is required for any liabilities pertaining to this claim.

vi) The exploration and production licence for the Point Ligoure Block expired in 2010. A new licence is currently being finalised. No provisions have been made for any liability in connection with the renewed licence.

vii) The group has performance bonds in respect of its lease operatorship agreements and licences amounting to approximately $334,000.

29 Employee Costs

Staff costs for the Group during the year

	2009	2010	2011
	$'000	$'000	$'000
Wages and salaries	2,622	3,358	4,678
Retirement benefit costs	28	42	56
	2,650	**3,400**	**4,734**

Average monthly number of people (including executive directors) employed by the Group

	2009	2010	2011
	number	number	number
Executive directors	3	2	3
Administrative staff	32	31	45
Operational staff	123	112	103
	158	**145**	**151**

30 Business Combination

Acquisition of Oilbelt Services Limited

On 22nd August 2011, Trinity Exploration and Production (Trinidad & Tobago) Limited (formerly known as Ten Degrees North Energy Limited) acquired 100% of the voting shares of Oilbelt Services Limited, an unlisted Company based in Trinidad and involved in the recovery and sale of crude oil which it produces from wells leased under the Petroleum Company of Trinidad & Tobago Limited (Petrotrin) Lease-Operatorship programme.

Trinity Exploration and Production (Trinidad & Tobago) Limited (formerly known as Ten Degrees North Energy Limited) acquired Oilbelt Services Limited by way of an amalgamation (the 'first amalgamation') whereby the shareholders of Oilbelt Services Limited cancelled their shares in Oilbelt Services Limited in exchange for shares in the amalgamated company, Ten Degrees North Energy 2011 Limited. The shareholders of Ten Degrees North Energy Limited similarly cancelled their shares in exchange for shares in the amalgamated Company, Ten Degrees North Energy 2011 Limited.

The shareholders of Ten Degrees North Energy 2011 Limited subsequently transferred their shareholding into Trinity Exploration and Production Limited ('Trinity') (the 'second amalgamation'). Trinity Exploration and Production Limit is a limited liability company incorporated in Scotland. The

30 Business Combination (Continued)

surviving entity from this second amalgamation is Trinity Exploration and Production (Trinidad & Tobago) Limited.

The assets and liabilities acquired in respect of the acquisition during the year were as follows:

	Book value	Fair value adjustment	Fair value
	$'000	$'000	$'000
Property plant and equipment	14,378	—	14,378
Assets recognised on acquisition	—	23,409	23,409
Inventories	83	—	83
Deferred tax asset	410	—	410
Trade and other payables	(1,183)	—	(1,183)
Deferred tax liabilities	(5,160)	(12,875)	(18,035)
Provisions	(3,595)	—	(3,595)
Translation difference	—	—	282
Total identifiable net assets acquired	**4,933**	**10,534**	**15,749**
Goodwill			16,952
Consideration			**32,701**
Consideration satisfied by:			
Cash			1,402
Issue of shares			31,299
			32,701

The Group has used acquisition accounting for the purchase of Oilbelt Services Limited and, in accordance with the Group's accounting policies, the goodwill arising on consolidation has been capitalised. The table above includes amounts relating to the acquisition of 100% of the share capital of Oilbelt Services Limited for a total consideration of $32m. The Company issued 7,479 ordinary shares as consideration for 100% shareholding in Oilbelt Services Limited. The fair value was derived following the valuation of Trinity Exploration and Production (Trinidad & Tobago) Limited. The total identifiable net assets of Oilbelt Services Limited are stated after recording provisional fair value adjustments of $10.5m. The fair value adjustments relate mainly to the recognition of the future value attributed to the reserves of the WD 5/6 Block producing asset. A deferred tax liability has been recognised to record the tax amortisation benefit accruing from the additional fair value recognised in respect of this asset.

The Company acquired Oilbelt Services Limited for the synergistic values it brings to its principal activities which are the exploration, development, production and sale of crude oil and natural gas under similar farm-out and lease operatorship agreements with Petrotrin.

The outflow of cash and cash equivalents on the acquisition made during the year is analysed as follows:

	$'000
Cash consideration	1,402
Cash outflow	**1,402**

30 Business Combination (Continued)

The results of the Group, as if the above acquisitions had been made at the beginning of period, would have been as follows:

	$'000
Continuing revenue	**75,411**
Continuing EBITDA	**31,800**
Revenue from business combination	**41,193**
EBITDA from business combination	**18,808**

31 Events after the Reporting Period

In 2005, certain persons were promised share options in the Company (Ten Degrees North Energy Limited). The share plan that would have governed the granting of the options was not approved by the then Board of Directors. In 2012, the share option plan was executed and approved by the Board of Directors. All option holders have surrendered their options originally promised in exchange for options in the ratified plan, which relates to shares in the new parent Company (Trinity Exploration and Production Limited).

As described in note 20, a supplementary agreement was signed in 2012 in respect of the settlement of the financial liability recorded in note 20 for the Settlement Agreement. In lieu of settlement in cash by the Buyer, the Company agreed to settle the cash liability by issuing the Seller the equivalent of 925 new shares in the Company at the execution price reached upon the occurrence of the Liquidation event. As the conditions of the settlement did not exist at 31 December 2011, this is a non-adjusting post balance sheet event and the shares shall be recorded in 2012.

SECTION 2: OILBELT SERVICES

The Oilbelt Services historical financial information in this section has been prepared in accordance with IFRS for small and medium sized enterprises. IFRS for SMEs differs in certain aspects from IFRS as adopted by the EU and as applied by Bayfield and Trinity and as such may not be a useful comparison. Additionally the Oilbelt Services financial information is prepared in Trinidad and Tobago dollars, whereas both Bayfield and Trinity report in United States dollars. A summary of the main differences between the two which would impact Oilbelt Services' historical financial information had it been prepared under IFRS as adopted by the EU are as follows:

Presentation

Under IFRS as adopted by the EU, the Oilbelt Services historical financial information would require the following additional disclosure:

- changes in equity in a standalone statement;
- financial risk management disclosures;
- credit quality of financial assets disclosures; and
- ageing and bad debt analysis with respect to accounts receivable.

Accounting policies and estimates

An accounting estimate difference exists between Oilbelt's accounting for depreciation compared to that applied by Bayfield and Trinity. Oilbelt historically calculated depreciation on a reducing balance basis whereas Bayfield and Trinity calculate depreciation on a unit of production basis. The magnitude of this difference on the Oilbelt historical financial information has not been quantified.

(A) FINANCIAL STATEMENTS OF OILBELT SERVICES FOR THE 7 MONTHS ENDED 31 JULY 2011

Oilbelt Services Limited

Financial Statements

31 July 2011

(Expressed in Trinidad and Tobago Dollars)

Oilbelt Services Limited

Financial Statements

31 July 2011

(Expressed in Trinidad and Tobago Dollars)

CONTENTS

Shahamad Ali & Associates SAA

146 Naparima Mayaro Road
St Clement's Village
San Fernando
Trinidad, West Indies
Tel 868-698-0412
Fax 868-653-3075

Independent Auditor's Report

To the members of
Oilbelt Services Limited

We have audited the accompanying financial statements of Oilbelt Services Limited which comprise the statement of financial position as at July 31, 2011, the statement of comprehensive income and retained earnings, and the statement of cash flows for the seven month period then ended and a summary of significant accounting policies and other explanatory notes, as set out on pages 301 to 311.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards for SMEs. This responsibility includes designing, implementing and maintaining internal controls relevant to the preparation and fair presentation of the financial statements that are free from material misstatement, whether due to fraud or error, selecting and applying appropriate accounting policies, and making accounting estimates that are reasonable in the circumstances.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with International Standards on auditing. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal controls relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate for the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of the accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Shahamad Ali & Associates SAA

Independent Auditor's Report

To the members of
Oilbelt Services Limited (Continued)

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of the company as of July 31, 2011 and the results of its operations and its cash flows for the seven month period then ended in accordance with International Financial Reporting Standards for SMEs.

Shahamad Ali & Associates

Chartered Accountants
San Fernando
Trinidad, West Indies
November 19, 2012

Oilbelt Services Limited

Statement of Financial Position

(Expressed in Trinidad and Tobago Dollars)

	Notes	31 July 2011	31 December 2010
Assets			
Current			
Inventories		$ 527,015	$ 126,188
Due by related companies	4	39,980	4,539,222
Taxation recoverable		3,300,252	3,456,019
Trade and other receivables	5	52,259,314	41,793,016
Investments	6	620,417	609,793
Cash at bank	7	28,139,159	3,322,025
		$ 84,886,137	$ 53,846,263
Non-Current			
Fixed assets	8	$ 92,285,184	$ 82,294,360
Deferred tax asset	9	8,002,104	2,145,836
		$100,287,288	$ 84,440,196
Total Assets		$185,173,425	$138,286,459
Equity and Liabilities			
Liabilities			
Current			
Due to related companies	4	$ 12,818,646	$ 12,047,203
Due to director	4	—	175,459
Trade and other payables	10	39,197,687	30,025,631
Dividends payable		24,482,429	—
Taxation payable		16,773,605	2,722,953
		$ 93,272,367	$ 44,971,246
Non-Current			
Taxation—interest and penalty		$ 4,650,000	$ —
Deferred taxation	9	37,009,827	33,470,237
Post employment benefit	11	4,729,260	3,901,520
Well abandonment provision	12	9,820,019	—
		$ 56,209,106	$ 37,371,757
Total Liabilities		$149,481,473	$ 82,343,003
Shareholders Equity			
Stated capital	13	$ 223,303	$ 223,303
Retained earnings		35,468,649	55,720,153
		$ 35,691,952	$ 55,943,456
Total Liabilities and Shareholders Equity		$185,173,425	$138,286,459

Director

Director

The notes on pages 304 to 311 form an integral part of these financial statements.

Oilbelt Services Limited

Statement of Comprehensive Income and Retained Earnings

(Expressed in Trinidad and Tobago Dollars)

	Notes	7 Months Ended 31 July 2011	Year Ended 31 December 2010
Revenue			
Crude Oil Sales		$142,359,616	$194,262,056
Other Income		1,010,865	74,600
		143,370,481	194,336,656
Cost and Expenses			
Royalties		65,431,277	80,882,190
Operating		13,947,703	24,712,441
Depreciation and amortisation		9,710,567	16,627,763
Administration		7,589,155	6,835,079
Waiver of intercompany debts		6,614,212	—
Finance Costs		345,323	295,696
Operating Expenses		103,638,237	129,353,169
Profit Before Taxation		39,732,244	64,983,487
Taxes other than Income Taxes	**14**	12,352,366	20,445,097
Profit Before Income Taxes		27,379,878	44,538,390
Income Taxes	**15**	21,697,845	24,783,727
Profit After Income Taxes		5,682,033	19,754,663
Dividends		25,694,970	27,500,000
Retained Earnings at Start of Year as Previously Stated		55,273,003	63,178,914
Prior Period Adjustment	**12**	—	160,574
Retained Earnings at Start of the Year restated		55,273,003	63,018,340
Retained Earnings at End of Year		$ 35,260,066	$ 55,273,003

The notes on pages 304 to 311 form an integral part of these financial statements.

Oilbelt Services Limited

Statement of Cash Flows

(Expressed in Trinidad and Tobago Dollars)

	Notes	7 Months Ended 31 July 2011	Year Ended 31 December 2010
Cash Flows From Operating Activities			
Profit before taxation		$ 39,732,244	$ 64,983,487
Adjustments To Reconcile Net Profit To Cash Provided By Operating Activities			
Depreciation and amortisation		9,710,567	16,627,763
Taxation—penalty and interest		4,650,000	—
Profit on disposal of fixed assets		(600,706)	(12,173)
Valuation adjustment—Abandonment Provision		332,524	155,709
Increase in retirement benefit provision		827,740	3,901,520
		54,652,369	85,656,306
Changes In Operating Assets/Liabilities			
Increase in trade and other receivables		(10,466,298)	(8,382,518)
Decrease in amounts due by related companies		4,499,242	18,611,016
(Increase) / Decrease in inventories		(400,827)	83,610
Decrease in amounts due to director		(175,459)	(421,764)
Increase in trade creditors and accruals		9,172,056	10,559,946
Increase / (Decrease) in amounts due to related companies		771,443	(3,585,497)
		58,052,526	102,521,099
Taxation paid		(21,868,889)	(71,949,722)
Cash Provided by Operating Activities		36,183,637	30,571,377
Investing Activities			
Purchase of fixed assets		(13,271,143)	(13,550,995)
Proceeds from sale of fixed assets		3,127,805	71,400
Net purchase of investments		(10,624)	(57,939)
Cash Used in Investing Activities		(10,153,962)	(13,537,534)
Financing Activities			
Dividend paid		(1,212,541)	(27,500,000)
Cash Used in Financing Activities		(1,212,541)	(27,500,000)
Cash Increase / (Decrease) During The Year		24,817,134	(10,466,157)
Cash And Cash Equivalents, Beginning Of Year		3,322,025	13,788,182
Cash And Cash Equivalents, End Of Year	7	$ 28,139,159	$ 3,322,025

The notes on pages 304 to 311 form an integral part of these financial statements.

Oilbelt Services Limited

Notes to the Financial Statements

31 July 2011

(Expressed in Trinidad and Tobago Dollars)

1 Incorporation And Principal Activities

The company is incorporated in the Republic of Trinidad and Tobago, with its registered office situated at Otaheite Industrial Estate, South Oropouche. It is a subsidiary of Well Services Holdings Limited which is also incorporated in the Republic of Trinidad and Tobago. Its principal activities are the recovery and sale of crude oil which it produces from wells leased under The Petroleum Company of Trinidad and Tobago Limited's (Petrotrin) lease-operatorship programme.

These financial statements were authorised for issue by the management on November 19, 2012.

2 Summary of Significant Accounting Policies

2.1 Basis of Preparation

These financial statements have been prepared in accordance with the International Financial Reporting Standards for Small and Medium-sized Entities issued by the International Accounting Standards Board. They are presented in Trinidad and Tobago dollars.

2.2 Property, Plant & Equipment

Property, plant & equipment are stated at cost less accumulated depreciation and accumulated impairment losses. Such cost includes the cost of replacing part of the plant and equipment when that cost is incurred, if the recognition criteria is met. Likewise, when a major inspection is performed, its cost is recognised in the carrying amount of the plant and equipment as a replacement if the recognition criteria is met. All other repair and maintenance costs are recognised in profit or loss as incurred.

The company's exploration and production activities are accounted for under the successful efforts method. Under this method exploration costs other than the costs of drilling exploratory wells , including geological and geophysical expenditure, are expensed when incurred. The costs of drilling exploratory wells are capitalised pending determination as to whether they have discovered proved commercial reserves. If proved reserves are not discovered, such drilling costs are expensed. The costs of all development wells, including development dry holes and related equipment used in the production of crude oil and natural gas are capitalised.

Depreciation is calculated on the reducing balance basis.

The following rates are considered appropriate to write off the assets over their estimated useful lives:

Land and Buildings	—	2%
Machinery and equipment	—	25%
Well costs and other equipment	—	25%
Office Furniture & Equipment	—	10%

The carrying values of property, plant and equipment are reviewed for impairment when events or changes in circumstances indicate that the carrying value may not be recoverable. If such indication exists and where the carrying values exceed the estimated recoverable amount, the assets are written down to their recoverable amount. The recoverable amount of property, plant and equipment is the greater of net selling price and value in use. Impairment losses are recognised in the income statement.

2.3 Inventories

Inventories are stated at the lower of cost and net realisable value, cost being determined on the weighted average basis. Cost is determined based on actual expenditure on production of crude.

Net realisable value is the estimate of the selling price in the ordinary course of business, less selling expenses.

2 Summary of Significant Accounting Policies (Continued)

2.4 Accounts Receivable

Accounts receivable are carried at anticipated realisable value. An estimate is made for doubtful receivables based on a review of all outstanding amounts at year-end. Bad debts are written off during the year in which they are identified.

2.5 Cash and Cash Equivalents

For the purposes of the cash flow statement, cash and cash equivalents comprise cash at bank and in hand, net of bank overdrafts.

2.6 Share Capital

Ordinary shares are classified as equity.

2.7 Hire Purchase Loans

Property, plant and equipment acquired under hire purchase contracts are stated at cost. Hire purchase instalments outstanding at the balance sheet date are stated net of interest not yet due. Hire purchase interest is charged against income in the period to which it relates.

2.8 Leases

Leases of property, plant and equipment where the company assumes substantially all the benefits and risks of ownership are classified as finance leases. Finance leases are capitalised at the estimated present value of the underlying lease payments. Each lease payment is allocated between the liability and finance charges so as to achieve a constant rate on the finance balance outstanding. The interest element of the finance charge is charged to the profit and loss account over the lease period. The property plant and equipment acquired under finance leases is depreciated over the useful life of the asset.

Leases of assets under which all the risks and benefits of ownership are effectively retained by the lessor are classified as operating leases. Payments made under operating leases are charged to the profit and loss account on the straight line basis over the period of the lease.

2.9 Taxation

Deferred income tax is provided using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying values for financial reporting purposes. Currently enacted tax rates are used to determine deferred taxation. The principal temporary differences arise from depreciation on fixed assets.

Deferred tax assets relating to the carry-forward of unused tax losses are recognised to the extent that it is probable that future taxable profits will be available against which the unused tax losses can be utilised.

2.10 Foreign Currencies

These financial statements are expressed in Trinidad and Tobago dollars which is the functional currency of the company. Transactions originating in foreign currencies are translated into Trinidad and Tobago dollars at the rates of exchange prevailing at the time of the transactions. Assets and liabilities in foreign currencies are expressed at the rates of exchange prevailing at the balance sheet date. All differences in translation are dealt with in the profit and loss account.

2 Summary of Significant Accounting Policies (Continued)

2.11 Financial Instruments

Financial instruments carried on the balance sheet include cash and bank balances, trade and other receivables, trade and other creditors, directors' loans and related company balances. The particular recognition methods adopted are disclosed in the individual policy statements associated with each item.

2.12 Provisions

Provisions are recognised when the company has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made.

2.13 Revenue Recognition

Revenue is recognised upon invoicing of products and performance of services net of sales taxes and discounts.

2.14 Comparatives

Where necessary, comparative figures have been adjusted to conform with changes in presentation in the current year.

3 Significant Accounting Estimates, Judgements and Assumptions

Estimates and judgements are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Key estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Income Taxes

Some judgement is required in determining the provision for income taxes. There are many transactions and calculations for which the ultimate tax determination is uncertain during the ordinary course of business. The company recognises liabilities for anticipated tax audit issues based on estimates of whether additional taxes will be due. Where the final tax outcomes of these matters is different from the amounts that were initially recorded, such differences will impact the income tax and deferred tax provisions in the period in which such determination is made.

Post Employment Benefit

The retirement benefit provision is calculated using actuarial valuations which involve making assumptions about discount rates, future salary increases, mortality rates and employees expected length of service. Due to the long term nature of this liability such estimates are subject to significant uncertainty.

Provision for Well Abandonment and Site Restoration

The provision for well abandonment and site restoration involves assumptions about the expected life of the fields, inflation and discount rates which are all subject to uncertainity.

4 Related Parties

4.1 Related Companies

	7 Months Ended 31-Jul-11	Year Ended 31-Dec-10
Amounts due by:		
Current:		
Industrial Transport Limited	$ —	$ 3,486,239
Rigtech Services Limited	—	576,856
Lease Operators Limited	39,980	358,660
Rancho Quemado Estates Limited	—	92,427
Blanket Security Limited	—	25,040
	$ 39,980	$ 4,539,222
Amounts due to:		
Current:		
Rigtech Services Limited	$ 8,515,775	$ 7,908,079
Well Services Petroleum Company Limited	4,085,504	2,446,729
Industrial Transport Limited	14,375	688,113
Lease Operators Limited	32,207	664,649
Blanket Security Limited	168,580	293,444
Well Serv Limited	591	22,289
Trinity Infrastructure Construction Limited	—	15,200
Rancho Quemado Estates Limited	1,614	8,700
	$12,818,646	$12,047,203

Parties are considered to be related if one party has the ability to control the other party or exercise significant influence over the other party in making financial or operational decisions.

The sales to and purchases from related parties are made at normal market prices. Outstanding balances at the year end are unsecured, interest free and settlement occurs in cash. There have been no guarantees provided or received for any related party receivables or payables. For the 7 months ended 31 July 2011, the company has not recorded any impairment of receivables relating to amounts owed by related parties. This assessment is undertaken each financial year through examining the financial position of the related party and the market in which the related party operates.

Transactions with related parties are effected on an arms length basis and comprise the following:

Sales		
Trading transactions	$ 1,851,283	$ 531
Purchases		
Trading transactions	$15,473,722	$17,251,303

4.2 Directors Accounts

Amounts due to:		
Director's account	$ —	$ 175,459

5 Trade and Other Receivables

	7 Months Ended 31-Jul-11	Year Ended 31-Dec-10
Trade receivables	$21,909,482	$17,196,921
Prepayments	32,116	127,914
VAT refundable	8,855,089	7,950,325
Other receivables	21,502,607	17,570,839
	52,299,294	42,845,999
Less: Receivables from related parties	(39,980)	(1,052,983)
	$52,259,314	$41,793,016

Terms and conditions of the above financial assets:

Trade receivables are non interest bearing and are normally received in 30 - 60 day terms.

Other receivables are non interest bearing and have an average term of 6 months.

For terms and conditions relating to related parties, refer to Note 4.

6 Investments

Trinidad and Tobago Unit Trust Corporation	$ 87,074	$ 85,718
Roytrin Money Market Fund	533,343	524,075
	$620,417	$609,793

7 Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with banks. Cash and cash equivalents included in the statement of cash flows comprise the following:

Cash at Bank	$28,139,159	$3,322,025

The company maintains an overdraft facility with RBC Royal Bank (Trinidad and Tobago) Limited of 300,000 which is secured as follows:

a) Registered first demand debenture stamped to secure $6,500,000 creating a fixed and floating charge on the assets of the company.

b) Assignment of fire and special perils insurance over equipment with a coverage value of $4,319,000.

c) Assignment of insurance over building at Palo Seco.

8 Property, Plant & Equipment

	Land & Buildings	Machinery & Equipment	Well Costs & Other Equipment	Abandonment Asset	Office Furniture & Fixtures	Total
7 Months Ended 31 July 2011						
Cost						
As at 01 January 2011	$ 1,870,240	$ 8,567,912	$152,875,280	$9,820,019	$626,828	$173,760,279
Additions	—	—	13,271,143	—	—	13,271,143
Disposals	(1,200,000)	(4,076,150)	—	—	—	(5,276,150)
As at 31 July 2011	$ 670,240	$ 4,491,762	$166,146,423	$9,820,019	$626,828	$181,755,272
Accumulated Depreciation						
As at 01 January 2011	$ 60,099	$ 5,555,979	$ 75,683,980	$ 837,958	$345,842	$ 82,483,858
Depreciation/ Amortisation	7,118	266,120	9,125,755	291,085	20,489	9,710,567
Acc Depreciation of Disposals	—	(2,749,051)	—	—	—	(2,749,051)
As at 31 July 2011	$ 67,217	$ 3,073,048	$ 84,809,735	$1,129,043	$366,331	$ 89,445,374
Carrying Amount At 01 January 2011	$ 1,810,141	$ 3,011,933	$ 77,191,300	$8,982,062	$280,986	$ 91,276,422
At 31 July 2011	$ 603,023	$ 1,418,714	$ 81,336,688	$8,690,976	$260,497	$ 92,309,898

9 Deferred Taxation

	7 Months Ended 31-Jul-11	Year Ended 31-Dec-10
Balance brought forward 01 January	$(30,777,884)	$(35,693,924)
Credit for the year	2,025,097	5,116,040
Balance at 31 December	$(28,752,787)	$(30,777,684)
The deferred taxation balance is made up as follows:		
Deferred Tax Liability—Accelerated capital allowances	$(32,243,383)	$(33,470,237)
—Abandonment asset	(4,780,037)	(4,940,134)
	(37,023,420)	(38,410,371)
Deferred Tax Asset—Post employment benefit	$ 2,601,094	$ 2,145,836
—Well abandonment provision	5,669,539	5,486,650
	8,270,633	7,632,486

10 Trade and Other Payables

Trade payables	$ 25,443,418	$ 24,768,006
Less: Related parties	(12,818,647)	(11,374,554)
Trade payables—net	12,624,771	13,393,452
Other payables and accruals	26,572,916	16,632,179
	$ 39,197,687	$ 30,025,631

Terms and conditions of the above financial liabilities:

Trade payables are non interest bearing and are normally settled in 30 - 60 day terms.

Other payables are non interest bearing and have an average term of 6 months.

For terms and conditions relating to related parties, refer to Note 4.

11 Post Employment Benefit

The Company has an obligation to employees, whereby post employment benefits are paid to the employees' dependent on the years of continuous service attained and their basic pay. Benefits falling due more than 12 months after the statement of financial position date are discounted to the present value. Key assumptions used in the calculation are as follows:

Discount rate	6.25%	7.00%
Salary increase	5.00%	5.00%

At 31 July 2011, a liability of $4,729,260 has been recorded in these financial statements. No funding has yet been provided with respect to this obligation.

12 Well Abandonment Provision

	7 Months Ended 31-Jul-11	Year Ended 31-Dec-10
Balance brought forward 01 January	9,975,728	9,498,222
Provision for New Wells	—	321,797
Valuation Adjustment	332,524	155,709
Balance at 31 December	10,308,252	9,975,728

The company signed a new lease operatorship agreement on 27 June 2011 with Petroleum Company of Trinidad and Tobago Limited whereby a number of conditions were added including the company's responsibility to contribute to the cost of abandonment of wells and site restoration. The effective date of this agreement was made retroactive to 02 March 2009. The provision for abandonment and the related abandonment asset have been recognised retrospectively to the effective date of 02 March 2009 and treated as a prior period adjustment. Comparative figures as at 31 December 2010 have been restated accordingly.

13 Stated Capital

Authorised
An unlimited number of ordinary shares of no par value

Issued and fully paid 223,303 ordinary shares of no par value	$223,303	$223,303

14 Taxes Other Than Income Taxes

Supplemental Petroleum Tax	$12,352,366	$20,445,097

15 Taxation

The charge for the period is made up as follows:

Petroleum profits tax	$21,367,207	$26,999,771
Unemployment levy	2,136,721	2,699,977
Green fund levy	144,005	200,019
Deferred taxation	(2,025,097)	(5,116,040)
Adjusments to prior period provisions	75,009	—
	$21,697,845	$24,783,727

The tax charge differs from the theoretical amount that would arise using the basic tax rate as follows:

Profit before tax	$27,379,878	$44,538,390
Tax calculated at PPT 55%	15,058,933	24,496,114
Green fund levy	144,005	200,019
Permanent differences	6,419,898	87,593
Adjusments to prior period provisions	75,009	—
	$21,697,845	$24,783,726

16 Staff Costs

	7 Months Ended 31-Jul-11	Year Ended 31-Dec-10
Included in operating and administrative expenses are the following:		
Wages and salaries	$2,721,345	$4,582,001
Medical and other benefits	261,691	391,458
	$2,983,036	$4,973,459
Average Number of Employees	36	36

17 Contingent Liabilities

The company has obtained a revised assessment from the Board of Inland Revenue (BIR) for interest on the late payment of taxes from 2002 to 2009 amounting to approximately $9,300,000 at 31 July 2011. Discussions are continuing with the BIR to have this interest waived and a partial waiver seems a very likely outcome at this time. As a result, a provision has been made for 50% of the liability in these financial statements. Whatever the outcome, the BIR will grant the company time to pay this liability at the company's request and hence the provision has been classified as a medium term liability.

18 Subsequent Events

Business Combination

On 02 August 2011 the shareholders of the company signed a business combination agreement with a third party whereby the shareholding of Oilbelt Services Limited changed. The end result of the business combination in no way affects the ability of Oilbelt Services Limited to continue as a going concern.

Collective Agreement

The Collective Agreement between the company and Oilfied Workers Trade Union for hourly and weekly rated employees of the company expired on 30 June 2012. Negotiations are currently in progress with respect to a new three year period.

(B) FINANCIAL STATEMENTS OF OILBELT SERVICES TO YEAR END 31 DECEMBER 2010

Oilbelt Services Limited

Financial Statements

31 December 2010

(Expressed in Trinidad and Tobago Dollars)

Oilbelt Services Limited

Financial Statements

31 December 2010

(Expressed in Trinidad and Tobago Dollars)

CONTENTS

Independent Auditor's Report

To the members of
Oilbelt Services Limited

We have audited the accompanying financial statements of Oilbelt Services Limited which comprise the statement of financial position as at December 31, 2010, the statement of comprehensive income and retained earnings, and the statement of cash flows for the year then ended and a summary of significant accounting policies and other explanatory notes, as set out on pages 315 to 325.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards for SMEs. This responsibility includes designing, implementing and maintaining internal controls relevant to the preparation and fair presentation of the financial statements that are free from material misstatement, whether due to fraud or error, selecting and applying appropriate accounting policies, and making accounting estimates that are reasonable in the circumstances.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We have conducted our audit in accordance with international Standards on auditing. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance whether the financial statements are freefrom material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal controls relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate for the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of the accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation. of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly the financial position of the company as of December 31, 2010 and the results of its operations and its cash flows for the year then ended in accordance with International Financial Reporting Standards for SMEs.

YLL

Chartered Accountants
San Fernando
Trinidad, West Indies
August 24, 2011

Oilbelt Services Limited

Statement of Financial Position

(Expressed in Trinidad and Tobago Dollars)

	Notes	31 December 2010	31 December 2009
Assets			
Current			
Inventories		126,188	209,799
Due by related companies	5	4,539,222	23,150,238
Taxation recoverable		3,456,019	155,767
Trade and other receivables	6	41,793,016	33,410,498
Investments	7	609,793	551,854
Cash at bank	8	3,322,025	13,788,182
		53,846,263	71,266,338
Non-Current			
Fixed assets	9	$ 82,294,360	$ 84,949,230
Deferred tax asset	10	2,145,836	
		84,440,196	84,949,230
Total Assets		**$138,286,459**	**$156,215,568**
Equity and Liabilities			
Liabilities			
Current			
Due to related companies	5	12,047,203	15,632,700
Due to director	5	175,459	597,223
Trade and other payables	11	30,025,631	19,465,685
Taxation payable		2,722,953	21,027,557
		$ 44,971,246	$ 56,723,165
Medium Term			
Deferred taxation	10	$ 33,470,237	$ 36,090,185
Long Term			
Retirement benefit		$ 3,901,520	$
Total Liabilities		**82,343,003**	**92,813,350**
Shareholders Equity			
Stated capital	12	$ 223,303	$ 223,303
Retained earnings		55,720,153	63,178,914
		$ 55,943,456	$ 63,402,217
Total Liabilities and Shareholders Equity		**$138,286,459**	**$156,215,568**

Director

The notes on pages 318 to 325 form an integral part of these financial statements.

Oilbelt Services Limited

Statement of Comprehensive Income and Retained Earnings

(Expressed in Trinidad and Tobago Dollars)

	Notes	Year Ended 31 December 2010	Year Ended 31 December 2009
Revenue			
Crude Oil Sales		$194,262,056	$159,141,444
Other Income		74,600	1,241,809
		194,336,656	160,383,253
Cost and Expenses			
Royalties		80,882,190	63,966,965
Operating		24,712,441	21,129,497
Depreciation		16,146,637	17,664,529
Administration		6,835,079	2,533,360
Interest		139,987	865,999
Operating Expenses		128,716,334	106,160,350
Operating Profit		65,620,322	54,222,903
Taxes Other Than Income Taxes	13	20,445,097	16,162,079
Profit Before Taxation		45,175,225	38,060.824
Taxation	14	25,133,986	21,094,787
Profit After Taxation		20,041,239	16,966,037
Dividends		27,500,000	20,000,000
Retained Earnings at Start of Year		**63,178,914**	**66,212,877**
Retained Earnings at End of Year		**$ 55,720,153**	**$ 63,178,914**

The notes on pages 318 to 325 form an integral part of these financial statements.

Oilbelt Services Limited

Statement of Cash Flows

(Expressed in Trinidad and Tobago Dollars)

	Notes	Year Ended 31 December 2010	Year Ended 31 December 2009
Cash Flows From Operating Activities			
Profit before taxation		$ 45,175,225	$ 38,060,824
Adjustments To Reconcile Net Profit To Cash Provided By Operating Activities			
Depreciation		16,146,637	17,664,529
Taxes other than income taxes	13	20,445,097	16,162,079
Profit on disposal of fixed assets		(12,173)	(98,134)
increase in retirement benefit provision		3,901,520	
Interest expense		139,987	865,999
		85,796,293	72,655,297
Changes In Operating Assets/Liabilities			
Increase in trade and other receivables		(8,382,518)	(21,799,288)
Decrease in amounts due by related companies		18,611,016	4,585,514
Decrease in inventories		83,610	14,138
(Decrease) / Increase in amounts due to director		(421,764)	597,223
Increase in trade creditors and accruals		10,559,946	10,657,147
(Decrease) / Increase in amounts due to related companies		(3,585,497)	3,004,040
		102,661,086	69,714,071
Taxation paid		(71,949,722)	(62,234,978)
Interest paid		(139,987)	(865,999)
Cash Provided by Operating Activities		30,571,377	6,613,094
Investing Activities			
Purchase of fixed assets		(13,550,995)	(19,330,167)
Proceeds from sale of fixed assets		71,400	825,139
Net (purchase) / redemption of investments		(57,939)	30,583,816
Cash (Used in) / Provided By Investing Activities		(13,537,534)	12,078,788
Financing Activities			
Dividend paid		(27,500,000)	(20,000,000)
Cash Used in Financing Activities		(27,500,000)	(20,000,000)
Cash Decrease During The Year		(10,466,157)	(1,308,118)
Cash And Cash Equivalents, Beginning Of Year		13,788,182	15,096,300
Cash And Cash Equivalents, End Of Year	8	$ 3,322,025	$ 13,788,182

The notes on pages 318 to 325 form an integral part of these financial statements.

Oilbelt Services Limited

Notes to the Financial Statements

31 December 2010

(Expressed in Trinidad and Tobago Dollars)

1 Incorporation And Principal Activities

The company is incorporated in the Republic of Trinidad and Tobago, with its registered office situated at Otaheite Industrial Estate, South Oropouche. It is a subsidiary of Well Services Holdings Limited which is also incorporated in the Republic of Trinidad and Tobago. Its principal activities are the recovery and sale of crude oil which it produces from wells leased under The Petroleum Company of Trinidad and Tobago Limited's (Petrotrin) lease-operatorship programme.

These financial statements were authorised for issue by the management on 24 August 2011.

2 Summary of Significant Accounting Policies

2.1 Basis of Preparation

These financial statements have been prepared in accordance with the International Financial Reporting Standards for Small and Medium-sized Entities issued by the International Accounting Standards Board. They are presented in Trinidad and: Tobago dollars.

2.2 Property, Plant & Equipment

Property, plant & equipment are stated at cost less accumulated depreciation and accumulated impairment losses Such cost includes the cost of replacing part of the plant and equipment when that cost is incurred, if the recognition criteria is met. Likewise, when a major inspection is performed, its cost is recognised in the carrying amount of the plant and equipment as a replacement if the recognition criteria is met. All other repair and maintenance costs are recognised in profit or loss as incurred.

The company's exploration and production activities are accounted for under the successful efforts method. Under this method exploration costs other than the costs of drilling exploratory wells, including geological and geophysical expenditure, are expensed when incurred. The costs of drilling exploratory wells are capitalised pending determination as to whether they have discovered proved commercial reserves. If proved reserves are not discovered, such drilling costs are expensed. The costs of all development wells, including development dry holes and related equipment used in the production of crude oil and natural gas are capitalised.

Depreciation is calculated on the reducing balance basis.

The following rates are considered appropriate to write off the assets over their estimated useful lives:

Land and Buildings	2%
Machinery and equipment	25%
Well costs and other equipment	25%
Office Furniture & Equipment	10%

The carrying values of property, plant and equipment are reviewed for impairment when events or changes in circumstances indicate that the carrying value may not be recoverable. If such indication exists and where the carrying values exceed the estimated recoverable amount, the assets are written down to their recoverable amount. The recoverable amount of property, plant and equipment is the greater of net selling price and value in use. Impairment losses are recognised in the income statement.

2.3 Inventories

Inventories are stated at the lower of cost and net realisable value cost being determined on the weighted average basis Work in progress represents work which has commenced but has either not been completed or invoiced at the year end. Work in progress is stated at the lower of cost and net realisable value. Cost is determined based on actual expenditure to date. Net realisable value is the estimate of the selling price in the ordinary course of business, less selling express.

2 Summary of Significant Accounting Policies (Continued)

2.4 Accounts Receivable

Accounts receivable are carried at anticipated realisable value. An estimate is made for doubtful receivables based on a review of all outstanding amounts at year-end. Bad debts are written off during the year in which they are identified.

2.5 Cash and Cash Equivalents

For the purposes of the cash flow statement, cash and cash equivalents comprise cash at bank and in hand, net of bank overdrafts.

2.6 Share Capital

Ordinary shares are classified as equity.

2.7 Hire Purchase Loans

Property, plant and equipment acquired under hire purchase contracts are stated at cost. Hire purchase instalments outstanding at the balance sheet date are stated net of interest not yet due. Hire purchase interest is charged against income in the period to which it relates.

2.8 Leases

Leases of property, plant and equipment where the company assumes substantially all the benefits and risks of ownership are classified as finance leases. Finance leases are capitalised at the estimated present value of the underlying lease payments. Each lease payment is allocated between the liability and finance charges so as to achieve a constant rate on the finance balance outstanding. The interest element of the finance charge is charged to the profit and loss account over the lease period. The property plant and equipment acquired under finance leases is depreciated over the useful life of the asset.

Leases of assets under which all the risks and benefits of ownership are effectively retained by the lessor are classified as operating leases. Payments made under operating leases are charged to the profit and loss account on the straight line basis over the period of the lease.

2.9 Taxation

Deferred income tax is provided using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying values for financial reporting purposes.

Currently enacted tax rates are used to determine deferred taxation. The principal temporary differences arise from depreciation on fixed assets.

Deferred tax assets relating to the carry-forward of unused tax losses are recognised to the extent that it is probable that future taxable profits will be available against which the unused tax losses can be utilised.

2.10 Foreign Currencies

These financial statements are expressed in Trinidad and Tobago dollars which is the functional currency of the company. Transactions originating in foreign currencies are translated into Trinidad and Tobago dollars at the rates of exchange prevailing at the time of the transactions. Assets and liabilities in foreign currencies are expressed at the rates of exchange prevailing at the balance sheet date.

All differences in translation are dealt with in the profit and loss account.

2 Summary of Significant Accounting Policies (Continued)

2.11 Financial Instruments

Financial instruments carried on the balance sheet include cash and bank balances, trade and other receivables. trade and other creditors, directors' loans and related company balances. The particular recognition methods adopted are disclosed in the individual policy statements associated with each item.

2.12 Provisions

Provisions are recognised when the company has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made.

2.13 Revenue Recognition

Revenue is recognised upon invoicing of products and performance of services net of sales taxes and discounts.

2.14 Comparatives

Where necessary. comparative figures have been adjusted to conform with changes in presentation in the current year.

3 Transition to the IFRS for SMEs

The company's financial statements for the year ended 31 December 2010 are its first annual financial statements prepared under accounting policies that comply with the IFRS for SMEs. The company's transition date is 1 January 2009. The company prepared its opening IFRS for SMEs statement of financial position at that date.

Reconciliation

On adoption of the IFRS for SMEs, no retrospective adjustments to prior year figures were required as at 1 January 2009. In addition the reported amounts at 31 December 2009 and 31 December 2010 are the same as that which would have been reported had the company continued to comply with full IFRS's.

4 Significant Accounting Estimates, Judgements and Assumptions

Estimates and judgements are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Key estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Income Taxes

Some judgement is required in determining the provision for income taxes. There are many transactions and calculations for which the ultimate tax determination is uncertain during the ordinary course of business. The company recognises liabilities for anticipated tax audit issues based on estimates of whether additional taxes will be due. Where the final tax outcomes of these matters is different from the amounts that were initially recorded, such differences will impact the income tax and deferred tax provisions in the period in which such determination is made.

4 Significant Accounting Estimates, Judgements and Assumptions (Continued)

Post Employment Benefit

The retirement benefit provision is calculated using actuarial valuations which involve making assumptions about discount rates, future salary increases, mortality rates and employees expected length of service. Due to the long term nature of this liability such estimates are subject to significant uncertainty.

5 Related Parties

5.1 Related Companies

	2010	2009
Amounts due by:		
Current:		
Industrial Transport Limited	$ 3,486,239	$ 3,000,239
Rigtech Services Limited	576,856	
Lease Operators Limited	358,660	6,456,518
Rancho Quemado Estates	92,427	
Blanket Security Limited	25,040	
Well Services Petroleum Company Limited		13,693,481
	$ 4,539,222	$23,150,238
Amounts due to:		
Current:		
Rigtech Services Limited	$ 7,908,079	$13,708,270
Well Services Petroleum Company Limited	2,446,729	
Industrial Transport Limited	688,113	977,545
Lease Operators Limited	664,649	907,669
Blanket Security Limited	293,444	
Well Serv Limited	22,289	39,216
Trinity Infrastructure Construction Limited	15,200	
Rancho Quemado Estates	8,700	
	$12,047,203	$15,632,700

Parties are considered to be related if one party has the ability to control the other party or exercise significant influence over the other party in making financial or operational decisions.

The sales to and purchases from related parties are made at normal market prices. Outstanding balances at the year end are unsecured, interest free and settlement occurs in cash. There have been no guarantees provided or received for any related party receivables or payables. For the year ended 31 December 2010, the company has not recorded any impairment of receivables relating to amounts owed by related parties. This assessment is undertaken each financial year through examining the financial position of the related party and the market in which the related party operates.

Transactions with related parties are effected on an arms length basis and comprise the following:

	2010	2009
Sales		
Trading transactions	$ 531	$
Purchases		
Trading transactions	$17,521,303	$27,643,496

5 Related Parties (Continued)

5.2 Directors Accounts

	2010	2009
Amounts due to:		
Director's account	$175,459	$597,223

These balances are interest free and carry no fixed terms of repayment.

6 Trade and Other Receivables

	2010	2009
Trade receivables	$17,196,921	$16,894,379
Prepayments	127,914	136,151
VAT refundable	7,950,325	8,105,932
Other receivables	17,570,839	8,414,815
	42,845,999	33,551,277
Less: Receivables from related parties	(1,052,983)	(140,779)
	$41,793,016	$33,410,498

Terms and conditions of the above financial assets:

Trade receivables are non interest bearing and are normally received in 30-60 day terms. Other receivables are non interest bearing and have an average term of 6 months.

For terms and conditions relating to related parties, refer to Note 5.

7 Investments

	2010	2009
Trinidad and Tobago Unit Trust Corporation	$ 85,718	$ 84,025
Roytrin Money Market Fund	524,075	467,829
	$609,793	$551,854

8 Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with banks. Cash and cash equivalents included in the statement of cash flows compose the following:

	2010	2009
Cash at Bank	$3,322,025	$13,788,182

The company maintains an overdraft facility with RBTT Bank Limited of 300,000 which is secured as follows:

a) Registered first demand debenture stamped to secure $6,500,000 creating a fixed and floating charge on the assets of the company.

b) Assignment of fire and special perils insurance over equipment with a coverage value of $4,319,000.

8 Cash and Cash Equivalents (Continued)

c) Assignment of insurance over building at Palo Seco.

9 Property, Plant & Equipment

	Land & Buildings	Machinery & Equipment	Well Costs & Other Equipment	Office Furniture & Fixtures	Total
Year Ended 31 December 2010					
Opening net book value	$1,822,545	$ 3,367,638	$ 79,482,081	$ 276,966	$ 84,949,230
Additions		237,307	13,273,857	39,831	13,550,995
Disposals		(59,227)			(59,227)
Depreciation	(12,404)	(721,583)	(15,376,840)	(35,811)	(16,146,638)
Closing net book value	$1,810,141	$ 2,824,135	$ 77,379,098	$ 280,986	$ 82,294,360
At 31 December 2010					
Cost/Valuation	$1,870,240	$ 8,691,976	$152,958,837	$ 626,828	$164,147,881
Accumulated Depreciation	(60,099)	(5,867,841)	(75,579,739)	(345,842)	(81,853,521)
	$1,810,141	$ 2,824,135	$ 77,379,098	$ 280,986	$ 82,294,360
Year Ended 31 December 2009					
Opening net book value	$1,835,185	$ 4,289,265	$ 77,571,020	$ 315,125	$ 84,010,595
Additions			19,330,167		19,330,167
Disposals		(46,200)	(680,803)		(727,003)
Depreciation	(12,640)	(875,427)	(16,738,303)	(38,159)	(17,664,529)
Closing net book value	$1,822,545	$ 3,367,638	$ 79,482,081	$ 276,966	$ 84,949,230
At 31 December 2009					
Cost/ Valuation	$1,870,240	$ 8,513,896	$139,684,980	$ 586,997	$150,656,113
Accumulated Depreciation	(47,695)	(5,146,258)	(60,202,899)	(310,031)	(65,706,883)
	$1,822,545	$ 3,367,638	$ 79,482,081	$ 276,966	$ 84,949,230

10 Deferred Taxation

	2010	2009
Balance brought forward 01 January	$(36,090,185)	$(37,905,317)
Credit for the year	4,765,784	1,815,132
Balance at 31 December	$(31.324,401)	$(36,090,185)
The deferred taxation balance is made up as follows:		
Deferred Tax Liability—Accelerated capital allowances	$(33,470,237)	$(36,090,185)
Deferred Tax Asset—Employment benefit provision	$ 2,145,836	$

11 Trade and Other Payables

	2010	2009
Trade payables	$24,768,006	$28,382,431
Less Related parties	(11,374,554)	(15,632,700)
Trade payables—net	13,393,452	12,749,731
Other payables and accruals	16,632,179	6,715,954
	$30,025,631	$19,465,685

11 Trade and Other Payables (Continued)

Terms and conditions of the above financial liabilities:

Trade payables are non interest bearing and are normally settled in 30-60 day terms.

Other payables are non interest bearing and have an average term of 6 months.

For terms and conditions relating to related parties. refer to Note 5.

12 Stated Capital

	2010	2009
Authorised		
An unlimited number of ordinary shares of no par value		
Issued and fully paid		
223,303 ordinary shares of no par value	$223,303	$223,303

13 Taxes Other Than Income Taxes

	2010	2009
Supplemental Petroleum Tax	$20,445,097	$16,162,079

14 Taxation

	2010	2009
The charge for the year is made up as follows:		
Petroleum profits tax	$26,999,771	$20,670,255
Unemployment levy	2,699,977	2,067,026
Green fund levy	200,019	159,141
Deferred taxation	(4,765,781)	(1,815,132)
Adjusments to prior period provisions		13,497
	$25,133,986	$21,094,787

The tax charge differs from the theoretical amount that would arise using the basic tax rate as follows:

	2010	2009
Profit before tax	$45,175,225	$38,060,824
Tax calculated at PPT 55%	24,846,374	20,933,453
Green fund levy	200,019	159,141
Permanent differences	87,593	(11,305)
Adjusments to prior period provisions		13,497
	$25,133,986	$21,094,787

15 Staff Costs

	2010	2009
Included in operating and administrative expenses are the following:		
Wages and salaries	$4,582,001	$3,626,657
Medical and other benefits	391,458	430,048
	$4,973,459	$4,056,706

16 Contingent Liability

The company has received an assessment from the Board of Inland Revenue for interest on the late payment of taxes from 2002 to 2009 amounting to approximately $7,500,000. Discussions are currently being held with the BIR to have this interest waived. No amounts have been accounted for in these financial statements.

17 Subsequent Event

The directors are currently in discussions with a third party with respect to a business combination involving this company. These discussions were ongoing up to the time of issue of these financial statements.

PART VIII

FINANCIAL INFORMATION ON THE BAYFIELD GROUP

The following financial information on the Bayfield Group is available on Bayfield's website at www.bayfieldenergy.com (up to Admission) or www.trinityexploration.com (following Admission), and is incorporated by reference into this document as explained in paragraph 23 of Part XII of this document:

Financial Information	Website Address (up to Admission)	Website Address (following Admission)
Unaudited consolidated interim statements of Bayfield for the six months ended 30 June 2012	www.bayfieldenergy.com/news.htm	www.trinityexploration.com/news.htm
Audited consolidated accounts of Bayfield for the year ended 31 December 2011	www.bayfieldenergy.com/investors.htm	www.trinityexploration.com/investors.htm
Audited consolidated accounts of BEL for the year ended 31 December 2010	www.bayfieldenergy.com/investors.htm (comprised in Bayfield's IPO Admission Document)	www.trinityexploration.com/investors.htm (comprised in Bayfield's IPO Admission Document)
Audited consolidated accounts of BEL for the year ended 31 December 2009	www.bayfieldenergy.com/investors.htm (comprised in Bayfield's IPO Admission Document)	www.trinityexploration.com/investors.htm (comprised in Bayfield's IPO Admission Document)

PART IX

UNAUDITED PRO FORMA STATEMENT OF NET ASSETS OF THE ENLARGED GROUP

Unaudited pro forma statement of net assets of the Enlarged Group as at 30 June 2012

The unaudited pro forma statement of net assets set out below has been prepared to illustrate the effect on the consolidated net assets of the Company as if the Merger had occurred on 30 June 2012. The information, which is provided for illustrative purposes only, by its nature addresses a hypothetical situation and therefore does not represent the actual financial position of the Enlarged Group. No adjustments have been made to reflect any transactions other than as set out in the unaudited pro forma statement of net assets.

	Bayfield as at 30 June 2012	Trinity as at 30 June 2012	Adjustments	Pro forma of Enlarged Group
	US$'000 (Note 1)	US$'000 (Note 2)	US$'000 (Note 3)	US$'000
Assets				
Non-Current Assets				
Intangible assets	35,695	16,952	—	52,647
Property, plant and equipment	49,790	54,583	—	104,373
Deferred tax assets	18,906	12,597	—	31,503
	104,391	**84,132**	**—**	**188,523**
Current Assets				
Inventories	9,403	2,695	—	12,098
Trade and other receivables	12,369	13,809	—	26,178
Taxation recoverable	—	119	—	119
Short term investments	—	37	—	37
Cash and cash equivalents	19,216	18,527	78,360	116,103
	40,988	**35,187**	**78,360**	**154,535**
Liabilities				
Current Liabilities				
Trade and other payables	(34,462)	(10,075)	—	(44,537)
Borrowings	—	(4,268)	268	(4,000)
Taxation payable	—	(5,227)	—	(5,227)
	(34,462)	**(19,570)**	**268**	**(53,764)**
Net current assets	**6,526**	**15,617**	**78,628**	**100,771**
Non-current liabilities				
Convertible loan notes	—	(6,837)	—	(6,837)
Borrowings	—	(6,139)	(9,861)	(16,000)
Provision for employee retirement benefits	—	(740)	—	(740)
Decommissioning provision	(6,676)	(6,580)	—	(13,256)
Deferred tax liability	—	(18,204)	—	(18,204)
	(6,676)	**(38,500)**	**(9,861)**	**(55,037)**
Net Assets	**104,241**	**61,249**	**68,767**	**234,257**

Notes to the unaudited pro forma statement of net assets

1. The Bayfield net assets have been extracted from the unaudited balance sheet at 30 June 2012 as presented in the 2012 BEH plc Half Year Report which is incorporated by reference into this document.

2. The Trinity net assets have been extracted from the unaudited Target Group Financial Information Table at 30 June 2012 included in Part VII Section A of this Document

3. Adjustments

(a) The increase in long term borrowings relates to the incremental drawdown on the new Citibank bank facility to take total drawdown to $20million.

(b) The increase in cash reflects the proceeds of the placing of 47,500,000 consolidated ordinary shares of $1.00 each multiplied by the post share consolidation price of £1.20 (converted from £:US$ at a rate of U$:£ of 1.58 being the rate prevailing at the date of this Document, net of transaction costs of $7.7 million plus $4.1 million of commission on equity to take total fees to $11.8 million.

(c) Under IFRS 3(R) "Business Combinations" this transaction is considered to be a reverse takeover of Bayfield by Trinity and therefore the following adjustments are made:

Consideration – the consideration is deemed to be the value of Bayfield by virtue of the number of Bayfield shares in issue prior to the Merger being 216,479,442 ordinary shares of US$0.10 each multiplied by Bayfield's share price on the date of the announcement of the Transaction of £0.2075 converted from £ to US$ at a rate of US$:£1 of 1.58 being the rate prevailing at the date of this Document. This amounts to consideration of approximately US$71.0 million.

Goodwill – the identified assets and liabilities of Bayfield will be adjusted to fair value at the date of purchase and a purchase price allocation ("**PPA**") exercise will be undertaken. Any excess of the costs of acquisition over the fair value of the indentified assets and liabilities of Bayfield will be recorded as goodwill on the balance sheet. Conversely if the fair value of the identified assets and liabilities of Bayfield is higher than the consideration, negative goodwill will result which will be recorded in the income statement in the year of acquisition.

The following table sets out the adjustment for the purposes of the proforma and in the absence of any fair value adjustments or a completed PPA exercise.

	US$'000
Consideration	70,973
Less: net assets acquired of Bayfield as at 30 June 2012	(104,241)
Excess of net assets acquired over cost (negative goodwill)	(33,268)

PART X

FURTHER INFORMATION ON THE EXPLORATION AND PRODUCTION INDUSTRY IN TRINIDAD AND TOBAGO

Introduction to Trinidad and Tobago

The twin island state of Trinidad and Tobago has earned a reputation as an excellent country for international businesses and has one of the highest growth rates and per capita incomes in Latin America. English is the official language and the country is governed by a parliamentary democracy. The country's economy is heavily reliant upon the energy sector which contributed 44 per cent. of GDP in 2010 and 83 per cent. of exports. Given the strength of commodity prices in recent years Trinidad and Tobago enjoys a strong financial position with GDP of US$20.9 billion (US$15,895 per capita) and net external debt of US$1.6 billion. Trinidad and Tobago has a credit rating of A from Standard & Poors.

Trinidad has a long history of oil production and more recently has established itself as a significant exporter of natural gas from its offshore fields. The country has significant energy infrastructure and is the largest producer and exporter of methanol and ammonia in the world. There are four LNG trains (14.8 million MTPA), four iron and steel mills, six power plants, eleven ammonia plants and one urea plant, together with a crude oil refinery (160,000 bbls per day throughput refinery capacity; the bulk of the feedstock is imported to supplement indigenous crude).

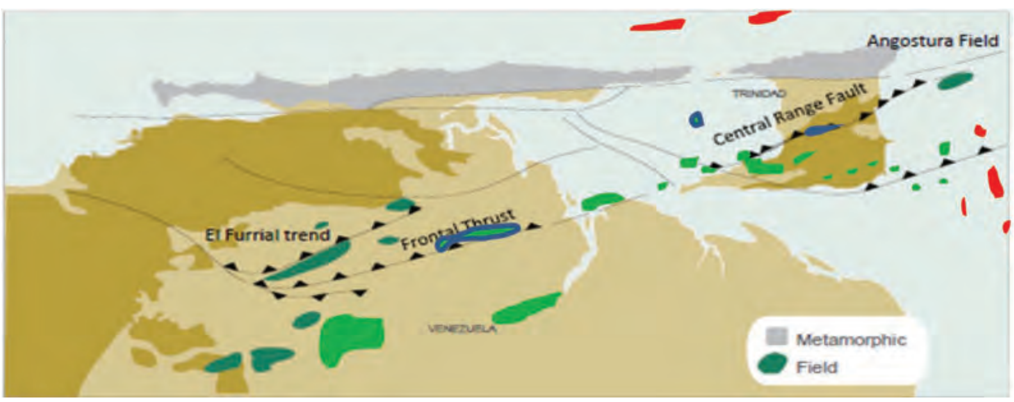
The workforce is highly trained and experienced, and has a long history in the energy sector. The oilfield services industry is well developed and the country has its own platform fabrication yard.

The combination of a world-class petroleum system, competitive fiscal terms and a well-established legal and regulatory framework for hydrocarbon exploration and production makes the country an excellent place for conducting upstream business. A number of large international E&P companies have invested in Trinidad in recent years including BP, BG, BHP, Centrica, EOG, Niko Resources, Repsol and Sinopec.

Geological Setting

Trinidad is located at the southerly extent of the Caribbean. Trinidad is situated at the Eastern end of the prolific Eastern Venezuelan hydrocarbon basin and is on trend with Venezuela's Orinoco Heavy Oil Belt, the world's largest known hydrocarbon accumulation.

Figure 10: Trinidad's geological setting

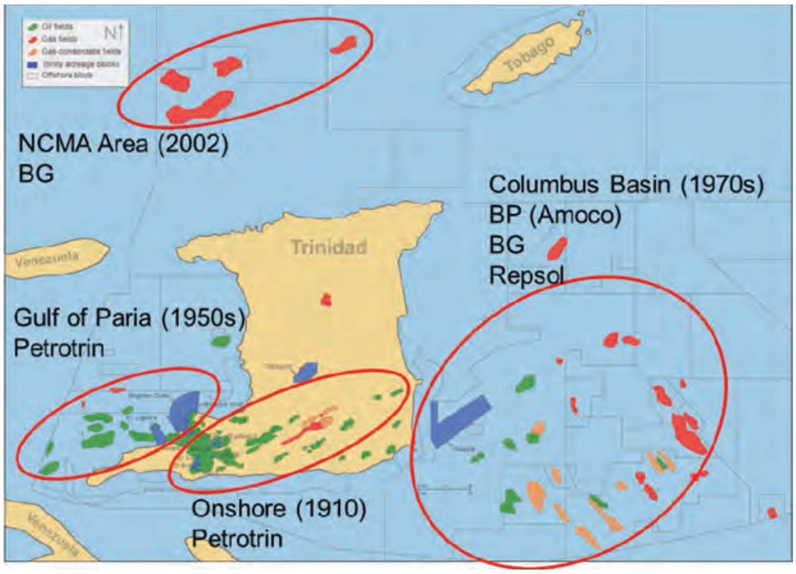


Source: Bayfield

Basin Development

Trinidad has a long history of oil production with commercial activities starting in 1908 near the Pitch Lake, La Brea. More recently the country has also established itself as a significant exporter of natural gas.

Figure 11: Trinidad's fields and blocks



Source: Bayfield

Marine activities started in the 1950's with Texaco and TRINMAR (now part of Petrotrin) developing the Gulf of Paria offshore Trinidad's West Coast. At the time, the Brighton platform was the largest of its type in the world.

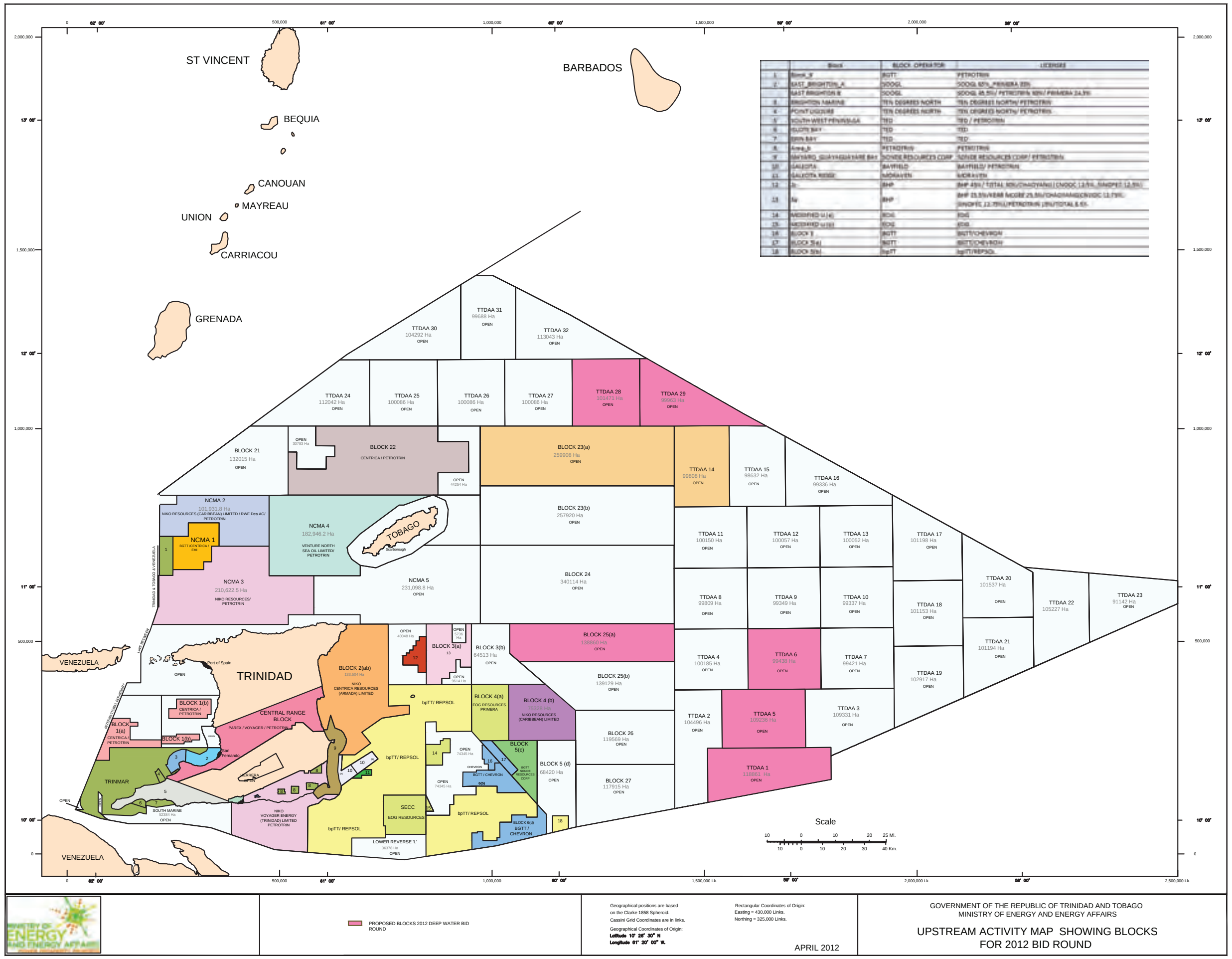
Drilling activity in the Columbus basin offshore Trinidad's East coast began in 1961 in the Galeota area, but the discovery was considered uneconomic at the time. The first commercial success was drilled in 1968 and commercial production began in 1972 from Amoco's Teak platform. Significant gas volumes were also discovered in the area and during the late 1990s BG, Repsol, Tractabel and the Government of Trinidad and Tobago formed the Atlantic LNG Company of Trinidad partnership to explore opportunities to export liquified gas to the US and Spain. The first cargos were delivered in 1999 and there are now four LNG trains with a total export capacity of 14.8 MTPA.

Gas was first discovered in Trinidad's North Coast Marine Area in 1971 but the area did not come into production until 2002 when the gas was developed as feedstock for Atlantic LNG trains 2, 3 and 4.

To date, Trinidad has produced a total of 3.5bn bbl of oil, of which 1.6bn bbl are from its onshore fields, and 22 Tcf of gas. As of January 2011 gross 3P gas Reserves were estimated at 27 Tcf and gross 3P oil Reserves were estimated at 570 MMBbl.

Trinidad and Tobago Lease Map

Figure 12: Trinidad and Tobago lease map

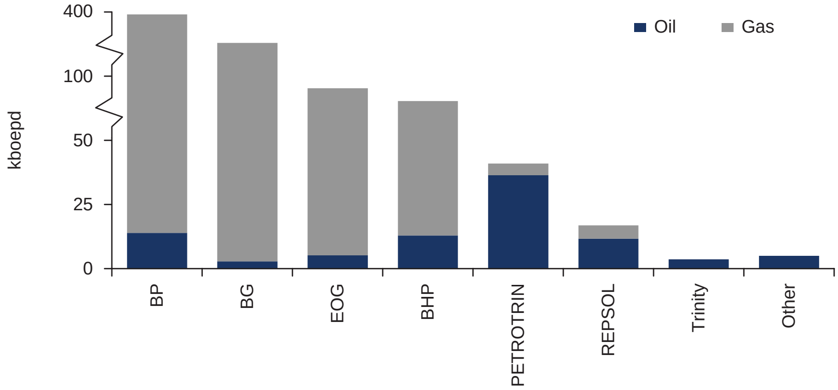


Source: Trinidad Ministry

Current Industry Conditions

Trinidad's oil and gas assets remain tightly held, with a production dominated by a small group of Majors/ large-cap companies and Petrotrin, the national oil company.

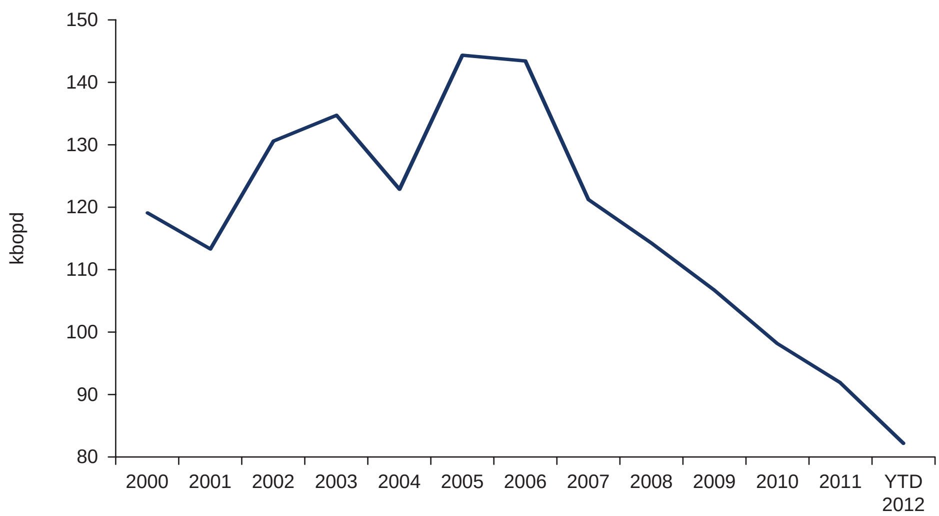
Figure 13: Production in Trinidad by company



Source: Trinidad Ministry

Trinidad produced 92,000 bbl/d of oil and 4.1 Bcf/d of gas in 2011. However, oil production has declined 36 per cent. since its peak in 2005 as asset owners have refocused their portfolios on larger investment opportunities elsewhere in the world. These asset owners have left under-exploited and stranded assets that smaller and more nimble operators can efficiently develop.

Figure 14: Production in Trinidad by year



Source: Trinidad Ministry

The Trinidad Ministry has recognised that reforms are needed to arrest these declines in production and has taken measures to encourage investment:

Fiscal Change

- Commitment by Trinidad Ministry to review fiscal terms every three years
  - Initial review in 2009 led to a reduction in the SPT rate and capital investment incentives for small or mature marine fields
  - 2012 review led to further reduction in SPT rate for small marine developments
- Willingness to review fiscal terms on other assets
  - LOAs re-negotiated in 2011 which led to the award of new licences with a 10-year term and 5-year option period and included drilling incentives for new wells
  - Negotiations were led by Trinity on behalf, and for the benefit, of the entire industry

Making acreage available to operators

- Successful Deepwater Bid Round 2012 saw 12 bids received for 5 blocks from companies including BG, BHP Billiton, Cairn Energy (in partnership with Trinity) and Kosmos Energy
- Further deepwater bid round expected in 2013
- New onshore bid round expected in Q1 2013
- New offshore bid round expected in Q2 2013
- Trinity awarded PGB licence out of a bid round in 2012

These measures are having the desired effect, with increased investment leading to new discoveries. BP Trinidad & Tobago discovered an additional 1 TCF of gas in the Savonette field in November 2012. In March 2012, Petrotrin announced the Jubilee discovery in the Gulf of Paria, estimated at 48 MMBbl. Also in March 2012, Bayfield announced the EG-8 discovery which the Directors believe identified gross development potential of 32 MMBbl of oil and 69 Bcf of gas. In 2012-2013, 19 exploration wells are expected to be drilled in Trinidad versus six in the previous year.

Legal and Fiscal regime

Trinidad and Tobago's legal system is based upon English common law and since independence in 1962 sanctity of contract within the rule of law has remained intact.

The Petroleum Act Chap. 62:01 of 1969, the Petroleum Regulations of 1970, Environmental Management Act Chap. 35:05 and Petroleum Taxes Act Chapter 75:04 are the main legislative acts that govern the petroleum industry of Trinidad and Tobago.

The Petroleum Act is the mechanism by which rights to explore for and produce petroleum are granted in Trinidad and Tobago. No person is entitled to engage in petroleum operations on land or in a submarine area, unless an exploration and production licence is first obtained. However, as an alternative to the issue of an exploration and production licence, a production sharing contract may be entered into between the Republic of Trinidad and Tobago and the licencee.

All the rights to petroleum in its natural condition are vested in the state. A licence does not confer any title to petroleum in strata, but provides an exclusive right to explore for, and produce petroleum within the licenced area and to dispose of such petroleum. Title to the petroleum is vested in the licencees upon production.

Pursuant to the Petroleum Act, applications for licences are made to the Trinidad Minister of Energy who may grant licences in accordance with the Petroleum Act and upon such terms and conditions as he considers appropriate. An applicant is however required to establish a place of business in Trinidad and Tobago before being granted a licence.

The prior approval of the Trinidad Minister of Energy is required before the licencee conducts any geophysical and drilling activities, and erects any fixed installations. The Trinidad Minister of Energy's prior consent is also required before the licencee abandons wells.

The licence granted by the Trinidad Minister of Energy sets out the term of the licence and the minimum work obligations and expenditure obligations that need to be complied with by the licencee during such term. The Trinidad Minister of Energy is entitled to revoke the licence and the licencee's right to carry out petroleum operations where there is a failure by the licencee to fulfil the minimum work obligations or to meet its expenditure obligations.

A licencee's operations under a licence are subject to the provisions of the Environmental Management Act Chap. 35:05, pursuant to which a certificate of environmental clearance is required prior to embarking upon activities arising out of petroleum exploration and production. The application for a certificate of environmental clearance may require the preparation of an environmental impact assessment and may also require public consultations with possibly affected parties. A certificate of environmental clearance is valid for a period of three years from its effective date and where it has expired, a new application will have to be made.

Licencees are required under the Petroleum Act to provide the Trinidad Minister of Energy with a performance guarantee in the form of a bond or bankers guarantee or such other form acceptable to the Trinidad Minister of Energy as security for the performance of its minimum work obligations and minimum expenditure obligations. The Petroleum Act provides for a reduction of the amount of the performance guarantee at the end of each twelve-month period by the actual exploration expenditure during the period.

In addition to other payments specifically provided for in the licence and the Petroleum Act (such as the application fee, signature bonus, licence fee, security deposit, environmental bonus, technical equipment bonus, surface area payment and production bonus) a royalty at the rate of 12.5 per cent. for each barrel of crude oil and natural gas produced is paid by the licencee to the Trinidad Minister of Energy. Further, licencees are also required to pay a petroleum impost in respect of all petroleum won and saved, at such rates as the Trinidad Minister of Energy may determine and publish in the official gazette.

Companies conducting petroleum operations in Trinidad and Tobago are liable to pay a petroleum profits tax at the rate of 50 per cent. of taxable profits. In addition to petroleum profits tax, a company conducting petroleum operations will also be subject to (i) a supplemental petroleum tax which is payable depending on the weighted average annual crude oil price and whether an exploration and production licence was granted pre or post 1 January 1988; (ii) an unemployment levy at the rate of five per cent. of the taxable profits of a company; (iii) a green fund levy at the rate of 0.1 per cent. of gross sales and receipts; and (iv) a petroleum production levy which is imposed on a producer conducting production business. The maximum charge imposed is four per cent. of gross income from the production of crude oil.

PART XI

SUMMARY OF KEY LICENCES AND AGREEMENTS

1. **Bayfield**

Galeota Block, Trinidad and Tobago

The Galeota Licence was granted by a deed of licence dated 21 April 2009 (the "**Effective Date**"), as amended by a letter agreement dated 9 March 2012 and grants Bayfield Galeota the right to explore for and produce petroleum from the licenced area. The manner in which the rights and obligations under the Galeota Licence are to be managed is governed by the Galeota Farm Out Agreement and the Galeota JOA which are intended to work together and are summarised below.

Exploration and Production (Public Petroleum Rights) Licence

Bayfield Galeota was awarded a 65 per cent. participating interest in the Galeota Licence and licenced area and Petrotrin was awarded a 35 per cent. participating interest. The Galeota Licence is granted under the Petroleum Act and the Petroleum Regulations.

Scope and duration

The licencee has exclusive rights in the licenced area to search, drill, get, win and dispose of petroleum, although the licencee has no right of ownership of any petroleum in strata or any other rights. The licencee has the right to sell all petroleum won and saved from the licenced area in Trinidad and Tobago and the right to export and sell all petroleum won and saved from the licenced area abroad, subject to a governmental right of pre-emption under the Petroleum Act and royalty and distraint rights under the Petroleum Regulations.

The licenced area is divided into two sections under the Galeota Licence—Area A and Area B. In respect of Area A, the minimum work programme involves the acquisition of 60 km^2 of 3D seismic within nine months of the Effective Date and the drilling of two exploratory wells, which are required to be drilled to a depth of at least 6,500 feet and at least 10,100 feet respectively and the drilling of one exploratory and appraisal well required to be drilled to a depth of 6,500 feet. The drilling requirements under the minimum work programme for Area A must be carried out within 36 months from 9 March 2012.

In respect of Area B, the minimum work programme involves the acquisition of 60 km^2 of 3D seismic within nine months of the Effective Date and the drilling of three exploratory wells; one to a depth of a least 6,500 feet, one to a depth of at least 8,000 feet and one to a depth of at least 10,000 feet, and the drilling of one exploratory or appraisal well to a depth of at least 6,500 feet with spudding of all such wells to be drilled not later than 36 months from 9 March 2012. Bayfield Galeota has undertaken to complete its exploration work programme in relation to drilling by March 2015 and in any event prior to the expiration of the initial licence period.

The initial term of the Galeota Licence is six years from the Effective Date and it therefore expires on 20 April 2015 unless it is determined at an earlier date. However, in the event that the licencee makes a commercial discovery of petroleum, the Galeota Licence may be extended for a maximum of 25 years from the Effective Date. Following this initial extension, the Galeota Licence may be further extended for a period of five years. Thereafter, the Galeota Licence may be extended for further five year periods from the end of each renewal period. The Trintes Field qualifies for the 25 year extension to the Galeota Licence from 21 April 2009.

Discoveries

In the event of a discovery of natural gas being made, the licencee must immediately submit a written notification to the Trinidad Minister of Energy, and 30 days after such notification, the licencee must inform the Trinidad Minister of Energy whether the discovery has commercial potential. Within 18 months from the discovery date, the licencee is required to declare to the Trinidad Minister of Energy whether the discovery is a commercial discovery, and, in the event that it is, the licencee must immediately present a development plan to the Trinidad Minister of Energy for approval.

If the licencee fails to declare a discovery or commercial discovery of natural gas within the specified timeframes, upon the expiry of the initial term of the Galeota Licence, such discovery will form part of the area to be surrendered by the licencee (see "**Surrender**" below).

Funding obligations

The licencee is obliged to make various payments under the Galeota Licence, including:

(a) production bonuses bound on a sliding scale of production, from US$1 million for 25,000 boepd to US$4 million for 100,000 boepd, and a further US$1 million for every 50,000 boepd exceeding 100,000 oil equivalent;

(b) a signature bonus of US$1 million payable within 10 days of the Effective Date;

(c) a technical equipment bonus of US$100,000 payable as directed by the Trinidad Minister of Energy;

(d) an environmental bonus of US$50,000 within 10 days of the Effective Date;

(e) royalties at a rate of 12.5 per cent. for each barrel of crude oil and natural gas;

(f) minimum quarterly payments in respect of the licenced area, ranging from US$3.00 per hectare during the first year of the Galeota Licence to US$4.25 per hectare during the sixth year;

(g) training contributions of US$100,000 for the first year increasing by six per cent. annually;

(h) research and development contributions of US$100,000 for the first year increasing by six per cent. annually; and

(i) funding of scholarships with a minimum annual expenditure of US$100,000.

The licencee is also under an obligation to provide the Trinidad Minister of Energy with a performance guarantee for US$16.25 million in the form of a bond or bankers guarantee or such other form acceptable to the Trinidad Minister of Energy. Under the Petroleum Act, the amount of the performance guarantee is reduced at the end of each 12 month period by the actual qualifying expenditure incurred pursuant to the Galeota Licence during the period.

Further, the licencee is required to make all other payments including import duties, income tax, excise duties, charges and fees for services rendered and fees of general application as may be appropriate to the Galeota Licence, and in accordance with any applicable law.

The licencee must also establish an escrow account in the name of the Trinidad Minister of Energy to be used as a contingency fund for pollution costs arising from petroleum operations and the eventual abandonment of wells in the licenced area, in addition to the decommissioning of facilities used for petroleum operations. The licencee must pay US$0.25 per barrel of oil equivalent into the escrow account.

In the event that the licencee fails to effect the environmental clean-up of an accident, properly abandon wells or decommission facilities to the satisfaction of the Trinidad Minister of Energy, he may access the escrow account at his sole discretion. In such case, the licencee must replace the sum used within 60 days. However, all existing funds in the escrow account will be returned to the licencee if it fulfils its environmental obligations to the satisfaction of the Trinidad Minister of Energy.

Further obligations

The licencee is required to return associated natural gas to the subsurface structure if it is not required for use in petroleum operations or for sale. In all other cases, the licencee must submit reasons to the Trinidad Minister of Energy, with supporting engineering and economic justification, as to why such associated natural gas cannot be economically used, sold or returned to the subsurface structure.

Further, the licencee is required to deliver, without compensation, any quantity of natural gas produced in association with crude oil not required by the licencee for its operations or for sale which may be needed in the public interest, at the request of the Trinidad Minister of Energy.

The licencee must also comply with the government's local content policy which includes submission of reports on local content to the Trinidad Minister of Energy and keeping records evidencing the satisfaction of local content obligations for a minimum of six years, for the purposes of inspection and audit.

Assignment

The licencee is prohibited from sub-licensing, assigning or transferring in whole or in part any of its rights or obligations under the Galeota Licence, without the prior written consent of the Trinidad Minister of Energy.

Any sub-licensing, assignment or transfer made without such consent will be null and void and may result in forfeiture of the Galeota Licence.

Environmental Matters

At the beginning of each year, the licencee is required to submit to the Trinidad Minister of Energy the programme of environmental remediation the licencee intends to undertake within the licenced area. Once the programme is approved by the Trinidad Minister of Energy, the licencee must execute such programme.

Surrender

At the end of the sixth year of the Galeota Licence, the licencee is required to surrender 50 per cent. of the licenced area, which does not form part of an area that has been determined to be a commercial discovery, provided that: (i) no individual block surrendered will be less than 30 per cent. of the licenced area unless the Trinidad Minister of Energy consents; (ii) the licencee may surrender the Galeota Licence in respect of the whole or part of the licenced area at any time on 90 days' notice in writing to the Trinidad Minister of Energy; (iii) surrender will not affect any obligations or liabilities of the licencee pursuant to the Galeota Licence or Petroleum Act that have not been performed or discharged prior to the date of surrender; (iv) the Galeota Licence remains in full force and effect for any area within the licenced area in which a commercial discovery is made prior to the expiry of the initial term (or any extension); (v) during the term of the Galeota Licence, the licencee is not required to surrender any area which has been determined to be a commercial discovery in the licenced area; and (vi) areas for surrender will be identified, defined and demarcated on the surface of the licenced area.

Termination

The Galeota Licence, together with all of the licencee's rights, licences, privileges and powers and all grants and leases of state lands for carrying out petroleum operations, may be revoked by the Trinidad Minister of Energy upon the occurrence of the following events: (i) failure of the licencee to fulfil the minimum work obligations or failure to meet its expenditure obligations (including the performance guarantee, bonuses, training, research and development and scholarships obligations); (ii) failure of the licencee to execute its work obligations within the prescribed time limits; (iii) breach of other terms and conditions of the Galeota Licence by the licencee in any material particular, the Trinidad Minister of Energy being sole judge of materiality; (iv) failure of the licencee to: (a) make the minimum payments specified in the Galeota Licence in accordance with the Petroleum Regulations; (b) make payments of rent, royalty, petroleum impost, petroleum production levy or taxes other than taxes derived from petroleum operations, within three calendar months of their being due; or (c) maintain the escrow account at the level required by the Galeota Licence; (v) failure by the licencee to pay any sum that may have been awarded against it in arbitration proceedings within three months of the date in the award, provided notice has been given to it of its obligation to make such payment; (vi) bankruptcy or liquidation of the licencee; or (vii) proof of wilful misrepresentation by the licencee in any material particular in the process of applying for the Galeota Licence.

All the above termination events, with the exception of the bankruptcy or liquidation of the licencee, are subject to the Trinidad Minister of Energy having provided to the licencee within a reasonable period written notice of non-compliance.

In the event of serious and repeated violations of the Galeota Licence, or any law or directions of the Trinidad Minister of Energy on the part of the licencee, the Trinidad Minster of Energy is entitled to order operations to be temporarily discontinued.

Amended Farmout Agreement

Bayfield Galeota is a party to a farmout agreement with Petrotrin in respect of the Galeota Block, dated 21 April 2009 (the "**FOA**"), which was amended pursuant to an amendment agreement dated on or around 24 October 2012. The effective date under the Galeota FOA is 1 May 2009 (the "**FOA Effective Date**").

Term

The Galeota FOA expires on the expiration of the initial six-year term of the Galeota Licence, although certain provisions survive expiration.

Funding obligations

Bayfield Galeota has various obligations pursuant to the Galeota FOA (the "**Carried Obligations**") which are considered to be joint operations under the Galeota JOA. Unless otherwise provided, Bayfield is solely responsible for the Carried Obligations, which include:

(a) the exploration work programme for Area A and Area B, which exclude the Trintes Field, with an estimated cost for Area A of US$24 million and for Area B of US$27.6 million. Pursuant to the Galeota FOA, the exploration work programme is required to be performed within the first four years of the term of the Galeota Licence (the "**Exploration Carry Period**");

(b) the development work programme in relation to the Trintes Field with an estimated cost of US$58.2 million. The estimated cost for the first two years was US$22.7 million and includes numerous obligations, including the refurbishment of two platforms and constructing two tripods for step out drilling. The estimated cost for the subsequent two years is US$35 million and also involves numerous obligations, including the refurbishment of two remaining platforms, the drilling of ten high-angle long-reach wells from existing platforms and other facility improvements. The development work programme is required to be performed within the first four years of the term of the Galeota Licence (the "**Development Carry Period**");

(c) petroleum operations in relation to the exploitation of the Trintes Field (the "**Trintes Field Operations**"), and the funding of the capital expenses which are not otherwise specified in the Galeota FOA, but which are related to the development work programme, operating expenses associated with the Trintes Field Operations, and any operational liabilities prior to the Galeota FOA Effective Date or resulting from the Trintes Field Operations (the "**Trintes Expenses**"). The Trintes Field Operations are required to be performed, and the Trintes Expenses funded, within the first four years of the term of the Galeota Licence, as amended;

(d) the funding of the financial obligations under the Galeota Licence comprising payments to the Trinidad Ministry of a signature bonus, environmental bonus, technical equipment bonus, minimum payments, escrow account, research and development, training contribution, scholarships, production bonuses and any surface rentals payable in relation to state land used to service the licenced area (the "**Financial Obligations**"). The Financial Obligations are required to be performed for the first six years of the term of the Galeota Licence (the "**Financial Carry Period**", together with the Exploration Carry Period and the Development Carry Period, the "**Carry Period**");

(e) other costs and expenses provided for in the Galeota FOA; and

(f) except for manpower costs assumed by Petrotrin during the initial 90-day period from the Galeota FOA Effective Date, on assuming operatorship of the Galeota Tank Farm, Bayfield Galeota will assume conduct of the Galeota Tank Farm operations and pay any capital and operating expenses related to the Galeota Tank Farm operations, including expenses from processing crude oil or natural gas produced from the Galeota Block, and any operational liabilities prior to the Galeota FOA Effective Date or resulting from the Galeota Tank Farm operations for the first four years of the term of the Galeota Licence.

During the Carry Period, Petrotrin will only be liable for a 35 per cent. participating interest share of the following costs: (i) royalties, supplemental petroleum tax and other taxes chargeable; (ii) US$0.25 per barrel of oil equivalent produced payable into the escrow account; (iii) production bonuses, if applicable; (iv) US$0.75 per barrel of oil equivalent produced from the Galeota Block payable into the Supplemental Abandonment Fund, as defined below; (v) work and operations pursuant to a development plan approved by the Trinidad Minister of Energy for any commercial discovery outside the Trintes Field; and (vi) costs associated with the conduct of operations or work outside the scope of the Carried Obligations.

Additional information in respect of work programmes

Under the Galeota FOA, the work programmes which Bayfield Galeota must complete have a broader scope than the work programmes under the Galeota Licence, as the Galeota FOA includes a development work programme in respect of Area A to revitalise the Trintes Field.

The parties are required not to undertake, within the Galeota Block, any new development work until satisfactory completion of the development work programme, except in relation to a commercial discovery, or any new exploration work, until satisfactory completion of the exploration work programme.

Any development work conducted outside of the Trintes Field area and any Trintes Field extensions will not form part of the Carried Obligations.

Other obligations

In addition to the Carried Obligations as set out above, Bayfield Galeota is required to make the following security arrangements:

(a) on or prior to the Galeota FOA Effective Date, establish a joint approval account of US$15 million for the performance by Bayfield Galeota of the Carried Obligations;

(b) provide a Letter of Credit Agreement ("**LCA**") in favour of Petrotrin as security in respect of the following:

  (i) the indemnities provided by Bayfield Galeota to Petrotrin against 65 per cent. of any past, present or future decommissioning and environmental liabilities; and

  (ii) any outstanding components of the development work programme not completed within four years of the Effective Date.

  The LCA is released upon completion of the exploration work programme to the satisfaction of both Petrotrin and the Trinidad Ministry and will then be transferred in favour of Petrotrin to secure outstanding components of the development work programme and any past, present or future decommissioning and environmental liabilities;

(c) provide such additional security as Petrotrin deems appropriate to guarantee the obligations in (a) and (b) above in the event that the LCA is not released and transferred to Petrotrin; and

(d) provide such other security as is acceptable to the Trinidad Minister of Energy for the performance of the Galeota Licence obligations.

Under both the Galeota FOA and Galeota JOA, the above LCA or other financial security is required to be furnished by Bayfield Galeota to Petrotrin on or prior to the expiry of the fourth year of the Galeota Licence for an initial sum of US$16.25 million. This sum is subject to annual review by Petrotrin and may be increased or decreased based on:

(a) the estimated current and future decommissioning and environmental liabilities;

(b) Bayfield Galeota's participating interest share of contributions to the Supplemental Abandonment Fund (as defined below);

(c) the value of the Carried Obligations completed at the time of the review;

(d) the value added to the Galeota Block for increased Reserves and petroleum production above that at the Galeota FOA Effective Date; and

(e) other factors Petrotrin deems relevant.

A failure by Bayfield Galeota to provide the LCA or other financial security in the timeframe required constitutes a default under the Galeota JOA.

In addition to the LCA, within 90 days of the Galeota FOA Effective Date, the parties were required under the Galeota FOA and Galeota JOA to establish a joint account to act as a sinking fund (the "**Supplemental Abandonment Fund**") to accumulate cash Reserves as a contingency for the purpose of settling decommissioning and environmental liabilities. From and including the Galeota FOA Effective Date, in the event that the monthly average price of Galeota crude exceeds US$60, the parties must pay their participating interest share of US$0.75 per barrel of oil equivalent produced from the Galeota Block into the Supplemental Abandonment Fund. Any shortfall will be funded by the parties in proportion to their participating interest. The Supplemental Abandonment Fund is separate from any escrow account or abandonment fund that may be required by the Trinidad Ministry under the Petroleum Act or the Galeota Licence.

Completion of Obligations

Subject to rights of assignment, neither party is permitted to withdraw from the Galeota FOA or Galeota JOA before completion of the Carried Obligations. In conducting and performing the Carried Obligations during the Carry Period, Petrotrin's right to vote is limited pursuant to the Galeota JOA. The Galeota FOA provides Bayfield Galeota with sole discretion to conduct the exploration and production operations in respect of the Carried Obligations, subject to the Galeota JOA. However, Bayfield Galeota is required to consult with Petrotrin in relation to the details and composition of all work programmes and health and safety matters.

Bayfield Galeota agrees that only performance of the works stipulated in the Galeota FOA, as opposed to substantial completion or significant expenditure in an effort to complete the works, discharges its obligations associated with the work programmes.

Bayfield Galeota is required to notify Petrotrin in writing of the completion of Carried Obligations, following which Petrotrin must issue to Bayfield Galeota a certificate of completion within one calendar month, such certificate not to be unreasonably withheld. Petrotrin must review the work carried out by Bayfield Galeota on a semi-annual basis and indicate its acceptance or non-acceptance of the completed work. If the parties disagree on the completion of the Carried Obligations, Bayfield Galeota is entitled to refer the matter to an independent expert under the Galeota JOA. Petrotrin must pay its participating interest share of costs of joint operations upon the issue of certificates of completion in respect of the discharge of the exploration work programme, the development work programme and the Trintes Expenses, except that the Financial Obligations will continue to be paid by Bayfield Galeota.

Exclusive Operations

The Galeota FOA provides that the only permitted instances of exclusive operations during the initial six years of the Galeota Licence are: (i) exploration work in the exploration area after completion of the exploration work programme; and (ii) development work on new commercial discoveries within the licenced area but outside the Trintes Field.

Joint Property

Pursuant to the Galeota FOA, title to equipment, tools and facilities relating to the Trintes Field will pass from Petrotrin to Petrotrin and Bayfield Galeota on the Galeota FOA Effective Date. Such equipment will then be held in proportion to the participating interests, and deemed to be joint property. The Galeota FOA provides that in order to evidence the title transfer, the parties will execute a separate chattel receipt covering the equipment. Petrotrin does not warrant fitness for purpose of such equipment.

Conversion Option

Petrotrin has the option to elect to convert its participating interest in any area within the licenced area which has been determined to be a commercial discovery, to an undivided interest in gross production of petroleum or natural gas that does not bear any exploration, development or production costs (including treatment costs), royalties or any other costs or taxes associated with such production (the "**Overriding Royalty**"). The Galeota FOA provides for a longstop date for this election of 180 days following the expiration of the Exploration Carry Period or, in respect of the Trintes Field, the Development Carry Period. In the event that Petrotrin fails to make an election within the required period, it will be deemed not to have made such an election and the conversion option will expire.

Within 30 days of Petrotrin's notice of election to convert its participating interest to an Overriding Royalty, the parties are required to negotiate mutually acceptable rates, failing which specific rates provided in the Galeota FOA will apply.

Renewal

In the event that a commercial discovery occurs during the Galeota Licence term in which Bayfield Galeota has participated, the parties are required to apply jointly to renew or extend the Galeota Licence for such area for the maximum period. If there is more than one commercial discovery, an application must be made for each area within the licenced area which has been determined to be a commercial discovery. Applications for extension must be made towards the end of the Galeota Licence term in order to allow the parties to obtain as much information as possible about such areas. The parties have agreed to apply to renew or extend the Galeota Licence for the Trintes Field for the maximum period, not more than 365 days before the expiry of the Galeota Licence.

Force Majeure

The Exploration Carry Period or Financial Carry Period will be extended by any period of force majeure permitted by the Trinidad Ministry under the Galeota Licence, in respect of Galeota Licence obligations which are duplicated under the Galeota FOA. If force majeure suspends the Galeota FOA for a continuous period of more than six months, the parties are required to meet and mutually agree how reasonably to deal with the force majeure event. The Development Carry Period will be extended by any period of force majeure applicable to the conduct of the development work programme or by mutual agreement of the parties. However, the Galeota FOA, Galeota JOA or Galeota Licence may not extend the Carry Period for longer than the first six years of the Galeota Licence term, as amended, and any clause to this effect shall be deemed to be null and void.

Remedies

In the event that Bayfield Galeota fails to execute any work required under the Galeota FOA, including Carried Obligations, Petrotrin may, if it is deemed expedient, pursue any remedy provided for in the Galeota FOA or Galeota JOA.

If any part of the exploration work programme remains outstanding at the end of the Exploration Carry Period, Bayfield Galeota is required to relinquish and assign to Petrotrin its participating interest in the exploration area of the Galeota Block, and the Galeota JOA and Galeota FOA will be limited to the Trintes Field and any other commercial discoveries made in the block up to the time of relinquishment.

After a period of three years from the Galeota FOA Effective Date, if Petrotrin believes for any reason, excluding a force majeure situation, that Bayfield Galeota may not complete the exploration work programme within the Exploration Carry Period, the parties are required to meet to agree a remedial or amended exploration work programme. If no such agreement is reached within 30 days, Bayfield Galeota's designation as operator will be suspended while Petrotrin completes the outstanding exploration work programme and Petrotrin will have the right to conduct any of Bayfield Galeota's outstanding obligations under the Galeota FOA and charge the costs to Bayfield Galeota.

Indemnities

Under the Galeota FOA, Bayfield Galeota has assumed all operational, environmental and decommissioning liabilities for the licenced area, including liabilities arising prior to the Galeota FOA Effective Date. In addition, Bayfield Galeota has undertaken to indemnify Petrotrin against any liability incurred by Petrotrin, and any claims by third parties and Bayfield Galeota, in relation to the Financial Obligations, as specified above. A full indemnity has also been provided in relation to environmental and decommissioning liabilities. The only exception to both of these indemnities is the gross negligence or wilful misconduct of Petrotrin.

Assignment

The Galeota FOA stipulates that Bayfield Galeota cannot assign its participating interest during the Exploration Carry Period or Development Carry Period other than to an affiliate and with the consent of Petrotrin. Such assignment must state that Bayfield Galeota is jointly and severally liable with such affiliate for any obligations. Assignments after the expiration of the longer of either the Exploration Carry Period or Development Carry Period will be governed by the Galeota JOA.

Amended Joint Operating Agreement

Bayfield Galeota is party to a joint operating agreement with Petrotrin, dated 21 April 2009 (the "**Galeota JOA**") and with an effective date of 1 May 2009 (the "**Galeota JOA Effective Date**") as amended by an amendment agreement dated on or around 24 October 2012, which determines the manner in which the rights and obligations as set out in the Galeota Licence are to be managed.

Operating Committee and Operator

The Galeota JOA provides for the establishment of an operating committee for general management purposes. Each party holding a participating interest is entitled to appoint one representative and one alternate to serve on the operating committee.

Except as provided, decisions of the operating committee require the affirmative vote of two or more parties that are not affiliates, holding collectively at least 75 per cent. of the participating interests.

The Galeota JOA stipulates that Petrotrin has no right to vote on any matter before the operating committee during a Carry Period and in respect of the relevant Carried Obligations unless the matter relates to health, safety and environment standards, corporate governance, or requires the unanimous consent of all parties. The Galeota JOA also stipulates that Bayfield Galeota is required to consult and agree with Petrotrin the details and composition of all work programmes and budgets. Further, once a party is liable to pay or pays its participating interest share of costs, whether during a Carry Period or not, it will be entitled to vote on the matter.

All decisions listed below require the unanimous vote of the operating committee:

(a) development plans;

(b) any matter relating to the extension, renewal, relinquishment or surrender of all or any part of the licence area;

(c) determination that a discovery is a commercial discovery including in respect of natural gas;

(d) unitisation under the terms of the Galeota Licence with an adjoining licence area;

(e) commercial arrangements for the use of spare capacity and joint property; and

(f) plugging, decommissioning and abandonment of wells and facilities and the methods/standards involved for executing such works.

If the parties are unable to reach the appropriate affirmative or unanimous decisions, as set out above, the Galeota JOA provides for the resolution of such deadlock as follows: (i) in respect of the conduct of any Carried Obligations, the operator proposals will prevail; and (ii) at all other times, the parties may follow the dispute resolution procedure in the Galeota JOA.

The Galeota JOA also provides for the appointment of an operator. Bayfield Galeota is designated as operator. Bayfield Galeota has agreed to the secondment of at least one senior Petrotrin manager to the Bayfield Galeota management team for the duration of the Galeota Licence. In addition, Petrotrin is entitled to request that Bayfield Galeota, as operator, engages at least six other current employees of Petrotrin for joint operations. The engagement of Petrotrin secondees during the Exploration Carry Period and Development Carry Period is regarded as a Carried Obligation.

Bayfield Galeota, as operator, has sole discretion in respect of contract awards. The operator is not required to obtain the approval of the operating committee during the period of Carried Obligations. Petrotrin also accepts that the operator's proposed work programme and budgets in respect of joint operations during the following five calendar quarters will be preliminary and will be updated, taking into account Petrotrin's internal budget deadlines in relation to its September financial year end.

In the event that Bayfield Galeota, as operator, is a defaulting party, it will be in material breach of the Galeota JOA and, if the material breach is not cured within 30 days of notice from non-operators, may be removed as operator by the unanimous decision of the non-operators.

Financial Obligations

The Galeota JOA provides that as security to Petrotrin for Bayfield Galeota performing its indemnity obligations in relation to decommissioning and environmental liabilities under the Galeota FOA, together with outstanding components of the development work programme, Bayfield Galeota is required to facilitate the release and transfer to Petrotrin of the LCA provided to the Trinidad Ministry as security for performing the exploration work programme. If the exploration work programme is not completed to the satisfaction of both Petrotrin and the Trinidad Ministry, with the result that the LCA provided to the Trinidad Ministry cannot be released and transferred in favour of Petrotrin, Bayfield Galeota is required to provide such other security as Petrotrin deems appropriate.

The provisions in the Galeota JOA for calculating the sum of the LCA and establishing the Supplemental Abandonment Fund, are the same as under the Galeota FOA.

Change of Control

Under the Galeota JOA, there are various change of control provisions, which will be triggered when:

(a) there is any direct or indirect change in the ownership of 50 per cent. or more of the voting rights in either Petrotrin or Bayfield Galeota, whether through merger, sale of shares or other equity interests, or otherwise, through a single transaction or series of related transactions, from one or more transferors to one or more transferees; and

(b) the market value of the relevant party's participating interest represents more than 50 per cent. of the aggregate market value of the assets of such party and its affiliates that are subject to the change in control.

The Galeota JOA provides for exceptions to such a change of control, as follows:

(a) an initial public offering, which is defined as a first and one-time only offer to the public of securities of a party or its affiliate;

(b) an initial private placement, which is defined as a first and one-time only offer to selected persons of securities of a party or affiliate which have not been previously issued, such private placement not requiring registration with any regulatory authority; and

(c) any corporate restructure affecting a party solely for the purposes of re-financing any group of companies of which such party is a member.

Once a party has completed an initial public offering or initial private placement, any future changes in ownership of 50 per cent. or more of the voting rights of the party or its affiliate would trigger the provision if at the time of the change the asset represents 25 per cent., as opposed to 50 per cent. in all other cases, of the aggregate market value of the assets of such party or affiliate.

The Galeota JOA provides that any party that has triggered a change of control provision must:

(a) obtain any necessary governmental approval and furnish any applicable replacement security required by the government or Galeota Licence on or before the applicable deadlines;

(b) provide evidence of financial capability, to the reasonable satisfaction of the other parties, to satisfy its payment obligations under the Galeota Licence and Galeota JOA. If the party subject to the change of control fails to provide such evidence, the other parties may require it to provide satisfactory security; and

(c) follow the pre-emptive rights procedure allowing another party to acquire the participating interest of the party subject to a change of control, unless the change of control results in ongoing control by an affiliate.

Pursuant to the pre-emptive rights procedure, once the final terms and conditions of a change in control have been fully negotiated, the acquired party must disclose all such final terms and conditions that are relevant to the acquisition of such party's participating interest and each other party will then have the right to acquire the acquired party's participating interest for the same monetary value and on the final terms and conditions negotiated with the proposed acquirer.

Conversion Option

The Galeota JOA stipulates that in the event that Petrotrin exercises any option either under the Galeota FOA or the Galeota JOA to convert its participating interest to an overriding royalty, during the period of conversion, Petrotrin will be released and discharged from all obligations under the Galeota JOA and the parties will not be obligated to Petrotrin, unless otherwise agreed. In this case, Petrotrin will only be entitled to its overriding royalty and will not receive its entitlement under the Galeota JOA.

In the event that only one other party exists upon Petrotrin's exercise of its option in respect of the overriding royalty, the Galeota JOA will lapse, save for any surviving obligations.

Completion of Obligations

Subject to the assignment rights under the Galeota JOA, the parties cannot withdraw from the Galeota JOA before the Carried Obligations are completed. The Galeota JOA also provides that without the prior written consent of the other parties, such consent not to be unreasonably withheld, no party may withdraw before the minimum work obligations under the Galeota Licence have been completed.

Termination

The Galeota JOA stipulates that in the event that any party thereto fails to: (i) pay its share of joint account expenses; or (ii) obtain and maintain any security required of such party pursuant to the Galeota Licence, such party will be deemed in default under the Galeota JOA.

A defaulting party may be required to withdraw completely from the Galeota JOA and the Galeota Licence for failure to remedy a default within 40 business days of receiving a default notice. If this withdrawal option is exercised, the defaulting party will be deemed to have transferred its participating interest to the non-defaulting parties.

In addition, upon a failure to remedy a default within 40 business days of receipt of a default notice, the Galeota JOA provides that the defaulting party will grant to the other parties the exclusive right and option to acquire pro rata all of its participating interests for an appraised value.

Pletmos Inshore Block, South Africa

Exploration Right

Scope and duration

An exploration right ("**Exploration Right**") was granted to Bayfield Energy Limited (the "**Licencee**") on, and with effect from, 17 April 2012 by the Minister of Mineral Resources (the "**Grantor**") under the Mineral and Petroleum Resources Development Act 2002 (the "**Act**"). The Exploration Right grants the Licencee, among other things, a right to conduct exploration and appraisal operations in the exploration area in accordance with the exploration work programme, an exclusive right to apply for and be granted a production right in respect of any commercial discoveries within the exploration area (provided an application for a production right is lodged prior to the expiry date of the Exploration Right) and a right to own and dispose of any and all facilities, materials, equipment, supplies and consumables purchased and/or leased for exploration operations in the exploration area. The Grantor does not guarantee that the Licencee will at all times be able to exercise its rights under the Exploration Right but it will make reasonable attempts to resolve any conflicts with other rights holders and/or interested and affected parties within and around the exploration area.

The term of the Exploration Right is 36 months from the effective date, being 17 April 2012. The Licencee may, unless otherwise extended by the Grantor, commence exploration operations within 90 days of the effective date. The Licencee has the right to apply for an extension of the term.

Exploration fee and financial provisions

An exploration fee is payable by the Licencee. Further, in accordance with the Act, the financial provisions will be assessed annually by, and increased to the satisfaction of, the Grantor.

Technical advisory committee

There will be a technical advisory committee, comprising members of both the Grantor and the Licencee in equal numbers (at least two each), whose functions include: review of the annual exploration work programme and progress of exploration operations; review any appraisal programme; review any development programme; review accounting of expenditure and maintenance of operating records and reports; and advising Licencee on efficient exploration operations.

Cancellation or suspension of Exploration Right

The Grantor has certain cancellation/suspension rights under the Act. Any cancellation/suspension of the Exploration Right is without prejudice to the Grantor's rights under the Exploration Right and applicable laws and any accrued obligations or liabilities of the Licencee up to the date of cancellation/ suspension.

Relinquishment and abandonment

The Licencee may voluntarily relinquish any part of the exploration area with 90 days prior written notice and abandon the Exploration right by relinquishing the entire exploration area with 180 days prior written notice, without prejudice to any cost, liability, obligation or expense incurred prior to the date of relinquishment or abandonment. In such circumstances, the Licencee has the obligation, among others, to provide the Grantor with and/or destroy certain data.

Rights to minerals and petroleum

Except as provided in the Exploration Right, the Exploration Right confers no rights in respect of any minerals in the exploration area. Upon a discovery being made, the Licencee must notify the Grantor, upon which the Grantor assumes ownership over such discovery.

Records and samples, reports and inspections

The Licencee is required to keep and maintain as reasonably required by the Grantor, and provide the Grantor with, accurate records of all technical information, data and samples acquired from exploration operations. At its own cost, the Licencee is required to collect samples at regular intervals and make such available for inspection by the Grantor and provide the Grantor any samples of potential value. The Grantor's consent is required to discard any samples and to export any technical information, data and samples related to the exploration area.

The Licencee must report to the Grantor all material developments relating to exploration operations and provide the Grantor with certain data. Further, in accordance with the Act, the Licencee must provide the Grantor with a written report of the exploration operations (including certain prescribed information) within 30 days from the end of each quarter and 60 days from the end of each year.

The Grantor, or any person duly authorised by the Grantor, may conduct routine inspections in the exploration area and exercise such related powers under the Act. In the case of offshore inspections, the Licencee must provide the Grantor with free transportation during normal business hours and free accommodation as reasonably required.

Annual exploration work programme and budget

Not later than 60 days from the effective date, the Licencee must submit to the Grantor for approval the annual exploration work programme for the current year. Thereafter, the deadline is 90 days prior to the commencement of each succeeding year. The Grantor's approval will not be unreasonably withheld. The annual exploration work programme must set forth the exploration operations, which will include the prescribed minimum work obligations, and expected costs. The Grantor has 30 days to approve or reject such proposal and its failure to respond within such timeframe will be deemed approval. There are prescribed timeframes for the Grantor's request for further information and the Licencee's response to such request. The Grantor may also propose amendments. Any disputes shall be resolved by arbitration in accordance with the procedures prescribed in the Exploration Right.

Exploration work programme

The estimated budget for the initial 3 years for exploration works is US$4,250,000. The exploration work programme includes: year 1—reprocessing, interpretation and evaluation of existing 2D seismic lines; year 2—acquisition and processing 2,000 km of new 2D seismic lines; year 3—interpretation and evaluation of such new seismic lines.

Discoveries and testing

In the case of a discovery, the Licencee must, among other things: notify the Grantor; carry out tests, in accordance to good international petroleum industry practices, of such discovery within a reasonable period of time in order to determine whether such discovery is worthy of appraisal or is a potential commercial discovery (the Grantor being entitled to witness such tests); and submit a report accordingly. If the discovery is a possible commercial discovery, the Licencee must take reasonable steps to appraise such discovery and submit a proposed appraisal programme for the Grantor's approval, approval of which must be granted or rejected within 30 days and failure to respond within such timeframe is deemed approval. The parties must use reasonable commercial efforts to agree an appraisal programme where there is an operational imperative with respect to the discovery.

Within 180 days of the completion of appraisal operations, the Licencee must submit to the Grantor: a full report of the results of the appraisal operations; a declaration of whether or not the discovery is a commercial discovery; and an election by the Licencee of whether or not it intends to develop such discovery.

If the discovery is a declared commercial discovery, the Licencee must submit within 180 days of such declaration a proposed development plan for the Grantor's approval, the approval of which must be granted or rejected within 60 days and failure to respond being deemed approval.

Conduct of exploration operations, the environmental management programme and health and safety

The Licencee must conduct its affairs in accordance with: applicable law (including with respect to health and safety); the prescribed environmental management programme; and good international petroleum industry practices. Further, the Licencee must take all reasonable and practical steps to prevent, among others: escape/waste of petroleum; damage to petroleum-bearing strata; and pollution of terrestrial or marine environment. In the event of such occurrence or an occurrence with respect to health and safety, the Licencee will take the actions prescribed in the Exploration Right, including taking prudent and necessary actions in accordance with Good International Petroleum Industry Practices.

Social and labour matters

The Licencee gives various undertakings with respect to promoting historically disadvantaged South Africans, e.g. as investment partners, through employment, through implementing training and skills development, by giving preference with respect to goods manufactured by such persons, through contracting and sub-contracting and through contributions to a specified trust which seeks to educate, train and provide experience to historically disadvantaged South Africans.

Indemnity and insurance

The Licencee indemnifies the Grantor group for all claims, costs, charges, liabilities and expenses suffered by any member of such Grantor group as a result of injury or death and damage or destruction to any property and/or the environment arising from the negligent and/or unlawful acts and/or omissions of the Licencee group. The Licencee must obtain and maintain sufficient insurance to cover certain prescribed items and such insurance, among other things, must name the Grantor as an additional insured party. The Licencee may implement a policy of self-insurance with written approval from the Grantor.

Change of law

If there are any changes to any laws in the Republic of South Africa after the effective date affecting petroleum exploration or production which materially and directly affects any rights of the Licencee, the parties will negotiate in the utmost good faith to agree on an equitable arrangement to take account of the impact of such changes. The matter will be referred to arbitration if the parties fail to agree.

State option

Subject to the provisions dealing with a change of law, the Grantor has the option to acquire up to a maximum of 10 per cent. of the participating interest in any production right provided it exercises such option within the prescribed period. The Grantor may assign its participating interest without the Licencee's consent to any technically and/or financially competent third party.

Disadvantaged South Africans option

A further option exists for 10 per cent. of the participating interest to be taken up by historically disadvantaged South Africans, on condition of payment of their share of forward costs and of past costs.

Unitisation

If the exploration area extends over different areas which geologically form part of the same petroleum bearing area which relate to rights of other rights holders (under a/an exploration right/mining lease/production right/prospecting lease), the Licencee together with other rights holders may be required by the Grantor to submit a proposal to the Grantor to produce such petroleum bearing area as a unit. Failing that, the Grantor may appoint a committee of experts to advise the Grantor on the same. Should the Grantor deem the unitisation to be objectively practical, fair and equitable to all parties concerned, then any unitisation decision will be binding on the rights holders. Failure by the Licencee to carry out the provision of the Grantor's proposal will result in the cancellation of the Exploration Right.

Gas discovery

Where there is a discovery and the Licencee considers that the economic development of such can only be achieve if gas produced was sold commercially, the Licencee may exercise its option to have any production right suspended for a period of up to 5 years from the effective date of the relevant production right. Not less than 90 days prior to the expiry of such period, the Licencee must advise the Grantor whether the gas can be commercially developed (and proceed to implement a development plan) or the gas cannot be commercially developed (which shall be deemed an abandonment of the production right). The Licencee's failure to give notice as prescribed will be deemed to be an abandonment of the production right. Any extensions to the suspension period are at the Grantor's sold discretion.

2. **Trinity**

Point Ligoure/Guapo Bay/Brighton Marine Blocks, Trinidad and Tobago

The PGB Licence grants TDN Operating and Petrotrin, together as licencee, the right to explore for and produce petroleum from the Point Ligoure Block, the Guapo Offshore Block and the relinquished sub-area A of the Brighton Marine Block. The provisions of the PGB Licence are summarised below.

It is proposed that TDN Operating and Petrotrin enter into a joint operating agreement to define their respective rights and obligations in connection with the licenced area (the "**Proposed PGB JOA**").

Exploration and Production (Public Petroleum Rights) Licence

TDN Operating was awarded a 70 per cent. participating interest in the PGB Licence and licenced area and Petrotrin was awarded a 30 per cent. participating interest. The PGB Licence is granted under the Petroleum Act and the Petroleum Regulations.

Scope and duration

The licencee has exclusive rights in the licenced area to search, drill, get, win and dispose of petroleum, although the licencee has no right of ownership of any petroleum in strata or any other rights. The licencee has the right to sell all petroleum won and saved from the licenced area in Trinidad and Tobago and the right to export and sell all petroleum won and saved from the licenced area abroad, subject to a governmental right of pre-emption under the Petroleum Act and royalty and distraint rights under the Petroleum Regulations.

The licenced area under the PGB Licence covers three blocks—the Point Ligoure Block, the Guapo Offshore Block and the relinquished sub-area A of the Brighton Marine Block. The initial term of the PGB Licence is six years from the date of the PGB Licence (being 18 December 2012) (the "**PGB Effective Date**"). However, in the event that the licencee makes a commercial discovery of petroleum, the PGB Licence may be extended for a maximum of 25 years from the PGB Effective Date. Following this initial extension, the PGB Licence may be further extended for a period of five years. Thereafter, the PGB Licence may be extended for further five year periods from the end of each renewal period.

The minimum work programme involves geological, geophysical and drilling programmes. The licencee is required to evaluate, integrate and map all data related to the licenced area. In respect of the geophysical work programme the licencee is required to acquire and process seismic resulting in full fold coverage of the entire acreage of the Point Ligoure Block within the licenced area with shooting to commence within twenty-four months after the PGB Effective Date, to reprocess seismic acquired in 1997 over the Brighton Marine Block, and to evaluate, integrate and map all seismic data related to the licenced area. The drilling requirements under the minimum work programme contemplates the drilling of at least two exploratory wells, namely, one to a minimum depth of 5,000 feet true vertical depth subsea within 24 months of the PGB Effective Date and one to a minimum depth of 5,000 feet true vertical depth subsea within 36 months of the PGB Effective Date. One additional exploration well may be drilled contingent on the results of the seismic interpretation.

Discoveries

In the event of a discovery of natural gas being made, the licencee must immediately submit a written notification to the Trinidad Minister of Energy, and 30 days after such notification, the licencee must inform the Trinidad Minister of Energy whether the discovery has commercial potential. Within 18 months from the discovery date, the licencee is required to declare to the Trinidad Minister of Energy whether the discovery is a commercial discovery, and in the event that it is, the licencee must immediately present a development plan to the Trinidad Minister of Energy for approval.

If the licencee fails to declare a discovery or commercial discovery of natural gas within the specified timeframes, upon the expiry of the initial term of the PGB Licence, such discovery will form part of the area to be surrendered by the licencee (see "***Surrender***" below).

Funding obligations

The licencee is obliged to make various payments under the PGB Licence, including:

(a) a signature bonus of US$275,000 payable within 10 days of the PGB Effective Date;

(b) a commerciality bonus of US$200,000 within 14 days from approval of the development plan in relation to a new commercial discovery;

(c) production bonuses on first attainment of a 60 consecutive day average at or in excess of the production levels computed on an energy equivalent basis;

(d) a technical equipment bonus of US$25,000 payable as directed by the Trinidad Minister of Energy either in cash within 10 days of the PGB Effective Date, or within 3 months of the date that a list of the technical assistance and/or equipment is agreed with the Trinidad Minister of Energy;

(e) an environmental bonus of US$50,000 within 10 days of the PGB Effective Date;

(f) royalties at a rate of 12.5 per cent for each barrel of crude oil and natural gas;

(g) minimum quarterly payments in respect of the licenced area, ranging from US$4.00 per hectare during the first year of the PGB Licence to US$5.25 per hectare during the sixth year. Thereafter minimum payment will increase annually at a rate of six per cent.;

(h) training contributions of US$25,000 for the first year, and increasing by six per cent. annually;

(i) research and development contributions of US$25,000 for the first year increasing by six per cent. annually; and

(j) funding of scholarships US$25,000 for the first year, and increasing by six per cent. annually.

The licencee is also under an obligation to provide the Trinidad Minister of Energy with a performance guarantee for US$8.35 million in the form of a bond or bankers guarantee or such other form acceptable to the Trinidad Minister of Energy. Under the Petroleum Act, the amount of the performance guarantee is reduced at the end of each 12 month period by the actual qualifying expenditure incurred pursuant to the PGB Licence during the period.

Further, the licencee is required to make all other payments including import duties, income tax, excise duties, charges and fees for services rendered and fees of general application as may be appropriate to the PGB Licence, and in accordance with any applicable law.

The licencee must also establish an escrow account in the name of the Trinidad Minister of Energy to be used as a contingency fund for pollution costs arising from petroleum operations and the eventual abandonment of wells in the licenced area, in addition to the decommissioning of facilities used for petroleum operations (see "***Abandonment costs***" below).

In the event that the licencee fails to effect the environmental clean-up of an accident, properly abandon wells or decommission facilities to the satisfaction of the Trinidad Minister of Energy, he may access the escrow account at his sole discretion. In such case, the licencee must replace the sum used within 60 days. However, all existing funds in the escrow account will be returned to the licencee if it fulfils its environmental obligations to the satisfaction of the Trinidad Minister of Energy.

Further obligations

The licencee is required to produce petroleum upon commercial discovery in accordance with the Petroleum Regulations, provide all data, reports, samples, information, interpretation of such data and all other information or work product pertaining to the licenced area to the Trinidad Minister of Energy, provide to the Trinidad Minister of Energy regular and complete information concerning all petroleum operations, and to perform all other duties stipulated under the Petroleum Act and the Petroleum Regulations.

The licencee is required to return associated natural gas to the subsurface structure if it is not required for use in petroleum operations or for sale. In all other cases, the licencee must submit reasons to the Trinidad Minister of Energy, with supporting engineering and economic justification, as to why such associated natural gas cannot be economically used, sold or returned to the subsurface structure.

Further, the licencee is required to deliver, without compensation, any quantity of natural gas produced in association with crude oil not required by the licencee for its operations or for sale which may be needed in the public interest, at the request of the Trinidad Minister of Energy.

The licencee must also comply with the government's local content policy which includes submission of reports on local content to the Trinidad Minister of Energy and keeping records evidencing the satisfaction of local content obligations for a minimum of six years, for the purposes of inspection and audit.

Assignment

The licencee is prohibited from sub-licensing, assigning or transferring in whole or in part any of its rights or obligations under the PGB Licence, without the prior written consent of the Trinidad Minister of Energy. Any sub-licensing, assignment or transfer made without such consent will be null and void and may result in forfeiture of the PGB Licence.

Environmental Matters

At the beginning of each year, the licencee is required to submit to the Trinidad Minister of Energy the programme of environmental remediation the licencee intends to undertake within the licenced area. Once the programme is approved by the Trinidad Minister of Energy, the licencee must execute such programme.

Abandonment costs

It has been proposed that the Proposed PGB JOA will provide that for certain stipulated pre-existing wells in the licenced area, TDN Operating will pay to Petrotrin a non-refundable amount equivalent to US$2.1 per bbl of oil produced from the licenced area (on a net basis), capped at approximately US$7.875 million (on a net basis), to be paid on a monthly basis and used by Petrotrin to meet the plugging and abandonment costs of such pre-existing wells. Petrotrin would be solely liable for any and all costs or liabilities arising out of or associated with the plugging and abandonment of such pre-existing wells.

It is further proposed that the Proposed PGB JOA will provide that any liability for the plugging and abandonment of all other wells in the licenced area will be allocated on a pro rata basis dependent on each party's participating interest share of cumulative oil production from such wells. Such amount would be based on a formula based on the crude oil production from the particular well to which a party is entitled and the total crude oil produced from that well relative to the period governed by the Proposed PGB JOA.

Surrender

At the end of the fourth year of the PGB Licence, the licencee is required to surrender 50 per cent. of the licenced area, and at the end of the sixth year of the PGB Licence the licencee is required to surrender all acreage in the licenced area which does not form part of an area that has been determined to be a commercial discovery, provided that: (i) no individual block surrendered will be less than 30 per cent. of the licenced area unless the Trinidad Minister of Energy consents; (ii) the licencee may surrender the PGB Licence in respect of the whole or part of the licenced area at any time on 90 days' notice in writing to the Trinidad Minister of Energy; (iii) the PGB Licence remains in full force and effect for any area within the licenced area in which a commercial discovery is made prior to the expiry of the initial term (or any extension); and (iv) during the term of the PGB Licence, the licencee is not required to surrender any area which has been determined to be a commercial discovery in the licenced area.

Distraint by the Trinidad Minister of Energy

If the licencee fails to pay the royalty or part thereof within 30 days of it becoming due, the Trinidad Minister of Energy may enter onto the licenced area and distrain on all or any stock of petroleum and all things found thereon and sell it if after 14 days of the distraint the sums remain unpaid, and shall be indemnified by the licencee for all actions, claims, liabilities and other obligations arising directly or indirectly from such action.

Termination

The PGB Licence, together with all of the licencee's rights, licences, privileges and powers and all grants and leases of state lands for carrying out petroleum operations, may be revoked by the Trinidad Minister of Energy upon the occurrence of the following events: (i) failure of the licencee to fulfil the minimum work obligations or failure to meet its expenditure obligations (including the performance guarantee, bonuses, training, research and development and scholarships obligations); (ii) failure of the licencee to execute its work obligations within the prescribed time limits; (iii) breach of other terms and conditions of the PGB Licence by the licencee in any material particular, the Trinidad Minister of Energy being sole judge of materiality; (iv) failure of the licencee to: (a) make the minimum payments specified in the PGB Licence in accordance with the Petroleum Regulations; (b) make payments of rent, royalty, petroleum impost, petroleum production levy or taxes other than taxes derived from petroleum operations, within three calendar months of their being due; or (c) maintain the escrow account at the level required by the PGB Licence; (v) failure by the licencee to pay any sum that may have been awarded against it in arbitration proceedings within three months of the date in the award, provided notice has been given to it of its obligation to make such payment; (vi) bankruptcy or liquidation of the licencee; or (vii) proof of wilful misrepresentation by the licencee in any material particular in the process of applying for the PGB Licence.

All the above termination events, with the exception of the bankruptcy or liquidation of the licencee, are subject to the Trinidad Minister of Energy having provided to the licencee within a reasonable period written notice of non-compliance.

In the event of serious and repeated violations of the PGB Licence, or any law or directions of the Trinidad Minister of Energy on the part of the licencee, the Trinidad Minster of Energy is entitled to order operations to be temporarily discontinued.

Brighton Marine, Trinidad and Tobago

The Brighton Marine Licence grants TDN Operating the right to explore for and produce petroleum from the Guapo Bay/Brighton Marine Block. The manner in which the rights and obligations under the Brighton Marine Licence are to be managed is governed by the Brighton Marine FOA (as defined below) and the Brighton Marine JOA (as defined below) which are intended to work together and are summarised below. TDN Operating is also a party to a conversion to an overriding royalty agreement and a crude offtake agreement in respect of the Brighton Marine Block. The terms of these agreements are also summarised below.

Exploration and Production Licence

Venture Production (Trinidad) Limited (now TDN Operating) together with Petrotrin, was awarded the Brighton Marine Licence, granted under the Petroleum Act and the Petroleum Regulations. Under a Farmout Agreement (the key terms of which are set out below) entered into contemporaneously with the Brighton Marine Licence, TDN Operating was awarded a 65 per cent. interest in Sub Area A and a 55 per cent. interest in Sub Area B of the licenced area.

Scope and duration

The licencee has exclusive rights in the licenced area to search, drill, get and win and dispose of Petroleum. However, the licencee has no right of ownership of any petroleum in the strata. The licencee has the right to sell all petroleum won and saved from the licenced area in Trinidad and Tobago and the right to export and sell all petroleum won and saved from the licenced area abroad, subject to a governmental right of pre-emption under the Petroleum Act and royalty and distraint rights under the Petroleum Regulations.

The licenced area was initially divided into two sections under the Brighton Marine Licence sub-area A and sub-area B. The minimum exploration work programme involves the drilling of two exploration wells in year one, to a depth between 3000 and 4000 feet, and the drilling of 2 exploration wells in year two, one to a depth between 3000 and 9500 feet, and the other as a Cretaceous test to a depth of 1500 feet below the Naparima Hill Formation.

The initial term of the Brighton Marine Licence was six years from the effective date and therefore was due to expire on 6 October 2005. However, as a commercial discovery of petroleum was made the Brighton Marine Licence was extended for 25 years from the effective date, to 6 October 2024. The Brighton Marine Licence may be further extended for a period of five years on terms laid down by the President of the Republic. Thereafter, the Brighton Marine Licence may be extended for further five year periods from the end of each renewal period.

Funding Obligations

The licencee is obliged to make various payments under the Brighton Marine Licence, including royalties at a rate of 10 per cent. for each barrel of crude oil and natural gas.

The licencee is also under an obligation to provide the Trinidad Minister of Energy with a performance guarantee for US$4 million in the form of a bond or banker's guarantee or such other form acceptable to the Trinidad Minister of Energy. Under the Petroleum Act, the amount of the performance guarantee is reduced at the end of each 12 month period by the actual qualifying expenditure incurred pursuant to the Brighton Marine Licence during the period.

The licencee must pay a rental fee for each of the first six years of the licence commencing at US$1.75 per hectare in the first year and increasing by US$0.25 per hectare each year until the sixth year. After the sixth year the rent increases by six percent of the rate of the year immediately preceding. The rent is payable on each anniversary of the effective date.

The licencee must also maintain an escrow account to be used as a contingency fund for pollution costs arising from petroleum operations and the eventual abandonment of wells in the licenced area, in addition to the decommissioning of facilities used for petroleum operations. The licencee must pay US$0.25 per barrel of oil equivalent into the escrow account.

Relinquishment

At the end of the first six years from the commencement of the Brighton Marine FOA (as defined below), TDN was required to relinquish to Petrotrin possession of sub-area A, or any part of sub-area A, for which there has been no declaration of commercial discovery. In such event, the Brighton Marine FOA would have been terminated as it relates to such relinquished area, however as referred to below, Petrotrin approved an extension.

Further obligations

The licencee is required to return associated natural gas to the subsurface structure if it is not required for use in petroleum operations or for sale. In all other cases, the licencee must submit reasons to the Trinidad Minister of Energy, with supporting engineering and economic justification, as to why such associated natural gas cannot be economically used, sold or returned to the subsurface structure.

Further, the licencee is required to deliver, without compensation, any quantity of natural gas produced in association with crude oil not required by the licencee for its operations or for sale which may be needed in the public interest, at the request of the Trinidad Minister of Energy.

Assignment

The licencee is permitted to assign or transfer in whole or in part any of its rights or obligations under the Brighton Marine Licence with respect to all or any parts of the licenced area, upon giving notice to the Trinidad Minister of Energy, provided that the assignee is qualified to assume all of the rights and obligations of the assignor.

Surrender

At the end of the sixth year of the Brighton Marine Licence, the licencee is required to surrender all acreage within sub-area A of the licenced area, which does not form part of an area that has been determined to be a commercial discovery, provided that: (i) any surrendered areas which were at the effective date under any Petrotrin licences shall automatically revert to Petrotrin; (ii) the licencee may surrender the Brighton Marine Licence in respect of the whole or part of the licenced area at any time on 90 days' notice in writing to the Trinidad Minister of Energy; (iii) surrender will not affect any obligations or liabilities of the licencee pursuant to the Brighton Marine Licence that have not been performed or discharged prior to the date of surrender; and, (iii) where any area of the licenced area within sub-area A becomes discharged from the provisions of the Brighton Marine Licence, the rights relinquished under the Petrotrin licences shall revert to Petrotrin. Further, where any area of the licenced areas within sub-area B becomes discharged from the provisions of the Brighton Marine Licence, the rights relinquished under the Petrotrin licences shall revert to Petrotrin.

Termination

The Brighton Marine Licence, together with all of the licencee's rights, licences, privileges and powers and all grants and leases of state lands for carrying out petroleum operations, may be revoked by the Trinidad Minister of Energy upon the occurrence of the following events: (i) failure of the licencee to fulfil the minimum work obligations; (ii) failure of the licencee to execute its work obligations within the prescribed time limits; (iii) breach of other terms and conditions of the Brighton Marine Licence by the licencee in any material particular, the Trinidad Minister of Energy being sole judge of materiality; (iv) failure of the licencee to: (a) make the minimum payments specified in the Brighton Marine Licence in accordance with the Petroleum Regulations; (b) make payments of rent, royalty, petroleum impost, petroleum production levy or taxes other than taxes derived from petroleum operations, within three calendar months of their being due; or (c) maintain the escrow account at the level required by the Brighton Marine Licence; (v) failure by the licencee to pay any sum that may have been awarded against it in arbitration proceedings within three months of the date in the award, provided notice has been given to it of its obligation to make such payment; (vi) bankruptcy or liquidation of the licencee; or (vii) proof of wilful misrepresentation by the licencee in any material particular in the process of applying for the Brighton Marine Licence.

All the above termination events, with the exception of the bankruptcy or liquidation of the licencee, are subject to the Trinidad Minister of Energy having provided to the licencee within a reasonable period written notice of non-compliance.

Amended Farmout Agreement

Venture Production (Trinidad) Limited (now TDN Operating) is a party to a farmout agreement with Petrotrin in respect of the Brighton Marine Block, dated 7 October 1999, which was amended pursuant to an amendment agreement entered into by the parties in November 2000 (the "**Brighton Marine FOA**").

Term

The Brighton Marine FOA was due to expire on 7 October 2005, such being the expiration of six years from the commencement of the term. However, as TDN Operating proposed a further exploration programme of areas in sub-area A before the expiration of that six year period, Petrotrin approved the extension.

Payment and earning

In exchange for TDN Operating paying to Petrotrin the sum of US$4 million, Petrotrin assigns to TDN Operating for the duration of the Brighton Marine JOA the respective participating interest share in all infrastructure, well and inventory. Further, for completing the minimum work obligations, TDN Operating is entitled to earn a 65 per cent. participating interest in sub-area A.

Minimum work obligations

The provisions for the minimum work obligations under the Brighton Marine FOA are the same as under the Brighton Marine Licence.

Funding obligations

TDN Operating shall bear the following costs:

(a) 100 per cent. of the exploration costs for the conduct of the minimum work obligations; and

(b) 100 per cent. of the exploration costs associated with any exploration wells forming part of the minimum work obligations.

The licencee is also under an obligation to provide the Trinidad Minister of Energy with a parent company letter of guarantee from its parent company.

Relinquishment

At the end of the first six years from the commencement of the Brighton Marine FOA, TDN Operating shall relinquish to Petrotrin possession of sub-area A, or any part of sub-area A for which there has been no declaration of commercial discovery. In such event the Brighton Marine FOA shall terminate as it relates to that relinquished area.

Indemnities

Under the Brighton Marine FOA, TDN Operating has undertaken to indemnify Petrotrin where any actions, demands or claims (actions), arising directly or indirectly from TDN Operating's activities or those of its sub-contractors and their respective agents and employees, are brought against Petrotrin by any third party during performance of the minimum work obligations, unless those actions are due to the wilful misconduct of Petrotrin or any of its directors or supervisory employees.

Termination

The Brighton Marine FOA will terminate automatically upon determination of the Brighton Marine Licence, or may be terminated early by Petrotrin upon the occurrence of the following events: (i) failure of TDN Operating to fulfil the minimum work obligations (unless such failure is caused by a declaration of force majeure under the Brighton Marine JOA); or (ii) breach by TDN Operating of its obligations under the Brighton Marine FOA, the Brighton Marine Licence and/or the Brighton Marine JOA, which TDN Operating fails to remedy in accordance with the Brighton Marine JOA.

Assignment

The Brighton Marine FOA stipulates that TDN Operating is prohibited from withdrawing from, assigning or transferring its rights and/or obligations under the Brighton Marine FOA unless it has first completed the minimum work obligations in accordance with the Brighton Marine JOA.

Amended Joint Operating Agreement

Venture Production (Trinidad) Limited (now TDN Operating) is party to a joint operating agreement with Petrotrin (the "**Brighton Marine JOA**"), with a commencement date of 7 October 1999, which defines the parties' respective rights and obligations with respect to their operations under the Brighton Marine Licence.

Conversion Option

The participating interests of each party are the same as that under the Brighton Marine FOA. Petrotrin has a one-time option, within 60 days of notice of the commercial discovery in sub-area A, to convert all of its participating interest in the field containing the discovery to an overriding royalty. In case of such conversion Petrotrin shall effect the transfer of its interest in the Brighton Marine Licence, the Brighton Marine FOA and other related agreements applicable to the converted area to TDN Operating. Petrotrin will be liable to TDN Operating for all obligations accrued prior to the transfer.

Financial Obligations

Liabilities and expenses incurred by the operator in connection with joint operations are to be charged to the parties according to their respective participating interests. TDN Operating is required to pay its participating share of expenses resulting from the joint operations.

TDN Operating is required to pay the following in respect of its fiftyfive per cent. participating interest in sub-area B:

(a) US$4 million upon execution of the contracts;

(b) US$1 million on the anniversary of the first million barrels of petroleum; and

(c) US$1 million upon the third millionth barrel of petroleum.

Failure to make these cash payments is a default under the Brighton Marine JOA.

The cost, risk and expense of the abandonment of wells drilled as joint operations other than in fulfilment of the minimum work obligations are as follows:

(a) where the well is a dry hole the costs shall be borne in accordance with the respective participating interests; and

(b) where the well was producing well the costs shall be divided among the parties in accordance with the pro rata share of the cumulative production of the well credited to each party.

TDN Operating is liable for payment of the abandonment costs for all wells drilled as part of the minimum work obligations or appraisal wells associated with the minimum work obligations.

Operator and Operating Committee

The Brighton Marine JOA also provides for the appointment of an operator. TDN Operating is designated as the operator. TDN Operating has agreed to the secondment of Petrotrin's employees to the TDN Operating during the joint operations.

In the event that TDN Operating, as operator, is a defaulting party, it will be in material breach of the Brighton Marine JOA and, if it has not commenced to cure the material breach within 30 days of notice from non-operators, may be removed as operator by the decision of the non-operators.

The Brighton Marine JOA provides for the establishment of an operating committee for overall supervision and direction of the joint operations. Each party holding a participating interest is entitled to appoint one representative and one alternate to serve on the operating committee.

All decisions listed below require the unanimous vote of the parties (excluding a defaulting party):

(a) determination of a commercial discovery;

(b) defining a field;

(c) vote by the non-operator party for the removal of the operator and the appointment of a successor operator;

(d) vote for the approval of an authorization for expenditure which is disputed by a party;

(e) the surrender of all or any part of the contract areas which is not required by the Brighton Marine Licence or the applicable laws or regulations;

(f) waiver of notices periods for meetings of the operating committee;

(g) the consideration at an operating committee meeting of maters not contained in the meeting agenda; and

(h) the locations of operating committee meeting if not held in Trinidad.

If the parties are unable to reach the appropriate affirmative or unanimous decisions, as set out above, the Brighton Marine JOA provides that for the resolution of such deadlock the parties shall follow the dispute resolution procedure in the Brighton Marine JOA.

Annual exploration work programme and budget

Not later than 60 days from the effective date, TDN Operating must submit to the parties for approval the proposed exploration work programme and budget for the current calendar year. Thereafter, on or before 1 September of each year TDN Operating is to deliver the proposed work programme and budget to the parties. The parties will meet to consider and endeavour to agree the work programme and budget within 45 days of delivery. The exploration work programme must detail the joint operations to be performed in the contract area for the following calendar year and must set forth the exploration operations, which will include the prescribed minimum work obligations.

Abandonment of Wells

Where a well which has been drilled as part of the joint operations is proposed to be plugged and abandoned this shall be done only upon the consent of all of the parties. Where a party does not consent to the abandonment it shall assume financial responsibility over the well under an exclusive operation.

Transfer of rights

The written consent of the other parties is required for a transferee to have rights under the contracts. The participating interest or part of it cannot be transferred until the minimum work obligations have been completed.

Completion of Obligations

Subject to the assignment rights under the Brighton Marine JOA, the parties cannot withdraw from the Brighton Marine JOA before the minimum work obligations under the Brighton Marine FOA are fulfilled.

Termination

The Brighton Marine JOA stipulates that in the event that any party thereto fails to: (i) pay its share of joint operation expenses; or (ii) comply with the cash payments obligations, or (iii) perform or complete the minimum work obligations under the Brighton Marine FOA, such party will be deemed in default under the Brighton Marine JOA.

A defaulting party may be required to withdraw completely from the Brighton Marine JOA and the Brighton Marine Licence for failure to remedy a default within 60 days of receiving a default notice. If this withdrawal option is exercised, the defaulting party will be deemed to have transferred its participating interest to the non-defaulting parties.

Conversion to Overriding Royalty Agreement

TDN Operating is a party to a conversion to overriding royalty agreement dated 21 September 2012 (the "**Brighton Marine ORR**") for the conversion of Petrotrin's participating interest in the Brighton Marine Block to an overriding royalty. The effective date of the Brighton Marine ORR is 1 July 2012 (the "**Brighton Marine ORR Effective Date**")

Term

The Brighton Marine ORR expires on 7 October 2024. However, the parties may enter into negotiations for a new overriding royalty agreement if at least 3 years before the expiry of the Brighton Marine ORR the parties agree to an extension and notify the Trinidad Minister of Energy of their intention to extend, and TDN Operating submits a firm written proposal for significant investment (in excess of US$15 million) in the contract area during the last three years of the term.

Scope

Pursuant to clause 6 of the Brighton Marine Licence, sub-area A was surrendered to the State, leaving a contract area under the Brighton Marine Licence comprising sub-area B as at the Brighton Marine ORR Effective Date. Under the Brighton Marine ORR the rights in respect of sub-area B granted by the Brighton Marine Licence continue to be vested in the parties with Petrotrin retaining its 45 per cent. share and TDN Operating retaining its fifty five per cent. share. However, Petrotrin waives and forgoes its 45 per cent. share in those rights. All of the Petroleum produced from sub-area B by TDN Operating shall be owned by TDN Operating for the duration of the contract period. Under the Brighton Marine ORR TDN Operating has the exclusive right to search for, drill and get Petroleum in and from Sub Area B.

Financial obligations

TDN Operating continues to be obligated to pay to Petrotrin the sums stipulated under the Brighton Marine JOA, which are:

(a) US$1 million on the anniversary of the first million barrels of petroleum sold from the contract area from the commencement date; and

(b) US$1 million upon the third millionth barrel of petroleum sold from the contract area from the commencement date.

TDN Operating is also required to meet the following financial obligations:

(a) Taxes: TDN Operating shall pay in respect of both State and private lands all relevant taxes, levies, royalties, duties, rents and other fees due on or arising out of its operations in sub-area B directly to the relevant government authority or private rights owner, unless the parties agree otherwise.

(b) Overriding royalty: TDN Operating is liable to pay to Petrotrin the overriding royalty on petroleum produced from sub-area B. Petrotrin is liable for all taxes levied on the overriding royalty. For the overriding royalty calculated on a petroleum sales price agreed by the parties for sale to Petrotrin, Petrotrin shall deduct the overriding royalty percentage from the sales price of each darrel of crude oil. For petroleum sold to a third party (a party other than Petrotrin), within five business days of the receipt of the proceeds of such sale, TDN Operating shall pay the overriding royalty calculated on the basis of the sales price agreed with the third party.

(c) Transportation and handling fees: Where TDN Operating uses Petrotrin's petroleum gathering, collection, storage, sales or any other facilities (exclusive of joint property) the parties shall meet and determine agreeable fees for such use.

Under the Brighton Marine ORR TDN Operating is to maintain insurance as follows:

(a) workmen's compensation insurance covering all of TDN Operating's employees;

(b) employer's liability insurance of not less than TT$2.5 million per accident/occurrence of injury to employees of TDN Operating; and

(c) public liability insurance of not less than TT$2 million per occurrence of death, injury or property damage to third party (including Petrotrin).

Abandonment costs

Under the Brighton Marine ORR the parties are responsible for abandonment costs in respect of each and any well in sub-area B as follows. Each party shall be obliged to pay a percentage of the abandonment costs in respect of each well, with such percentage being calculated by way of an equation based on a number of variables including (i) the number of barrels of oil produced by the well since 1 July 2002 and during the term of the Brighton Marin ORR, and (ii) the number of barrels of oil produced by the well prior to and during the term of the Brighton Marine JOA.

Surrender

If TDN Operating and Petrotrin are required to surrender any portion of sub-area B they shall determine the size, shape, depth and horizons of the surrendered area. Any such surrender requires agreement of both of the parties.

Termination

The Brighton Marine ORR may be terminated by one party in the event of the other party's dissolution, liquidation, winding-up, insolvency, bankruptcy, assignment for creditors benefit, or court ordered reorganization under bankruptcy/insolvency, or appointment of a receiver for that other party's participating interest or a substantial part of its assets. Either party may terminate the Brighton Marine ORR for cause upon providing written notice of termination if a material breach has not been remedied within 30 days. The Brighton Marine ORR terminates automatically upon termination of the Brighton Marine Licence.

Withdrawal

Either party may withdraw from the Brighton Marine ORR and Brighton Marine Licence upon giving at least 60 days but no more than 180 days written notice. However, the withdrawing party must satisfy all of its obligations and liabilities before its withdrawal, must fully satisfy or release all liens, charges and other encumbrances it has placed on its participating interest, and must assign its participating interest to another party.

Assignment

The consent of the other party, which shall not be unreasonably withheld, is required for the assignment of a party's interest in the Brighton Marine ORR.

Change of Control

Under the Brighton Marine ORR the written consent of the other party is required prior to an acquired party effecting a change of control. Where there is a change of control without such written consent the other party may terminate the Brighton Marine ORR or require the acquired party to provide security to guarantee performance of the acquired party's obligations under the Brighton Marine ORR and the Brighton Marine Licence. Change of control is defined to exclude changes in control due to trading on a stock exchange.

Crude Offtake Agreement

Venture Production (Trinidad) Limited (now TDN Operating) is a party to a crude offtake agreement with Petrotrin, effective 7 October 1999 (the "**Crude Offtake Agreement**") for the delivery by TDN Operating of its share of the crude oil produced from the Brighton Marine Block in accordance with the Brighton Marine JOA.

Obligations

Under the Crude Offtake Agreement TDN Operating as operator under the Brighton Marine JOA is required to deliver to the designated delivery point crude oil produced. TDN Operating is required to notify the parties by 1 June of each year of the estimated volumes of crude oil to be delivered and disposed of by the parties during the following calendar year by month, and shall communicate quarterly to the parties its best estimate of the crude oil volumes to be delivered for the next following 30, 60 and 90 days. Any crude oil obtained further to the Brighton Marine JOA is to be offered first for sale to Petrotrin.

Financial obligations

Each party is required to pay to the government of Trinidad and Tobago all royalties with respect to its proportionate share of the crude oil in accordance with the Brighton Marine JOA and the laws and regulations of Trinidad and Tobago.

Assignment

The Crude Offtake Agreement is assignable by any party only with the written consent of the other parties, except where such assignment is to an affiliate of the assigning party, in which case the assigning party is required to notify the other parties in writing promptly.

Termination

Where a defaulting party does not remedy the default within 30 days of first meeting to resolve the dispute the Crude Offtake Agreement may be terminated. The Crude Offtake Agreement may also be terminated for any of the following reasons:

(a) mutual consent of the parties;

(b) termination of the Brighton Marine Licence; or

(c) a party ceasing to be a party to the Brighton Marine JOA.

Tabaquite Block, Trinidad and Tobago

The Tabaquite FOA (as defined below) grants the Trinity Group a 100 per cent. operated WI in the Tabaquite Block. The provisions of the Tabaquite FOA are summarised below.

The Tabaquite Farmout Agreement

Coastline International Inc. (a former affiliated company of TDN Operating) was a party to a farmout agreement with Petrotrin in respect of the Tabaquite Block, dated 1 March 2000 (the "**Tabaquite FOA**"). The Tabaquite FOA has expired. However, Trinity is in negotiations with the Trinidad Ministry for the issue and execution of a new sub-licence and anticipate that a new sub-licence shall be granted to its subsidiary Tabaquite Exploration & Production Company Limited in early 2013.

Term

The Tabaquite FOA was due to expire on the expiration of five years from the commencement of the term, however upon written notice to Petrotrin it was renewed for an additional five years to 28 February 2010.

TDN Operating continues to function as operator and sub-licencee of the block, produce oil therefrom, dispose of the same in accordance with the provisions of the expired Tabaquite FOA and provide reports to Trinidad Minister of Energy in accordance with the Tabaquite FOA and the Petroleum Regulations and otherwise complies with all of the requirements of a licence holder and an operator.

Scope and duration

Under the Tabaquite FOA the sub-licencee has exclusive rights in the farmout area to search, drill, get and win and dispose of petroleum. However, the sub-licencee has no right of ownership of any petroleum in the strata.

Minimum work obligations

The minimum work obligations involve the drilling of two horizontal wells and a minimum of one exploration well within the first year. Further, the sub-licencee must use its best efforts to explore and exploit the petroleum in the contract area. The wells are to be drilled to a depth of 1,000 to 1,500 feet below the base of the Nariva C Sand or 4,000 feet subsea, whichever occurs first.

Funding Obligations

The sub-licencee is obliged to make various payments under the Tabaquite FOA, including the following:

(a) all royalties, the supplemental petroleum taxes, petroleum profits tax, oil impost, petroleum levy, unemployment levy, national recovery impost and any other taxes, rents or fees due on or arising out of the operations in the contract area;

(b) overriding royalties at a rate of 18 per cent. for the first 1,500 barrel of crude oil produced for any calendar month, and an overriding royalty of 12.5 per cent. for any crude oil produced over that amount. The sub-licencee is also required to pay an overriding royalty of five per cent. on all natural gas won and saved;

(c) where the sub-licencee chooses to use Petrotrin's gathering, collection, storage, sales, etc. facilities Petrotrin and the sub-licencee shall meet and determine the transmission, collection and storage fees for the use of the facilities.

Under the Tabaquite FOA the amount that the sub-licencee is required to pay for petroleum is calculated by way of an equation based on the spot price of WTI plus an adjustment factor.

Assignment

The sub-licencee is required to obtain Petrotrin's written consent to the assignment, sub-contracting or transfer of the Tabaquite FOA.

Termination

The Tabaquite FOA may be terminated by Petrotrin if there is breach of a fundamental term of the Tabaquite FOA (including the failure to achieve the diligent prosecution of the minimum work obligations or to make prompt payment of the financial obligations under the Tabaquite FOA) which extends without remedy beyond 14 days of the provisions by Petrotrin of written notice of the breach. The Tabaquite FOA may also be terminated as follows: (i) by mutual agreement of the parties; (ii) by the sub-licencee upon giving six months written notice after satisfactory completion of the minimum work obligations of the second programme period; (iii) upon failure by a party to pay any sum awarded against it in arbitration; (iv) if any party commits an act of bankruptcy or makes an arrangement or composition with its creditors; or (v) if Petrotrin has reasonable grounds for believing that an authorised official, senior employee or agent of the sub-licencee has been involved in any theft, larceny or other wrong doing pertaining to the licencee's or any other company's surface or sub-surface equipment and/or petroleum and gas.

Forest Reserve Area, Trinidad and Tobago

The LOAs (as defined below) grant the Trinity Group a 100 per cent. operated WI in the Forest Reserve Area. The provisions of LOAs are summarised below.

The LOAs

The following lease operatorship agreements (sub-licences) were entered into by Petrotrin with the following Trinity Group companies as operators:

(a) Lennox Production Services Limited dated 28 June 2011 for the FZ-2 Block with an effective date of 2 August 2006 (further to an Exploration and Production (Public Petroleum Rights) Licence dated 10 October 2006 in respect of the Herrera Horizons under which Petrotrin is the head-licencee);

(b) Pioneer Petroleum Company Limited dated 28 June 2011 for the GU-1 Block with an effective date of 2 August 2006 (further to an Exploration and Production (Public Petroleum Rights) Licence dated 10 October 2006 in respect of the Guapo-Oropouche-Brighton Horizons under which Petrotrin is the head-licencee);

(c) Oilbelt Services Limited dated 27 June 2011 for the WD5/6 Block with an effective date of 2 March 2009 (further to an Exploration and Production (Public Petroleum Rights) Licence dated 10 October 2006 in respect of the Cruse Horizons under which Petrotrin is the licencee;

(d) Lennox Production Services Limited dated 28 June 2011 for the WD-2 Block with an effective date of 31 May 2007 (further to an Exploration and Production (Public Petroleum Rights) Licence dated 10 October 2006 in respect of the Cruse Horizons under which Petrotrin is the head-licencee);

(e) Antilles Resources Limited dated 28 June 2011 for the WD-13 Block with an effective date of 2 January 2007 (further to an Exploration and Production (Public Petroleum Rights) Licence dated 10 October 2006 in respect of the Herrera Horizons under which Petrotrin is the licencee);

(f) NAKT Company Limited dated 28 June 2011 for the WD-14 Block with an effective date of 2 August 2006 (further to an Exploration and Production (Public Petroleum Rights) Licence dated 10 October 2006 in respect of the Herrera Horizons under which Petrotrin is the head-licencee); and

(g) Lennox Production Services Limited dated 28 June 2011 for the WD-16 Block with an effective date of 15 May 2006 (further to an Exploration and Production (Public Petroleum Rights) Licence dated 10 October 2006 in respect of the Cruse Horizons under which Petrotrin is the head-licencee),

(together, the "**LOAs**" and each an "**LOA**").

The purpose of these LOAs is the grant to the operator of an agreement the right to manage and operate certain wells, including the re-drilling of existing wells and the drilling of new wells located within the specified block. The grants by Petrotrin of the LOAs are currently awaiting consent from the Trinidad Minister of Energy.

Term

The initial period of each LOA was from the respective effective dates to 31 December 2010. The current term of each LOA expires on 31 December 2020.

Petrotrin may terminate any LOA for cause with 30 days written notice. The parties to each LOA may terminate such LOA at any time by mutual consent.

Change of Control

If at any time during the term of an LOA there is a proposed change of control of the operator, the operator shall first obtain the written consent of Petrotrin (such consent not to be unreasonably withheld) prior to the proposed change of control and furnish to Petrotrin such information as Petrotrin may request in connection with the transaction which produces the change of control. Failure to obtain such prior consent entitles Petrotrin to terminate the agreement upon 45 days written notice. Petrotrin has provided its consent for the purpose of the Proposals.

Financial Obligations

The operator under the respective LOAs is required to make the following payments to Petrotrin:

(a) the notional overriding royalty in respect of crude oil (as defined in the LOAs) (see *Overriding Royalty* below);

(b) the user fee (as defined in the LOAs);

(c) Petrotrin's rate for all material and services not specifically provided for in the LOA which Petrotrin may agree to provide at the request of the operator; and

(d) such other amounts as may be contemplated under the LOA.

Each operator is obliged under the sixth schedule of its respective LOA to make various payments to Petrotrin as a proportion of the financial obligations existing under the head licence upon which the LOA was granted, including the following:

(a) minimum quarterly payments in respect of the licensed area, ranging from × per cent. of US$3.00 per hectare during the first year of the head licence to × per cent. of US$4.25 per hectare during the sixth year. Thereafter the minimum payment will increase annually at a rate of six percent for the unexpired term of the LOA;

(b) annual surface rental payments in respect of the licensed area, ranging from × per cent. of US$5.00 per hectare during the first year of the head licence to × per cent of US$6.25 per hectare during the sixth year;

(c) US$0.25 per boe into the escrow account established by Petrotrin in the name of the Trinidad Minister of Energy to be used as a contingency fund for pollution costs arising from petroleum operations and the eventual abandonment of wells in the licensed area, in addition to the decommissioning of facilities used for petroleum operations (see *Abandonment* below);

(d) a training contribution of × per cent. of the initial training contribution payable by Petrotrin for the financing of nationals in appropriate fields of study associated with the energy sector for the first year of the term of the LOA and increasing annually at a rate of six per cent. for the unexpired term. In the event of a commercial discovery the amount shall increase to the figure specified in each LOA in the year following the commercial discovery and increase by six per cent. per annum for the remaining term of the LOA.

The training contributions and their post commercial discovery increases under the respective LOAs are as follows:

LOA	Initial training contribution	Post commercial discovery increase
FZ-2 Block	US$200,000.00	US$300,000.00
GU-1 Block	US$125,000.00	US$150,000.00
WD5/6 Block	US$150,000.00	US$175,000.00
WD-2 Block	US$150,000.00	US$175,000.00
WD-13 Block	US$200,000.00	US$300,000.00
WD-14 Block	US$200,000.00	US$300,000.00
WD-16 Block	US$150,000.00	US$175,000.00

(e) a research and development contribution of × per cent. of the initial research and development contribution payable by Petrotrin for the financing of nationals in appropriate fields of study associated with the energy sector for the first year of the term of the LOA and increasing annually at a rate of six per cent. for the unexpired term. In the event of a commercial discovery the amount shall increase to the figure specified in each LOA in the year following the commercial discovery and increase by six per cent. per annum for the remaining term of the LOA.

The research and development contributions and their post commercial discovery increases under the respective LOAs are as follows:

LOA	Initial research and development contribution	Post commercial discovery increase
FZ-2 Block	US$200,000.00	US$300,000.00
GU-1 Block	US$125,000.00	US$150,000.00
WD5/6 Block	US$150,000.00	US$175,000.00
WD-2 Block	US$150,000.00	US$175,000.00
WD-13 Block	US$200,000.00	US$300,000.00
WD-14 Block	US$200,000.00	US$300,000.00
WD-16 Block	US$150,000.00	US$175,000.00

(f) an annual scholarship contribution of × per cent. of the minimum expenditure in respect of annual scholarships payable by Petrotrin which is US$50,000.00 under each head licence and LOA;

(g) a signature bonus of × per cent. of the signature payable by Petrotrin. The signature bonuses under the respective LOAs are as follows:

LOA	Signature bonus
FZ-2 Block	US$1,500,000.00
GU-1 Block	US$ 500,000.00
WD5/6 Block	US$1,000,000.00
WD-2 Block	US$1,000,000.00
WD-13 Block	US$1,500,000.00
WD-14 Block	US$1,500,000.00
WD-16 Block	US$1,000,000.00

(h) a percentage of the production bonus payable by Petrotrin under the head licence (which Petrotrin is required to pay on first attainment of a 60 consecutive day average at or in excess of the production levels computed on an energy equivalent basis), which is determined by Petrotrin based on the percentage that the operator's production of Petroleum from the block bears to the cumulative production from within the whole licensed area;

(i) a technical equipment bonus of × per cent. of the technical equipment bonus payable by Petrotrin under the relevant head licence. The annual scholarship contributions under the respective LOAs are as follows:

LOA	Technical equipment bonus
FZ-2 Block	US$400,000.00
GU-1 Block	US$200,000.00
WD5/6 Block	US$300,000.00
WD-2 Block	US$300,000.00
WD-13 Block	US$400,000.00
WD-14 Block	US$400,000.00
WD-16 Block	US$300,000.00

(j) an environmental bonus of × per cent. of the environmental bonus payable by Petrotrin which is US$50,000.00 under each head licence and LOA.

For the purposes of the above percentages, "x" represents the production of a particular lease operator relative to the total production under the core licence for a particular period excluding any farmout production. These percentages will vary from period to period depending upon production.

Overriding Royalty

The operator is liable to pay the Notional Overriding Royalty to Petrotrin. The Notional Overriding Royalty comprises a Base NORR figure and an Enhanced NORR figure and is calculated as follows:

	Notional Overriding Royalty to Petrotrin as a percentage of market value	
Market value ($US/bbl)	Base NORR (≤ bopm)	Base NORR (> bopm)
<30.00	to be negotiated	to be negotiated
30.01 - 40.00	20	17.5
40.01 - 50.00	25	17.5
50.01 - 90.00	33	17.5
90.01 - 200.00	35	22.5
> 200	to be negotiated	to be negotiated

The Base NORR is the Notional Overriding Royalty rate applicable to all petroleum produced by the operator during each month up to a base production figure which varies from year to year as set out below:

Base production (bopm)	Year 1	Year 2	Year 3	Year 4	Year 5
WD-5/6	34,359	33,672	32,999	32,339	31,692
FZ-2	2,741	2,686	2,633	2,580	2,528
WD-13	2,265	2,220	2,176	2,132	2,089
WD-14	2,854	2,797	2,741	2,686	2,633
WD-16	257	252	247	242	237
WD-2	2,081	2,039	1,999	1,959	1,919
GU-1	2,626	2,573	2,522	2,472	2,422

Base production (bopm)	Year 6	Year 7	Year 8	Year 9	Year 10
WD-5/6	31,058	30,437	29,828	29,232	28,647
FZ-2	2,478	2,428	2,380	2,332	2,285
WD-13	2,048	2,007	1,967	1,927	1,889
WD-14	2,580	2,528	2,478	2,428	2,380
WD-16	232	228	223	219	214
WD-2	1,881	1,843	1,807	1,770	1,735
GU-1	2,374	2,326	2,280	2,234	2,189

The Enhanced NORR is the Notional Overriding Royalty rate applicable to petroleum produced in excess of the base production for each month.

The LOAs contain drilling incentives for new wells which reduce the Notional Overriding Royalty, as detailed below:

(a) crude oil production from a new well during the first year of production is subject to a 0% Notional Overriding Royalty; and

(b) crude oil production from a new well during the first year of production is subject to a 10% Notional Overriding Royalty.

The drilling incentives applicable to new wells cease once 70,000 barrels have been produced from the new well or after two years from the date of first production from the well.

Minimum work obligations

The minimum work obligations of the Trinity Group under each LOA are summarised as follows:

Field	**Operator**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
WD2 . .	Lennox Production Services Limited	First Period:	First Period:	First Period:	First Period:	First Period:
		drill 1 well, 1 reactivation, 1 recompletion, 3 swabs	drill 1 well, 1 reactivation, 1 recompletion, 3 swabs, 1 coil tubing foam job	drill 1 well, 1 reactivation, 1 recompletion, 3 swabs, 1 coil tubing foam job	1 reactivation, 1 recompletion, 3 swabs	—
		Second Period:	Second Period:	Second Period:	Second Period:	Second Period:
		drill 2 wells, 1 recompletion, 2 reactivation/ swabbing	drill 1 well, 1 recompletion, 2 reactivation/ swabbing	drill 1 well, 1 recompletion, 2 reactivation/ swabbing	drill 1 well, 1 recompletion, 2 reactivation/ swabbing	drill 1 well, 2 reactivation/ swabbing
WD5/6 .	Oilbelt Services Limited	First Period:	First Period:	First Period:	First Period:	First Period:
		drill 3 wells, 1 recompletion	drill 2 wells, 4 recompletions	—	—	—
		Second Period:	Second Period:	Second Period:	Second Period:	Second Period:
		drill 3 wells	1 stimulation	1 recompletion	drill 1 well	1 stimulation
WD13 .	Antilles Resources Limited	First Period:	First Period:	First Period:	First Period:	First Period:
		drill 1 well, 3 recompletions, 1 Fracpac	drill 3 wells, 3 recompletions, 1 Fracpac	drill 3 wells, 3 recompletions	drill 2 wells, 2 recompletions	—
		Second Period:	Second Period:	Second Period:	Second Period:	Second Period:
		1 recompletion, 2 reactivations/ swabs	drill 1 well, 2 reactivations/ swabs	1 recompletion, 2 reactivations/ swabs	drill 1 well, 2 reactivations/ swabs	1 recompletion, 2 reactivations/ swabs
WD14 .	NAKT Limited	First Period:				
		Reactivate 40 wells, recomplete 15 wells, drill 9 wells, 2 FracPacs, routine well maintenance				
		Second Period:	Second Period:	Second Period:	Second Period:	Second Period:
		drill 1 well, 2 recompletions, 2 reactivations/ swabs	drill 1 well, 1 recompletion, 2 reactivations/ swabs	drill 1 well, 1 recompletion, 2 reactivations/ swabs	drill 1 well, 2 reactivations/ swabs	drill 1 well, 2 reactivations/ swabs
WD16 .	Lennox Production Services Limited	First Period:	First Period:	First Period:	First Period:	First Period:
		2 recompletions, 1 reactivation/ swab	1 reactivation/ swab	—	—	—
		Second Period:	Second Period:	Second Period:	Second Period:	Second Period:
		1 recompletion, 2 reactivations/ swabs	1 recompletion, 2 reactivations/ swabs	1 recompletion, 2 reactivations/ swabs	2 reactivations/ swabs	2 reactivations/ swabs

Field	Operator	Year 1	Year 2	Year 3	Year 4	Year 5
GU1 . .	Pioneer Petroleum Co. Limited	First Period:	First Period:	First Period:	First Period:	First Period:
		2 RCP, 1 coil tubing foam job, 2 fishing jobs, 5 reactivations	1 side track, 1 gravel pack, 3 recompletions, 1 coil tubing foam job, 2 fishing jobs	2 side tracks, 2 gravel packs, 2 recompletions, 1 stimulation, 2 coil tubing foam jobs, 1 fishing job	drill 2 wells, 1 gravel pack, 2 recompletions, 1 stimulation	1 stimulation
		Second Period:	Second Period:	Second Period:	Second Period:	Second Period:
		1 recompletion, 2 reactivations/ swabs	drill 1 well, 2 recompletions, 2 reactivations/ swabs	drill 1 well, 1 recompletion, 2 reactivations/ swabs	drill 1 well, 1 recompletion, 2 reactivations/ swabs	drill 1 well, 1 recompletion, 2 reactivations/ swabs
FZ2 . .	Lennox Production Services Limited	First Period:	First Period:	First Period:	First Period:	First Period:
		3 recompletions, 2 reactivations, 1 coil tubing foam job swabbing	3 recompletions, 2 reactivations, 1 coil tubing foam job swabbing	2 recompletions, 1 reactivation, 1 coil tubing foam job swabbing	1 reactivation, swabbing	1 reactivation, swabbing
		Second Period:	Second Period:	Second Period:	Second Period:	Second Period:
		drill 1 well, 2 recompletions, 2 reactivations/ swabs	drill 1 well, 2 recompletions, 2 reactivations/ swabs	drill 1 well, 2 recompletions, 2 reactivations/ swabs	drill 1 well, 2 recompletions, 2 reactivations/ swabs	drill 1 well, 2 recompletions, 2 reactivations/ swabs

Abandonment

Under the LOAs, Petrotrin is required to establish a well abandonment fund and a general abandonment fund. The well abandonment fund is to be used as a contingency for the abandonment of wells which Petrotrin does not wish to retain and the general abandonment fund is to be used for decommissioning and removal of infrastructure and facilities within the block. The operator is required to contribute US$0.25 per boe into the well abandonment fund and US$0.03 per boe into the general abandonment fund.

During the term of the LOA, the operator may propose the plugging or abandonment of any well at its sole cost if the operator considers that this is necessary from a technical perspective or if the well is uneconomical. Any such cost shall be agreed between the operator and Petrotrin before the commencement of the plugging or abandonment work and shall be credited against the contributions due to the well abandonment fund.

On the expiration or termination of each LOA:

(a) the operator shall abandon new wells drilled which Petrotrin does not wish to retain within 90 days of written confirmation from Petrotrin, at the operator's sole cost; and

(b) in respect of existing wells from which the operator has produced petroleum and new wells drilled by the operator which Petrotrin does wish to retain, Petrotrin shall inform the operator by written notice of the abandonment contribution payable and the operator shall pay its abandonment contribution within 30 days of receiving the notice. The operator's abandonment contribution is a proportional share of the well abandonment costs based on the quantity of petroleum produced from the well by the operator as a proportionate part of Petrotrin's reasonable estimate of cumulative production.

Within 90 days of the expiration or termination of each LOA, the operator is required to remove all moveable assets and such fixed assets as Petrotrin directs from the block and to perform necessary site restoration, at the operator's sole cost.

PART XII

ADDITIONAL INFORMATION

1. **Responsibility**

1.1 The Company, its Directors and the Proposed Directors (whose names and functions appear in paragraph 13 of Part I of this document) accept responsibility for the information contained in this document and for compliance with the AIM Rules for Companies. To the best of the knowledge of the Company, the Directors and the Proposed Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and contains no omission likely to affect its import.

1.2 RPS, whose registered address is Centurion Court, 85 Milton Park, Abingdon, Oxfordshire OX14 4RY, accepts responsibility for the information contained in the Trinity Competent Person's Report set out in Part V of this document. Insofar as the Trinity CPR is based on data provided by Trinity, RPS has relied on the accuracy and completeness thereof and confirms to the best of the knowledge of RPS (who has taken all reasonable care to ensure that such is the case), the information contained therein is in accordance with the facts and contains no omission likely to affect its import.

1.3 GCA, whose registered address is Bentley Hall, Blacknest, Alton, Hampshire GU34 4PU, accepts responsibility for the information contained in the Bayfield Competent Person's Report set out in Part VI of this document. Insofar as the Bayfield CPR is based on data provided by Bayfield, GCA has relied on the accuracy and completeness thereof and confirms to the best of the knowledge of GCA (who has taken all reasonable care to ensure that such is the case), the information contained therein is in accordance with the facts and contains no omission likely to affect its import.

2. **The Company and its Subsidiaries**

2.1 The Company was incorporated and registered in England and Wales on 21 February 2011 under the Act as a public limited company with the name Bayfield (Topco) plc and with the registered number 07535869. The Company changed its name to Bayfield Energy Holdings plc on 10 March 2011. The Company is the holding company of the Bayfield Group.

2.2 The principal legislation under which the Company operates is the Act and the regulations made thereunder. The liability of the members is limited.

2.3 The Company is domiciled in the United Kingdom.

2.4 Up to Admission, the website address of the Company for the purposes of AIM Rule 26 is www.bayfieldenergy.com. Following Admission, the website address of the Company for the purposes of AIM Rules 26 will be www.trinityexploration.com.

2.5 The Company's registered office is Fourth Floor, Burdett House, 15-16 Buckingham Street, London WC2N 6DU (telephone number 0207 747 9200 or, if dialling from outside the United Kingdom, + 44 207 747 9200).

2.6 Pursuant to a court approved scheme of arrangement under Part 26 of the Act, which became effective on 19 May 2011, the Bayfield Group was reorganised so that the Company became the holding company of the Bayfield Group. Pursuant to the Scheme, BEL, which had previously been the holding company of the Bayfield Group, became a directly owned subsidiary of the Company and the existing shareholders of BEL ceased to be shareholders in BEL and became shareholders in the Company.

2.7 The Company acts as the holding company of the Bayfield Group and, following Admission, will be the holding company of the Enlarged Group. On Admission, the Company will have the following significant subsidiary undertakings.

Name	Country of Incorporation and residence	Business Activity	Percentage ownership
Bayfield Energy Limited	England and Wales	Holding company. Holds shares in Bayfield Energy (St. Lucia) Limited, Bayfield Energy (Services) Ltd, Bayfield Energy do Brasil Ltda,	100[1]

Name	Country of Incorporation and residence	Business Activity	Percentage ownership
		Bayfield Energy (Alpha) Ltd and Bayfield Energy New Ventures Limited Holds participating interest in the Pletmos licence	
Bayfield Energy (St. Lucia) Limited	St Lucia	Holding company. Holds shares in Bayfield Energy (Galeota) Limited and Galeota Oilfield Services Limited	100 (indirect)
Bayfield Energy (Services) Ltd	England and Wales	Service company	100 (indirect)
Bayfield Energy do Brasil Ltda	Brazil	Dormant	100 (indirect)
Bayfield Energy (Galeota) Limited	Trinidad and Tobago	Holds participating interest in the Galeota Licence	100 (indirect)
Galeota Oilfield Services Limited	Trinidad and Tobago	Service company	100 (indirect)
Bayfield Energy (Alpha) Ltd	England and Wales	Holding company. Holds shares in Astrakhanskaya Gas and Oil Company	100 (indirect)
Astrakhanskaya Gas and Oil Company	Russia	In the process of being liquidated	74 (indirect)
Bayfield Energy New Ventures Limited	England and Wales	Holding company. Holds shares in Bayfield Energy South Africa Limited	100 (indirect)
Bayfield Energy South Africa Limited	England and Wales	Operating company	100 (indirect)
Trinity Exploration and Production (Barbados) Limited	Barbados	Holding company	100 (indirect)
Trinity Exploration and Production (Trinidad and Tobago) Limited	Trinidad and Tobago	Holding company	100 (indirect)
Ten Degrees North Operating Company Limited[2] (formerly Venture Production (Trinidad) Limited)	Trinidad and Tobago	Operating company. Holds a participating interest in the Point Ligoure Block and the Brighton Marine Block	100 (indirect)
Trinity Exploration and Production Services Limited (formerly TDN Services Limited)	Trinidad and Tobago	Service Company	100 (indirect)
Antilles Resources Limited	Trinidad and Tobago	Holds the interest in the lease operatorship with Petrotrin for the WD 13 Block located at Forest Reserve	100 (indirect)
Ligo Ven Resources Limited	Trinidad and Tobago	Holds a participating interest in the Point Ligoure Block	100 (indirect)
NAKT Company Limited	Trinidad and Tobago	Holds the interest in the lease operatorship with Petrotrin for the WD 14 Block located at Forest Reserve	100 (indirect)

Name	Country of Incorporation and residence	Business Activity	Percentage ownership
Pioneer Petroleum Company Limited	Trinidad and Tobago	Holds the interest in the lease operatorship with Petrotrin for the Guapo 1 (GU1) Block located at Guapo	100 (indirect)
Lennox Production Services Limited	Trinidad and Tobago	Holds the interest in the lease operatorship with Petrotrin for the FZ 2, WD 2 and WD 16 Blocks located at Forest Reserve	100 (indirect)
Tabaquite Exploration and Development Company Limited	Trinidad and Tobago	Not trading. Intention is that it will hold the interest in the licence with Petrotrin for the Tabaquite block once it is renewed	100 (indirect)
Oilbelt Services Limited	Trinidad and Tobago	Holds the interest in the lease operatorship with Petrotrin for the WD5/6 Block located at Forest Reserve	100 (indirect)

Notes

1 The share capital of BEL is divided into 118,567,634 shares of US$0.10 each held by the Company and two shares of £1 each held by Darcy Carr.

2 Ten Degrees North Operating Company Limited had a branch, Coastline International Inc. which held the interest in the licence with Petrotrin for the Tabaquite Block, which the Trinity Group intends will be held by Tabaquite Exploration and Production Company Limited once it has been renewed.

2.8 Save for the undertakings set out in paragraph 2.7 of this Part XII, there are no undertakings in which the Company holds a proportion of the capital that is likely to have a significant effect on the assessment of its own assets and liabilities, financial position or profits.

3. **Share Capital**

3.1 The Company was incorporated with one ordinary share of US$0.10, which was allotted on 21 February 2011 as a subscriber share (the "**Subscriber Share**") to Swift Nominees Limited at par value. Since the incorporation of the Company there have been the following changes in the share capital and the issued and fully paid share capital of the Company:

(a) on 7 March 2011 the Subscriber Share was transferred from Swift Nominees Limited to Amanda Bateman at par value;

(b) on 7 March 2011, in order to enable the Company to obtain a trading certificate, the Company allotted 50,000 redeemable preference shares of £1 each to Finian O'Sullivan, Andrey Pannikov and Brian Thurley. The redeemable preference shares were allotted as follows:

Name	Number of redeemable preference shares
Finian O'Sullivan	16,666
Andrey Pannikov	16,667
Brian Thurley	16,667

(c) on 7 March 2011, the Subscriber Share was transferred from Amanda Bateman to Brian Thurley at par value;

(d) on 19 May 2011, immediately following the Scheme becoming effective, the Company allotted 118,567,634 Existing Unconsolidated Ordinary Shares to the following persons:

Name	Number of Existing Unconsolidated Ordinary Shares
Andrey Pannikov	28,645,470
Brian Thurley	25,050,434
Prelude Holdings Limited	23,397,314
Alta Limited	9,758,366
William Hatcher	3,875,000
Finian O'Sullivan	5,248,156
Simon Gill	4,983,333
Wajang Holdings Limited	3,875,000
Konstantinos Giannatos	3,500,000
Simon Moy	1,742,045
Andrew Rose	1,633,862
Elvira Gill	1,266,744
Stefano Santoni	1,166,666
Ian Bingham	725,245
Ionian Isle Holdings Limited	599,999
Averil Bingham	100,000

(resulting in 118,567,635 Existing Unconsolidated Ordinary Shares being in issue as at such date);

(e) on 18 July 2011 (being the date of admission of the Company's share capital to AIM pursuant to the IPO), the Company issued 90,625,000 Existing Unconsolidated Ordinary Shares pursuant to the 2011 Placing and 5,386,807 Existing Unconsolidated Ordinary Shares pursuant to the conversion of the 2011 Notes (resulting in 214,579,442 Existing Unconsolidated Ordinary Shares being in issue as at such date);

(f) since 18 July 2011, there have been 1,900,000 Existing Unconsolidated Ordinary Shares issued on exercise of Options (resulting in 216,479,442 Existing Unconsolidated Ordinary Shares being in issue as at 23 January 2013, being the last practicable date prior to the date of this document);

(g) pursuant to an ordinary resolution of the Company passed at the annual general meeting of the Company on 2 July 2012 the Directors are generally and unconditionally authorised for the purposes of section 551 of the Companies Act to exercise all of the powers of the Company to allot shares and grant rights to subscribe for, or convert any security into, shares in the Company: (i) up to an aggregate nominal amount of US$7,208,765 (such amount to be reduced by the nominal amount allotted or granted under (ii) in excess of such sum); and (ii) comprising equity securities (as defined in section 560 of the Companies Act) up to an aggregate nominal amount of US$14,439,178 (such amount to be reduced by the allotments or grants made under (i)) in connection with or pursuant to an offer or invitation by way of a rights issue.

Such authorities expire at the conclusion of the annual general meeting of the Company in 2013 or on 30 June 2013, whichever is the earlier, save that the Company may before such expiry make any offer or agreement which would or might require shares to be allotted or rights to be granted, after such expiry and the Directors may allot shares, or grant rights to subscribe for or to convert any security into shares, in pursuance of any such offer or agreement as if the authorities conferred by such resolution had not expired;

(h) pursuant to a special resolution of the Company passed at the annual general meeting of the Company on 2 July 2012 the Directors are empowered pursuant to sections 570(1) and 573 of the Companies Act to: (i) allot equity securities of the Company (as defined in section 560 of the Companies Act) for cash pursuant to the authority conferred by the resolution detailed at paragraph 3.1(g) above; and (ii) sell ordinary shares (as defined in section 560(1) of the Companies Act) held by the Company as treasury shares for cash, as if section 561 of the Companies Act did not apply to such allotment or sale.

Such power is limited to the allotment of equity securities and sale of treasury shares for cash:

(A) in connection with or pursuant to an offer of or invitation to acquire equity securities (but in the case of the authority granted under the resolution described at paragraph 3.1(g)(ii) above, by way of a rights issue only) in favour of holders of ordinary shares in proportion (as nearly as practicable) to the respective number of ordinary shares held by them on the record date for such allotment (and holders of any other class of equity securities entitled to participate therein or if the directors consider it necessary, as permitted by the rights of those securities) but subject to such exclusions or other arrangements as the Directors may consider necessary or expedient to deal with fractional entitlements, record dates or legal or practical difficulties which may arise; and

(B) in the case of the authorisation granted under the resolution described at paragraph 3.1(g)(i) above (or in the case of any sale of treasury shares) and otherwise than pursuant to sub-paragraph 3.1(h)(A) above, up to an aggregate nominal amount of US$2,164,794,

such powers expire on the conclusion of the annual general meeting of the Company in 2013 or on 30 June 2013, whichever is the earlier, save that the Company may before such expiry make any offer or agreement that would or might require equity securities to be allotted, or treasury shares to be sold, after such expiry, and the Directors may allot equity securities or sell treasury shares in pursuance of any such offer or agreement as if the power conferred by such resolution had not expired;

(i) on or after the date (but after the time of publication) of this document and prior to Admission, the Company intends to issue eight Existing Unconsolidated Ordinary Shares to Finian O'Sullivan, the Company's Executive Chairman, at a price per share equal to one tenth of the Placing Price and an aggregate subscription price of £0.96. The Company proposes to take such action so that its issued share capital as at the date the Share Consolidation is effected will be 216,479,450 Existing Unconsolidated Ordinary Shares, thereby ensuring that no fraction of a share arises in respect of the aggregate share capital of the Company upon the Share Consolidation being effected; and

(j) for the purposes of implementing the Share Consolidation, the Merger and the Placing, the following resolution will be proposed at the General Meeting in relation to the share capital of the Company:

(i) in addition to all previous authorities to the extent unused, to generally and unconditionally authorise the Directors for the purposes of section 551 of the Companies Act, to exercise all the powers of the Company to allot shares in the Company and grant rights to subscribe for or convert any securities into shares in the Company up to an aggregate nominal amount of US$73,214,129, such authority to expire on 31 December 2013 unless previously renewed, varied or revoked by the Company in general meeting (save that the Company may before such expiry make an offer or agreement which would or might require shares to be allotted, or rights to be granted, after such expiry and the Directors may allot shares or grant rights to subscribe for or to convert any security into shares, in pursuance of such offer or agreement as if the authorisations conferred by such resolution had not expired);

(ii) in addition to all previous powers to the extent unused, to unconditionally empower the Directors pursuant to section 570 of the Companies Act to allot equity securities (as defined in section 560 of the Act) wholly for cash pursuant to the authority to be granted to the Directors pursuant to paragraph 3.1(i)(i) above of this Part XII as if section 561 of the said Act did not apply to any such allotment, provided that such power shall be limited to the allotment of equity securities up to an aggregate nominal amount of US$73,214,129 and such power shall expire on 31 December 2013 unless previously renewed, varied or revoked by the Company in general meeting, (save that the Company may before such expiry make an offer or agreement which would or might require shares to be allotted, or rights to be granted, after such expiry and the Directors may allot shares or grant rights to subscribe for or to convert any security into shares, in pursuance of such offer or agreement as if the power conferred by such resolution had not expired); and

(iii) every ten issued ordinary shares of US$0.10 in the capital of the Company be consolidated into one ordinary share of US$1.00 in the capital of the Company.

3.2 The following tables show the issued share capital of the Company as at the date of this document and the issued share capital as it is expected to be immediately following Admission (assuming that the Resolution is passed).

Issued and fully paid as the date of this document

Nominal Value Ordinary (US$)	Number
0.10	216,479,450[1]

1 The figure of 216,479,450 includes the eight Existing Unconsolidated Ordinary Shares that the Company intends to issue to Finian O'Sullivan, the Company's Executive Chairman, on or after the date (but after the time of publication) of this document and prior to Admission, further details of which are set out in paragraph 3.1(i) of this Part XII.

Issued and fully paid immediately following Admission

Nominal Value Ordinary (US$)	Number
1.00	94,799,986

3.3 Subject to Admission:

(a) 47,500,000 new Consolidated Ordinary Shares will be issued pursuant to the Placing at a price of 120p per new Consolidated Ordinary Share, representing a premium of 57p over their nominal value of $1.00 each, which price is payable in full on application; and

(b) 25,652,041 new Consolidated Ordinary Shares will be issued pursuant to the Merger Agreements, which will dilute existing shareholders by approximately 55 per cent. following the Merger (but prior to the Placing and on the basis that Centrica will not convert its Centrica Loan Notes).

3.4 Save for the Options and the LTIP Awards, the Company has no securities in issue not representing share capital.

3.5 Save as disclosed in this Part XII:

(a) there has been no change in the amount of the issued share or loan capital of the Company in the three years preceding the date of this document;

(b) no commissions, discounts, brokerages or other special terms have been granted by the Company in connection with the issue or sale of any share or loan capital of the Company in the three years preceding the date of this document;

(c) no share or loan capital of the Company is under option or is agreed, conditionally or unconditionally, to be put under option;

(d) there are no shares of the Company held by or on behalf of itself or by any member of the Bayfield Group; and

(e) no person has any preferential subscription rights for any share capital in the Company and the Company has given no undertakings to any third party to increase the capital of the Company.

3.6 The Existing Unconsolidated Ordinary Shares are in registered form and, subject to the provisions of the Regulations, the Directors may permit the holding of shares of any class in uncertificated form and title to such shares may be transferred by means of a relevant system (as defined in the Regulations). Where Existing Unconsolidated Ordinary Shares are held in certificated form, share certificates will be sent to the registered members by first class post. Where Existing Unconsolidated Ordinary Shares are held in CREST, the relevant CREST stock account of the registered members will be credited.

3.7 The Consolidated Ordinary Shares will be in registered form and, subject to the provisions of the Regulations, the Directors will be entitled to permit the holding of shares of any class in uncertificated form and title to such shares may be transferred by means of a relevant system (as defined in the Regulations). Where Consolidated Ordinary Shares are held in certificated form, share certificates will be sent to the registered members by first class post. Where Consolidated Ordinary Shares are held in CREST, the relevant CREST stock account of the registered members will be credited.

3.8 As of 21 February 2011 (being the date of incorporation of the Company) the Company had one Existing Unconsolidated Ordinary Shares in issue, being the Subscriber Share, and on 1 January 2012 the Company had a total number of 214,979,442 Existing Unconsolidated Ordinary Shares in issue. As at 23 January 2013, being the last practicable date prior to the date of this document, the total number of Existing Unconsolidated Ordinary Shares in issue was 216,479,442.

4. **Options and LTIP Awards**

4.1 *Bayfield*

As at 23 January 2013 (being the last practicable date prior to the date of this document), the following Options have been granted under individual option agreements by the Company and are outstanding:

Name	Exercise Price (US$)	Number of Existing Unconsolidated Ordinary Shares subject to Options	Number of new Consolidated Ordinary Shares to be subject to Options following Admission	Exercise Price following Admission (US$)
Simon Gill	0.25	3,500,000	350,000	2.5
Stefano Santoni	0.40	118,443	11,844	4.0
Ionian Isle Holdings Limited	0.40	829,103	82,910	4.0
Total		*4,447,546*	*444,754*	

The Options held by Simon Gill are exercisable from 31 August 2011 until 31 August 2015, when they lapse. There are no performance conditions attached to such Options.

The Options granted to Stefano Santoni and Ionian Isle Holdings Limited at an exercise price of US$0.40 are exercisable from the date of grant until 30 September 2013 and are not subject to performance conditions.

The above Options will be adjusted in accordance with their terms following Completion to reflect the Consolidation, and the figures set out in the table above show the numbers of Consolidated Ordinary Shares to be subject to the Options following Admission.

As at 23 January 2013 (being the last practicable date prior to the date of this document), the following LTIP Awards are outstanding:

Holder	**Number of Existing Unconsolidated Ordinary Shares subject to LTIP Awards[1]**	**Number of new Consolidated Ordinary Shares to be subject to LTIP Awards following Completion**	**Date of Grant**
Richard Fritz	758,138	75,813	18 July 2011[2] and 26 January 2012
Konstantinos Giannatos	4,230,613	—[1]	18 July 2011[3] and 26 January 2012
Hywel John	3,750,000	—	18 July 2011[4] and 26 January 2012
Michael Kelly	221,354	22,135	18 July 2011
Peter Machikan	329,036	32,903	18 July 2011[5] and 26 January 2012
Shawn McNicholls	107,646	10,764	18 July 2011
David Mohammad	103,340	10,334	18 July 2011
Simon Moy	1,000,000	—	26 January 2012
Cecilia Odergren	608,507	—	18 July 2011[6] and 26 January 2012
Stefano Santoni	2,000,000	—	7 June 2011
Steve Shu	217,014	21,701	18 July 2011
Total	*13,325,648*	*173,650*	

1 The LTIP Awards held by Konstantinos Giannatos, Hywel John, Simon Moy and Stefano Santoni will lapse on their cessation of employment with the Bayfield Group pursuant to the rules of the LTIP. The remaining LTIP Awards will be adjusted in accordance with the rules of the LTIP following Completion to reflect the Consolidation, and the figures set out in the table above show the numbers of Consolidated Ordinary Shares subject to LTIP Awards after such adjustment has been made.

2 Of Richard Fritz's 758,138 LTIP Awards, 258,138 were granted on 18 July 2011 and the remaining 500,000 were granted on 26 January 2012.

3 Of Konstantinos Giannatos' 4,230,613 LTIP Awards, 730,613 were granted on 18 July 2011 and the remaining 3,500,000 were granted on 26 January 2012.

4 Of Hywel John's 3,750,000 LTIP Awards, 3,000,000 were granted on 18 July 2011 and the remaining 750,000 were granted on 26 January 2012.

5 Of Peter Machikan's 329,036 LTIP Awards, 179,036 were granted on 18 July 2011 and the remaining 150,000 were granted on 26 January 2012.

6 Of Cecilia Odergren's 608,507 LTIP Awards, 108,507 were granted on 18 July 2011 and the remaining 500,000 were granted on 26 January 2012.

The LTIP Awards are conditional awards of Existing Unconsolidated Ordinary Shares and vest three years from the date of grant, subject to the satisfaction of certain performance conditions (based on the growth in the Company's total shareholder return). No payment is required on vesting and there is no accelerated vesting arising as a result of the Merger.

4.2 *Trinity*

As at 23 January 2013 (being the last practicable date prior to the date of this document), the following Trinity Options have been granted by Trinity and are outstanding:

Name	Date of Grant	Exercise Price (US$)	Number of Trinity Shares subject to Options
Bruce Alan Ian Dingwall	4 July 2012	US$1,000	837
James Lee-Young	4 July 2012	US$1,000	1,097
Ian MacDonald	4 July 2012	US$1,000	324
Joel Montgomery Pemberton	4 July 2012	US$1,000	660
Graham Stuart	4 July 2012	US$1,000	150
	4 July 2012	US$4,185	150
Bryan Ramsumair	4 July 2012	US$1,000	20
	4 July 2012	US$4,185	55
Jonathan Murphy	4 July 2012	US$1,000	100
Brian Montgomery Besson	4 July 2012	US$4,185	50
Denis Hosam	4 July 2012	US$4,185	20
Robert Gair	4 July 2012	US$4,185	75
Sookdeo Heeralal	4 July 2012	US$4,185	100
Total			3,638

The Trinity Options will become exercisable on completion of the Merger. To the extent Trinity Options are not exercised, they will (subject as set out below) lapse following completion of the Merger.

The holders of Trinity Options have been offered the opportunity to surrender their Trinity Options (conditionally upon Completion) in return for the grant by Bayfield of New Options over approximately 747.8 new Consolidated Ordinary Shares for each Trinity Share over which a Trinity Option was held. New Options will be held on the terms of the Mirror Scheme, the main terms of which are set out below:-

(a) *Exercise Price:* in respect of those Trinity Options with an exercise price of US$1,000 per Trinity Share, the aggregate exercise price shall be the same as the aggregate exercise price for the surrendered Trinity Option held. In respect of those Trinity Options with an exercise price of US$4,185, the exercise price per Consolidated Ordinary Share shall be equal to the lower of the Placing Price and US$ 5.59614615.

(b) *Exercise of Options:* the New Options shall be exercisable on the earlier of:-

  (i) the third anniversary of the date of grant of the Trinity Option (unless the Trinity Option was granted subject to an earlier exercise date);

  (ii) death of the option holder;

  (iii) cessation of service due to injury, ill-health, disability or redundancy, or retirement by agreement between the option holder and their employer company, or at the discretion of the Remuneration Committee of the Company;

  (iv) a person obtains control of the Company as a result of a general offer, a scheme of arrangement is effected for the acquisition of shares under Part 26 of the Act;

  (v) a resolution for a voluntary winding up of the Company;

  (vi) a demerger at the discretion of the Remuneration Committee of the Company; and

  (vii) any event which the Remuneration Committee of the Company consider to justify exercise.

(c) *Lapse:* the New Options will lapse on the earlier of:-

(i) the tenth anniversary of the date of grant of the original Trinity Option;

(ii) first anniversary of death;

(iii) six months following a change of control, scheme of arrangement or resolution for voluntary winding up;

(iv) cessation of service (unless for reasons specified in (b)(iii) above in which case the option shall lapse 6 months after cessation or, if later, six months after the New Option becomes exercisable or as otherwise determined by the Remuneration Committee of the Company).

Jonathan Murphy has chosen to exercise 100 of his Trinity Options (being all of the Trinity Options he holds) conditional upon Completion and Bryan Ramsumair has chosen to exercise 20 of his 75 Trinity Options conditional upon Completion, and, by executing share purchase agreements, have agreed to transfer the new Trinity Shares they will be allotted as a result of such exercise to Bayfield and receive Consolidated Ordinary Shares for such transfer on the same terms as the existing Trinity Shareholders. 89,736 Consolidated Ordinary Shares in aggregate will be issued to Jonathan Murphy and Bryan Ramsumair as a result of the exercise of their Trinity Options and sale of the resulting Trinity Shares to Bayfield.

Bruce Alan Ian Dingwall, James Lee-Young, Ian MacDonald, Joel Montgomery Pemberton, Graham Stuart, Bryan Ramsumair (in respect of his remaining 55 Trinity Options), Brian Montgomery Besson, Denis Hosam, Robert Gair and Sookdeo Heeralal, being the remainder of the holders of Trinity Options who together hold 3,518 Trinity Options, have chosen to surrender their Trinity Options in consideration for the grant by Bayfield of New Options. This will result in the issue of 2,630,759 New Options in aggregate to Bruce Alan Ian Dingwall, James Lee-Young, Ian MacDonald, Joel Montgomery Pemberton, Graham Stuart, Bryan Ramsumair, Brian Montgomery Besson, Denis Hosam, Robert Gair and Sookdeo Heeralal.

The following table summarises the number of new Consolidated Ordinary Shares to be issued following the exercise of Trinity Options and the transfer of such Trinity Shares to Bayfield at completion of the Merger, and the number of New Options to be issued following surrender of Trinity Options at Completion:

Name	**Number of Trinity Shares subject to Options**	**Exercise Price per Trinity Shares subject to Options (US$)**	**Number of new Consolidated Ordinary Shares to be issued following exercise and transfer at Admission**	**Number of Consolidated Ordinary Shares subject to New Options to be issued at Admission**	**Aggregate Exercise price of each New Option to be issued at Admission (US$)**
Bruce Alan Ian Dingwall	837	US$1,000	0	625,908	837,000
James Lee-Young	1,097	US$1,000	0	820,336	1,097,000
Ian MacDonald	324	US$1,000	0	242,287	324,000
Joel Montgomery Pemberton	660	US$1,000	0	493,548	660,000
Graham Stuart	150	US$1,000	0	112,170	150,000
	150	US$4,185	0	112,170	[1]
Bryan Ramsumair	20	US$1,000	14,956	0	n/a
	55	US$4,185	0	41,129	[1]
Jonathan Murphy	100	US$1,000	74,780	0	n/a
Brian Montgomery Besson	50	US$4,185	0	37,390	[1]
Denis Hosam	20	US$4,185	0	14,956	[1]
Robert Gair	75	US$4,185	0	56,085	[1]
Sookdeo Heeralal	100	US$4,185	0	74,780	[1]
Total	*3,638*	*n/a*	*89,736*	*2,630,759*	*n/a*

Note

1 Exercise price of each of these New Options to be issued at Admission is to be equal to the lower of the Placing Price and US$5.59614615 (aggregate price rounded to the nearest US$0.01).

5. **Articles of Association**

5.1 The Articles are available for inspection at the business address specified in paragraph 22 of this Part XII.

5.2 The Articles were adopted by special resolution passed on 6 June 2011. The Articles contain provisions, *inter alia*, to the following effect:

(a) *Voting rights in respect of Existing Unconsolidated Ordinary Shares*

(i) Shareholders shall have the right to receive notice of, to attend and to vote at all general meetings of the Company. Save as otherwise provided in the Articles, on a show of hands each holder of shares present in person and entitled to vote shall have one vote and upon a poll each such holder who is present in person or by proxy and entitled to vote shall have one vote in respect of every share held by him.

(ii) No member shall be entitled to attend or vote at any general meeting if any call or other sum presently payable by him in respect of shares remains unpaid (unless the Directors otherwise determine) or if a member has been served by the Directors with a restriction notice in the manner described in paragraph 5.2(b) below.

(b) *Restrictions on Existing Unconsolidated Ordinary Shares*

If a member or any person appearing to the Directors to be interested in shares in the capital of the Company held by such member has been duly served with a notice pursuant to section 793 of the Act and is in default in supplying to the Company information thereby required within 14 days from the date of service of such notice the Company may serve on such member or on any such person a notice (a "restriction notice") in respect of the shares in relation to which the default occurred (the "restricted shares") and any other shares held at the date of the restriction notice directing that the member shall not be entitled to be present or to vote at any general meeting or class meeting of the Company or to be reckoned in any quorum. Where the restricted shares represent at least 0.25 per cent. (in nominal value) of the issued shares of the Company of the same class the restriction notice may in addition direct, *inter alia*, that any dividend or other monies which would otherwise be payable on or in respect of the restricted shares shall be withheld by the Company without liability to pay interest; where the Company has offered the right to elect to receive shares instead of cash in respect of any dividends any election by such member of such restricted shares will not be effective; and no transfer of any of the shares held by the member shall be registered unless the member is not himself in default in supplying the information requested and the transfer is part only of the member's holding and is accompanied by a certificate given by the member in a form satisfactory to the Directors to the effect that after due and careful enquiry the member is satisfied that none of the shares which is the subject of the transfer is a restricted share.

(c) *Variation of Class Rights*

If at any time the share capital is divided into different classes of shares, the rights attached to any class or any of such rights may, subject to the provisions of the Act, the Regulations, and every other statute or subordinated legislation for the time being in force concerning companies and affecting the Company (the "Statutes") whether or not the Company is being wound up, be abrogated or varied with the consent in writing of the holders of at least three-quarters in nominal value of the issued shares of that class (excluding any shares of that class held as treasury shares), or with the sanction of a special resolution passed at a separate general meeting of the holders of the shares of that class. To every such separate general meeting the provisions of chapter 3 of part 13 of the Act (save as stated in section 334(2) to (3)) and the provisions of the Articles relating to general meetings shall, *mutatis mutandis*, so far as applicable apply, subject to the following provisions, namely: (i) the necessary quorum at any such meeting, other than an adjourned meeting, shall be two persons present holding at least one-third in nominal value of the issued shares of the class in question (excluding any shares of that class held as treasury shares) and at an adjourned meeting one person present holding shares of the class in question; and (ii) any holder of shares of the class in question present in person or by proxy may demand a poll. For the purposes of (i) above, where a person is present by proxy or proxies, he is treated as holding only the shares in respect of which those proxies are authorised to exercise voting rights. The rights attached to any class of shares shall, unless otherwise expressly provided by the terms of issue of the shares of that class or by the terms upon which such shares are for the time being held, be deemed not to be abrogated or varied by the creation or issue of further shares ranking *pari passu* therewith.

(d) *Alteration of capital*

(i) The Company may by ordinary resolution consolidate all or any of its share capital into shares of larger amount and sub-divide all or any of its shares into shares of smaller amount.

(ii) Subject to the provisions of the Statutes, the Company may by special resolution reduce its share capital, any capital redemption reserve any share premium account and any redenomination account in any way.

(iii) Subject to the provisions of the Statutes, any shares may be issued on terms that they are to be redeemed or liable to be redeemed at the option of the Company or the shareholders. The terms and conditions and manner of redemption may be determined by the Directors provided that this is done before the shares are allotted.

(iv) Subject to the provisions of the Statutes, the Company may purchase any of its own shares (including any redeemable shares).

(e) *Transfer of Shares*

(i) Subject to paragraph 5.2(e)(ii) below, the instrument of transfer of a certificated share shall be signed by or on behalf of the transferor (and, in the case of a share which is not fully paid, by or on behalf of the transferee) and the transferor shall be deemed to remain the holder of the share until the name of the transferee is entered in the register in respect thereof. All transfers of certificated shares shall be effected by instrument in writing in any usual or common form or any other form which the Directors may approve. The Directors may, in their absolute discretion, refuse to register the transfer of a share which is not fully paid (whether certificated or uncertificated) provided that where such shares are admitted to the Official List, such discretion may not be exercised in a way which the FSA or the London Stock Exchange regards as preventing dealings in the shares of the relevant class or classes from taking place on an open and proper basis. The Directors may likewise refuse to register any transfer of a share (whether certificated or uncertificated), whether fully paid or not, in favour of more than four persons jointly. In relation to certificated shares, the Directors may decline to recognise any instrument of transfer unless it is left at the registered office of the Company or such other place as the Directors may determine, accompanied by the relevant certificate and such other evidence as the Directors may reasonably require to show the right of the transferor to make the transfer (and, if the instrument of transfer is executed by some other person on his behalf, the authority of that person so to do), and unless the instrument is in respect of only one class of share.

(ii) Notwithstanding any other provision of the Articles to the contrary, unless otherwise determined by the Directors, any shares in the Company may be held in uncertificated form and title to shares may be transferred by means of a relevant system (in each case as defined in the Regulations) such as CREST.

(f) *General Meetings*

An annual general meeting shall be called by not less than 21 clear days' notice, and a meeting of the Company other than an annual general meeting shall be called by not less than 14 clear days' notice. The notice shall state the place, the date and the time of meeting and the general nature of that business. It shall be given, in the manner hereinafter mentioned or in such other manner, if any, as may be prescribed by the Statutes or by the Company in general meeting, to such persons as are entitled to receive such notices from the Company and shall comply with the provisions of the Statutes as to informing Members of their right to appoint proxies. A notice calling an annual general meeting shall state that the meeting is an annual general meeting and a notice convening a meeting to pass a special resolution shall specify the intention to propose the resolution as such and shall include the text of the resolution.

A meeting of the Company shall, notwithstanding that it is called by shorter notice than that specified in the paragraph above, be deemed to have been duly called if it is so agreed in the case of a meeting called as the annual general meeting, by all the Members entitled to attend and vote thereat; and in the case of any other meeting, by a majority in number of the Members having a right to attend and vote at the meeting, being a majority together holding not less than 95 per cent. in nominal value of the shares giving that right (excluding any shares in the Company held as treasury shares). The short notice provision noted in this paragraph does not apply to general meetings (other than meetings of holders of a class of shares) of a traded company (as defined in section 360C of the Act).

The accidental failure to give notice of a meeting, or of a resolution intended to be moved at a meeting, or to issue an invitation to appoint a proxy with a notice where required by the Articles, to any one or more persons entitled to receive notice, or the non-receipt of notice of a meeting or of such a resolution or of an invitation to appoint a proxy by any such persons, shall be disregarded for the purpose of determining whether notice of the meeting or of any resolution to be moved at the meeting is duly given.

(g) *Directors*

Unless and until the Company in general meeting shall otherwise determine, the number of Directors shall be not more than 15 nor less than two. The Company may by ordinary resolution from time to time vary the minimum number and/or maximum number of Directors. A Director shall not be required to hold any shares in the capital of the Company. A Director who is not a member shall nevertheless be entitled to receive notice of and attend and speak at all general meetings of the Company and all separate general meetings of the holders of any class of shares in the capital of the Company. There shall not be an age limit for Directors.

No Director shall be disqualified by his office from entering into, or being otherwise interested in, any other office or place of profit with the Company, except that of Auditor whether by himself or though his firm, or any other contract, transaction or arrangement with the Company or in which the Company has a (direct or indirect) interest. Subject to the provisions of the Statutes and save as therein provided no such contract, transaction or arrangement shall be liable to be avoided on the grounds of the Director's interest, nor shall any Director be liable to account to the Company for any remuneration or other benefit which derives from any such contract, transaction or arrangement or interest by reason of such Director holding that office or of the fiduciary relationship thereby established, but he shall declare the nature of his interest in accordance with the requirements of the Statutes.

A Director shall (in the absence of some other material interest than is indicated below) be entitled to vote (and be counted in the quorum) in respect of any resolution concerning any of the following matters, namely:

(i) the giving of any guarantee, security or indemnity in respect of money lent or obligations incurred by him or by any other person at the request of or for the benefit of the Company or any of its subsidiary undertakings;

(ii) the giving of any guarantee, security or indemnity in respect of a debt or obligation of the Company or any of its subsidiary undertakings for which he himself has assumed responsibility in whole or in part under a guarantee or indemnity or by the giving of security;

(iii) any proposal concerning an offer of securities of or by the Company or any of its subsidiary undertakings in which offer he is or may be entitled to participate as a holder of securities or in the underwriting or sub-underwriting of which he is to participate;

(iv) any contract, arrangement or transaction concerning any other body corporate in which he is interested, directly or indirectly and whether as an officer or shareholder or otherwise howsoever, provided that he does not to his knowledge hold an interest (within the meaning of sections 820 to 825 of the Act) in one per cent. or more of any class of the equity share capital of such body corporate or of the voting rights available to members of the relevant body corporate;

(v) any contract, arrangement or transaction for the benefit of employees of the Company or any of its subsidiary undertakings which does not accord to him any privilege or advantage not generally accorded to the employees to whom the scheme relates;

(vi) any contract, arrangement or transaction concerning any insurance which the Company is to purchase and/or maintain for, or for the benefit of, any Directors or persons including Directors;

(vii) the giving of an indemnity pursuant to the Article in relation to the indemnity of the Directors; and

(viii) the provision of funds to any Director to meet, or the doing of anything to enable a Director to avoid incurring, expenditure of the nature described in section 205(1) or 206 of the Act.

If any question shall arise at any meeting as to an interest or as to the entitlement of any Director to vote and such question is not resolved by his voluntarily agreeing to abstain from voting, such question shall be referred to the chairman of the meeting and his ruling in relation to any Director other than himself shall be final and conclusive except in a case where the nature or extent of the interests of the Director concerned have not been fairly disclosed.

Save as provided in the Articles, a Director shall not vote in respect of any contract, arrangement or transaction whatsoever in which he has an interest which is to his knowledge a material interest otherwise than by virtue of interests in shares or debentures or other securities of or otherwise in or through the Company. A Director shall not be counted in the quorum at a meeting in relation to any resolution on which he is debarred from voting.

The Directors shall be paid out of the funds of the Company by way of fees for their services as Directors such sums (if any) as the Directors may from time to time determine (not exceeding, in the aggregate an annual sum, excluding amounts payable under any other provision of the Articles of £400,000, or such larger amount as the Company may by ordinary resolution determine) and such remuneration shall be divided between the Directors as they shall agree or, failing agreement, equally. Such remuneration shall be deemed to accrue from day to day. The Directors may also be paid all reasonable travelling, hotel and other expenses properly incurred by them in attending and returning from meetings of the Directors or any committee of the Directors or general meetings of the Company or of the holders of any class of shares or debentures of the Company or otherwise in connection with the business of the Company. Any Director who is appointed to any executive office or who serves on any committee or who devotes special attention to the business of the Company, or who otherwise performs services which in the opinion of the Directors are outside the scope of the ordinary duties of a Director, may be paid such extra remuneration by way of salary, percentage of profits or otherwise as the Directors may determine. The Articles do not permit a director to vote on, or be counted in the quorum in relation to, any resolution of the board concerning his own appointment as the holder of any office or place of profit with the Company or any company in which the Company is interested including fixing or varying the terms of his appointment or the termination thereof.

Each Director shall have the power at any time to appoint as an alternate Director either (i) another Director or (ii) any other person approved for that purpose by a resolution of the Directors, and, at any time, to terminate such appointment.

At every annual general meeting, there shall retire from office any Director who shall have been a Director at each of the preceding two annual general meetings and who was not appointed or re-appointed by the Company in general meeting at, or since, either such meeting. A retiring Director shall be eligible for re-appointment.

The Directors may exercise all the powers of the Company to give or award pensions, annuities, gratuities or other retirement, superannuation, death or disability allowances or benefits (whether or not similar to the foregoing) to (or to any person in respect of) any persons who are or have at any time been Directors of the Company or of any body corporate which is or was a subsidiary undertaking or a parent undertaking of the Company or another subsidiary undertaking of a parent undertaking of the Company or otherwise associated with the Company or any such body corporate, or a predecessor in business of the Company or any such body corporate, and to the spouses, civil partners, former spouses, former civil partners, children and other relatives and dependants of any such persons and may establish, maintain, support, subscribe to and contribute to all kinds of schemes, trusts and funds (whether contributory or non-contributory) for the benefit of such persons as are hereinbefore referred to or any of them or any class of them, and so that any Director or former Director shall be entitled to receive and retain for his own benefit any such pension, annuity, gratuity, allowance or other benefit (whether under any such trust, fund or scheme or otherwise).

(h) *Borrowing Powers*

The Directors may, save as the Articles otherwise provide, exercise all the powers of the Company to borrow money, and to mortgage or charge its undertaking, property and assets (present and future) and uncalled capital, or any part thereof, and, subject to the provisions of the Statutes to issue debentures, debenture stock, and other securities whether outright or as security for any debt, liability or obligation of the Company or of any third party.

(i) *Dividends and Distributions on Liquidation to Shareholders*

(i) The Company in general meeting may declare dividends, but no dividend shall exceed the amount recommended by the Directors. Subject to the Statutes and the rights of any persons entitled to shares with any priority, preference or special rights, all dividends shall be declared and paid according to the amounts paid up on the shares and shall be apportioned and paid proportionately to the amounts paid up on the shares during any portion of the period in respect of which the dividend is paid.

(ii) Subject to the provisions of the Statutes, the Directors may from time to time pay such interim dividends as they think fit and may pay the fixed dividends payable on any shares of the Company half yearly or otherwise on fixed dates.

(iii) Any dividend unclaimed for a period of 12 years or more after becoming due for payment shall be forfeited and shall revert to the Company.

(iv) On a liquidation, the liquidator may, subject to the Statutes and with the sanction of a special resolution of the Company and any other sanction required by the Statutes, divide amongst the members in specie or in kind the whole or any part of the assets of the Company and may, for such purpose, set such value as he deems fair upon any property to be divided and may determine how such division shall be carried out.

(j) *Non-United Kingdom Shareholders*

There are no limitations in the Articles on the rights of non-United Kingdom shareholders to hold, or to exercise voting rights attached to the Existing Unconsolidated Ordinary Shares. However, non-United Kingdom shareholders are not entitled to receive notices or any other documents or information from the Company unless they have given an address in the United Kingdom to which such notices may be sent.

(k) *Unlimited objects*

The Articles contain no restriction on the objects of the Company.

6. **Directors, Proposed Directors and Other Interests**

6.1 The interests of the Directors, Proposed Directors and of persons connected with them (within the meaning of sections 252 to 256 of the Act) all of which are beneficial unless otherwise stated in the issued share capital of the Company, were and the existence of which is known to them or could, with reasonable diligence, be ascertained by the Directors and the Proposed Directors, as at the date of this document and as expected to be immediately following the Share Consolidation, the Placing, the Merger and Admission are as follows:

Name	As at the date of this document		Immediately following Admission	
	Number of Existing Unconsolidated Ordinary Shares	Percentage of existing issued share capital	Number of Consolidated Ordinary Shares	Percentage of Enlarged Share Capital
Hywel John	—	—	—	—
Finian O'Sullivan[1]	36,261,665	16.75	3,626,166	3.83
Andrey Pannikov[2]	38,513,363	17.79	3,851,336	4.06
Jonathan Cooke[3]	102,436	0.05	10,243	0.01
David MacFarlane	—	—	—	—
Bruce Dingwall[4]	—	—	5,781,472	6.10
Joel Pemberton[4]	—	—	494,315	0.52
Jon Murphy[4]	—	—	4,877,421	5.14
Anthony Brash[4]	—	—	5,593,018	5.90
Ronald Harford	—	—	—	—

1 29,299,515 Existing Unconsolidated Ordinary Shares are held by Prelude Holdings Limited, a company owned by Finian O'Sullivan and members of his family and which is controlled by Finian O'Sullivan for the purposes of the Act. 1,576,483 Existing Unconsolidated Ordinary Shares are held jointly by Finian O'Sullivan and his spouse and 444,000 Existing Unconsolidated Ordinary Shares are held by The O'Sullivan Family Charitable Trust which Finian O'Sullivan and members of his family are trustees of.

2 3,041,667 Existing Unconsolidated Ordinary Shares are held by Latravia Limited and 34,971,696 Existing Unconsolidated Ordinary Shares are held by Lion Invest and Trade Limited, companies which are wholly owned and controlled by Andrey Pannikov.

3 66,085 Existing Unconsolidated Ordinary Shares are held by Jonathan Cooke's spouse.

4 The number of Consolidated Ordinary Shares immediately following Admission takes into account any Consideration Shares and Placing Shares these individuals may acquire pursuant to the Merger and the Placing, and any additional Consolidated Ordinary Shares they may acquire following the transfer to the Company of any Trinity Shares they might acquire following the exercise of any of their Trinity Options upon completion of the Merger.

Save as disclosed in this paragraph 6.1, none of the Directors or Proposed Directors has any interest, beneficial or non-beneficial, in the share or loan capital of the Company or any of its subsidiaries.

6.2 Details of the Options and LTIP Awards granted to Directors are set out in paragraph 4 of this Part XII.

6.3 The Directors and Proposed Directors hold, and have during the five years preceding the date of this document held, the following directorships or partnerships (other than the Company):

Name	Current directorships/partnerships	Previous directorships/partnerships
Hywel John	Bayfield Energy (Alpha) Limited Bayfield Energy (St. Lucia) Limited Bayfield Energy (Services) Limited BEL Bayfield Energy New Ventures Limited Bayfield South Africa	Burren Energy (Egypt) Limited Burren Energy India Limited Burren Energy (Services) Limited
Finian O'Sullivan	Home Farm Hursley Limited Bayfield Energy (Services) Limited Bayfield Energy (Alpha) Limited Prelude Holdings Limited	Burren Energy (Services) Limited Burren Energy PLC Burren Energy (Egypt) Limited Burren Energy India Limited Eni Yemen Limited Burren Energy Drilling Services Limited Burren Energy (652A) Limited Burren Energy New Ventures Limited BEL
Andrey Pannikov	Lion Invest & Trade Limited Zounini Limited	Burren Energy PLC

Name	Current directorships/partnerships	Previous directorships/partnerships
	Latravia Limited AGOC Sunfloat Shipping Limited Urals Administration Limited	
Jonathan Cooke		
David MacFarlane	Atlantic Petroleum P/F Energy Assets Group plc Kentz Corporation Limited	Dana Petroleum (E&P) Limited Dana Petroleum plc Dana Petroleum (Algeria) Limited Dana Petroleum (North Sea) Limited Dana Petroleum (Russia) Limited Croft (UK) Limited Croft Exploration Limited Croft Offshore Oil Limited Croft Oil & Gas plc Dana Petroleum (BVUK) Limited Dana Petroleum Limited Dana Petroleum (Cyprus) Limited Dana Petroleum (Jersey) Limited Dana Petroleum (Ghana) Limited Dana Petroleum Norway AS Dana Petroleum North Zeit Bay Ltd. Dana Petroleum East Zeit Ltd. Dana Petroleum Ras Abu Darag Ltd. Dana Petroleum WAG, Ltd. Dana Petroleum East Beni Suef, Ltd. Dana Petroleum Qarun Ltd. Dana Petroleum South October, Ltd. Dana Petroleum North Qarun, Ltd. Bow Valley Energy, Ltd. Bow Valley Iran Ltd. Bow Valley International (Jersey) Ltd. Dana Petroleum (Holdings) B.V. Dana Petroleum Manzala B.V. Dana Petroleum Netherlands B.V. Closed Joint Stock Company YoganOil Open Joint Stock Company Yogan-neft Nio Petroleum Limited
Bruce Dingwall	Trinity Exploration & Production Limited Trinity Exploration and Production (Barbados) Limited Ten Degrees North Operating Company Limited Trinity Exploration and Production Services Limited Tabaquite Exploration and Production Company Limited Lennox Petroleum Services Limited Pioneer Petroleum Company Limited Antilles Resources Limited NAKT Company Limited Dingwall Energy Advisors Limited Millsilver Limited The Fettes Foundation East Newton Farming Limited	Ten Degrees North Energy 2011 Limited Ten Degrees North Energy Limited Centrica Production Limited Centrica Production Trustees Limited Centrica North Sea Gas Limited Centrica North Sea Oil Limited Tullibardine Limited PGS EM Limited Venture Production (Britain) Limited Vesta Petroleum Investments Limited MTem Limited
Joel Pemberton	Trinity Exploration & Production Limited Trinity Exploration and Production (Barbados) Limited Trinity Exploration and Production (Trinidad and Tobago) Limited Oilbelt Services Limited	Ten Degrees North Energy Limited 2011 Ten Degrees North Energy Limited

Name	Current directorships/partnerships	Previous directorships/partnerships
	Ten Degrees North Operating Company Limited Trinity Exploration and Production Services Limited Tabaquite Exploration and Production Company Limited Lennox Petroleum Services Limited Pioneer Petroleum Company Limited Antilles Resources Limited NAKT Company Limited	
Jon Murphy	Trinity Exploration & Production Limited New Town Energy Investments Limited Hurricane Exploration PLC	Ten Degrees North Energy Limited Centrica Production Limited Centrica North Sea Gas Limited Centrica North Sea Oil Limited Centrica Production Trustees Limited The United Kingdom Offshore Oil and Gas Industry Association Limited NSIP (GKA) Limited Centrica Production (DMF) Limited Centrica Production (GMA) Limited CH4 Energy Limited CH4 OLD Limited Centrica Production (Services) Limited The UKOOA 1990 Pension Scheme Trustee Company Limited Centrica Infrastructure Limited Centrica Upstream Investment Limited Centrica North Sea Gas Exploration Limited Centrica F3 Developments Limited Venture Production Holdings Limited Advantage Employment Limited
Anthony Brash	Trinity Exploration & Production Limited Trinity Exploration and Production (Trinidad and Tobago) Limited Oilbelt Services Limited Well Services Holdings Limited Well Services Petroleum Company Limited Rigtech Services Limited Oil Mop Environmental Services Limited Industrial Transport Limited Lease Operators Limited Caribbean Welding Supplies Limited Paria Suites Hotel Limited Well Serve Limited Rancho Quemado Estates Limited Oil Mop Environmental Services N.V. (SXM) La Riviera Limited Blanket Security Limited Sweet Water Marina Limited Ridac (2007) Limited Trinity Maritime Crewing Limited Trinity Liftboat Services Limited Trinity Service and Repair Limited Trinity Equipment Leasing Company Limited Trinity Infrastructure Company Limited Trinity Industries Limited	Oilbelt Holdings Limited

Name	Current directorships/partnerships	Previous directorships/partnerships
	Trinity Offshore Supply & Towing Limited	
Ronald Harford	Republic Bank Limited Republic Bank Trinidad & Tobago (Barbados) Limited Republic Bank (Barbados) Limited Republic Bank Finance & Trust Corporation Republic Bank (Grenada) Limited Mario's Pizzeria Ltd. Bertrich Limited UWI Development & Endowment Foundation Arthur Lok Jack Graduate School Caricris Saber Investments Co. Ltd. Arturon Limited Santa Fe Inc. Dorstenia Co. Ltd.	Grenada Industrial Development Corporation BNB Mortgage Finance Co Ltd

6.4 None of the Directors or Proposed Directors has:

(a) any unspent convictions relating to indictable offences (including fraudulent offences);

(b) any bankruptcies or entered into any individual voluntary arrangements with his creditors;

(c) save as set out in paragraph 6.9 of this Part XII of this document, been a director of any company at the time of, or within the 12 months preceding, any receivership or liquidation (including compulsory liquidation, creditors' voluntary liquidation), administration, company voluntary arrangement or any composition or arrangement with creditors generally or any class of creditors of such company;

(d) been a partner of any partnership at the time of, or within the 12 months preceding, any compulsory liquidation, administration or partnership voluntary arrangement of such partnership;

(e) had any of their assets made the subject of any receivership or have been a partner of a partnership at the time of or within the 12 months preceding any assets thereof being the subject of a receivership;

(f) received any official public incrimination and/or sanction by any statutory or regulatory authorities (including recognised professional bodies) or have been disqualified by a court from acting as a director of a company or from acting in the management or conduct of the affairs of a company.

6.5 Save as disclosed in this paragraph 6.5 or paragraph 6.1 of this Part XII as at 23 January 2013 (being the latest practicable date prior to the publication of this document), none of the Directors or Proposed Directors are aware of any interest which represents three per cent. or more of the issued share capital of the Company as at the date of this document or on Admission or of any persons who, directly or indirectly, jointly or severally, exercise or could exercise control over the Company:

	As at the date of this document		On Admission	
Shareholder	Number of Existing Unconsolidated Ordinary Shares	Percentage of existing issued share capital	Number of Consolidated Ordinary Shares	Percentage of Enlarged Share Capital
Alta Limited	9,758,366	4.51	975,836	1.03
Brian Thurley	24,780,037	11.45	2,478,003	2.61
BlackRock Investment Management	20,594,128	9.51	2,059,412	2.17
Regent Pacific Group Limited	—	—	3,539,555	3.73

6.6 None of the major shareholders of the Company set out above has different voting rights from any other holder of Existing Unconsolidated Ordinary Shares in respect of any Existing Unconsolidated Ordinary Share held by them.

6.7 None of the Directors or Proposed Directors or any person connected with them (within the meaning of section 252 of the Act) is interested in any related financial product referenced to the Existing Unconsolidated Ordinary Shares (being a financial product whose value is, in whole or in part, determined directly or indirectly by reference to the price of the Existing Unconsolidated Ordinary Shares including a contract for difference or a fixed odds bet).

6.8 Excluding professional advisers otherwise named in this document and trade suppliers, no person has at any time within the 12 months preceding the date of this document received, directly or indirectly, from the Company or entered into any contractual arrangement to receive, directly or indirectly, from the Company on or after Admission any fees totalling £10,000 or more or securities in the Company with a value of £10,000 or more or any other benefit with a value of £10,000 or more.

6.9 Until 29 February 2012, Finian O'Sullivan, Hywel John and Andrey Pannikov were directors of AGOC, which is currently in the process of being liquidated.

7. Directors' and Proposed Directors' Service Agreements and Letters of Appointment

7.1 *Directors*

Details of titles and dates of appointment of the Directors are set out below:

Name	Title/function	Date of appointment
Hywel John	Chief Executive Officer	21 February 2011
Finian O'Sullivan	Executive Chairman	21 February 2011
Andrey Pannikov	Non-Executive Director	21 February 2011
Jonathan Cooke	Non-Executive Director	8 July 2011
David MacFarlane	Non-Executive Director	8 July 2011

(a) Hywel John has entered into a service contract with the Company dated 11 July 2011. The agreement is terminable on not less than 12 months' notice given by either party. Under the terms of the agreement, Mr John is entitled to an annual salary of £200,000 which is subject to review. In addition, he is entitled to a discretionary bonus, participation in applicable share schemes including the LTIP, and in any pension scheme operated by the Company. He is also entitled to 30 days' annual leave (plus public holidays) and, in the event of sickness absence, payment of full salary for up to 90 working days in any 12 month period. The agreement contains provisions entitling the Company to pay the executive Director in lieu of his notice period on termination to the value of his basic salary at the time of termination. The agreement also contains: (i) six month post termination restrictive covenants against competing with the Company or relevant Group companies; and (ii) 12 month post termination restrictive covenants against soliciting key employees.

(b) The non-executive Directors and the Executive Chairman have entered into appointment letters with the Company dated 11 July 2011. Under the terms of these letters, the non-executive Directors and the Executive Chairman are entitled to an annual fee as set out below. The appointments are terminable by either party on one month's notice or in certain circumstances including misconduct or bankruptcy, with immediate effect. All non-executive Directors and the Executive Chairman are covered by the Company's directors' and officers' liability insurance and are entitled to be reimbursed for reasonable expenses incurred in carrying out their duties.

Name	Annual Fee (less deductions required by law)
Finian O'Sullivan	£100,000
Andrey Pannikov	£0
Jonathan Cooke	£40,000 plus £5,000 in respect of chairmanship of the remuneration committee
David MacFarlane	£40,000 plus £10,000 in respect of chairmanship of the audit committee

(c) Andrey Pannikov and Jonathan Cooke have signed letters of resignation dated 25 January 2013 under which their respective appointments as directors of the Company will terminate effective on Completion. Jonathan Cooke will be paid £3,750 in lieu of one month's notice.

(d) Hywel John has entered into a compromise agreement with the Company dated 25 January 2013 pursuant to which his employment with the Company and appointment to the Board will terminate effective on Completion. Under the agreement Mr John will receive a payment of £200,000 (less tax and NI) in lieu of notice together with £50,000 as compensation for loss of office.

(e) Finian O'Sullivan has entered into an appointment letter dated 25 January 2013 to replace his existing appointment letter effective on Completion pursuant to which he is entitled to an annual fee of £40,000. The appointment is terminable by either party on three months' notice or in certain circumstances including misconduct or bankruptcy, with immediate effect.

(f) David MacFarlane has entered into an appointment letter dated 25 January 2013 to replace his existing appointment letter effective on Completion pursuant to which he is entitled to an annual fee of £40,000 plus £10,000 in respect of chairmanship of the audit committee. The appointment is terminable by either party on three months' notice or in certain circumstances including misconduct or bankruptcy, with immediate effect.

(g) In the period ended 31 December 2011 the total aggregate remuneration paid and benefits-in kind granted to the Directors was £306,614. The amounts payable to the Directors by the Company under the arrangements in force at the date of this document and on Admission in respect of the period ending 31 December 2012 are estimated to be £395,000 (excluding any discretionary payments which may be made under these arrangements).

7.2 *Proposed Directors*

Details of titles and dates of appointment of the Proposed Directors are set out below:

Name	Title/function	Date of appointment
Bruce Dingwall	*Executive Chairman*	On Completion
Joel Montgomery Pemberton	*Executive Director*	On Completion
Jon Murphy	*Non-Executive Director*	On Completion
Anthony Brash	*Non-Executive Director*	On Completion
Ronald Harford	*Non-Executive Director*	On Completion

(a) Bruce Dingwall has entered into a service contract with the Company dated 25 January 2013 under which he is appointed Executive Chairman of the Company, such appointment effective on Completion. The agreement is terminable on not less than six months' notice given by either party. Under the terms of the agreement, Mr Dingwall is entitled to an annual salary of US$300,000 which is subject to annual review. In addition, he is entitled to participation in applicable share schemes. Mr Dingwall is required to work a minimum of 80 hours per month. He is also entitled to 112 hours annual leave and, in the event of sickness absence, payment of full salary for up to three months, and half pay for the next three months, in any 12 month period. The agreement contains provisions entitling the Company to pay the executive Director in lieu of his notice period on termination to the value of his basic salary at the time of termination. The agreement also contains: (i) six month post termination restrictive covenants against competing with the Company or relevant Group companies; and (ii) six month post termination restrictive covenants against soliciting key employees, customers, prospective customers and suppliers.

(b) Monty Pemberton has entered into a service contract with the Company dated 25 January 2013 under which he is appointed Chief Executive Officer of the Company, such appointment effective on Completion. The agreement is terminable on not less than 12 months' notice given by either party. Under the terms of the agreement, Mr Pemberton is entitled to an annual salary of US$350,000 which is subject to annual review. In addition, he is entitled to a discretionary bonus, participation in applicable share schemes including the LTIP, and in any pension scheme, permanent health insurance scheme, life assurance scheme and private medical insurance scheme operated by the Company. He is also entitled to

35 days' annual leave and, in the event of sickness absence, payment of full salary for up to three months, and half pay for the next three months, in any 12 month period. The agreement contains provisions entitling the Company to pay the executive Director in lieu of his notice period on termination to the value of his basic salary at the time of termination. The agreement also contains: (i) nine month post termination restrictive covenants against competing with the Company or relevant Group companies; and (ii) 12 month post termination restrictive covenants against soliciting key employees, customers, prospective customers and suppliers.

(c) Jon Murphy, Anthony Brash and Ronald Harford have entered into appointment letters with the Company dated 25 January 2013 under which they are each appointed as Non-Executive Directors of the Company, such appointment effective on Completion. Under the terms of these letters, Mr Murphy is entitled to an annual fee of £40,000 plus £5,000 in respect of chairmanship of the remuneration committee, Mr Brash is entitled to an annual fee of £40,000 and Mr Harford is entitled to an annual fee of £40,000. The appointments are terminable by either party on three months' notice or in certain circumstances including misconduct or bankruptcy, with immediate effect.

(d) All Proposed Directors will be covered by the Company's directors' and officers' liability insurance from the date of their appointment and are entitled to be reimbursed for reasonable expenses incurred in carrying out their duties.

7.3 *Other service contracts*

Save as disclosed in paragraph 7.1 and 7.2 above, there are no existing or proposed service contracts between Directors or Proposed Directors and the Company nor have any such service contracts been entered into or amended within six months of the date of this document.

8. **Summary of the Bayfield Long Term Incentive Plan**

8.1 *Eligibility*

Any employee (including a director) of the Company or any member of the Bayfield Group who is required to devote substantially the whole of his working time to his employment or office shall be eligible to participate in the Plan. The Board may in its absolute discretion grant awards to such eligible employees as it shall select and will take into account the extent to which an eligible employee may be able to contribute to the performance of the Company over the vesting period.

8.2 *Awards under the Plan*

An award may be granted over Existing Unconsolidated Ordinary Shares in the company in the form a conditional award of a specified number of Existing Unconsolidated Ordinary Shares or an option to acquire a specified number of Existing Unconsolidated Ordinary Shares at an exercise price determined by the Board.

Participants may be granted any combination of awards, whether in a single grant or pursuant to a series of grants.

No payment is required for the grant of an award.

No award may be granted later than ten years after the date on which the Plan is adopted by the Board nor at any time at which a dealing would not be permitted under the Company's share dealing code.

Subject to the limit set out in paragraph 8.5 below, awards may be satisfied by the issue of new Existing Unconsolidated Ordinary Shares or by the transfer of Existing Unconsolidated Ordinary Shares, either from treasury or otherwise.

8.3 *Conditions on vesting or exercise*

An award may be granted subject to such performance condition or conditions as the Board in its discretion sees fit (the "**Performance Condition(s)**") which must be satisfied before an award may be exercised or vest. Performance will be measured over a period determined by the Board (the "**Performance Period**"). The intention of the Board is for the Performance Period to be a period of three years. There will be no provision for re-testing.

If an event occurs which causes the Board to determine that the Performance Condition(s) have ceased to be appropriate, it may in its discretion vary or waive those condition(s) provided that any new condition(s) imposed (or any variation) are in its opinion fair, reasonable and no more difficult to satisfy than the previous condition(s).

The initial Performance Condition applying to awards granted under the LTIP is based on growth in the Company's total shareholder return ("**TSR**") over the Performance Period being in the case of the initial awards 3 years from the date of grant, as detailed below:

Growth in Company's TSR over the Performance Period	Per cent. of Award which shall vest
Less than 5 per cent. per annum	0 per cent
5 per cent. per annum	25 per cent
10 per cent. per annum	50 per cent
15 per cent. per annum	75 per cent
20 per cent. per annum	100 per cent

8.4 *Individual Limit*

No award shall be granted to any individual if the aggregate market value of the Existing Unconsolidated Ordinary Shares subject to that award together with the aggregate market value of any Existing Unconsolidated Ordinary Shares committed to be issued or transferred pursuant to any other award made to him after the Company's shares are admitted to trading on AIM during the previous 12 months under the Plan would exceed a sum equal to his earnings.

8.5 *Overall Dilution Limit*

No award may be granted under the Plan on any date if, as a result, the aggregate number of Existing Unconsolidated Ordinary Shares issued or transferred from treasury, or committed to be issued or transferred from treasury, pursuant to awards made after the Company's shares are admitted to trading on AIM under the Plan and pursuant to grants or appropriations made after the Existing Unconsolidated Ordinary Shares became so admitted during the previous ten years under all other employee share schemes established by the Company would exceed ten per cent. of the issued ordinary share capital of the Company on that date.

8.6 *Exercise of Awards*

In normal circumstances, a conditional award may not vest nor an option become exercisable unless the Performance Condition(s) have been satisfied at the end of the Performance Period and provided the participant remains employed by the Bayfield Group. Having become exercisable, an Option may be exercised for a period determined by the Board but ending no later than the day preceding the tenth anniversary of its grant.

If a participant ceases to be employed within the Bayfield Group before the expiry of the Performance Period by reason of:

(a) death;

(b) injury, ill-health or disability;

(c) redundancy;

(d) retirement;

(e) the company employing the participant ceasing to be, or the business to which the participant's office or employment relates being transferred to a person who is not, a member of the Bayfield Group; or

(f) any other reason (apart from dishonesty, fraud, misconduct or any other circumstances justifying summary dismissal) and the Board in its discretion permits exercise or vesting,

a conditional award will vest and an option will become exercisable and remain exercisable for a period of six months (or 12 months in the case of death). The number of Existing Unconsolidated Ordinary Shares which vest or over which Options are exercisable will, in these circumstances, be determined by reference to the extent to which the Performance Condition(s) have been satisfied over the shortened Performance Period and shall be subject to a pro rata reduction to reflect the position of the Performance Period which has elapsed, unless the Board in its discretion shall determine that time apportionment shall not apply.

If a participant ceases to be employed within the Bayfield Group for one of the reasons set out above on or after the expiry of the Performance Period, a subsisting Option may be exercised for a period of six months (or 12 months in the case of death) to the extent that the Performance Condition(s) have been satisfied.

An award will, in any event, lapse on the tenth anniversary of its date of grant, if not previously vested or exercised.

8.7 *Takeover, scheme of arrangement and liquidation*

In the event of a takeover or scheme of arrangement or the voluntary winding-up of the Company occurring before the expiry of the Performance Period, a conditional award will vest and an option will become exercisable and remain exercisable for a period of six months or until the expiry of any compulsory acquisition period, if earlier. The number of Existing Unconsolidated Ordinary Shares which vest or over which options are exercisable will, in these circumstances, be determined by reference to the extent to which the Performance Condition(s) have been satisfied over the reduced Performance Period.

If such an event takes place on or after the expiry of the Performance Period, a subsisting option may be exercised for a period of six months to the extent that the Performance Condition(s) have been fulfilled.

If such an event occurs, an award may also be released in exchange for an equivalent new award to be granted by any acquiring company, if the participant so wishes and the acquiring company agrees.

Where any such event occurs as part of an internal reorganisation of the Company, subsisting awards will be exchanged for new awards granted by the acquiring company unless such an offer is not forthcoming from the acquiring company in which case vesting or exercise as set out above will be permitted.

8.8 *Variation of Share Capital*

In the event of any variation in the ordinary share capital of the Company (such as the proposed Share Consolidation), such adjustments to the number of Existing Unconsolidated Ordinary Shares subject to awards and the price at which they may be acquired may be made by the Board as it may determine to be appropriate.

8.9 *Voting, Dividend and Other Rights*

Until awards are exercised or vest, participants have no voting or other rights in respect of the Existing Unconsolidated Ordinary Shares subject to those awards.

Existing Unconsolidated Ordinary Shares issued or transferred pursuant to the Plan will rank pari passu in all respects with Existing Unconsolidated Ordinary Shares already in issue except that they will not rank for any dividend or other distribution paid or made by reference to a record date falling prior to the date of exercise or vesting of the relevant award.

Benefits obtained under the Plan shall not be pensionable. Awards are not assignable or transferable.

8.10 *Administration and Amendment*

The operation of the Plan will be administered under the direction of the Board which may amend the Plan by resolution provided that no amendment may be made which would alter to the disadvantage of participants any rights already acquired by them under the Plan without the prior approval of a majority of the affected participants.

8.11 *Overseas Plans*

The Board may from time to time and without further formality establish further plans in overseas territories, any such plan to be similar to the Plan but modified to take account of local tax, exchange control or securities laws, regulation or practice. Existing Unconsolidated Ordinary Shares made available under any such plan would count against any limits on overall or individual participation in the Plan save that only newly issued Existing Unconsolidated Ordinary Shares or Existing Unconsolidated Ordinary Shares transferred from treasury would count against the overall dilution limits.

8.12 *Termination*

The Plan may be terminated at any time by resolution of the Board or of the Company in general meeting and in any event no awards may be granted on or after the tenth anniversary of the date on which the Plan is approved by the Company in general meeting. Termination will not affect the outstanding rights of participants.

9. **Working Capital**

In the opinion of the Directors and the Proposed Directors, having made due and careful enquiry, and taking into account the proceeds of the Placing and the Enlarged Group's loan facilities, the working capital available to the Enlarged Group will be sufficient for its present requirements that is for at least the next 12 months from the date of Admission.

10. **United Kingdom Taxation**

10.1 *General*

The following comments are intended only as a general guide to the position under current United Kingdom tax law and what is understood to be the current practice (both of which are subject to change at any time, possibly with retrospective effect) of HM Revenue & Customs and may not apply to certain classes of investors, such as dealers in securities, insurance companies, collective investment schemes and persons who acquired securities in connection with their employment. Any person who is in doubt as to his tax position is strongly recommended to consult his own professional tax adviser.

10.2 *Share Consolidation*

For the purposes of UK taxation on chargeable gains it is expected that the Share Consolidation should be regarded as a reorganisation of the Company's share capital for the purposes of UK tax on chargeable gains. Accordingly, a Shareholder will not generally be treated as making a disposal of all or part of his or her holding of Existing Unconsolidated Ordinary Shares by reason of the Share Consolidation being implemented. Consolidated Ordinary shares which replace a Shareholder's holding of Existing Unconsolidated Ordinary Shares as a result of the Share Consolidation will, for the purpose of UK tax on chargeable gains, be treated as the same asset as, and having been acquired at the same time as, the Shareholder's Existing Unconsolidated Ordinary Shares.

10.3 *Receipt of Consolidated Ordinary Shares*

A UK resident or, in the case of an individual, ordinarily resident holder of shares in Trinity who does not hold (either alone or together with other persons connected with him) more than 5 per cent. of, or of any class of, shares in or debentures of Trinity should not be treated as having made a disposal or part disposal of his shares in Trinity for the purposes of UK taxation of chargeable gains as a result of the Merger. Instead, any chargeable gain or allowable loss which would otherwise have arisen on a disposal of such holder's shares in Trinity should be "rolled over" into the Consolidated Ordinary Shares which he acquires. As a result, those Consolidated Ordinary Shares should be treated as the same asset and as having been acquired at the same time and for the same consideration as the shares in Trinity from which they derived.

A UK resident or, in the case of an individual, ordinarily resident holder of shares in Trinity who holds as at Completion (either alone or together with other persons connected with him) more than 5 per cent. of, or of any class of, shares in or debentures of Trinity should qualify for the "roll over" treatment described above provided the Merger is effected for bona fide commercial reasons and does not form part of a scheme or arrangement of which the main purpose, or one of the main purposes, is avoidance of a liability to capital gains tax or corporation tax. If these conditions are not met, then such a person will be treated, on receiving Consolidated Ordinary Shares in exchange for his shares in Trinity, as having made a disposal of those shares in Trinity which may, depending on individual circumstances and subject to any available exemption or relief, give rise to a chargeable gain or allowable loss for the purposes of UK taxation of chargeable gains.

10.4 *Taxation of Dividends*

(a) *The Company*

The Company will not be required to withhold tax at source on any dividends it pays to its shareholders in respect of the Consolidated Ordinary Shares.

(b) *UK resident shareholders*

Individuals resident in the UK for taxation purposes are generally liable to UK income tax on the aggregate amount of any dividend received and a non-repayable tax credit equal to 10 per cent. of the gross dividend (or one-ninth of the dividend received). For example, on a dividend received of £90, the tax credit would be £10, and an individual would be liable to income tax on £100.

No further income tax is payable in respect of the dividend by a UK resident individual to the extent such individual is not liable to income tax at the higher rate (currently 40 per cent) or the additional rate (currently 50 per cent). UK resident individuals who are subject to tax at the basic rate only will be charged to tax on the gross dividend at the dividend ordinary rate of 10 per cent. and therefore the tax liability will be treated as satisfied in full by the tax credit and no additional tax liability will arise for such shareholders.

UK resident individuals who are subject to tax at the higher rate are subject to tax on dividends at the dividend upper rate (currently 32.5 per cent) but are entitled to offset the 10 per cent. tax credit against such liability, resulting in an effective tax rate of 25 per cent. of the net dividend received. For example, on a dividend received of £90 such a taxpayer would have to pay additional tax of £22.50 (representing 32.5 per cent. of the gross dividend less the 10 per cent. tax credit). UK resident individuals who are subject to tax at the additional rate are subject to tax on dividends at the dividend additional rate (currently 42.5 per cent) but are entitled to offset the 10 per cent. tax credit against such liability, resulting in an effective tax rate of 36.11 per cent. of the net dividend received. For example, on a dividend received of £90 such a taxpayer would have to pay additional tax of £32.50 (representing 42.5 per cent. of the gross dividend less the 10 per cent. tax credit). For this purpose, dividends are treated as the top slice of an individual's income.

The United Kingdom Chancellor of the Exchequer announced in the Budget on 21 March 2012 that the additional rate of income tax (currently 50 per cent) will fall to 45 per cent. from 6 April 2013 and the dividend additional rate (currently 42.5 per cent) will also fall to 37.5 per cent. from 6 April 2013, which will reduce the effective rate of tax on dividends for UK resident individuals subject to tax at the dividend additional rate to 30.55 per cent. from the current effective tax rate of 36.11 per cent.

No repayment of the tax credit in respect of dividends paid by the Company (including in respect of any dividend paid where the Consolidated Ordinary Shares are held in a personal equity plan or in an individual savings account) can be claimed by a United Kingdom resident shareholder (including pension funds and charities).

Provided that certain anti-avoidance provisions do not apply, and subject to certain exceptions for traders in securities and insurance companies, a corporate shareholder resident in the United Kingdom for tax purposes will generally not be subject to corporation tax on dividends received from the Company in respect of the Consolidated Ordinary Shares. Shareholders within the charge to UK corporation tax are advised to consult their independent professional tax advisers in relation to the implication of the legislation.

(c) *Non UK resident shareholders*

Non-UK resident shareholders are not generally entitled to claim any part of the tax credit and any ability to do so will depend on the terms of any applicable double tax treaty between the Company and the country in which the shareholder is resident. Non-UK resident shareholders may also be subject to tax on dividend income under any law to which they are subject outside the UK. Such shareholders should consult their own tax advisers concerning their tax liabilities.

10.5 *Taxation of Capital Chargeable Gains*

(a) *UK Resident Shareholders*

A disposal of the Consolidated Ordinary Shares by a shareholder who is (at any time in the relevant United Kingdom tax year) resident or, in the case of an individual, ordinarily resident in the United Kingdom for tax purposes, may give rise to a chargeable gain or an allowable loss for the purposes of United Kingdom taxation of chargeable gains, depending on the shareholder's circumstances and subject to any available exemption or relief.

(b) *Non-resident Shareholders*

A shareholder who is not resident in the United Kingdom for tax purposes but who carries on a trade, profession or vocation in the United Kingdom through a branch or agency (or, in the case of a non-UK resident corporate shareholder, a permanent establishment) to which the Consolidated Ordinary Shares are attributable will be subject to the same rules which apply to United Kingdom resident shareholders.

A shareholder who is an individual and who after acquiring his Consolidated Ordinary Shares, ceases to be resident or ordinarily resident for tax purposes in the United Kingdom for a period of less than five complete years of assessment and who disposes of the Consolidated Ordinary Shares during that period may also be liable, on his return, to United Kingdom taxation of chargeable gains (subject to any available exemption or relief).

10.6 *Stamp Duty and Stamp Duty Reserve Tax*

The statements below summarise the current position and are intended as a general guide only to stamp duty and SDRT. Special rules apply to agreements made by brokers, dealers and market makers in the ordinary course of their business and to certain categories of person (such as depositories and clearance services) who may be liable to stamp duty or SDRT at a higher rate.

No stamp duty or SDRT will generally be payable on the issue or on the registration of the Consolidated Ordinary Shares to be issued pursuant to the Placing and Admission.

A transfer for value of the Consolidated Ordinary Shares will generally be subject to stamp duty or SDRT. Stamp duty will arise on the execution of an instrument to transfer Consolidated Ordinary Shares and SDRT will arise on the entry into an agreement to sell the Consolidated Ordinary Shares.

Stamp duty and SDRT are normally a liability of the purchaser or transferee (although where such purchase is effected through a stockbroker or other financial intermediary, that person should normally account for the liability to SDRT and should indicate this has been done in any contract note issued to a buyer).

The amount of stamp duty or SDRT payable on the transfer is generally calculated at the rate of 0.5 per cent. of the amount or value of the consideration paid (with stamp duty rounded up to the nearest £5). No stamp duty is chargeable on an instrument transferring Consolidated Ordinary Shares where the amount or value of the consideration is £1,000 or less, and it is certified on the instrument that the transaction effected by the instrument does not form part of a larger transaction or series of transactions for which the aggregate consideration exceeds £1,000. A liability to SDRT will be cancelled and any SDRT already paid will be repaid, generally with interest, where an instrument of transfer is executed and stamp duty is paid on that instrument within six years of the date on which the liability to SDRT arises.

Paperless transfers of the Consolidated Ordinary Shares within the CREST system are generally liable to SDRT, rather than stamp duty, at the rate of 0.5 per cent. of the amount or value of the consideration payable. SDRT on relevant transactions is generally settled within the CREST system. Deposits of shares into CREST will generally not be subject to SDRT, unless the transfer into CREST is itself for consideration.

Following the decision in HSBC Holdings Plc and the Bank of New York Mellon Corporation v HMRC (2012) UKFTT163 (TC) and HSBC Holdings plc and Vidacos Nominees Ltd v Commissioners for HMRC (C569/07), issues of shares to persons who issue depositary receipts or to clearance services located anywhere in the world should not be subject to a 1.5 per cent. charge to

SDRT under section 93 of the Finance Act 1986. HMRC have confirmed that they will not seek to impose SDRT on issues of UK shares and securities to such entities anywhere in the world.

11. Material Contracts

11.1 *Bayfield*

The following contracts (not being contracts entered into in the ordinary course of business) have been entered into by members of the Bayfield Group (a) in the two years immediately preceding the date of this document and are, or may be, material or (b) contain provisions under which any member of the Bayfield Group has any obligation or entitlement which is material to the Bayfield Group as at the date of this document:

(a) *Sceptre Agreement*

On 11 September 2008 Bayfield Galeota entered into the Sceptre Agreement with Sceptre, a company controlled by Darcy Carr, pursuant to which Sceptre was appointed as an adviser in connection with the farm-in of the Galeota Block. The term of the Sceptre Agreement is expressed to be the later of (i) eight years from the date of the Sceptre Agreement or (ii) full payment of the consulting fee due under the Sceptre Agreement.

Sceptre's consulting fee (the "**Consulting Fee**") is dependent upon the Galeota Block exceeding certain levels of oil production, calculated with reference to the average number of bbl/d produced over any consecutive 90 day period. The fees payable are as follows:

bbl/d (column 1)	Fee Payable (US$) (column 2)
2,000	500,000
4,000	1,500,000
8,000	3,500,000

The Consulting Fee is expressed to become due and payable when the total gross daily oil production from the Galeota Block when averaged over any 90 consecutive day period exceeds the production targets set out in column 1 above. Accordingly, the maximum payment that could be required to be made under the Sceptre Agreement is US$5.5 million.

The Sceptre Agreement was entered into at a time when Darcy Carr was also a director and employee of BEL and Bayfield Galeota and, so far as the Company is aware, no services have ever been provided by Sceptre pursuant to the Sceptre Agreement.

Bayfield Galeota is disputing the validity of the Sceptre Agreement and therefore the obligation to pay any part of the Consulting Fee. Further information can be found in paragraph 12.1 of this Part XII and the possible risks to the Group in connection with the Sceptre Agreement can be found in Part IV of this document.

(b) *Drilling Contract*

On 1 April 2011, Bayfield Galeota entered into the Drilling Contract with Rowan Drilling (Trinidad) Limited ("**Rowan**") and Niko for the provision of the jack-up "Rowan Gorilla III" drilling unit and related services as amended pursuant to an amendment agreement dated 22 July 2011 ("**Amendment No.1**") and pursuant to an amendment agreement dated on or around 24 October 2012 ("**Amendment No. 2**") (the "**Drilling Contract**"). The term of the contract extends up to the period required to complete the drilling of eight firm wells for Niko and Bayfield and one well for SOOGL.

The day rates applicable to well spudding during the first 790 days of the contract term are as follows: the operating day rates ("**ODR**") for the first 425 days of the contract term (following completion of the one well for SOOGL) and once the drilling unit has arrived in the delivery location in Trinidad (the "**Initial Rate Period**") are US$120,000 and the following 365 days after this Initial Rate Period are charged at ODR of US$130,000. The ODR applicable to wells spud in the 365 days following 9 January 2014 are US$155,000; the repair day rate, stand-by/waiting on weather day rate, and force majeure day rate are each calculated at 80 per cent. of the ODR for each applicable rate period; the moving rate is calculated at 70 per cent. of the ODR for each applicable rate period; and the lump sum fixed mobilisation/demobilisation charges are each US$3.5 million. Each of the lump sum mobilisation and demobilisation fees will be split so that Niko will pay US$1.375 million and Bayfield Galeota will pay US$2.125 million. The operating rate applicable to well spudding following the expiry of the second year will be mutually agreed between the parties.

Payments due under the contract will be payable notwithstanding any breach of representation or warranty, or the negligence or fault of Rowan, including sole, concurrent or gross negligence, latent defects, unseaworthiness of any vessel (including the drilling rig), and any other liability at law. Bayfield Galeota/Niko will not be entitled to bring an action against Rowan for recovery or reimbursement of amounts under the contract as damages. Niko and Bayfield Galeota are jointly and severally liable for each others' obligations, regardless of which entity has operational control over the drilling unit.

The contract cannot be terminated by Rowan except for non-payment by Bayfield Galeota/ Niko on 30 days' written notice, provided that if payment is made within this 30 day notice period, the notice shall be deemed to have been withdrawn. If notice for non payment has been given and payment has not been received within the 30 day notice period, Rowan will be entitled to an early termination fee which is calculated according to the operating day rate and the number of days left in the term of the contract, depending on the particular well. If the drilling unit becomes a total loss, the contract will terminate and Rowan will have no obligation to provide or pay for a substitute and will have no further obligations to Bayfield Galeota/Niko.

Bayfield Galeota/Niko will assume the entire risk and be solely responsible for loss, destruction or damage to its equipment or its contractors' equipment or materials. The risk and responsibility for loss of or damage to the wells will be borne entirely by Bayfield Galeota/Niko, provided that if such loss or damage is caused by Rowan's wilful misconduct, at the request of Bayfield Galeota/Niko and as its exclusive remedy, Rowan will either: (1) re-drill the same or an equivalent well or hole to the same depth as the lost well/hole; or (2) repair the damaged well or hole to its original state. During such drilling or repair operations, Bayfield Galeota/Niko will pay Rowan the standby day rate. Bayfield Galeota/ Niko will be responsible for bearing the entire cost of killing or controlling a blowout well, and will indemnify Rowan from such costs. If Rowan and/or its subcontractors have caused the loss or damage due to its wilful misconduct, Rowan will be liable to bear the costs up to a limit of US$2 million and Bayfield Galeota/Niko will be responsible for the costs in excess of this figure.

Rowan will be responsible for, and will indemnify Bayfield Galeota/Niko from all claims relating to pollution or contamination which originates above the surface of the water, wholly in the possession and control of Rowan or its subcontractors, and directly associated with the operation of the drilling unit. Bayfield Galeota/Niko's responsibility and indemnity is for pollution or contamination which may result from fire, blowout, cratering, seepage or other uncontrolled flow of oil, gas or water from any reservoir or well. However, where the blowout or loss of control of a well is due to Rowan or its subcontractors' wilful misconduct, Rowan will reimburse Bayfield Galeota/Niko the first US$1 million of costs and Bayfield Galeota/Niko will be responsible for the costs in excess of this figure.

Parent company guarantees were provided by Niko Resources Limited and BEL in favour of Rowan, dated 4 April 2011 and 1 April 2011 respectively, guaranteeing the performance of Niko and Bayfield Galeota's obligations under the contract.

(c) *Drilling Contract Novation Agreement*

On 26 May 2011 Bayfield Galeota entered into a novation agreement with Rowan, Niko and AMSI in respect of the Drilling Contract pursuant to which AMSI replaces Rowan under the Drilling Contract and assumes the rights and liabilities of Rowan under the Drilling Contract.

(d) *Drilling Contract Assignment Agreement*

On 19 August 2011 Bayfield Galeota entered into an assignment agreement with Niko, AMSI and SOOGL pursuant to which Bayfield Galeota and Niko agree to assign their liabilities and obligations under the Drilling Contract to SOOGL for a minimum of 62 days for the drilling of one well in the East Brighton Block Offshore, Trinidad and Tobago and SOOGL agrees to re-assign to Bayfield Galeota and Niko once the well has been drilled and the drilling rig returned to an agreed drilling location.

The assignment includes the payment by SOOGL of the US$3.5 million lump sum mobilisation fee in accordance with the Drilling Contract and ODR of US$130,000 and SOOGL agrees to pay all costs associated with the drilling rig during the period of assignment.

In the event that operations at SOOGL's well continue past 62 days, SOOGL continues to assume 100 per cent. of all costs associated with the drilling rig until the operations are completed and will be liable to Bayfield Galeota and Niko for penalties contained in the terms of an memorandum of agreement dated 29 March 2001 as amended on 8 July 2011.

(e) *Drilling Contract Partial Assignment Novation and Assumption Agreement and Agreement for Rig Sharing of the "Rowan Gorilla III".*

On or around 24 October 2012 Bayfield Galeota and Niko and EOG Resources Trinidad—U(a) Block Limited ("**EOG**") entered into an agreement for rig sharing of the "Rowan Gorilla III" drilling unit in order to coordinate their respective efforts in drilling and completing wells in their respective offshore areas in Trinidad (the "**Rig Sharing Agreement**"). Pursuant to the Rig Sharing Agreement, Bayfield Galeota and Niko agree to share and release the drilling rig to EOG and EOG agrees to return the drilling rig to either Bayfield Galeota or Niko upon termination.

Contemporaneous to the execution of the Rig sharing Agreement, Niko, Bayfield Galeota and EOG entered into a Partial Assignment, Novation and Assumption Agreement providing for the partial transfer of the Drilling Contract from Bayfield Galeota and Niko to EOG (the "**EOG Assignment**") in order for the balance of the three wells remaining to be drilled in the primary term of the Drilling Contract to be undertaken by EOG. Under the EOG Assignment, Niko and Bayfield Galeota are obliged to assign the drilling rig to EOG at any time during a window between 1 November 2012 and 1 February 2013. If such an assignment does not take place then the EOG Assignment will not take effect.

Once control and custody of the drilling rig is passed to EOG, Bayfield Galeota and Niko are released from any and all obligations and liabilities that they have to the drilling contractor under the Drilling Contract until the custody of the drilling rig is passed back to Bayfield Galeota and Niko or to the drilling contractor under the Drilling Contract.

A drilling rig inspection was carried out in October 2012 by EOG and subsequent to this Bayfield Galeota and Niko are obligated to deliver the drilling unit in substantially the same condition that it was in at the time of the inspection (normal wear and tear excepted). Redelivery of the drilling rig will be subject to a similar inspection by Bayfield Galeota and Niko and EOG are obligated to redeliver the drilling rig in substantially the same condition it was in at the time of its delivery to EOG (normal wear and tear excepted). Bayfield Galeota and Niko will take back control of the drilling rig once: (i) EOG has completed its drilling program; (ii) EOG has offloaded its equipment for the drilling rig; and (iii) the drilling rig is free and afloat under tight tow from EOG's well location, together defined as the "**EOG Release Event**".

Once the EOG Release Event has taken place, EOG's right, title and interest under the Rig Sharing Agreement and the Drilling Contract terminates. EOG are responsible for an early termination fee should they fail to drill the required three wells as set out in the EOG Assignment.

EOG will replace Bayfield Galeota and Niko in all respects under the Drilling Contract during the term of the Rig Sharing Agreement and will assume all rights, duties and obligations and liabilities and indemnities of Bayfield Galeota and Niko arising from the Drilling Contract. EOG will indemnify and hold harmless Bayfield Galeota and Niko from all claims and causes of action arising out of the Drilling Contract and the EOG Assignment during this period. Bayfield Galeota and Niko provide a similar indemnity for all claims and causes of action prior to or post (as the case may be) the term of the Rig Sharing Agreement provided that EOG remain liable for obligations incurred during the period of the EOG Assignment.

EOG will be responsible for all costs relating to the use of the drilling rig (including those demobilisation costs up to a cap of US$3.5 million but not the mobilisation costs under the Drilling Contract) during the term of the Rig Sharing Agreement with Bayfield Galeota and Niko responsible for any other costs incurred after the EOG Release Event.

(f) *Amended and Restated Shared Services Agreement*

On 1 April 2011 Bayfield Galeota entered into an amended and restated shared services agreement with Niko (the "**SSA**"), the purpose of which is to replace a memorandum of agreement between the parties and set out mutual obligations and liabilities in relation to the Drilling Contract and various drilling services contracts that the two parties propose to enter into. The SSA provides that in relation to the mutual obligations of the parties, in the event of a conflict between the SSA and the Drilling Contract, the SSA will prevail.

Niko and Bayfield Galeota have agreed that while their liability under any other drilling services contract will be several (and not joint), their liability under the Drilling Contract will be joint and several.

Niko and Bayfield Galeota have agreed on a fixed number of firm and optional wells that each party will be entitled and obliged to use under the Drilling Contract and the sequence of drilling. Bayfield Galeota is entitled to five firm and two optional wells, in the order specified in the SSA. Each party is entitled to use the drilling rig for an agreed period of the drilling contract (185 days for Bayfield Galeota) and is obliged to bear an agreed proportion of the mobilisation and demobilisation fee (Bayfield Galeota's share is US$4.3 million).

Neither party is entitled to assign the Drilling Contract to a third party without the prior written consent of the other.

Niko and Bayfield Galeota have each agreed to indemnify and hold the other harmless against (i) liability that might arise from the performance of its Rowan drilling program or operations; (ii) its failure to perform obligations under the Drilling Contract, the drilling services contracts and the SSA; (iii) personal injury, illness or death to members of its group; (iv) environmental loss arising from performance of the drilling programme; and (v) all third party claims.

In relation to the liability assumed and the indemnities granted under the SSA, both Niko and Bayfield Galeota are obliged to maintain the following insurance:

(i) physical loss or physical damage insurance—minimum limit of US$6 million;

(ii) control of wells risk insurance—minimum limit of US$50 million;

(iii) general third party liability insurance—minimum limit of US$100 million; and

(iv) charterers legal liability—minimum limit of US$25 million.

The parties are required under the Drilling Contract to pay a termination fee in the event of early termination for convenience or without cause. Under the SSA, where both parties wish to terminate the drilling contract, each party is required to pay its proportion of the termination fee based on the number of unused days allocated to it under the drilling schedule and its proportion of the mobilisation and demobilisation fee. If only one party wishes to terminate the Drilling Contract, it is required to pay to the other party (and not directly to the drilling contractor) its proportion of the termination fee and the mobilisation and demobilisation fee. Where the other party is able to renegotiate the drilling schedule with Rowan or otherwise able to use the rig options and therefore avoid payment of the termination fee to Rowan, the cancelling party will receive a reimbursement of 80 per cent. of the termination fee. The mobilisation and demobilisation fee will not be reimbursed unless the drilling rig is used by another operator.

(g) *Crude Oil Sales Agreement*

On 1 May 2009 Bayfield Galeota entered into a crude sales agreement with Petrotrin, regarding the sale of crude oil by Bayfield Galeota to Petrotrin.

Petrotrin agreed to enter into the agreement to ensure that Bayfield Galeota has access to a market for crude oil over the life of the Galeota Licence, by agreeing to purchase at least 50 per cent. of Bayfield Galeota's share of the crude oil produced from the Galeota Block.

Bayfield Galeota is not obliged to sell more than 50 per cent. of the crude oil produced from the Galeota Block, however, if it does so Petrotrin is obliged to purchase the full quantity delivered. Bayfield Galeota's determination as to the quantity and quality of the crude oil is conclusive and binding on the parties (following certain applicable standards). The quality will be examined quarterly to determine whether the parties need to review the terms of the agreement to reflect any material changes. Petrotrin accepts that the delivery of the crude oil may be made on an irregular basis.

The agreement will continue until it is terminated: (1) by the agreement of both parties; (2) in the event that Bayfield Galeota sells less than 50 per cent. of its total proportionate share of crude oil for a continuous period of 60 calendar days; (3) in the event that the Galeota Licence terminates; (4) if a material breach is not remedied within 10 business days of notice (after the parties have attempted to resolve the matter through good faith consultation); (5) in the event that either party suffers an insolvency event; (6) in the event of a breach of the Galeota FOA or Galeota JOA which results in the termination of either such agreement; or (7) on 30 working days' written notice if a force majeure event causes the agreement to be suspended for more than three months and the parties are unable to reach an agreement on an appropriate course of action.

The price per barrel to be paid is based on a formula based on the settlement prices per barrel of "NYMEX Light Sweet Crude Oil" futures contracts less an adjustment factor (17.5 per cent. as at the date of the Crude Oil Sales Agreement), and a transportation cost of US$1 per gross barrel delivered. Such pricing terms have now been amended pursuant to the amendment agreement described at paragraph 11.1(i) below of this Part XII. Amounts due will be invoiced monthly and due 20 days following receipt (but not due earlier than the 25th day of the calendar month following the month in respect of which the crude oil was delivered). Interest at the three month LIBOR rate on the due date plus 2 per cent. will be payable on invoices unpaid after the date due.

If Petrotrin fails to pay any amount due under the payment provisions of the agreement within five business days after receipt of written notice from Bayfield Galeota, Bayfield Galeota may suspend deliveries of crude oil until the default is cured and is entitled to sell its crude oil to third parties during such suspension.

If Bayfield Galeota sells part of its share of production of the crude oil to a third party, then it must notify Petrotrin at least one month in advance with certain details of the sale, including the consequent projected deliveries. Bayfield Galeota must also notify Petrotrin of any material change to the monthly volume supplied resulting out of the work programme being completed.

(h) *Amendment Agreement to Crude Oil Sales Agreement*

On 20 September 2012 (effective from 1 August 2012) Bayfield entered into an amendment agreement with Petrotrin in respect of the Crude Oil Sales Agreement (the "**COSA Amendment Agreement**") pursuant to which Bayfield and Petrotrin have agreed to vary the pricing terms for Bayfield's crude oil under the Crude Oil Sales Agreement. The price per barrel to be paid is now based on a formula based on the settlement prices per barrel of "Brent Crude Oil" futures contracts less an adjustment factor of 9.5 per cent. (for a minimum period of 12 months) and a transportation cost of US$1 per gross barrel delivered.

(i) *2011 Placing Agreement*

On 11 July 2011 the Company entered into a placing agreement (the "**2011 Placing Agreement**") with the Directors and Seymour Pierce pursuant to which Seymour Pierce agreed, subject to certain conditions, to act as agent for the Company and to use its reasonable endeavours to procure placees to subscribe for Existing Unconsolidated Ordinary Shares pursuant to the 2011 Placing at 60p per Existing Unconsolidated Ordinary Share.

The 2011 Placing Agreement contains warranties from the Company and the Directors in favour of Seymour Pierce in relation to, inter alia, the accuracy of the information in the admission document in respect of the IPO and other matters relating to the Bayfield Group and its business. In addition, the Company agreed to indemnify Seymour Pierce in respect of certain liabilities they may incur in respect of the 2011 Placing.

Under the 2011 Placing Agreement the Company agreed to pay Seymour Pierce (i) a corporate finance fee of £200,000 and (ii) a commission of 3.5 per cent on the value at the placing price of the placing shares (being 60p per placing share). Additionally, the Company agreed to pay all of Seymour Pierce's costs and expenses (including any applicable VAT) of the 2011 Placing.

Under the 2011 Placing Agreement, the Directors (and their Associates) (the "**2011 Placing Locked-in Persons**") undertook to the Company and Seymour Pierce in respect of an aggregate of 103,111,088 Existing Unconsolidated Ordinary Shares, representing 48.1 per cent of the share capital immediately following IPO Admission (subject to certain limited exceptions including transfers to related parties or to trustees for their benefit, disposals by way of acceptance of a takeover offer for the entire issued share capital of the Company, disposals pursuant to a court order and, if applicable, the death of the 2011 Placing Locked-in Person) not to dispose of such Existing Unconsolidated Ordinary Shares following IPO Admission or any other securities in exchange for or convertible into, or substantially similar to, Existing Unconsolidated Ordinary Shares (or any interest in them or in respect of them) at any time prior to the first anniversary of IPO Admission. In addition, the 2011 Placing Locked-in Persons agreed for a further period of 12 months not to dispose of any interest in Existing Unconsolidated Ordinary Shares other than through Seymour Pierce.

On Admission, the restrictions on the 2011 Placing Locked-in Persons will be superseded in respect of Finian O'Sullivan and Andrey Pannikov (and their Associates) who will be subject to the terms of new lock-in agreements as described in paragraph 11.1(n) of this paragraph 11.1 of this Part XII below. Jonathan Cooke will remain bound by his obligation in the 2011 Placing Agreement not to dispose of any interest in Existing Unconsolidated Ordinary Shares other than through Seymour Pierce or such broker of the Company from time to time until 12 months following the first anniversary of the IPO Admission.

(j) *2011 Lock-in and Orderly Marketing Agreements*

On 11 July 2011 the Company and Seymour Pierce entered into lock-in and orderly market agreements with certain Shareholders, (the "2011 Locked-in Shareholders") pursuant to which each of them have undertaken to the Company and Seymour Pierce in respect of an aggregate of 103,111,088 Existing Unconsolidated Ordinary Shares representing 48.1 per cent of the share capital of the Company as at IPO Admission (subject to certain limited exceptions including transfers to related parties or to trustees for their benefit, disposals by way of acceptance of a takeover offer for the entire issued share capital of the Company, disposals pursuant to a court order and, if applicable, the death of the Locked-in Shareholder) not to dispose of such Existing Unconsolidated Ordinary Shares following IPO Admission or any other securities in exchange for or convertible into, or substantially similar to, Existing Unconsolidated Ordinary Shares (or any interest in them or in respect of them) at any time prior to the first anniversary of IPO Admission and at any time prior to the second anniversary of IPO Admission other than through Seymour Pierce or such broker of the Company from time to time.

On Admission, the restrictions on the 2011 Placing Locked-in Persons will be superseded in respect of Brian Thurley and Alta Limited (and their Associates) who will be subject to the terms of new lock-in agreements as described in paragraph 11.1(n) of this paragraph 11.1 of this Part XII below.

(k) *Nominated Adviser and Broker Agreement with Seymour Pierce*

On 11 July 2011 the Company entered into a nominated adviser and broker agreement with Seymour Pierce pursuant to which the Company appointed Seymour Pierce to act as nominated adviser and broker to the Company for the purposes of the AIM Rules for

Companies. The Company has agreed to pay Seymour Pierce a fee of £50,000 plus VAT per annum for its services as nominated adviser and broker.

The agreement contains undertakings from the Company to Seymour Pierce regarding, inter alia, compliance with the AIM Rules for Companies. Bayfield has given notice to Seymour Pierce pursuant to the agreement to terminate the agreement with effect from Admission. Following Admission, RBC will be appointed as nominated adviser to the Company. Details of the nominated adviser agreement with RBC are set out at paragraph 11.1(o) of this Part XII of this document.

(l) *Placing Agreement*

On 25 January 2013 the Company entered into the Placing Agreement with Finian O'Sullivan, David MacFarlane, the Proposed Directors, Trinity, Seymour Pierce and the Placing Agents pursuant to which the Placing Agents have agreed, subject to certain conditions, to use their reasonable endeavours to procure placees to subscribe for 45,199,000 of the Placing Shares at the Placing Price and to underwrite the payment obligations of those placees procured in connection with the Placing Agreement.

The Placing Agreement is conditional upon, inter alia (a) the Merger Agreements becoming unconditional in all respects (save for Admission) and having been completed in escrow and (b) Admission occurring on or before 8.00 a.m. on 14 February 2013 (or such later date as the Company, Seymour Pierce and the Joint Bookrunners may agree, being not later than 8.30 a.m. on 28 February 2013).

The Placing Agreement contains warranties (i) from the Company, Finian O'Sullivan and the Proposed Directors (other than Ronald Harford, who has given warranties in relation to the information regarding himself in this document) in favour of Seymour Pierce and the Placing Agents in relation to the accuracy of the information in this document, (ii) from the Company and Finian O'Sullivan in relation to matters regarding the Bayfield Group and its business, and (iii) from the Company and the Proposed Directors (other than Ronald Harford) in relation to matters regarding the Trinity Group and its business.

In addition, the Company has agreed to indemnify Seymour Pierce and the Placing Agents in respect of certain liabilities they may incur in respect of the Placing. Seymour Pierce and the Joint Bookrunners have the right to terminate the Placing Agreement in certain circumstances prior to Admission, in particular, in the event of a breach of the warranties and on the occurrence of certain force majeure events.

Under the Placing Agreement and subject to it becoming unconditional and not being terminated in accordance with its terms, the Company has agreed to pay:

(i) Seymour Pierce a corporate finance fee of £300,000;

(ii) RBC a corporate finance fee of £250,000;

(iii) (a) each of the Placing Agents a commission, to be allocated in the Placing Proportion, of (i) 2 per cent. of the aggregate value at the Placing Price of the Placing Shares placed with placees who are either based in Trinidad and Tobago (and have not been independently sourced by the Placing Agents) or current shareholders of Trinity ("**Trinity Placees**") and (ii) 4.5 per cent. of the aggregate value at the Placing Price of the Placing Shares placed with placees who are not Trinity Placees; and

(iv) at its sole discretion, an additional commission of up to 0.5 per cent. of the aggregate value at the Placing Price of the Placing Shares in such proportion between the Placing Agents as the Company may decide.

Additionally, the Company has agreed to pay all of Seymour Pierce's and the Placing Agents' costs and expenses (including any applicable VAT) of the Placing.

(m) *Lock-in Agreements and Orderly Marketing Agreements*

On 25 January 2013 the Company and the Joint Bookrunners entered into lock-in and orderly market agreements with each of the Trinity Locked-In Shareholders (other than David Segel) pursuant to which each of them have undertaken to the Company and the Joint

Bookrunners in respect of an aggregate of 16,797,078 Consolidated Ordinary Shares representing 17.72 per cent. of the Enlarged Share Capital (subject to certain limited exceptions including transfers to related parties or to trustees for their benefit, disposals by way of acceptance of a takeover offer for the entire issued share capital of the Company, disposals pursuant to a court order and, if applicable, the death of the Trinity Locked-In Shareholders (other than David Segel) not to dispose of such Consolidated Ordinary Shares following Admission or any other securities in exchange for or convertible into, or substantially similar to, the Consolidated Ordinary Shares (or any interest in them or in respect of them) at any time prior to the first anniversary of Admission. The Trinity Locked-In Shareholders (other than David Segel) have agreed for a further six months not to dispose of any interest in Consolidated Ordinary Shares other than through either of the Joint Bookrunners to ensure an orderly market in the Consolidated Ordinary Shares.

In addition, Finian O'Sullivan, Andrey Pannikov and Alta Limited (the "**Locked-in Bayfield Shareholders**") who, on Admission, will be interested, in aggregate, in 8,453,338 Consolidated Ordinary Shares representing approximately 8.92 per cent. of the Enlarged Share Capital have given undertakings to the Company and the Joint Bookrunners (subject to certain limited exceptions including transfer to related parties or to trustees for their benefit, disposals by way of acceptance of a takeover offer for the entire issued share capital of the Company, disposals pursuant to a court order and, if applicable, the death of the shareholder) not to dispose of such Consolidated Ordinary Shares following Admission or any other securities in exchange for or convertible into, or substantially similar to, the Consolidated Ordinary Shares (or any interest in them or in respect of them) at any time prior to six months following Admission. The Locked-in Bayfield Shareholders have agreed for a further six months not to dispose of any interest in Consolidated Ordinary Shares other than through either of the Joint Bookrunners to ensure an orderly market in the Consolidated Ordinary Shares.

Brian Thurley and David Segel who, on Admission, will be directly or indirectly interested, in aggregate, in 5,755,741 Consolidated Ordinary Shares representing approximately 6.07 per cent. of the Enlarged Share Capital have given undertakings to the Company and the Joint Bookrunners (subject to certain limited exceptions including transfer to related parties or to trustees for their benefit, disposals by way of acceptance of a takeover offer for the entire issued share capital of the Company, disposals pursuant to a court order and, if applicable, the death of the shareholder) not to dispose of, in aggregate, 4,029,019 Consolidated Ordinary Shares following Admission or any other securities in exchange for or convertible into, or substantially similar to, the Consolidated Ordinary Shares (or any interest in them or in respect of them) at any time prior to six months following Admission, after which they have agreed not to dispose of such Consolidated Ordinary Shares for a further period of six months other than through either of the Joint Bookrunners to ensure an orderly market in the Consolidated Ordinary Shares. In addition, Brian Thurley and David Segel have agreed for a period of 12 months following Admission not to dispose of any interest, in aggregate, in 1,726,722 Consolidated Ordinary Shares other than through either of the Joint Bookrunners to ensure an orderly market in the Consolidated Ordinary Shares.

(n) *Nominated Adviser and Broker Agreement with RBC*

On 25 January 2013 the Company entered into a nominated adviser and broker agreement with RBC pursuant to which the Company appointed RBC to act as nominated adviser and joint broker to the Company for the purposes of the AIM Rules for Companies with effect from Admission. The Company has agreed to pay RBC a fee of £75,000 plus VAT per annum, from the first anniversary of the date of Admission, for its services as nominated adviser and joint broker. The agreement contains undertakings from the Company to RBC regarding, inter alia, compliance with the AIM Rules for Companies.

(o) *Bayfield Undertakings*

On 12 October 2012 the Company, Trinity and certain Trinity Shareholders (the "**Addressees**") received irrevocable undertakings from Andrey Pannikov, Brian Thurley, Jonathan Cooke, Finian O'Sullivan and Alta Limited (which were subsequently amended on 19 December 2012, 19 December 2012, 5 December 2012 and 5 December 2012, respectively) to vote in favour of the Resolution in respect of a total of 109,415,867 Existing Unconsolidated Ordinary Shares representing in total 50.54 per cent. of the Existing Unconsolidated Ordinary Shares (the "**Irrevocable Undertakings**").

The Irrevocable Undertakings shall terminate automatically if: (i) the Merger Agreements are terminated; (ii) the Merger Agreements fail to become unconditional; or (iii) the General Meeting has not occurred on or before 3.00 p.m. on 31 March 2013 (or such later time and/or date as the Addressees may agree in writing).

(p) *Merger Agreements*

On 12 October 2012 the Company entered into the Main Merger Agreement with the Trinity Management Shareholders and a minority merger agreement with certain other Trinity Shareholders (the "**Initial Minority Merger Agreement**"). Between 21 November 2012 and 27 December 2012 the Company entered into a number of further minority merger agreements with those Trinity Shareholders who had not been a party to either the Main Merger Agreement or the Initial Minority Merger Agreement (the "**Secondary Minority Merger Agreements**" and, together with the Initial Minority Merger Agreement, the "**Minority Merger Agreements**").

On 19 December 2012 the Company entered into deeds of amendment and side letters to the Merger Agreements with certain Trinity Shareholders (the "**Merger Amendments**") pursuant to which the parties thereto:

(i) recognised the proposed Share Consolidation and agreed to the amendments necessary to the Main Merger Agreement and the Initial Minority Merger Agreements as a result;

(ii) agreed to waive their pre-emption rights for any new Trinity Shares to be issued by way of the exercise of Options currently in issue; and

(iii) agreed to extend the "Posting Date" and "Long Stop Date" (each as defined in the Main Merger Agreement and the Minority Merger Agreements) by two months,

and thereby consented to the necessary amendments to the Main Merger Agreement and the Minority Merger Agreements.

Pursuant to the Merger Agreements (as amended by the Merger Amendments), the Company has conditionally agreed to acquire the whole of the issued share capital of Trinity for a consideration of approximately 747.8 new Consolidated Ordinary Shares for each Trinity Share held, which will result in the issue by Bayfield of 25,652,041 new Consolidated Ordinary Shares in aggregate. Subject to completion of the Merger Agreements, Trinity Shareholders will own approximately 55 per cent. of Bayfield and Bayfield Shareholders will own approximately 45 per cent. of Bayfield on a fully diluted basis but before the issue of the Placing Shares (and on the basis Centrica will not convert its Centrica Loan Notes).

Both Petrotrin and the Trinidad Minister of Energy have given their respective consents to the Merger. The Merger Agreements are conditional upon, inter alia, the following further matters:

(i) Bayfield Shareholder approval of the Resolutions to be proposed at the General Meeting;

(ii) Bayfield acquiring not less than 90 per cent. of the Trinity Shares;

(iii) the Placing Agreement becoming unconditional (save for Admission and any condition relating to the Merger Agreements becoming unconditional), and not having been terminated in accordance with its terms; and

(iv) Admission.

If the conditions of the Merger Agreements have not been satisfied or waived by 6 p.m. on the date of the General Meeting, the Trinity Management Shareholders or the Company may terminate the Main Merger Agreement or postpone completion under the Merger Agreements. If the Main Merger Agreement is terminated, each other Merger Agreement shall automatically terminate.

Under the Main Merger Agreement, the Trinity Management Shareholders have agreed to procure that the Trinity Group observes and Bayfield has agreed to procure that the Bayfield Group observes certain restrictive covenants during the period between signing of the Main Merger Agreement and Completion.

Under the relevant Merger Agreement each Seller has given warranties in relation to title to their Trinity Shares and their capacity to enter into the relevant Merger Agreement and perform his/its obligations thereunder. The liability of each Seller in respect of such warranties is not limited.

The Main Merger Agreement also contains business and other warranties given by Bayfield to the Trinity Management Shareholders and by the Trinity Management Shareholders to Bayfield respectively. The aggregate liability of the Trinity Management Shareholders and the Company under such warranties is £250,000.

Under the Main Merger Agreement the Company and the Trinity Management Shareholders have certain termination rights in respect of, inter alia, a breach by the Company or the Trinity Management Shareholders (as the case may be) of the warranties given under the agreement or its/his obligations under the agreement or the occurrence of a material adverse change. Under the Minority Merger Agreements the Company has certain termination rights in respect of a breach by a Seller of the warranties given under those agreements. If the Main Merger Agreement is terminated in accordance with its terms, each other Merger Agreement shall automatically terminate.

(q) *Loan Agreement between the Company and Trinity (T&T)*

On 27 December 2012 Bayfield Galeota and Galeota Oilfield Services Limited ("**GOS**") as borrowers, Trinity T&T as lender and RBC Trust (Trinidad & Tobago) Limited as collateral agent entered into a bilateral term loan agreement (the "Trinity Loan Agreement").

The Trinity Loan Agreement for a principal amount of US$10 million for the purpose of meeting the Bayfield Group's working capital requirements and the repayment of certain of the Bayfield Group's existing debts. The maturity date of the Trinity Loan Agreement is 30 September 2013.

Under the Trinity Loan Agreement one drawdown is permitted and the principal amount together with all accrued interest is payable by a single bullet payment on the maturity date. Interest is charged at the rate of 10 per cent. per annum, to accrue from day to day and computed on the basis of a 360 day year with twelve 30 day months. Customary covenants, representations, warranties and events of default apply.

As security for the payment of all sums owed by, and for the discharge of all obligations and liabilities of, the borrowers under the Trinity Loan Agreement, the following security deeds have been entered into:

- first priority debentures granted by each of Bayfield Galeota and GOS in favour of RBC Trust (Trinidad & Tobago) Limited (acting on behalf of the lender) containing fixed and floating charges over all the assets of each of the borrowers; and
- share charges granted by Bayfield Energy (St. Lucia) Limited in favour of RBC Trust (Trinidad & Tobago) Limited (acting on behalf of the lender) over the shares of each of Bayfield Galeota and GOS.

The Trinity Loan has been drawn down and the Company has used these funds to repay certain of the Bayfield Group's existing debts.

11.2 *Trinity*

The following contracts (not being contracts entered into in the ordinary course of business) have been entered into by members of the Trinity Group (a) in the two years immediately preceding the date of this document and are, or may be, material or (b) contain provisions under which any member of the Trinity Group has any obligation or entitlement which is material to the Trinity Group as at the date of this document:

(a) *Amalgamations*

TDN and Oilbelt Services entered into a business combination agreement dated 22 August 2011 to set out the terms and conditions upon which the parties were to merge to facilitate joint ownership and management (the "**Business Combination Agreement**"). TDN, Well Services, Charles Anthony Brash Jnr., David Bernard Brash and Daniel Cuthbert Brash also entered into an amalgamation agreement dated 22 August 2011 (the "**Oilbelt Amalgamation Agreement**") to record the terms of the post-closing adjustments to be made in favour of the shareholders of Oilbelt Holdings (being Well Services, Anthony Brash Jnr., David Bernard Brash and Daniel Cuthbert Brash) and to provide for the enforceability of the terms and conditions of the Business Combination Agreement by the shareholders of Oilbelt Holdings.

Pursuant to the Business Combination Agreement and the Oilbelt Amalgamation Agreement, TDN (at that time, the ultimate parent company of the Trinity Group) and Oilbelt Holdings amalgamated to form TDN 2011 on 1 November 2011 ("**Amalgamation 1**"). The entire issued share capital of TDN 2011 was then, immediately following Amalgamation 1, held by the old shareholders of TDN and Oilbelt Holdings, and TDN and Oilbelt Holdings ceased to exist in their own right. Oilbelt Services was a subsidiary of Old Oilbelt, and therefore Amalgamation 1 effected the acquisition of the business and assets of Oilbelt including Oilbelt Services.

TDN 2011, Old Trinity T&T and Trinity entered into an amalgamation agreement dated 2 November 2011 (the "**TDN 2011 Amalgamation Agreement**") to record the terms upon which TDN 2011 and Old Trinity T&T would amalgamate. Pursuant to the terms of the TDN 2011 Amalgamation Agreement TDN 2011 (as was formed by Amalgamation 1) and Old Trinity T&T amalgamated to form Trinity T&T on 18 November 2011 (effectively retaining the same name as Old Trinity T&T) ("**Amalgamation 2**"). The entire issued share capital of Trinity T&T was then, immediately following Amalgamation 2 (and still remains to be) held by Trinity Barbados (the wholly owned direct subsidiary of Trinity), and TDN 2011 and Old Trinity T&T ceased to exist in their own right.

In consideration for the shareholders of Oilbelt Holdings and the shareholders of TDN surrendering their shares in Oilbelt Holdings and TDN respectively as part of Amalgamation 1, the Oilbelt Holdings shareholders acquired shares in TDN 2011. In consideration for the shareholders of TDN 2011 (being the old shareholders of Oilbelt Holdings and TDN) surrendering their shares in TDN 2011 as part of Amalgamation 2, the TDN 2011 shareholders acquired Trinity Shares. Following the Amalgamations, 7,479 Trinity Shares (equating to 25 per cent. of the issued share capital of Trinity at that time) were held by the old shareholders of Oilbelt Holdings and 22,384 Trinity Shares (equating to 75 per cent. of the issued share capital of Trinity at that time) were held by the old shareholders of TDN.

(b) *Blackout Agreement*

In order to proceed with the 2011 Reorganisation, the shareholders' agreement between the shareholders of TDN dated 16 December 2005 (as amended) (the "**TDN Shareholders' Agreement**") had to be terminated. This required, inter alia, the consent of Canboulay Energy Capital Limited ("**Canboulay**"), one of the shareholders in TDN at that time (who has since transferred its shareholding by way of a permitted transfer under the Trinity Articles to Lower Guardian Investment Holdings (B.V.I.) Ltd). In order to give Canboulay the necessary comfort it required to give its consent, Trinity, TDN and certain other shareholders of TDN entered into a blackout agreement with Canboulay in August 2011 (the "**Blackout Agreement**"). Following the execution of the Blackout Agreement, the TDN Shareholders' Agreement was duly terminated.

Under the terms of the Blackout Agreement, the parties agreed that, inter alia, none of the parties can transfer or assign (or similar) their Trinity Shares without Canboulay's consent, Canboulay can appoint an observer to attend and speak at board meetings of Trinity (for so long as Canboulay is a shareholder in Trinity), Trinity can not issue equity shares that would be senior to any of Canboulay's Trinity Shares (for so long as Canboulay is a shareholder in

Trinity), Canboulay can require Trinity to purchase at market value any Trinity Shares they hold after 2 years from the date of the Blackout Agreement if a listing has not occurred (and if no other shareholders of Trinity wish to purchase them), and the Trinity Articles cannot be altered until immediately prior to a listing unless with the consent of Canboulay. As Canboulay transferred its entire shareholding in Trinity to Lower Guardian Investment Holdings (B.V.I) Limited on 16 February 2012, some provisions of the Blackout Agreement are no longer enforceable, but the Blackout Agreement remains in force as at the date of this document. Under paragraph 5(a) of the Blackout Agreement the shareholders of Trinity that are a party to it are permitted to transfer their Trinity Shares pursuant to a bona fide third party take-over bid or similar acquisition transaction made to all shareholders on identical terms. On 15 January 2013 the parties to the Blackout Agreement signed a letter of termination to agree and acknowledge that the Blackout Agreement would terminate on Completion.

(c) *Centrica Loan Notes*

On 16 December 2005, TDN created unsecured convertible subordinated loan notes (the "**Original Loan Notes**") by virtue of a convertible loan note instrument (which was subsequently amended in or around January 2011) (the "**Original Loan Note Instrument**") and issued US$10,000,000 of those Original Loan Notes to Venture Production (the "**Original Venture Loan Notes**"). The Original Venture Loan Notes were subsequently transferred to Centrica by way of a deed of transfer dated 26 June 2007.

Pursuant to the terms of the Original Loan Note Instrument, the reorganisation undertaken by the Trinity Group in 2011 would have constituted a change in the Controlling Interest (as defined in the Original Loan Note Instrument) in TDN, and consequently Centrica would have been entitled to demand repayment of the remaining sums outstanding under the Original Venture Loan Notes issued to it.

In order to avoid such repayment mechanism being triggered, it was proposed that TDN's rights, interests, liabilities and obligations under the Original Loan Note Instrument and the Original Loan Notes be transferred and novated to Trinity by way of a deed of novation (the "**Deed of Novation**"), so that Trinity would become liable for the repayment to Centrica of the outstanding sums under Original Venture Loan Notes. It was agreed that Trinity would enter into a new restated and amended loan converted loan note instrument which would replace the Original Loan Note Instrument (the "**Restated and Amended Loan Note Instrument**") and issue unsecured convertible subordinated loan notes thereunder to Centrica in the same amount as the outstanding Original Venture Loan Notes in replacement of the Original Venture Loan Notes (the "**Centrica Loan Notes**").

TDN, Trinity and Centrica entered into a framework agreement on 27 September 2011 under which the parties agreed to give effect to the above arrangement (which was subsequently amended to take account of delays in the completion of the reorganisation by way of a side letter between TDN, Trinity and Centrica dated 10 November 2011) (the "**Framework Agreement**"). Under the Framework Agreement, inter alia:

(i) TDN and Trinity agreed to enter into the Deed of Novation upon completion of the reorganisation;

(ii) Trinity agreed to enter into the Restated and Amended Loan Note Instrument upon completion of the reorganisation;

(iii) Trinity agreed to issue the Centrica Loan Notes to Centrica upon completion of the reorganisation;

(iv) Trinity agreed to pay to Centrica the sum of US$2,500,000 in partial repayment of the Original Venture Loan Notes upon completion of the reorganisation;

(v) Centrica agreed not to exercise the repayment right under the Original Loan Note Instrument; and

(vi) Trinity and TDN gave Centrica certain representations, warranties and undertakings.

In accordance with the terms of the Framework Agreement, on 8 December 2011 TDN, Trinity and Centrica entered into the Deed of Novation and the Restated and the Amended Loan Note Instrument (which was subsequently amended to include transfer, assignation and novation provisions by way of the side letter between TDN, Trinity and Centrica dated 10 November 2011), and Trinity issued the Centrica Loan Notes to Centrica representing US$6,837,246 (being the same amount outstanding under the Original Venture Loan Notes less the US$2,500,000 redeemed as referenced below).

US$2,500,000 of Centrica Loan Notes were redeemed following the reorganisation in accordance with the terms of the Restated and Amended Loan Note Instrument (as amended).

US$500,000 of Centrica Loan Notes were redeemed on 31 December 2012, at which time interest of US$61,373.78 which had accrued on the Centrica Loan Notes up to 31 December 2012 was also paid.

Accordingly, as at the date of this document Centrica holds Centrica Loan Notes in the principal amount of US$6,337,246.58, which are convertible into Trinity Shares as more particularly described in the Restated and Amended Loan Note Instrument.

Completion will constitute:

(i) an Accelerated Repayment Event (as defined in the Restated and Amended Loan Note Instrument) and thereby entitle Centrica to require Trinity to repay the Centrica Loan Notes in full unless otherwise redeemed or converted; and

(ii) a Conversion Event (as defined in the Restated and Amended Loan Note Instrument) and thereby entitle Centrica to convert such number of Centrica Loan Notes as they might elect, subject to a minimum of US$1,000,000 and a maximum of US$5,000,000, and receive such number of Trinity Shares as is equivalent to 110 per cent. of the aggregate of the total nominal amount of the Centrica Loan Notes to be converted divided by the aggregate of the consideration per Trinity Share payable to the Trinity Shareholders as consideration pursuant to the terms of the Merger.

Assuming that Centrica does not elect to exercise its conversion rights, Trinity expects to fully repay the Centrica Loan Notes (in an amount equal to US$6,337,246.58 together with interest accrued from 1 January 2013) shortly after Completion.

In the event that Centrica were to exercise its conversion right it could have the consequences set out in the risk factor entitled "Centrica has a right to convert certain of the Centrica Loan Notes into Trinity Shares" set out in paragraph 1 of Part IV.

(d) *2011 Trinity Placing*

Trinity raised US$14,203,890.00, by way of a private placing (the "**2011 Trinity Placing**") to use for onshore drilling and well completions, construction of infrastructure, gathering of seismic data, debt repayment and general and administrative costs, with new and existing investors (the "**2011 Trinity Placees**") pursuant to subscription agreements entered into between September 2011 and November 2011 (the "**2011 Trinity Subscription Agreements**"). The 2011 Trinity Placees agreed to subscribe for an aggregate of 3,394 new Trinity Shares (the "**2011 Trinity Placing Shares**") at US$4,185.00 per Trinity Share (the "**2011 Trinity Placing Price**") and Trinity agreed to allot and issue those 2011 Trinity Placing Shares. 397 of the 2011 Trinity Placing Shares were allotted in exchange for cash funded from the proceeds of the redemption of existing promissory notes and the remaining 2,997 2011 Trinity Placing Shares were allotted for cash.

Pursuant to the 2011 Trinity Subscription Agreements Trinity gave certain limited warranties to the 2011 Trinity Placees and the 2011 Trinity Placees gave certain limited warranties, representations and covenants to Trinity, each of the type commonly found in such agreements.

The 2011 Trinity Placing Shares were allotted on 30 November 2011 in accordance with the terms of the 2011 Trinity Subscription Agreements.

(e) *Oriel Broker Engagement Letter*

Pursuant to an engagement letter between Oriel Securities Limited ("**Oriel**") and Trinity dated 8 July 2011, Oriel was appointed as broker to Trinity for the 2011 Trinity Placing to assist with introducing potential subscribers for the 2011 Trinity Placing Shares. In consideration for Oriel's services being received by Trinity, Trinity agreed to pay Oriel US$100,000 (at the sole discretion of Trinity), issue Trinity Shares to Oriel to the value of US$150,000 (based on the price per Trinity Share at which the 2011 Trinity Placing, such being US$4,185) and to grant an option to Oriel over Trinity Shares equivalent in value to 0.25 per cent. of the value of Trinity following the 2011 Trinity Placing by way of the issue of share warrants (to be exercisable at the share price at which those new funds were raised, such being US$4,185).

In November 2011 Trinity issued 120 Trinity Shares to Oriel pursuant to the above arrangements. The warrants were issued as set out in paragraph 11.2(f) below.

(f) *Trinity Warrant Instrument*

To formalise Oriel's contractual entitlement to the share warrants, Trinity executed a warrant instrument on 22 November 2012 (the "**Trinity Warrant Instrument**") and formally issued to Oriel 83 warrants to subscribe for Trinity Shares thereunder (the "**Trinity Warrants**") and issued a warrant certificate to Oriel in respect of those Trinity Warrants.

Under the terms of the Trinity Warrant Instrument Oriel can subscribe for 83 Trinity Shares by making payments in cash for all or such number of the Trinity Shares as it elects at a price of US$4,185 per Trinity Share between the date of the Trinity Warrant Instrument and the fifth anniversary of the date of the Trinity Warrant Instrument. If an offer is made to all of the ordinary shareholders of Trinity to acquire the whole or any part of the issued ordinary share capital of Trinity whereby as a result the right to cast a majority of votes at a general meeting of Trinity becomes vested in such offeror, Trinity shall procure (to the extent that it is able) that a like offer is made to Oriel as if the Trinity Warrants had been exercised and Trinity Shares so issued immediately prior to the record date for such an offer.

The Trinity Warrant Instrument also specifically provides for the situation where Bayfield enters into an agreement or agreements to acquire at least 90 per cent. of the issued share capital of Trinity at any time at which Trinity Warrants are in issue. These provisions are triggered by execution of the Merger Agreements and Admission.

Under the terms of the Trinity Warrant Instrument Trinity may elect at its sole discretion, with the consent of Bayfield, to novate, assign and transfer its rights, benefits and obligations to Bayfield. The effect would be that from Admission each Trinity Warrant would be deemed a warrant to subscribe for share capital in Bayfield on the same terms and conditions as under the Trinity Warrant Instrument as if Bayfield was Trinity. The Trinity Warrant Instrument allows for any adjustments required to the subscription rights to make them consistent with the terms on which Bayfield makes the Acquisition. As it is proposed that Bayfield issues 747.8 Consolidated Ordinary Shares to existing Trinity Shareholders in consideration for each Trinity Share it acquires from them, each new warrant to subscribe for shares in Bayfield due to Oriel would be deemed to be a warrant to subscribe for 747.8 Consolidated Ordinary Shares. Trinity would cease to be a party to the Trinity Warrant Instrument with Bayfield taking its place and Bayfield would assume the liabilities, perform the obligations and be entitled to the rights and benefits under the Trinity Warrant Instrument in place of Trinity as though all references in the Trinity Warrant Instrument to Trinity were to Bayfield.

Oriel has confirmed by way of letter to Trinity dated 22 November 2012 that it does not wish to exercise its Trinity Warrants. Accordingly, Trinity (with the consent of Bayfield) intends to exercise its discretion under the Trinity Warrant Instrument to enter into a deed of novation and assignment under which it will novate, assign and transfer its rights, benefits and obligations to Bayfield, effective upon Admission.

(g) *Loan Facility—Citibank (Trinidad and Tobago) Limited*

TDN and Citibank entered into a loan agreement with an effective date of 4 November 2011 (the "**2011 Citibank Loan Agreement**") setting out the terms and conditions pursuant to which Citibank as lender agreed to provide a loan of US$13,000,000 to TDN as borrower to finance its drilling program and to partially repay existing credit facilities (the "**2011 Citibank Loan**"). The term of the 2011 Citibank Loan Agreement was 3 years.

As security for the 2011 Citibank Loan debentures were granted over the fixed and floating assets of TDN, TDN Operating, Antilles Resources Limited, Ten Degrees North Services Limited, Lennox Production Services Limited, Nakt Company Limited, and Pioneer Petroleum Company Limited (the "**Trinity Security Subsidiaries**").

To effect these debentures deeds of debenture were entered into between Citibank and each of the Trinity Security Subsidiaries, each dated 4 November 2011, creating a first fixed and floating charge over the assets of each of the Trinity Security Subsidiaries in favour of Citibank. Furthermore, deeds of release of assignment were also entered into between Citibank and each of the Trinity Security Subsidiaries to release and reassign unto each of the Trinity Security Subsidiaries their respective right, title, benefit and interest it may have in and to the receivables under the contract.

On 6 December 2012 Trinity T&T entered into a new facility agreement with Citibank (the "**2012 Citibank Loan Agreement**") under which Citibank has agreed to provide a new loan facility of up to US$20,000,000 to Trinity T&T (the "**2012 Citibank Loan**").

The 2012 Citibank Loan replaces the 2011 Citibank Loan. Pursuant to the terms of the 2012 Citibank Loan Agreement the following terms and conditions apply to the 2012 Citibank Loan:

(i) the 2012 Citibank Loan is a floating rate medium term loan for US$20,000,000;

(ii) the 2012 Citibank Loan has a term of five years;

(iii) the purpose of the 2012 Citibank Loan is to refinance the Trinity Group's existing debt of approximately US$9,500,000 and to finance the recompletion of onshore and offshore wells;

(iv) the total facility amount was available for draw down at any time up until 31 December 2012 and Trinity T&T drew down the full amount on 27 December 2012;

(v) interest will be charged at a rate will be US LIBOR plus 600bps per annum, based on an actual/360 day basis and payable quarterly;

(vi) the principal amount under the 2012 Citibank loan will be repaid in 18 equal quarterly instalments, beginning three months after drawdown;

(vii) an arrangement fee of US$100,000 (or 0.5 per cent. of the notional facility amount) and a commitment fee of 0.5 per cent. per annum on the unused commitment applies;

(viii) the 2012 Citibank Loan is secured by debentures granted by Antilles Resources Limited, Lennox Production Services Limited, NAKT Company Limited, Oilbelt Services Limited and Trinity Exploration and Production Services Limited containing fixed and floating charges over all the assets of such companies; and

(ix) customary covenants, pledges, representations, warranties and events of default apply.

(h) *Promissory Note—David and Christina Segel Living Trust*

Trinity Exploration and Production (Trinidad and Tobago) Limited, a wholly owned indirect subsidiary of Trinity, issued a promissory note to the David and Christina Segel Living Trust on 8 March 2011 for a principal amount of US$2,000,000. This was then rolled over (together with interest) into a new promissory note issued by Trinity Exploration and Production (Trinidad and Tobago) Limited on 1 January for a principal sum of US$2,171,111.11. This promissory note was repaid and a new promissory note issued by

Oilbelt Services, another wholly owned subsidiary of Trinity, on 1 July 2012 for a principal sum of US$2,000,000. This promissory note was then subsequently repaid (together with interest due) and another new promissory note issued by Oilbelt Services to The David and Christina Segel Living Trust on 1 October 2012 for a principal sum of US$2,051,111.11 (reflecting the US$12,000,000 of principal plus interest accrued from 1 July 2012 to 30 September 2012) (the "**Segel Promissory Note**").

The Segel Promissory Note accrues interest at a rate of 10 per cent. per annum (on a 30/360 day basis) and matures on 30 September 2014. Events of default of a form usual for an arrangement of this nature apply. Should an event of default occur the whole of the principal sum under the Segel Promissory Note together with the interest thereon shall immediately become due and payable.

(i) *Settlement and Variation Agreement—Jim Lee Young*

On 14 April 2010 TDN and Dr. Jim Lee Young ("**Dr. Young**") entered into a settlement agreement (the "**Young Settlement Agreement**") whereby, inter alia, TDN agreed to repurchase 1,200 shares in TDN from Dr. Young for US$1,000 per share. This repurchase was duly effected in 2010. In addition to the US$1,000 per share, TDN agreed to pay, upon certain events (including any restructuring of TDN's share capital), the difference between the unit price payable by a third party for a TDN share less the sum of US$1,000 multiplied by the 1,200 TDN shares (the "**Young Additional Consideration**").

By way of a variation agreement entered into between Dr. Young, Trinity and Trinity T&T dated 8 May 2012, it was agreed that the terms of the Young Settlement Agreement would be varied so that the Young Additional Consideration would constitute 925 Trinity Shares to be allotted on 25 April 2012. On 25 April 2012 925 Trinity Shares were duly allotted to Dr Young.

(j) *RBC Engagement Letter*

Pursuant to an engagement letter dated 4 October 2012, RBC was appointed to act as exclusive financial adviser to Trinity in connection with the Merger. In consideration for RBC providing advice to Trinity in connection with the Merger, subject to the Merger completing during the term of RBC's engagement with Trinity or within 12 months following the expiration or termination of RBC's engagement, Trinity has agreed to pay RBC a fee equal to US$1.2 million plus applicable taxes and reasonable expenses. The engagement letter provides that it governs the basis on which RBC has been providing services to Trinity since 11 May 2012. Under this engagement letter, Trinity has given certain customary undertakings and indemnities to RBC in connection with its engagement.

(k) *Placing Agreement—Placing Agents, Seymour Pierce, Bayfield and others*

On 25 January 2013 Trinity entered into a placing agreement with the Placing Agents, Seymour Pierce, Bayfield, Finian O'Sullivan, David MacFarlane and the Proposed Directors. Further details on this placing agreement are set out at paragraph 11.1(m) of this Part XII.

(l) *Loan Agreement between Trinity T&T and the Company*

On 27 December 2012 Trinity T&T entered into the Trinity Loan Agreement with Bayfield Galeota and Galeota Oilfield Services Limited. Further details on the Trinity Loan Agreement are set out at paragraph 11.1(q) of this Part XII.

(m) *Sale Agreement—Well Services Rig and Equipment*

On 5 May 2011 TDN entered into an agreement with Well Services for the sale and purchase of a rig, at a purchase price of US$275,000.00, to be set off against amounts owed by TDN to Well Services for drilling services performed by Well Services for TDN. The purchase price under this agreement has been fully paid.

(n) *Crude Offtake Agreement—Petrotrin*

Petrotrin and TDN Operating entered into an agreement (undated) for the delivery by TDN of its share of the crude oil produced in accordance with the Brighton Marine JOA. The financial and other terms of the Brighton Marine JOA apply to the crude offtake agreement. Please see paragraph 2 of Part XI of this document for further information on the Brighton Marine JOA. In the case of a default which is not remedied within 30 days of a meeting between the parties so as to remedy the default, the other party may terminate the agreement.

(o) *Crude Oil Sales Agreement (Point Ligoure)—Petrotrin*

TDN Operating, Ligo Ven and KPA (together the "**Consortium**") and Petrotrin entered into a crude oil sales agreement dated 28 October 2004 under which Petrotrin agreed to purchase the Consortium's total proportionate share of production of crude oil from the Point Ligoure Block.

Under the agreement, the payment for every net barrel of crude oil delivered was the price for Petrotrin's equity land blend crude excluding Guapo. TDN Operating was required to pay a transportation fee of US$0.38 per gross barrel for use of the crude transfer facilities. The transportation fee was capable of being renegotiated at the instance of either party.

The term of the agreement commenced on 1 November 2004 and was capable of subsisting for consecutive terms of 12 months upon the provision of written notice not less than 30 days before the end of each term.

The agreement was capable of being terminated automatically if the licence assignment for Point Ligoure was terminated. It was also capable of being terminated by either party by mutual agreement for material breach after the breach is not corrected within 10 business days of notification of same and for liquidation of either party.

The agreement expired on 31 October 2005 and was not renewed, however notwithstanding the expiry of the agreement TDN Operating has continued to supply and sell crude oil to Petrotrin under the general terms of the expired agreement.

(p) *Crude Oil Sales Agreement (Brighton Marine)—Petrotrin*

Petrotrin and TDN Operating entered into a number of crude oil sales agreements (the last of which was dated 14 October 2004, as amended by supplemental agreements dated 11 October 2005 and 20 November 2006) under which TDN Operating agreed to sell to Petrotrin the total production of crude oil from the Brighton Marine Block.

The initial term of the agreement commenced on 8 October 2004 and was extended by the supplemental agreement dated 11 October 2005 to 7 October 2006. By the supplemental agreement dated 20 November 2006 the term of the agreement was extended to 7 October 2007, renewable for successive one year periods unless the parties terminated the agreement.

Under the agreement TDN Operating was required to pay a transportation fee of US$0.25 per gross barrel for use of the crude transfer facilities. The transportation fee was capable of being renegotiated at the instance of either party.

The agreement was capable of being terminated automatically if the Brighton Marine Licence was terminated. It was also capable of being terminated by either party by mutual agreement for material breach if the breach was not corrected within 10 business days of notification of same, if the parties were unable to reach an agreement on the appropriate price for Crude Oil before the exploration of any contract period, and for liquidation of either party.

12. **Litigation**

12.1 *Bayfield*

Save as disclosed in this paragraph 12.1, neither the Company nor any member of the Group is or has been involved in any governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) which may have, or have had during the 12 months prior to the date of this document, a significant effect on the Company and/or the financial position or profitability of the Group.

(a) *Assertions by Darcy Carr and Wajang*

Darcy Carr and Wajang, a company understood to be controlled by Darcy Carr, have made various requests and/or assertions against certain members of the Bayfield Group. Wajang is a shareholder of the Company, which will following Admission be interested in approximately 0.22 per cent. of the Company's Enlarged Share Capital. Darcy Carr was previously a director of BEL until he was removed as a director in March 2011.

Darcy Carr has:

(i) requested that certain vesting conditions over 3,500,000 share options granted to Wajang ("**Wajang Options**") be removed in association with his stepping down as a director of BEL and has asserted that the period to exercise the Wajang Options be extended as described below; and

(ii) requested that Bayfield Galeota ratify and confirm the terms of a production bonus consultancy agreement purportedly entered into between Bayfield Galeota and Investments International (Trinidad) Limited ("**Investments Trinidad**") on 17 June 2008 ("**Investments Trinidad Agreement**").

In accordance with the terms of the option agreement in relation to the Wajang Options, Wajang was given the opportunity occasioned by the change of control pursuant to the Scheme to exercise the Wajang Options. Wajang claimed that it was being treated differently to those optionholders who were employees or officers of BEL. These optionholders were given the opportunity to surrender their options over shares in BEL in exchange for equivalent options over shares in the Company. Darcy Carr has asserted that the only reason he was not involved in the affairs of BEL was because he had been improperly removed as a director in March 2011. He sought to obtain an extension to the exercise period within which the Wajang Options needed to be exercised. BEL refused to grant such an extension. Wajang did not exercise the Wajang Options and, in accordance with the terms of the option agreement pursuant to which the Wajang Options were granted, in the Directors' opinion the Wajang Options have now lapsed. Darcy Carr has however asserted that he has been treated unfairly and has reserved his rights in relation to making an unfair prejudice claim in relation to the loss of the Wajang Options. The Directors consider that BEL has complied with its obligations under the option agreement in relation to the Wajang Options and refute that Darcy Carr has been treated unfairly. The Directors also consider that Darcy Carr was properly removed as a director in accordance with BEL's articles of association and the shareholders agreement between the then shareholders of BEL.

The Directors are not aware that the Investments Trinidad Agreement exists, but they are aware of a similar agreement made between Bayfield Galeota and Sceptre dated 11 September 2008. As consideration for the services to be provided under the Sceptre Agreement, Bayfield Galeota was to pay a consulting fee (the "**Consulting Fee**") which was to be referable to production from the Galeota Block as set out below:

A Product Target (Bopd)	B Production Payment
2000	US$0.5 million
4000	US$1.5 million
8000	US$3.5 million

The Consulting Fee is expressed to be due and payable when the total gross daily oil production from the Galeota Block when averaged over any ninety consecutive day period exceeds the production targets set out in column A above. The term of the Sceptre Agreement is for eight years from the date of issue of the Galeota Licence, or the date of payment of the Consulting Fee which ever is the later.

Notwithstanding Darcy Carr's request to ratify and confirm the terms of the Investments Trinidad Agreement, Darcy Carr subsequently indicated to BEL that the Sceptre Agreement was intended to supersede the terms of such agreement. The Sceptre Agreement was entered into at a time when Darcy Carr was a director and employee of both BEL and Bayfield Galeota the terms of which stated that Sceptre was to provide advice to Bayfield Galeota in connection with the farm-in of the Galeota Block. So far as the Directors are aware no services have ever been provided by Sceptre pursuant to the Sceptre Agreement. Neither the purported Investments Trinidad Agreement nor the Sceptre Agreement were approved by the boards of either Bayfield Galeota or Bayfield Galeota's parent, BEL.

In light of the above, the Directors believe that Bayfield Galeota does not have any obligation to Investments Trinidad or to Sceptre in relation to either the purported Investments Trinidad Agreement or the Sceptre Agreement. However, in the event that any of Investments Trinidad, Sceptre or Darcy Carr do establish a basis for a claim against Bayfield Galeota under the Sceptre Agreement which is upheld in the courts the maximum liability that Bayfield Galeota could incur would be limited to the maximum consulting fee payable thereunder of US$5.5 million in aggregate plus any costs and expenses incurred in relation to the claim.

On 28 September 2012, Bayfield Galeota received a pre-action notice from lawyers representing Sceptre claiming a sum of US$500,000 in respect of the first amount due in respect of the consultancy fee under the Sceptre Agreement. On 12 December 2012, the lawyers advising Bayfield Galeota replied to such pre-action notice, denying, for the reasons set out above, any liability of Bayfield Galeota to Sceptre and asserting that Bayfield Galeota considers the Sceptre Agreement to be null and void. Bayfield Galeota intends to continue to vigorously resist this claim and any other claim in relation to the Investments Trinidad Agreement and the Sceptre Agreement.

Prior to the Scheme becoming effective, there existed a shareholders agreement dated 13 March 2009 between the then shareholders of BEL and BEL in relation to BEL and its subsidiaries (the "**BEL Shareholders Agreement**"). The BEL Shareholders Agreement contains provisions which are inappropriate for a company whose shares were proposed to be admitted to trading on AIM. However, to terminate it would have required the approval of all of the then shareholders of BEL. In light of the dispute with Darcy Carr referred to above, it was not possible for BEL to obtain his agreement to the termination of the BEL Shareholders Agreement. As a result of this, and for other reasons unassociated with the dispute with Darcy Carr, the directors of BEL proposed and implemented the Scheme so that the quoted vehicle for the Group upon IPO Admission would be the Company rather than BEL. A consequence of the Scheme is that the parties to the BEL Shareholders Agreement are now the Company, BEL and Darcy Carr. The Bayfield Shareholders Agreement continues to have effect in relation to BEL and its subsidiaries (but not the Company), but in view of the fact that the Company owns 118,567,634 shares in BEL (representing in excess of 99 per cent. of the voting rights in the share capital of Bayfield), Darcy Carr's interest in the two other issued shares in BEL has no practical effect on the operations of the Bayfield Group or BEL.

12.2 *Trinity*

Save as disclosed in this paragraph 12.2, neither Trinity nor any member of the Trinity Group is or has been involved in any governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which Trinity is aware) which may have, or have had during the 12 months prior to the date of this document, a significant effect on Trinity and/or the financial position or profitability of the Trinity Group.

(a) *Petrotrin Arbitration*

A settlement has been reached for a claim commenced under Article 25 of the Farmout Agreement and Article XVIII of the Joint Operating Agreement for TT$8,095,122.14 (which is equal to approximately US$1,262,890) brought by Petrotrin in respect of the twelve (12) wells located in the Point Ligoure Block that were plugged and abandoned in 2008/2009. The parties have agreed in principle the terms of settlement (including the payment of TTS$8,095,122.14) and are in the process of formalising the same.

(b) *Mora Ven Holding Claim*

A claim has been brought by Mora Ven Holdings Limited against TDN Operating (as first defendant) and Krishna Persad (as second defendant) alleging that the sale of the shares in Ligoven Resources Limited to TDN Operating was at a gross undervalue, and claiming that TDN Operating holds the shares in constructive trust for the claimant and damages for conspiracy. The value of the claim is yet un-quantified. The case management was heard on 15 June 2012 and the matter was adjourned to 17 December 2012. No trial date has been set. The value of the claim is yet un-quantified and will be dependent on the final outcome of the court case. However, in the event Mora Ven Holdings Limited is successful, any account of profits ordered by the Court is likely to take into account Ligoven Resources Limited's responsibility for any liability, cost expense or risk arising out of its obligations under a joint operating agreement regarding the Point Ligoure Block and minimum work obligations including its obligations to bear proportionate to its interest (17.5 per cent) in the exploration and production prospects of the Point Ligoure Block, the costs, risk and expenses associated with the plugging and/or abandonment of the oil wells drilled in accordance with the terms of that joint operating agreement. The financial impact of the planned counter claim is expected to be greater than the value of the claim by Mora Ven Holdings Limited. An application has been made to strike out the claim due to Mora Ven Holdings Limited's failure to adhere to the Court rules as they relate to disclosure of documents.

13. **No Significant Change**

13.1 *Bayfield*

Save as disclosed in this document there has been no significant change in the financial or trading position of the Bayfield Group since 30 June 2012, being the date to which the last financial information of the Company, incorporated into this document by reference, as set out in Part VIII and paragraph 23 of this Part XII of this document, was prepared.

13.2 *Trinity*

Save as disclosed in this document there has been no significant change in the financial or trading position of the Trinity Group since 30 June 2012, being the date to which the last financial information of Trinity, included in Part VII of this document, was prepared.

14. **Related Party Transactions**

14.1 *Bayfield*

(a) On 14 December 2010 Bayfield Alpha entered into a share purchase agreement (the "**AGOC SPA**") to purchase 74 shares (representing a 74 per cent. interest) in the issued charter capital of AGOC from Lion. The consideration payable by Bayfield Alpha comprised: (i) US$30,000; (ii) the issue and allotment of 3,000,000 ordinary shares in BEL; and (iii) the issue and allotment of 3,000,000 ordinary shares in Bayfield Alpha to BEL. The remaining 26 shares (representing a 26 per cent. interest) in AGOC are held by the Agency on Management of State Assets of the Astrakhan Region.

If, within a ten year period from 31 May 2010 (being the date that Lion and ENI Energy Russia B.V. had earlier entered into a sale and purchase agreement (the "**ENI AGOC SPA**"), pursuant to which Lion acquired 54 shares in AGOC), AGOC (i) achieves an average daily production of 1,000 bbl/d or 1,000 boepd in the case of gas production over a consecutive three-month period; or (ii) is authorised by the relevant authorities, upon any discovery of hydrocarbons to develop AGOC's licence area in the onshore portion of the Volga Delta which is the subject of the exploration and production licence agreement granted by AGOC on 26 October 2006 (the "**Karalatsky Block**") and bring it into production, Bayfield Alpha is obliged to pay Lion a fee of US$13.3 million (the "**AGOC Contingency Payment**"). The AGOC Contingency Payment is to enable Lion to discharge its similar obligations to ENI Energy Russia B.V. under the ENI AGOC SPA.

Pursuant to the AGOC SPA, a pre-existing loan agreement between Lion and AGOC was novated and Bayfield Alpha replaced Lion as lender to AGOC (see "Bayfield Novation Agreement" below). Pursuant to the Bayfield Novation Agreement, Bayfield Alpha is entitled to repayment from AGOC of a loan amount of US$13.3 million (equal to the AGOC Contingency Payment) in circumstances where the AGOC Contingency Payment becomes payable.

Bayfield Alpha has agreed to ensure that any purchaser of its AGOC shares agrees to be bound by the obligations in the AGOC SPA, including the obligation to make the AGOC Contingency Payment. Bayfield Alpha's obligations survive assignment or transfer such that it must guarantee the performance of the obligation by the new owner of the AGOC shares.

Bayfield Alpha has entered into a separate loan agreement with Lion, under the terms of which, should the AGOC Contingency Payment become payable, Lion agrees to lend Bayfield Alpha US$10 million towards satisfaction of its obligations under the AGOC Contingency Payment (see "Lion Loan Agreement" below). AGOC is in the process of being liquidated and will not therefore develop the Karalatsky Block.

(b) On 2 February 2011 and as a condition of the AGOC SPA, Bayfield Alpha and Lion entered into a loan agreement (the "**Lion Loan Agreement**"), pursuant to which Bayfield Alpha may borrow US$10 million from Lion where Bayfield Alpha becomes liable under the AGOC SPA to pay the AGOC Contingency Payment.

(c) On 2 February 2011, Lion, Bayfield Alpha and AGOC entered into a novation agreement (the "**Bayfield Novation Agreement**"), pursuant to which Bayfield Alpha replaced Lion as the lender under a loan agreement with AGOC. As at the date of this document, US$1,741,040 is owed to Bayfield Alpha by AGOC under such loan agreement; Bayfield Alpha has written off such amount in its accounts for the year ended 31 December 2011.

(d) The AGOC SPA, Lion Loan Agreement and Bayfield Novation Agreement are transactions or arrangements entered into between members of the Bayfield Group and related parties by virtue of Andrey Pannikov's (a Non-Executive Director of the Company) control of Lion.

(e) US$3 million of the 2011 Notes issued by BEL on 4 March 2011 was subscribed for by Andrey Pannikov and Finian O'Sullivan, each of whom is a related party of the Bayfield Group by virtue of him being a Director. The 2011 Notes were issued on an arms-length basis on the same terms as to non-related parties. The 2011 Notes were redeemed on 18 July 2011 resulting in the issue of 5,386,807 Existing Unconsolidated Ordinary Shares.

(f) Save as disclosed herein, and as far as Bayfield is aware, there have been and are currently no agreements or other arrangements between members of the Bayfield Group and individuals or entities that may be deemed to be related parties under the AIM Rules.

14.2 *Trinity*

(a) The (i) agreement entered into between Trinity Exploration and Production Services Limited and Well Services dated 14 June 2012 for the supply of an onshore drilling rig and services, (ii) contract for the provision of production workover rig services entered into between Trinity Exploration and Production Services Limited and Rigtech Services Limited dated 5 October 2012, (iii) contract for the provision of swabbing services entered into between Trinity Exploration and Production Services Limited and Rigtech Services Limited dated 5 October 2012, and (iv) contract for the provision of security services between Trinity Exploration and Production Services Limited and Blanket Securities Limited dated 5 October 2012 are transactions or arrangements entered into between members of the Trinity Group and related parties by virtue of (1) Well Services Petroleum Company Limited and Blanket Securities Limited being subsidiaries of Well Services Holdings Limited which is a shareholder in Trinity, (2) Charles Anthony Brash Jnr being a director of Rigtech Services Limited, (2) Charles Anthony Brash Jnr being a director of Trinity, a shareholder in Trinity, (3) Charles Anthony Brash Jnr being a director of Well Services Petroleum Company Limited and Well Services Holdings Limited, and (4) Charles Anthony Brash Jnr, David Bernard Brash and Daniel Cuthbert Brash being related parties and each a shareholder in Trinity.

(b) A member of the Trinity Group has entered into a contract for the provision of services with IAM Consulting Limited which is a transaction or arrangement entered into between members of the Trinity Group and related parties by virtue of Ian MacDonald being a director of Trinity, a shareholder in Trinity and a director and shareholder of IAM Consulting Limited.

(c) A member of the Trinity Group has entered into a contract for the provision of services with Dingwall Energy Advisors Limited which is a transaction or arrangement entered into between members of the Trinity Group and related parties by virtue of Bruce Alan Ian Dingwall being a director of Trinity, a shareholder in Trinity and a director and shareholder of Dingwall Energy Advisors Ltd.

(d) The promissory note summarised at paragraph 11.2(h) of this Part XII of this document is a transaction or arrangement entered into between members of the Trinity Group and related parties by virtue of The David and Christina Segel Living Trust being a shareholder in Trinity.

(e) The Trinity Warrants summarised at paragraph 11.2(e) of this Part XII of this document is a transaction or arrangement entered into between members of the Trinity Group and related parties by virtue of Oriel being a shareholder in Trinity and acting as broker to Trinity in the 2011 Trinity Placing.

(f) Save as disclosed herein, and as far as Trinity is aware, there have been and are currently no agreements or other arrangements between members of the Trinity Group and individuals or entities that may be deemed to be related parties under the AIM Rules.

15. **Public Takeover Bids**

15.1 *City Code*

The City Code applies to the Company and will, *inter alia*, regulate all transactions howsoever effected which have as their objective or potential effect (directly or indirectly) obtaining or consolidating control of the Company. Control for such purposes is defined as an interest or interests in shares carrying 30 per cent. or more of the voting rights of a company, irrespective of whether such interests give *de facto* control.

15.2 *Mandatory Bids*

Under the City Code, where:

(a) any person acquires, whether by a series of transactions over a period of time or not, an interest in shares which (taken together with shares in which he is already interested, and in which persons acting in concert with him (as such expression is defined in the City Code) are interested) carry 30 per cent. or more of the voting rights of a company; or

(b) any person, who together with persons acting in concert with him, is interested in shares which in the aggregate carry not less than 30 per cent. of the voting rights of a company, but does not hold more than 50 per cent. of such voting rights and such person, or any person acting in concert with him, acquires an interest in any other shares which increases the percentage of shares carrying voting rights in which he is interested, such person shall, except in limited circumstances, be obliged to extend offers, on the basis set out in Rules 9.3, 9.4 and 9.5 of the City Code, to the holders of any class of equity share capital whether voting or non-voting, and also to the holders of any other class of transferable securities carrying voting rights. Offers for different classes of equity share capital must be comparable.

15.3 *Squeeze-out*

Under sections 979 to 982 of the Act, if an offeror were to acquire 90 per cent. of the issued share capital of a company it could compulsorily acquire the remaining 10 per cent. The offeror is required to serve notice on the outstanding shareholders informing them of its intention to compulsorily acquire the shares. No such notice may be served after the end of: (a) the period of three months beginning with the day after the last day on which the offer can be accepted; and (b) if earlier, and the offer is not one to which section 943(1) of the Act applies, the period of six months beginning with the date of the offer.

Six weeks following service of such notice, the offeror must send a copy of it to the Company together with the consideration for the issued share capital to which the notice relates, and an instrument of transfer executed on behalf of the outstanding shareholder(s) by a person authorised by the offeror. The Company will hold the consideration on trust for the outstanding shareholders.

15.4 *Sell-out*

Sections 983 to 985 of the Act also give minority shareholders in the Company a right to be bought out in circumstances by an offeror which has made a takeover offer. If the takeover offer related to all the issued ordinary shares and at any time before the end of the period within which the offer could be accepted the offeror held or had agreed to acquire not less than 90 per cent. of the issued ordinary shares, any holder of issued ordinary shares to which the offer related, who had not accepted the offer, could by written communication to the offeror require it to acquire those shares. The offeror is required to give any shareholder notice of his right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of minority shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period or; if longer, a period of three months from the date of the notice. If a shareholder exercises his/her rights, the offeror is bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

15.5 *Existing or impending takeover bids*

The Company and the Directors are not aware of the existence of any takeover bid pursuant to the rules of the City Code, or any circumstances which may give rise to any takeover bid, and the Company and the Directors are not aware of any public takeover bid by third parties for the Existing Unconsolidated Ordinary Shares.

16. **Premises**

16.1 *Bayfield*

The Bayfield Group leases the following principal properties:

(a) Burdett House, 15-16 Buckingham Street, London WC2N 6DU; and

(b) Maska Compound South Trunk Road, Gulf View, La Romain, Trinidad and Tobago, West Indies.

16.2 *Trinity*

The Bayfield Group leases the following principal properties:

(a) office space at 2nd Floor, 40-44 Sutton Street, San Fernando, Trinidad;

(b) warehousing and yard space at 242 Jokhan Trace, San Francique Road, Penal, Trinidad;

(c) office space at Suite 635, 1580 Lincoln Street, Denver, Colorado, 80203, USA; and

(d) office space in Scotland at Suite 4, 23 Melville Street, Edinburgh.

17. **Employees**

17.1 *Bayfield*

The Bayfield Group employs 55 full-time employees.

17.2 *Trinity*

The Trinity Group employs 230 full-time employees.

18. **Market Quotations**

The following table shows the closing middle market quotation for the Existing Unconsolidated Ordinary Shares as derived from the London Stock Exchange Daily Official List on: (i) the first business day of each the six months immediately before the date of this document; and

(ii) 12 October 2012 (being the last day of dealings in the Company's shares prior to the publication of this document):

Date	Price per Existing Unconsolidated Ordinary Share
1 June 2012	24p
2 July 2012	15p
1 August 2012	17.75p
3 September 2012	17.625p
1 October 2012	20.75p
12 October 2012	20.75p

19. **CREST**

The Articles permit the Company to issue shares in uncertificated form in accordance with the CREST Regulations. CREST is a paperless settlement system enabling title to securities to be evidenced otherwise than by certificates and transferred otherwise than by written instrument. Settlement of transactions in Consolidated Ordinary Shares following Admission may take place within the CREST system if Shareholders so wish. CREST is a voluntary system and Shareholders who wish to receive and retain share certificates will be able to do so upon request from the Registrar.

20. **Consents**

20.1 Seymour Pierce has given and has not withdrawn its written consent to the issue of this document with the inclusion herein of references to its name in the form and context in which it appears.

20.2 RPS has given and has not withdrawn its written consent to the inclusion in this document of the Trinity Competent Person's Report set out in Part V of this document, and the references thereto and to its name, in the form and context in which they appear and has authorised the contents of those parts of this document. This report was prepared at the request of the Company. RPS has no interest in the share capital of the Bayfield Group.

20.3 GCA has given and has not withdrawn its written consent to the inclusion in this document of the Bayfield Competent Person's Report set out in Part VI of this document, and the references thereto and to its name, in the form and context in which they appear and has authorised the contents of those parts of this document. This report was prepared at the request of the Company. GCA has no interest in the share capital of the Bayfield Group.

20.4 PricewaterhouseCoopers LLP has given and has not withdrawn its written consent to the inclusion of its report set out in paragraph B of Section 1 of Part VII of this document ("**Accountants' Report on the Historical Financial Information relating to Trinity**") in the form and context in which it is included and has authorised the contents of its report for the purposes of Schedule Two of the AIM Rules for Companies.

20.5 Shahamad Ali & Associates has given and has not withdrawn its written consent to the inclusion of its reports set out in paragraphs A and B of Section 2 of Part VII of this document ("*Financial Statements of Oilbelt Services for the 7 Months Ended 31 July 2011*" and "*Financial Statements of Oilbelt Services for the 12 Months Ended 31 December 2010*"), and the inclusion herein to references to its name in the form and context in which they are included.

21. **Miscellaneous**

21.1 The total costs and expenses payable by the Company in connection with or incidental to the Proposals, including London Stock Exchange fees, professional fees and commissions, consulting and investor relation services and the costs of printing and distribution, are estimated to amount to approximately £7 million (excluding VAT).

21.2 The gross proceeds expected to be raised by the Placing are approximately £57 million (approximately US$90 million). The net proceeds are expected to be £50 million (approximately US$78 million).

21.3 The financial information contained in this document does not constitute statutory accounts within the meaning of section 434 of the Act.

21.4 The Existing Unconsolidated Ordinary Shares are in registered form and the Consolidated Ordinary Shares will, on Admission, be capable of being held in uncertificated form. The Consolidated Ordinary Shares will be admitted with the ISIN GB00B8JG4R91.

21.5 No public takeover bids have been made by third parties in respect of the Company's issued share capital in the current financial year nor in the last financial year.

21.6 Save as disclosed in this document, the Directors and the Proposed Directors are not aware of any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Enlarged Group's prospects for the current financial year.

21.7 Save as disclosed in this document, the Company had no principal investments for each financial year covered by the historical financial information and there are no principal investments in progress and there are no principal future investments on which the Board has made a firm commitment.

21.8 Save as disclosed in this document, Trinity had no principal investments for each financial year covered by the historical financial information and there are no principal investments in progress and there are no principal future investments on which the directors of Trinity made a firm commitment.

21.9 Information sourced from third parties has been accurately reproduced and so far as the Company and Trinity are aware, and able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

21.10 Save as disclosed in this document, the Directors are not aware of any exceptional factors which have influenced the activities of the Bayfield Group as set out in this document and the Proposed Directors are not aware of any exceptional factors which have influenced the activities of the Trinity Group as set out in this document.

21.11 There are no patents or other intellectual property rights, licences or particular industrial, commercial or financial contracts or new manufacturing processes which are of fundamental importance to the Enlarged Group's business or profitability.

21.12 Save as disclosed in Part IV, the Directors and the Proposed Directors are not aware of any material environmental issues or risks affecting the utilisation of the Enlarged Group's tangible fixed assets or its operations.

21.13 Save as disclosed in this document, there have been no significant trends in production, sales and inventory and the costs and selling prices of the Bayfield Group since 31 December 2011 and there have been no significant trends in production, sales and inventory and the costs and selling prices of the Trinity Group since 31 December 2011.

21.14 Other than as set out in this document, there are no outstanding convertible securities, exchangeable securities or securities with warrants issued by the Company.

21.15 No auditors of the Company have resigned or been removed or not re-appointed during the years ended 31 December 2009, 2010 and 2011.

22. Documents Available for Inspection

Copies of the following documents will be available for inspection during normal business hours on any weekday (Saturday, Sundays and public holidays excepted) at the offices of Ashurst LLP, Broadwalk House, 5 Appold Street, London EC2A 2HA from the date of this document until at least 30 days after the date of Admission and will be available for viewing on the Company's website at www.bayfieldenergy.com (up to Admission) or www.trinityexploration.com (following Admission):

(a) the Articles;

(b) the Trinity Articles;

(c) the Bayfield CPR;

(d) the Trinity CPR;

(e) the Deloitte IPO Accountants' Report;

(f) the audited consolidated accounts for the Bayfield Group for the financial year ended 31 December 2011;

(g) the PwC Accountants' Report;

(h) the consent letters referred to in paragraph 20 of this Part XII of this document;

(i) the service contracts and letters of appointment referred to in paragraph 7 of Part XII of this document;

(j) the Merger Agreements;

(k) the irrevocable undertakings referred to in paragraph 11.1(o) of Part XII of this document; and

(l) this document.

23. **Documents Incorporated by Reference**

The following information, available free of charge in electronic format on the Bayfield Group's website at www.bayfieldenergy.com (up to Admission) or www.trinityexploration.com (following Admission) is incorporated into this document by reference.

Reference document	Information incorporated by reference	Pages of such document
Half Yearly Financial Report 2012 of the Company	Independent auditor's report	6 - 7
	Condensed consolidated statement of comprehensive income	8
	Condensed consolidated statement of financial position	9
	Condensed consolidated statement of changes in equity	10
	Condensed consolidated statement of cash flows	11 - 12
	Notes to the consolidated financial statements	13 - 17
Annual report and accounts 2011	Independent auditor's report	27
	Consolidated income statement	28
	Consolidated statement of comprehensive income	29
	Consolidated balance sheet	30
	Consolidated statement of changes in equity	31
	Consolidated cash flow statement	32
	Notes to the consolidated financial statements	33 - 63
Deloitte IPO Accountants' Report (in respect of financial information relating to BEL as at and for the financial years ended 31 December 2010 and 31 December 2009)	Independent auditor's report	142 - 143
	Consolidated balance sheet	144
	Consolidated statement of comprehensive income	145
	Consolidated statement of changes in equity	146
	Consolidated statement of cash flows	147
	Summary of significant accounting policies and explanatory notes	148 - 172

Hard copies of the documents noted in this paragraph 23 of this Part XII as incorporated into this document by reference will not be sent to Shareholders unless requested by them. However, should Shareholders wish to receive hard copies of such documents they should request copies from the Company at Burdett House, 15-16 Buckingham Street, London WC2N 6DU or by telephone on +44 (0)20 7747 9200.

Dated: 25 January 2013

PART XIII

DEFINITIONS

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

"acting in concert"	has the meaning given to it in the City Code
"Admission"	re-admission of the Consolidated Ordinary Shares and the admission of the Consideration Shares and the Placing Shares, in each case, to trading on AIM becoming effective in accordance with the AIM Rules
"AGOC"	Astrakhan Gas & Oil Company, a subsidiary of the Company
"AIM"	AIM, a market of the London Stock Exchange
"AIM Rules"	the AIM Rules for Companies and the AIM Rules for Nominated Advisers, as applicable
"AIM Rules for Companies"	the rules for AIM companies published by the London Stock Exchange, as amended or re-issued from time to time
"AIM Rules for Nominated Advisers"	the rules for nominated advisers to AIM companies published by the London Stock Exchange, as amended or re-issued from time to time
"Amendment No. 1"	has the meaning given to it in paragraph 11.1(b) of Part XII of this document
"Amendment No. 2"	has the meaning given to it in paragraph 11.1(b) of Part XII of this document
"AMSI"	Atlantic Maritime Services Inc.
"Articles"	the articles of association of the Company as at the date of this document, a summary of certain provisions of which is set out in paragraph 5 of Part XII of this document
"Associates"	as that term is defined in the definition of "related party" in the AIM Rules
"Base NORR"	the Notional Overriding Royalty rate applicable to all petroleum produced by the operator under and during the term of each LOA up to and including the base production figures specified in each LOA, as set out in paragraph 2 of Part XI of this document
"Bayfield Alpha"	Bayfield Energy (Alpha) Limited, a subsidiary of the Company
"Bayfield CPR" or "Bayfield Competent Person's Report"	the independent technical report of GCA dated 25 January 2013, which is reproduced in its entirety in Part VI of this document
"Bayfield Galeota"	Bayfield Energy (Galeota) Limited (formerly Burren Energy (Galeota) Limited), a subsidiary of the Company incorporated in Trinidad and Tobago
"Bayfield Group"	the Company and its subsidiaries as at the date of this document and, as the context requires, prior to 19 May 2011 (the date upon which the Scheme became effective), BEL and its subsidiaries as the context requires
"Bayfield Locked-In Shareholders"	Finian O'Sullivan, Andrey Pannikov, Alta Limited, Brian Thurley and, in each case, their Associates
"Bayfield South Africa"	Bayfield Energy South Africa Limited, a subsidiary of the Company

"Bayfield Undertakings"	irrevocable undertakings from Finian O'Sullivan, Andrey Pannikov, Alta Limited, Brian Thurley and Jonathan Cooke to vote, and to procure that their respective Associates vote, in favour of the Resolution to be proposed at the General Meeting
"BEL"	Bayfield Energy Limited, a subsidiary of the Company
"Blackout Agreement"	the agreement entered into among the Company, Ten Degrees North Energy Limited, certain other shareholders of Ten Degrees North Energy Limited and Canboulay Energy Capital Limited in August 2011
"Board"	the board of directors of the Company as constituted from time to time
"Brighton Marine Block"	the Brighton Marine area/ block, the subject of the Brighton Marine Licence
"Brighton Marine FOA"	has the meaning set out in paragraph 2 of Part XI of this document
"Brighton Marine Licence"	the deed of licence dated 7 October 1999 to Petrotrin and TDN Operating to search and bore for and get petroleum in the sub-soil under the Guapo Bay/Brighton Marine Block
"Brighton Marine ORR	has the meaning set out in paragraph 2 of Part XI of this document
"Brighton Marine ORR Effective Date"	has the meaning set out in paragraph 2 of Part XI of this document
"Burren Energy"	Burren Energy plc
"Business Day"	a day (other than Saturday or Sunday) on which banks are generally open for business in London
"Capita Registrars"	a trading name of Capita Registrars Limited
"Centrica"	Centrica Upstream Investment Limited (Registered Number SC314144) whose registered office is at 5th Floor IQ Building, 15 Justice Mill Lane, Aberdeen, United Kingdom AB11 6EQ
"Centrica Loan"	a convertible loan made by Centrica to Trinity pursuant to a loan note instrument dated 18 November 2011
"Centrica Loan Notes"	the loan notes constituted by the Centrica Loan
"certificated" or "in certificated form"	the description of a share or other security which is not in uncertificated form (that is, not in CREST)
"Citibank"	Citibank (Trinidad and Tobago) Limited
"City Code"	the City Code on Takeovers and Mergers in the United Kingdom
"Columbus Basin"	the Columbus Basin which forms the easternmost part of the Eastern Venezuela Basin and is situated along the converging margins in the Caribbean and South American plates
"Companies Act" or "Act"	the Companies Act 2006, as amended
"Company" or "Bayfield" or "Bayfield Energy"	Bayfield Energy Holdings PLC, a company incorporated in England and Wales with registration number 07535869
"Company Direct Placing"	means the proposed placing of 2,301,000 Placing Shares at the Placing Price to be made by the Company to certain investors and not pursuant to the Placing Agreement
"Completion"	completion of the Merger

"Consideration Shares"	the 25,652,041 Consolidated Ordinary Shares to be issued to the Sellers (and those holders of Trinity Options who will have exercised their Trinity Options) on Completion
"Consolidated Ordinary Shares"	the ordinary shares in the capital of Bayfield with a par value of $1.00 each following the Share Consolidation
"Corporate Governance Code"	the UK Corporate Governance Code, published by the Financial Reporting Council
"COSA" or "Crude Oil Sales Agreement"	the crude oil sales agreement dated 1 May 2009 (as amended on 20 September 2012) between Bayfield Galeota and Petrotrin which sets out the respective obligations to buy and sell oil production of Bayfield Galeota, further details of which are set out in paragraph 11.1(h) in Part XII of this document
"COSA Amendment Agreement"	has the meaning set out in paragraph 11.1(h) of Part XII of this document
"CREST"	the computerised settlement system, facilitating the paperless settlement of trades and the holding of uncertificated shares administered by Euroclear UK & Ireland Limited, the operator of CREST
"CREST Regulations" or "Regulations"	the Uncertificated Securities Regulations 2001 of the UK (SI 2001/3755) (as amended)
"Crude Offtake Agreement"	has the meaning set out in paragraph 2 of Part XI of this document
"Darcy Carr"	Mr Darcy Carr, a former director of BEL
"Deloitte IPO Accountants' Report"	the accountants' report prepared by Deloitte LLP in respect of BEL and its subsidiaries for the purposes of the IPO and contained in Part 4 of the IPO Admission Document
"Directors"	the current directors of the Company, whose names are set out on page 5 of this document
"Drilling Contract" or "Rowan Drilling Contract"	a drilling contract dated 1 April 2011, between Niko, Bayfield Galeota and Rowan Drilling (Trinidad) Limited as amended pursuant to a novation agreement dated 26 May 2011 between Niko, Bayfield Galeota, Rowan and AMSI
"DTR" or "Disclosure and Transparency Rules"	the Disclosure and Transparency Rules made by the FSA pursuant to section 73A of the FSMA
"East Galeota"	the five discoveries in the Galeota Block other than the Trintes Field
"Enhanced NORR"	the Notional Overriding Royalty rate applicable to petroleum produced in excess of the base production figures specified in each LOA, as set out in paragraph 2 of Part XI of this document. For the avoidance of doubt, it is only that petroleum produced over and above the relevant base production for any one month that shall benefit from the enhanced Notional Overriding Royalty rates
"Eni"	Eni S.p.A, an Italian multinational oil and gas company
"Enlarged Group"	Bayfield and its subsidiaries following Completion
"Enlarged Group Board"	the Board as it will be constituted on Completion
"Enlarged Share Capital"	the enlarged share capital of the Company upon Admission, comprising the Consolidated Ordinary Shares, the Consideration Shares and the Placing Shares

"EOG Assignment"	has the meaning given to it in paragraph 11.1(e) of Part XII of this document
"EOG Resources" or "EOG"	has the meaning given to it in paragraph 11.1(d) of Part XII of this document
"EU"	the European Union
"Existing Unconsolidated Ordinary Shares"	the ordinary shares in the capital of Bayfield with a par value of $0.10 each in issue as at the date of this document and prior to the completion of the Share Consolidation
"FirstEnergy"	FirstEnergy Capital LLP
"Forest Reserve Area"	the Forest Reserve Area, the subject of the LOAs
"Form of Proxy"	the form of proxy accompanying this document for use in respect of the General Meeting
"FSA"	the United Kingdom Financial Services Authority
"FSMA"	the UK Financial Services and Markets Act 2000 (as amended) including any regulations made pursuant thereto
"Galeota Block"	Bayfield Galeota's licence area offshore Trinidad, the subject of the Galeota Licence
"Galeota Farm Out Agreement" or "Galeota FOA"	the farm out agreement between Bayfield Galeota and Petrotrin which sets out the obligations of Bayfield Galeota arising from the acquisition of its 65 per cent. participating interest in the Galeota Licence effective from 1 May 2009, details of which are set out in paragraph 1 of Part XI of this document
"Galeota JOA"	the joint operating agreement between Bayfield Galeota and Petrotrin governing the relationship, rights and obligations of Bayfield Galeota and Petrotrin under the Galeota Licence and Bayfield Galeota's responsibilities as operator details of which are set out in Part XI of this document
"Galeota Licence"	the "Exploration and Production (Public Petroleum Rights) Licence, Galeota Area" granted to Petrotrin and Bayfield Galeota dated 21 April 2009 as amended by a letter agreement dated 9 March 2012, details of which are set out in Parts II and XI of this document
"Galeota Tank Farm"	Bayfield Galeota's facility for storage of liquid petroleum products or petrochemicals situated onshore Trinidad
"GCA"	Gaffney, Cline & Associates Ltd
"Guapo Offshore Block"	the Guapo Offshore Block, the subject of the PGB Licence
"General Meeting"	the general meeting of the Company to be held on 13 February 2013 (and any adjournment thereof) for the purposes of considering the Resolution, notice of which is set out at the end of this document
"IFRS"	International Financial Reporting Standards as adopted by the European Union
"Initial Minority Merger Agreement"	the conditional agreement dated 12 October 2012 between the Company and certain Trinity Shareholders in relation to the acquisition of 17,916 Trinity Shares, further details of which are set out in paragraph 11.1(p) of Part XII of this document
"IPO"	the initial public offering in relation to the Company in July 2011

"IPO Admission"	admission of the then share capital of the Company to trading on AIM pursuant to the IPO on 18 July 2011
"IPO Admission Document"	the AIM admission document drawn up in accordance with the AIM Rules in connection with IPO Admission
"Jefferies"	Jefferies International Limited
"Joint Bookrunners"	RBC and Jefferies
"KPA"	Krishna Persad and Associates Limited
"Legacy Bayfield Shareholders"	holders of the Existing Unconsolidated Ordinary Shares in issue immediately prior to Admission
"Legacy Trinity Shareholders"	holders of the Trinity Shares in issue immediately prior to Admission
"Lion"	Lion Invest and Trade Limited
"Ligo Van"	Ligo Ven Resources Limited, a subsidiary of Trinity
"LOAs"	has the meaning set out in paragraph 2 of Part XI of this document
"Locked-In Shareholders"	the Bayfield Locked-In Shareholders and the Trinity Locked-In Shareholders
"London Stock Exchange"	London Stock Exchange plc
"LTIP" or "Plan"	the Bayfield Energy Long Term Incentive Plan, details of which are set out in paragraph 4 of Part XII of this document
"LTIP Awards"	share awards granted pursuant to the rules of the LTIP
"Main Merger Agreement"	the conditional agreement dated 12 October 2012 between the Company and the Trinity Management Shareholders in relation to the acquisition of 8,460 Trinity Shares, further details of which are set out in paragraph 11.1(p) of Part XII of this document
"Merger"	the proposed merger by the Company with Trinity through the acquisition of the entire issued share capital of Trinity
"Merger Agreements"	the Main Merger Agreement, the Initial Minority Merger Agreement and the conditional agreements between the Company and all Trinity Shareholders (including any holders of Trinity Options that have agreed to exercise their Trinity Options and who will accordingly receive Trinity Shares) dated between 12 October 2012 and 27 December 2012 in relation to the acquisition of the entire issued share capital of Trinity by the Company, further details of which are set out in paragraph 11.1(p) of Part XII of this document
"Merger Amendments"	the amendments to the Main Merger Agreement and Initial Minority Merger Agreement dated 19 December 2012 between the Company and certain Trinity Shareholders, further details of which are set out in paragraph 11.1(p) of Part XII of this document
"Mirror Scheme"	the terms on which the holders of Trinity Options who have elected to surrender their Trinity Options in exchange for New Options conditional on Completion will be issued options over Consolidated Ordinary Shares which will mirror the terms of the Trinity Share Option Scheme save that the Mirror Scheme will operate over Consolidated Ordinary Shares and references to "Company" shall be read as references to "Bayfield," a summary of which are set out in paragraph 4.2 of Part XII of this document

"New Options"	the options over Consolidated Ordinary Shares proposed to be granted to holders of Trinity Options in exchange for the surrender of their Trinity Options, further details of which are set out in paragraph 4.2 of Part XII of this document
"Niko"	Niko Resources (Trinidad and Tobago) Limited
"Nominated Adviser"	Seymour Pierce
"Notice"	the notice convening the General Meeting set out at the end of this document
"Notional Overriding Royalty"	the notional undivided interest in the market value of petroleum when and as produced from wells that bears no portion of exploration, development, operating or any other costs, royalties or taxes associated with such production and payable by the operator to Petrotrin under each LOA
"Official List"	the Official List of the UK Listing Authority
"Oilbelt Holdings"	Oilbelt Holdings Limited, a company incorporated in Trinidad and Tobago with registration number O 1123 (95) (but which no longer exists by virtue of an amalgamation with TDN to form TDN 2011)
"Oilbelt Services"	Oilbelt Services Limited, a company incorporated in Trinidad and Tobago with registration number O-53 (C) and a subsidiary of Trinity
"Old Trinity T&T"	Trinity Exploration and Production (Trinidad and Tobago) Limited, a company incorporated in Trinidad and Tobago with registered number T 6768 (95) (but which no longer exists by virtue of an amalgamation with TDN 2011 to form Trinity T&T)
"OPEC"	the Organisation of the Petroleum Exporting Countries
"Options"	the existing options over Existing Unconsolidated Ordinary Shares granted to certain of the employees of the Bayfield Group under individual option agreements
"Oriel"	Oriel Securities Limited
"Petroleum Act"	the Petroleum Act of the Laws of the Republic of Trinidad and Tobago, an act to consolidate certain enactments about petroleum, offshore installations and submarine pipelines
"Petroleum Regulations"	the regulations made under the Petroleum Act
"Petrotrin"	Petroleum Company of Trinidad and Tobago Limited, a state owned oil company in Trinidad and Tobago
"PGB"	Point Ligoure Block, Guapo Offshore Block and the relinquished Sub Area A of the Brighton Marine Block, the subject of the PGB Licence
"PGB Licence"	a deed of licence dated 18 December 2012 granted to Petrotrin and TDN Operating to explore for and produce petroleum from the Point Ligoure Block, Guapo Offshore Block and the relinquished Sub Area A of the Brighton Marine Block
"PGB Effective Date"	has the meaning set out in paragraph 2 of Part XI of this document
"Placing"	means, as the context requires, the proposed placing of 45,199,000 Placing Shares at the Placing Price pursuant to the Placing Agreement and for the proposed placing of 2,301,000 Placing Shares at the Placing Price pursuant to the Company Direct Placing

"Placing Agents"	RBC, Jefferies and FirstEnergy
"Placing Agreement"	the conditional agreement dated 25 January 2013 between Seymour Pierce, the Placing Agents, Finian O'Sullivan, David MacFarlane, Trinity, the Proposed Directors and the Company further details of which are set out in paragraph 11.1(l) of Part XII of this document
"Placing Price"	120p per Placing Share
"Placing Proportion"	RBC (52.5 per cent.), Jefferies (35 per cent.) and FirstEnergy (12.5 per cent.)
"Placing Shares"	45,199,000 new Consolidated Ordinary Shares to be issued by the Company pursuant to the Placing Agreement and the 2,301,000 new Consolidated Ordinary Shares to be issued by the Company pursuant to the Company Direct Placing
"Pletmos Inshore Block"	an area offshore South Africa, the subject of the Pletmos Licence
"Pletmos Licence"	a licence over the Pletmos Inshore Block granted to BEL effective 17 April 2012, details of which are set out in paragraph 1 of Part XI of this document
"Point Ligoure Block"	the Point Ligoure area/ block, the subject the PGB Licence
"President of the Republic"	the President of the Republic of Trinidad and Tobago
"Proposals"	the proposals set out in this document, including the Share Consolidation, the change of name, the Merger, the Placing and Admission
"Proposed Directors"	the proposed directors of the Company, who will be appointed to the Board of the Company with effect from Completion, namely, Bruce Alan Ian Dingwall, Joel Montgomery Pemberton, Jonathan David Murphy, Charles Anthony Brash Junior and Ronald Harford
"Prospectus Directive"	Directive 2003/71/EC (and amendments thereto including 2010 PD Amending Directive), including any relevant amending implementing measures in each member state of the European Economic Area that has implemented Directive 2003/71/EC
"Prospectus Rules"	the rules published by the FSA under FSMA governing the publication of a prospectus, as derived from the Prospectus Directive
"PwC"	PricewaterhouseCoopers LLP
"PwC Accountants' Report"	the accountants' report prepared by PwC in respect of the Trinity Group set out in paragraph A of Section 1 of Part VII of this document
"RBC"	RBC Europe Limited (trading as RBC Capital Markets)
"Registrar"	Capita Registrars Limited
"Relevant Member State"	each Member State of the European Economic Area which has implemented the Prospectus Directive
"Repsol"	Repsol E&PT&T Limited
"Resolution"	the resolution set out in the Notice
"Restricted Jurisdiction"	any non-EEA jurisdiction where local laws or regulations may result in a significant risk of civil, regulatory or criminal sanction if information concerning the Proposals is sent or made available to Shareholders in that jurisdiction

"Rig Sharing Agreement"	has the meaning given to it in paragraph 11.1(e) of Part XII of this document
"Rowan"	Rowan Drilling (Trinidad) Limited
"RPS"	RPS Energy Consultants Limited
"Sceptre"	Sceptre Company Limited
"Sceptre Agreement"	a production sharing bonus agreement between Sceptre and Bayfield Galeota dated 11 September 2008
"Scheme" or "Scheme of Arrangement"	the scheme of arrangement under Part 26 of the Companies Act pursuant to which Bayfield Energy became the holding company of the Group in May 2011
"SDRT"	Stamp Duty Reserve Tax
"Securities Industry Act"	the Securities Industry Act, 1995 of the laws of Trinidad and Tobago
"Senior Managers" or "Proposed Senior Managers"	Bryan Ramsumair, Ian MacDonald, Sookdeo Heeralal, Brian Besson, Robert Gair, Lennox Wiltshire and Jim Strachan
"Seymour Pierce"	Seymour Pierce Limited, the Company's nominated adviser and broker for the purposes of the AIM Rules
"Share Consolidation"	the share capital consolidation to be proposed pursuant to the Resolution set out in the Notice whereby, if such Resolution is approved by Bayfield Shareholders, every ten Existing Unconsolidated Ordinary Shares held by any Bayfield Shareholders will be consolidated into one Consolidated Ordinary Share
"Shareholders" or "Bayfield Shareholders"	holders of: a) the Existing Unconsolidated Ordinary Shares from time to time prior to the completion of the Share Consolidation; or b) the Consolidated Ordinary Shares from time to time following the completion of the Share Consolidation
"SOOGL"	means SOOGL Antilles (Trinidad) Limited
"State"	the Republic of Trinidad and Tobago
"Tabaquite Block"	the Tabaquite area/ block, the subject the Tabaquite Farmout Agreement
"Tabaquite Farmout Agreement"	the farmout agreement (sub-licence) between Coastline International Inc. and Petrotrin dated 1 March 2000, for a term of up to five (5) years, with an option to renew for a further period of 10 years (i.e. to 28 February 2010)
"TDN"	Ten Degrees North Energy Limited, a company incorporated in Trinidad and Tobago with registration number T 4376 (95) (but which no longer exists by virtue of an amalgamation with Oilbelt Holdings to form TDN 2011)
"TDN 2011"	Ten Degrees North Energy 2011 Limited, a company incorporated in Trinidad and Tobago with registration number T 6948 (95) A (but which no longer exists by virtue of an amalgamation with Old Trinity T&T to form Trinity T&T)
"TDN Operating"	Ten Degrees North Operating Company Limited, a company incorporated in Trinidad and Tobago with registered number T5084(95) (formerly Venture Production (Trinidad) Limited), a subsidiary of Trinity

"Trinidad"	one of the islands making up Trinidad and Tobago
"Trinidad and Tobago"	the Republic of Trinidad and Tobago
"Trinidad Ministry"	the Republic of Trinidad and Tobago Ministry of Energy and Energy Affairs
"Trinidad Minister of Energy"	the Trinidad Minister of Energy and Energy Affairs
"Trinity"	Trinity Exploration & Production Limited (company number SC396945)
"Trinity Articles"	the articles of association of Trinity as at the date of this document
"Trinity Barbados"	Trinity Exploration and Production (Barbados) Limited, a company incorporated in Barbados with registration number 34784, a subsidiary of Trinity
"Trinity CPR" or "Trinity Competent Person's Report"	the independent technical report of RPS dated 25 January 2013 which is reproduced in its entirety in Part V of this document
"Trinity Group"	Trinity and its subsidiaries
"Trinity Directors"	the current directors of Trinity, being Bruce Dingwall, Joel Montgomery Pemberton, Jon Murphy, Anthony Brash and Ian MacDonald
"Trinity Loan"	the term loan bridge facility of US$10 million dated 20 December 2012
"Trinity Locked-In Shareholders"	Bruce Alan Ian Dingwall, Joel Montgomery Pemberton, Ian MacDonald, Charles Anthony Brash Jr, David Bernard Brash, Daniel Cuthbert Brash, Jonathan Murphy, David Segel and Well Services Holdings Limited and, in each case, their Associates
"Trinity Management Shareholders"	Bruce Alan Ian Dingwall, Joel Montgomery Pemberton and Ian MacDonald
"Trinity Options"	options over Trinity Shares granted under the Trinity Share Option Scheme
"Trinity Placing"	the private placing of Trinity Shares undertaken by Trinity in 2011
"Trinity Shareholders" or "Sellers"	the shareholders of Trinity from time to time
"Trinity Shares"	ordinary shares of US$1.00 each in the issued share capital of Trinity
"Trinity Share Option Scheme"	the Trinity Exploration & Production Limited Share Option Scheme adopted by Trinity on 1 March 2012
"Trinity T&T"	Trinity Exploration and Production (Trinidad and Tobago) Limited, a company incorporated in Trinidad and Tobago with registration number T 6973 (95) A, a subsidiary of Trinity
"Trinity Warrant Instrument"	the warrant instrument issued by Trinity dated 22 November 2012
"Trinity Warrant Shares"	the Consolidated Ordinary Shares which would fall to be issued upon exercise of the Trinity Warrant were the Trinity Warrant to be exercised in full following Admission
"Trinity Warrants"	warrants to subscribe for 83 Trinity Shares pursuant to the Trinity Warrant Instrument, as described in paragraph 15 of Part I of this document

"Trintes Field"	the Trintes field within the Galeota Block which was originally discovered in 1963 and which is now operated by the Bayfield Group
"TT$"	the Trinidad and Tobago dollar, the lawful currency from time to time of Trinidad and Tobago
"UK Listing Authority"	the FSA acting in its capacity as the competent authority for the purposes of Part VI of FSMA
"uncertificated" or "uncertificated form"	recorded on the relevant register of the share or security concerned as being held in uncertificated form in CREST and title to which may be transferred by means of CREST
"United Kingdom" or "UK"	the United Kingdom of Great Britain and Northern Ireland
"United States", "United States of America" or "US"	the United States of America, its territories and possessions, any state of the United States of America and the District of Columbia and all other areas subject to its jurisdiction
"US Securities Act"	the United States Securities Acts of 1933, as amended, and the rules and regulations promulgated thereunder
"US$" or "US dollar"	the US dollar, the lawful currency from time to time of the United States
"Venture Production"	Venture Production plc (now Centrica Production Limited)
"Wajang"	Wajang Holdings Limited
"Wajang Options"	has the meaning given to it in Part IV
"Well Services"	Well Services Petroleum Company Limited
"£" or "Sterling"	pounds sterling, the lawful currency from time to time of the United Kingdom
"2011 Citibank Loan"	the loan facility provided by Citibank in 2011 described as such in paragraph 11.2(g) of Part XII of this document
"2012 Citibank Loan"	the loan facility provided by Citibank in 2012 described as such in paragraph 11.2(g) of Part XII of this document
"2011 Citibank Loan Agreement"	the loan agreement entered into with Citibank in 2011 as described as such in paragraph 11.2(g) of Part XII of this document
"2012 Citibank Loan Agreement"	the loan agreement entered into with Citibank in 2012 as described as such in paragraph 11.2(g) of Part XII of this document
"2011 Instrument"	the loan note instrument dated 4 March 2011 constituting the 2011 Notes
"2011 Notes"	US$4.25million, 10 per cent. unsecured convertible loan notes 2012 issued by BEL pursuant to the 2011 Instrument
"2011 Placing"	the placing of Existing Unconsolidated Ordinary Shares made by the Company in July 2011, upon its admission to AIM, which raised gross proceeds of £54.5 million

PART XIV

GLOSSARY OF TECHNICAL TERMS

The following glossary of technical terms applies throughout this document unless the context requires otherwise:

Variable	Meaning
1C	Contingent Resources with a low estimate scenario
2C	Contingent Resources with a best estimate scenario
3C	Contingent Resources with a high estimate scenario
2D	two dimensional
3D	three dimensional
API	a scale to measure comparative gravity of a petroleum liquid to water as determined by the American Petroleum Institute
Best Estimate	projected volumes. Often associated with a central, P50 or mean value
bbl	barrel
bbl/d	barrels of oil per day
boe	the barrel of oil equivalent
boepd	barrels of oil equivalent per day
bopm	barrels of oil per month
Bscf or Bcf	billions of standard cubic feet
CO2	carbon dioxide
Contingent Resources	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. 1C denotes a low scenario estimate, 2C denotes best estimate scenario, and 3C denotes a high estimate scenario. Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorisation when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves
COS or GCOS	exploration or geological chance of success. The probability, typically expressed as a percentage, that a given outcome will occur
D	day
Downdip	located down the slope of a dipping plane or surface
°F / °C	Degrees Fahrenheit/Centigrade
E&P	exploration and production
ft	feet
GDT	Gas Down To
GR	gamma ray
GPoS	geological probability of success
GTL	gas to liquid
h	thickness
HIIP	Hydrocarbons Initially in Place

IOR	improved oil recovery
k	permeability
Kboepd	thousand barrels of oil equivalent per day
km	kilometres
Km2	square kilometres
Lead	a feature identified on seismic data that has the potential to become a prospect. Usually a Lead is associated with poorer quality or limited 2D seismic data
LNG	Liquefied Natural Gas
m	metres
Majors	major oil and gas exploration companies
Mbal	Material Balance. A means of assessing HIIP
Mbbl	thousand barrels of oil
Mean	the arithmetic average of a set of values
MM	million
MMBbl or MMbbl	million barrels of oil
MMboe	million barrels of oil equivalent
MMscf/d	million standard cubic feet per day
MMstb	millions stock tank barrels
Mstb	thousands stock tank barrels
MTPA	million tons per annum
NGL	natural gas liquids
NOCs	national oil companies, often state owned or historically state owned
P99	the probability that a stated volume will be equalled or exceeded. In this example a 99 per cent. chance that the actual volume will be greater than or equal to that stated Play A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects
Pres	reservoir pressure
PRMS	the Society of Petroleum Engineers/World Petroleum Council/ American Association of Petroleum Geologists/Society of Petroleum Evaluation Engineers Petroleum Resources Management System
Producing	related to development projects (e.g. wells and platforms): Active facilities, currently involved in the extraction (production) of hydrocarbons from discovered reservoirs
Prospect	prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that they are considered viable drilling targets
Prospective Resources	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. 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. Unless otherwise stated, references to Prospective Resources in this document are on a "best" estimate basis
Proved Reserves	Proved Reserves (1P) are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 per cent. probability that the quantities actually recovered will equal or exceed the estimate
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P or P50). In this context, when probabilistic methods are used, there should be at least a 50 per cent. probability that the actual quantities recovered will equal or exceed the 2P estimate
Possible Reserves	Possible Reserves are those additional Reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P or P10) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10 per cent. probability that the actual quantities recovered will equal or exceed the 3P estimate
Recoverable Oil	those quantities of oil that are estimated to be produceable from discovered or undiscovered accumulations
Reserves	those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status. Unless otherwise stated, references to net Reserves in this document account for the WI share of Reserves before the deduction of government royalty and/ or Petrotrin over-riding royalty
Resources	those volumes of hydrocarbons either yet to be found (prospective) or if found, the development of which depends upon a number of factors being resolved (contingent). Unless otherwise stated, references to net Resources in this document for the the WI share of Resources before the deduction of government royalty and/ or Petrotrin over-riding royalty
scf	standard cubic foot

SPT	supplemental petroleum tax
Sw	water saturation
TCF or Tcf	trillion cubic feet of gas at standard distribution pressure of 14.73 pounds per square inch at 60 degrees Fahrenheit
unrisked recoverable oil	those quantities of oil that are estimated to be produceable from discovered or undiscovered accumulations, without factoring the probability that the given outcome will occur
Well Head Gas	gas volume before liquid stripping at the separator
WHP	wellhead pressure
WI	working interest
WTI	West Texas intermediate crude oil

NOTICE OF GENERAL MEETING

Bayfield Energy Holdings PLC
("Company")

(Registered in England and Wales No. 07535869)

NOTICE IS HEREBY GIVEN that a general meeting of the Company ("**General Meeting**") will be held at the offices of Ashurst LLP, Broadwalk House, 5 Appold Street, London EC2A 2HA on 13 February 2013 at 1.00 p.m. for the purposes of considering and, if thought fit, passing the following resolution.

SPECIAL RESOLUTION

1. THAT:

(a) the proposed merger with Trinity Exploration & Production Limited ("**Merger**") on the terms and conditions set out in the merger agreements as summarised in the admission document in relation to the Company dated 25 January 2013 ("**Admission Document**") of which this notice forms part, be and is hereby approved for the purposes of Rule 14 of the AIM Rules for Companies published by London Stock Exchange plc and the board of directors of the Company (or a duly constituted committee of the board), be and is hereby authorised to waive, amend, vary or extend any of the conditions and terms of the Merger and to do all such things as it may consider necessary or desirable to complete the Merger;

(b) in addition to all previous authorities to the extent unused, the directors of the Company ("**Directors**") be and are hereby generally and unconditionally authorised for the purposes of section 551 of the Companies Act 2006 ("**Act**"), to exercise all the powers of the Company to allot shares in the Company and grant rights to subscribe for or convert any securities into shares in the Company up to an aggregate nominal amount (within the meaning of sections 551(3) and (6) of the said Act) of US$73,214,129, this authority to expire on 31 December 2013 unless previously renewed, varied or revoked by the Company in general meeting, save that the Company may before such expiry make any offer or agreement which would or might require shares in the Company to be allotted or rights to subscribe for or to convert any securities into shares in the Company to be granted after such expiry and the Directors may allot shares in the Company, or grant rights to subscribe for or to convert any securities into shares in the Company in pursuance of any such offer or agreement as if the authority conferred hereby had not expired;

(c) in addition to all previous powers to the extent unused, the Directors be and are hereby generally and unconditionally empowered pursuant to section 570 of the Act to allot equity securities (as defined in section 560 of the Act) wholly for cash pursuant to the authority granted to the Directors pursuant to paragraph 1(b) above as if section 561 of the said Act did not apply to any such allotment, provided that this power shall be limited to the allotment of equity securities up to an aggregate nominal amount of US$73,214,129, and this power shall expire on 31 December 2013 unless previously renewed, varied or revoked by the Company in general meeting, save that the Company may before such expiry make any offer or agreement which would or might require equity securities to be allotted after such expiry and the Directors may allot equity securities in pursuance of any such offer or agreement as if the power conferred hereby had not expired;

(d) the name of the Company be changed to "Trinity Exploration & Production plc"; and

(e) conditional upon Admission (as that term is defined in the Admission Document) taking place, every ten issued ordinary shares of US$0.10 each in the capital of the Company be and are hereby consolidated into one ordinary share of US$1.00 each in the capital of the Company, such shares having the rights and being subject to the restrictions set out in the Company's articles of association.

By order of the Board

Amanda Bateman
Secretary

25 January 2013

Registered Office
Fourth Floor
Burdett House
15-16 Buckingham Street
London WC2N 6DU

NOTES:

1. Pursuant to regulation 41 of the Uncertificated Securities Regulations 2001, the Company specifies that in order to have the right to attend and vote at the General Meeting (and also for the purpose of determining how many votes a person entitled to attend and vote may cast), a person must be entered on the register of members of the Company no later than 6.00 p.m. on 11 February 2013 or, if the meeting is adjourned, 6.00 p.m. on the day which is two days before the time fixed for the adjourned meeting. Changes to entries on the register of members after this time shall be disregarded in determining the rights of any person to attend or vote at the meeting.

2. Only holders of ordinary shares are entitled to attend and vote at this meeting.

   A member is entitled to appoint another person as his proxy to exercise all or any of his rights to attend, to speak and to vote at the General Meeting. A member may appoint more than one proxy in relation to the meeting, provided that each proxy is appointed to exercise the rights attached to a different share or shares held by him. A proxy need not be a member of the Company. A form of proxy for the meeting is enclosed.

   To be valid any proxy form or other instrument appointing a proxy must be received by post or by hand (during normal business hours only) by our registrar, Capita Registrars, PXS, 34 Beckenham Road, Beckenham, Kent BR3 4TU, in each case no later than 48 hours before the time for the holding of the meeting or any adjournment of it. If you are a CREST member, see note 3 below.

   Completion of a form of proxy, or other instrument appointing a proxy or any CREST Proxy Instruction will not preclude a member attending and voting in person at the meeting if he/she wishes to do so.

3. Alternatively, if you are a member of CREST, you may register the appointment of a proxy by using the CREST electronic proxy appointment service. Further details are contained below.

   CREST members who wish to appoint a proxy or proxies through the CREST electronic proxy appointment service may do so for the General Meeting and any adjournment(s) thereof by using the procedures, and to the address, described in the CREST Manual (available via www.euroclear.com/CREST) subject to the provisions of the Company's articles of association. CREST personal members or other CREST sponsored members, and those CREST members who have appointed a voting service provider(s), should refer to their CREST sponsor or voting service provider(s), who will be able to take the appropriate action on their behalf.

   In order for a proxy appointment or instruction made using the CREST service to be valid, the appropriate CREST message (a "**CREST Proxy Instruction**") must be properly authenticated in accordance with Euroclear UK and Ireland Limited's ("**Euroclear**") specifications and must contain the information required for such instructions, as described in the CREST Manual. The message, regardless of whether it constitutes the appointment of a proxy or an amendment to the instruction given to a previously appointed proxy, must, in order to be valid, be transmitted so as to be received by the issuer's agent (CREST ID RA10) by the latest time(s) for receipt of proxy appointments specified in the notice of the General Meeting. For this purpose, the time of receipt will be taken to be the time (as determined by the time stamp applied to the message by the CREST Applications Host) from which the issuer's agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST. After this time any change of instructions to proxies appointed through CREST should be communicated to the appointee through other means.

   CREST members and, where applicable, their CREST sponsors or voting service provider(s) should note that Euroclear does not make available special procedures in CREST for any particular messages. Normal system timings and limitations will therefore apply in relation to the input of CREST Proxy Instructions. It is the responsibility of the CREST member concerned to take (or, if the CREST member is a CREST personal member or sponsored member or has appointed a voting service provider(s), to procure that his CREST sponsor or voting service provider(s) take(s)) such action as shall be necessary to ensure that a message is transmitted by means of the CREST system by any particular time. In this connection, CREST members and, where applicable, their CREST sponsors or voting service provider(s) are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings.

   The Company may treat as invalid a CREST Proxy Instruction in the circumstances set out in Regulation 35(5)(a) of the Uncertificated Securities Regulations 2001.

4. Any corporation which is a member can appoint one or more corporate representatives who may exercise on its behalf all of its powers as a member provided that they do not do so in relation to the same shares.

5. Any member attending the General Meeting has the right to ask questions. The Company must cause to be answered any such question relating to the business being dealt with at the meeting but no such answer need be given if (a) to do so would interfere unduly with the preparation for the meeting or involve the disclosure of confidential information, (b) the answer has already been given on a website in the form of an answer to a question, or (c) it is undesirable in the interests of the company or the good order of the meeting that the question be answered.

6. A copy of the articles of association are available for inspection at the Company's registered office during normal business hours from the date of this notice until the close of the General Meeting (Saturdays, Sundays and public holidays excepted) and will be available for inspection at the place of the meeting for at least 15 minutes prior to and during the meeting. A copy of this notice can be found at www.bayfieldenergy.com.

7. As at 23 January 2013 (being the last practicable date prior to the publication of this notice) the Company's issued share capital consists of 216,479,442 ordinary shares, carrying one vote each. Therefore, the total voting rights in the Company as at that date are 216,479,442.

8. You may not use any electronic address (within the meaning of section 333(4) of the Companies Act 2006) provided in this Notice of Meeting (or in any related documents including the proxy form) to communicate with the Company for any purposes other than those expressly stated.

Merrill Corporation Ltd, London
12ZDJ42801