IMPORTANT: This e-mail is intended for the named recipient(s) only. If you are not an intended recipient, please delete this e-mail from your system immediately. You must read the following disclaimer before continuing. The following disclaimer applies to the preliminary offering circular attached to this e-mail. You are therefore advised to read this disclaimer carefully before reading, accessing or making any other use of the attached. In accessing the attached document, you agree to be bound by the following terms and conditions, including any modifications to them from time to time, each time you receive any information from us as a result of such access.

Confirmation of Your Representation: You have accessed the attached document on the basis that you have confirmed your representation to each of Credit Suisse (Singapore) Limited, DBS Bank Ltd. and J.P. Morgan (S.E.A.) Limited that (1)(i) you and any customer you represent are not resident in the United States and, to the extent you purchase the securities described in the attached preliminary offering circular, you will be doing so pursuant to Regulation S under the U.S. Securities Act of 1933, as amended (the "**Securities Act**") **OR** (ii) you are acting on behalf of, or you are, a qualified institutional buyer, as defined in Rule 144A under the Securities Act, (2) you represent and warrant that you are either an institutional investor as defined under Section 4A of the Securities and Futures Act, Chapter 289 of Singapore (the "**Securities and Futures Act**"), a relevant person as defined under Section 275(2) of the Securities and Futures Act or persons to whom an offer is made, as referred to in Section 275(1A) of the Securities and Futures Act, (3) you agree to be bound by the limitations and instructions herein, **AND** (4) you consent to delivery of the attached preliminary offering circular and any amendments or supplements thereto by electronic transmission.

The attached document has been made available to you in electronic form. You are reminded that documents transmitted via this medium may be altered or changed during the process of transmission and consequently neither (i) the issuer, (ii) the underwriters, namely Credit Suisse (Singapore) Limited, DBS Bank Ltd. and J.P. Morgan (S.E.A.) Limited nor (iii) any person who controls them or any director, officer, employee, representative or agent of them or affiliate of any such person accepts any liability or responsibility whatsoever in respect of any discrepancies between the document distributed to you in electronic format and the hard copy version. We will provide a hard copy version to you upon request.

Restrictions: The attached preliminary offering circular is being furnished in connection with an offering exempt from registration under the Securities Act solely for the purpose of enabling a prospective investor to consider the purchase of the securities described in the preliminary offering circular. You are reminded that the information in the attached preliminary offering circular is not complete and may be changed. An investment decision should only be made on the basis of a complete final offering circular.

THE SECURITIES HAVE NOT BEEN, AND WILL NOT BE, REGISTERED UNDER THE SECURITIES ACT, OR THE SECURITIES LAWS OF ANY STATE OF THE U.S. OR OTHER JURISDICTION AND MAY NOT BE OFFERED OR SOLD WITHIN THE U.S., EXCEPT PURSUANT TO AN EXEMPTION FROM, OR IN A TRANSACTION NOT SUBJECT TO, THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT AND ANY APPLICABLE STATE OR LOCAL SECURITIES LAWS.

NOTHING IN THIS ELECTRONIC TRANSMISSION CONSTITUTES AN OFFER OF SECURITIES FOR SALE IN ANY JURISDICTION WHERE IT IS UNLAWFUL TO DO SO.

The attached preliminary offering circular has not been registered as a prospectus by the Monetary Authority of Singapore. Accordingly, the attached preliminary offering circular may not be circulated or distributed, directly or indirectly, in Singapore.

Except with respect to eligible investors in jurisdictions where such offer is permitted by law, nothing in this electronic transmission constitutes an offer or an invitation by or on behalf of either the issuer or any of Credit Suisse (Singapore) Limited, DBS Bank Ltd. and J.P. Morgan

(S.E.A.) Limited to subscribe for or purchase any of the securities described therein, and access has been limited so that it shall not constitute a "general advertisement" or "general solicitation" (as those terms are used in Regulation D under the Securities Act) or directed selling efforts (within the meaning of Regulation S under the Securities Act) in the United States or elsewhere. If a jurisdiction requires that the offering be made by a licensed broker or dealer and the underwriters or any affiliate of the underwriters is a licensed broker or dealer in that jurisdiction, the offering shall be deemed to be made by Credit Suisse (Singapore) Limited, DBS Bank Ltd. and J.P. Morgan (S.E.A.) Limited or their eligible affiliates on behalf of the issuer in such jurisdiction.

You are reminded that you have accessed the attached preliminary offering circular on the basis that you are a person into whose possession this preliminary offering circular may be lawfully delivered in accordance with the laws of the jurisdiction in which you are located and you may not nor are you authorised to deliver or forward this document, electronically or otherwise, to any other person. If you have gained access to this transmission contrary to the foregoing restrictions, you will be unable to purchase any of the securities described therein.

Actions that You May Not Take: You should not reply by e-mail to this announcement, and you may not purchase any securities by doing so. Any reply e-mail communications, including those you generate by using the "Reply" function on your e-mail software, will be ignored or rejected.

YOU ARE NOT AUTHORISED AND YOU MAY NOT FORWARD OR DELIVER THE ATTACHED PRELIMINARY OFFERING CIRCULAR, ELECTRONICALLY OR OTHERWISE, TO ANY OTHER PERSON OR REPRODUCE SUCH OFFERING CIRCULAR IN ANY MANNER WHATSOEVER. ANY FORWARDING, DISTRIBUTION OR REPRODUCTION OF THIS DOCUMENT AND THE ATTACHED PRELIMINARY OFFERING CIRCULAR IN WHOLE OR IN PART IS UNAUTHORISED. FAILURE TO COMPLY WITH THIS DIRECTIVE MAY RESULT IN A VIOLATION OF THE SECURITIES ACT OR THE APPLICABLE LAWS OF OTHER JURISDICTIONS.

You are responsible for protecting against viruses and other destructive items. Your use of this e-mail is at your own risk and it is your responsibility to take precautions to ensure that it is free from viruses and other items of a destructive nature.

IF YOU DO NOT AGREE TO THE TERMS CONTAINED IN THIS E-MAIL, YOU SHOULD NOT OPEN THE ATTACHED DOCUMENT AND SHOULD DELETE THIS E-MAIL. THIS E-MAIL AND ITS ATTACHMENT ARE PERSONAL TO YOU, ARE CONFIDENTIAL AND MAY ONLY BE READ BY THE ADDRESSEE AND MAY NOT BE REPRODUCED OR REDISTRIBUTED ELECTRONICALLY OR OTHERWISE TO ANY OTHER PERSON.

The information in this preliminary offering circular is not complete and may be changed. This preliminary offering circular is not an offer to sell securities and is not soliciting an offer to buy securities in any jurisdiction where the offer or sale is not permitted.

THIS OFFERING DOCUMENT COMPRISES TWO VOLUMES AND THIS IS VOLUME ONE OF TWO. INVESTORS MUST RECEIVE TWO VOLUMES, IF YOU HAVE RECEIVED ONLY VOLUME ONE, PLEASE REQUEST FOR THE SECOND VOLUME FROM THE BANKS LISTED ON PAGE XIII.

PRELIMINARY OFFERING CIRCULAR (Subject to Completion)
Dated 25 November 2013

NOT FOR DISTRIBUTION IN SINGAPORE
STRICTLY CONFIDENTIAL

LINC ENERGY LTD

(incorporated in Australia under the Australian Corporations Act 2001 (Cth) on 29 October 1996)

Offering Shares
Offering Price: S$[●] per Offering Share

This is an offering of [●] ordinary shares ("Shares", and each a "Share") in Linc Energy Ltd (the "Company", and together with our subsidiaries, the "Group"). We are issuing an aggregate of [●] Shares (the "Offering Shares") for subscription at the Offering Price (as defined below). The Offering consists of: (i) an international placement (the "Placement") of [●] Offering Shares to investors, including institutional and other investors in Singapore, outside the United States in reliance on Regulation S ("Regulation S") under the U.S. Securities Act of 1933, as amended (the "U.S. Securities Act") and within the United States only to qualified institutional buyers in reliance on Rule 144A under the U.S. Securities Act ("Rule 144A") and (ii) a public offer of [●] Offering Shares in Singapore (the "Public Offer", and together with the Placement, the "Offering"). The Offering Shares offered may be re-allocated between the Placement and the Public Offer, at the discretion of the Joint Bookrunners and Joint Lead Managers (as defined below), subject to any applicable law. See "Plan of Distribution".

Credit Suisse (Singapore) Limited, DBS Bank Ltd., and J.P. Morgan (S.E.A.) Limited are the joint issue managers, joint bookrunners and joint lead managers for the Offering (the "Joint Issue Managers" or "Joint Bookrunners and Joint Lead Managers").

There is currently no public market for our Shares. Application has been made to the Singapore Exchange Securities Trading Limited (the "SGX-ST") for permission to list all the issued Shares, the existing Shares, the Offering Shares, the Additional Shares, the Employee Option Plan Shares, the Performance Rights Plan Shares, and the CN Shares (each, as defined herein) on the Main Board of the SGX-ST. Such permission for the listing of our Shares will be granted when we have been admitted to the Official List of the SGX-ST.

We have received a letter of eligibility from the SGX-ST for the listing and quotation of the issued Shares, the existing Shares, the Offering Shares, the Additional Shares, the Employee Option Plan Shares and the Performance Rights Plan Shares and the CN Shares on the Main Board of the SGX-ST. The SGX-ST assumes no responsibility for the correctness of any statements or opinions made or reports contained in this offering document. Our eligibility to list is not an indication of the merits of the Offering, our Company, our Group or our Shares.

Investing in our Shares involves certain risks. Our principal activities consist of oil, gas and coal exploration, development and production and we may not progress to the next stage of development or to a stage where we are able to generate revenue for a portion of our assets. See "Risk Factors" of this offering document.

Investors in the Placement will be required to pay a brokerage fee of 1.0% of the Offering Price in connection with their subscription of the Offering Shares. See "Plan of Distribution".

The Offering Shares have not been and will not be registered under the U.S. Securities Act, and may not be offered or sold within the United States except pursuant to an exemption from or in a transaction not subject to, the registration requirements of the U.S. Securities Act. Accordingly, the Offering Shares are being offered and sold (i) outside the United States (including to institutional and other investors in Singapore) to non-U.S. Persons (as defined in Regulations S) in offshore transactions in reliance on Regulation S and (ii) within the United States only to qualified institutional buyers in reliance on Rule 144A. For further details about restrictions on offers, sales and transfers of our Shares, see "Plan of Distribution" and "Transfer Restrictions".

In connection with the Offering, we will grant J.P. Morgan (S.E.A.) Limited as stabilising manager (the "Stabilising Manager"), on behalf of the Joint Bookrunners and Joint Lead Managers, an over-allotment option (the "Over-allotment Option"), to subscribe for up to an aggregate of [●] Shares (representing not more than 10.0% of the total Offering Shares) at the Offering Price (the "Additional Shares"), exercisable in full or in part on one or more occasions, from the date trading of the Shares on the SGX-ST commences (the "Listing Date") until the earliest of (i) the date falling 30 days from the Listing Date, (ii) the date when the Stabilising Manager has bought on the SGX-ST, an aggregate of [●] Shares, representing not more than 10.0% of the total Offering Shares, to undertake stabilising actions, and (iii) the date falling 30 days after the date of adequate public disclosure of the Offering Price, solely to cover the over-allotment of the Offering Shares, if any, subject to any applicable laws and regulations. In the event the Over-allotment Option is exercised in full, the total number of issued Shares outstanding immediately after the completion of the Offering will be increased to [●] Shares.

The several Initial Purchasers are offering the Offering Shares subject to receipt and acceptance of orders by them and subject to their right to reject any order in whole or in part. Payment for the Offering Shares is expected to be made on or about [●], 2013, in immediately available funds.

This offering document has not been registered as a prospectus by the Monetary Authority of Singapore (the "Authority"). Accordingly, this offering document may not be circulated or distributed, directly or indirectly, in Singapore. A copy of the prospectus for distribution in Singapore (the "Singapore Prospectus") has been lodged with and registered by the Authority on 25 November 2013 and [●], 2013, respectively. The Authority assumes no responsibility for the contents of the Singapore Prospectus.

Joint Issue Managers, Joint Bookrunners and Joint Lead Managers

CREDIT SUISSE DBS J.P.Morgan

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NOTICE TO INVESTORS

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No person is authorised to give any information or to make any representation not contained in this offering document and any information or representation not so contained must not be relied upon as having been authorised by or on behalf of us or the Joint Bookrunners and Joint Lead Managers. Neither the delivery of this offering document nor any offer, sale or transfer made hereunder shall under any circumstances imply that the information herein is correct as at any date subsequent to the date hereof or constitute a representation that there has been no change or development reasonably likely to involve a change in our affairs, conditions and prospects of us or our Group since the date hereof. Where such changes occur and are material or required to be disclosed by law to the SGX-ST and/or any other regulatory or supervisory body or agency, we will make an announcement of the same to the SGX-ST and, if required, issue and lodge an amendment to the Singapore Prospectus or a supplementary document or replacement document pursuant to Section 240 or, as the case may be, Section 241 of the Securities and Futures Act and take immediate steps to comply with the said sections. Investors should take notice of such announcements and documents and upon release of such announcements or documents shall be deemed to have notice of such changes.

Neither us nor the Joint Bookrunners and Joint Lead Managers, or any of our or its respective affiliates, directors, officers, employees, agents, representatives or advisers is making any representation or undertaking to any investors in our Shares regarding the legality of an investment by such investor under applicable legal, investment or similar laws. In addition, this offering document is issued solely for the purpose of the Offering and investors in our Shares should not construe the contents of this offering document or its appendices as legal, business, financial or tax advice. Investors should be aware that they may be required to bear the financial risks of an investment in our Shares for an indefinite period of time. Investors should consult their own professional advisers as to the legal, tax, business, financial and related aspects of an investment in our Shares.

Our Shares are subject to restrictions on transferability and resale and may not be transferred or resold in the United States, except as permitted under the U.S. Securities Act and applicable state securities laws pursuant to registration or an exemption from registration under the U.S. Securities Act. For the purpose of the Shares being offered in the United States to "qualified institutional buyers" in reliance on Rule 144A under the U.S. Securities Act, the international offering circular is being furnished in the United States to certain "qualified institutional buyers" on a confidential basis solely for the purpose of enabling prospective purchasers to consider the purchase of the Offering Shares. Its use for any other purpose in the United States is not authorised. In the United States, it may not be copied or reproduced in whole or in part nor may it be distributed or any of its contents be disclosed to anyone other than the prospective purchasers to whom it is submitted. See "Transfer Restrictions" for more information on these restrictions.

The Shares have neither been approved nor disapproved by the U.S. Securities and Exchange Commission, any State securities commission in the United States or any other U.S. regulatory authority nor have any of the foregoing authorities passed upon or endorsed the merits of the Offering or the accuracy or adequacy of this document. Any representation to the contrary is a criminal offence in the United States.

In addition, until 40 days after the commencement of the Offering, an offer or sale of the Offering Shares within the United States by a dealer, whether or not participating in the

Offering, may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A.

By applying for the Offering Shares on the terms and subject to the conditions in this offering document, each investor of the Offering Shares represents and warrants that except as otherwise disclosed to the Joint Bookrunners and Joint Lead Managers in writing, he is not (i) a Director or Substantial Shareholder of our Company, (ii) an associate of any of the persons mentioned in (i), and (iii) a connected client of the Joint Bookrunners and Joint Lead Managers or any lead brokers or distributors of the Offering Shares.

The distribution of this offering document and the offering, purchase, sale or transfer of our Shares in certain jurisdictions may be restricted by law. We and the Joint Bookrunners and Joint Lead Managers require persons into whose possession this offering document comes to inform themselves about and to observe any such restrictions at their own expense and without liability to us or the Joint Bookrunners and Joint Lead Managers. This offering document does not constitute an offer of, or an offering to purchase, any of our Shares in any jurisdiction in which such offer or offering would be unlawful. Persons to whom a copy of this offering document has been issued shall not circulate to any other person, reproduce or otherwise distribute this offering document or any information herein for any purpose whatsoever nor permit or cause the same to occur.

We are subject to the provisions of the Securities and Futures Act and the Listing Manual regarding the contents of the Singapore Prospectus. In particular, if, after the Singapore Prospectus is lodged but before the close of the Offering, we become aware of:

(a) a false or misleading statement or matter in the Singapore Prospectus;

(b) an omission from the Singapore Prospectus of any information that should have been included in it under Section 243 of the Securities and Futures Act; or

(c) a new circumstance that has arisen since the Singapore Prospectus was lodged with the Authority which would have been required by Section 243 of the Securities and Futures Act to be included in the Singapore Prospectus if it had arisen before the Singapore Prospectus was lodged,

and that is materially adverse from the point of view of an investor, we may lodge a supplementary or replacement document with the Authority pursuant to Section 241 of the Securities and Futures Act.

Where applications have been made under the Singapore Prospectus to subscribe for the Offering Shares prior to the lodgement of the supplementary or replacement document and the Offering Shares have not been issued and/or transferred to the applicants, we shall either:

(a) within seven days from the date of lodgement of the supplementary or replacement document, provide the applicants with a copy of the supplementary or replacement document and, as the case may be, provide the applicants with an option to withdraw their applications; or

(b) treat the applications as withdrawn and cancelled and return all monies paid, without interest or any share of revenue or other benefit arising from such application, and at the applicant's own risk, in respect of any application accepted within seven days from the date of lodgement of the supplementary or replacement document, and the applicants will not have any claim against us or the Joint Bookrunners and Joint Lead Managers.

Where applications have been made under the Singapore Prospectus to subscribe for the Offering Shares prior to the lodgement of the supplementary or replacement document and the Offering Shares have been issued and/or transferred to the applicants, we shall either:

(a) within seven days from the date of lodgement of the supplementary or replacement document, provide the applicants with a copy of the supplementary or replacement document and, as the case may be, provide the applicants with an option to return, to us those Offering Shares that the applicants do not wish to retain title in; or

(b) treat the issue and/or sale of the Offering Shares as void and return all monies paid, without interest or any share of revenue or other benefit arising from such application, in respect of any applications received, within seven days from the date of lodgement of the supplementary or replacement document, and the applicants will not have any claim against us or the Joint Bookrunners and Joint Lead Managers.

Any applicant who wishes to exercise his option to withdraw his application or return the Offering Shares issued to him shall, within 14 days from the date of lodgement of the supplementary or replacement documents, notify us whereupon we shall, within seven days from the receipt of such notification, return the application monies without interest or any share of revenue or other benefit arising from such application and at the applicant's own risk.

See instructions booklet titled "Terms, Conditions and Procedures for Application for and Acceptance of the Offering Shares in Singapore".

Under the Securities and Futures Act, the Authority may, in certain circumstances issue a stop order (the "**Stop Order**") to our Company, directing that no or no further Shares to which the Singapore Prospectus relates, be allotted, issued or sold. Such circumstances will include a situation where the Singapore Prospectus (i) contains a statement or matter which, in the opinion of the Authority, is false or misleading, (ii) omits any information that should be included in accordance with the Securities and Futures Act or (iii) does not, in the opinion of the Authority, comply with the requirements of the Securities and Futures Act.

Where the Authority issues a Stop Order pursuant to Section 242 of the Securities and Futures Act:

(a) in the case where the Offering Shares have not been issued to the applicants, the applications for the Offering Shares pursuant to the Offering shall be deemed to have been withdrawn and cancelled and we shall, within 14 days from the date of the Stop Order, pay to the applicants all monies the applicants have paid on account of their applications for the Offering Shares; or

(b) in the case where the Offering Shares have been issued to the applicants and the issue of the Offering Shares pursuant to the Offering is required by the Securities and Futures Act to be deemed void, we shall, within 14 days from the date of the Stop Order, pay to the applicants all monies paid by them for the Offering Shares.

Such monies paid in respect of the applicant's application will be returned to the applicant, in the case of applications for Offering Shares under the Public Offer, at the applicant's own risk, without interest or any share of revenue or other benefit arising from such application, and the applicant will not have any claim against our Company and the Joint Bookrunners and Joint Lead Managers.

We have granted the Stabilising Manager, on behalf of the Joint Bookrunners and Joint Lead Managers, an Over-allotment Option to subscribe for up to an aggregate of the Additional Shares at the Offering Price, exercisable in full or in part on one or more occasions, from the Listing Date until the earliest of (i) the date falling 30 days from the Listing Date, (ii) the date when the Stabilising Manager or its appointed agent has bought on the SGX-ST, an aggregate of [●] Shares, representing not more than [●]% of the total Offering Shares, to undertake stabilising actions, or (iii) the date falling 30 days after the date of adequate public disclosure of the Offering Price, solely to cover the over-allotment of the Offering Shares, if any, subject to any applicable laws and regulations. In the event the Over-allotment Option is exercised in full, the total number of issued Shares after the completion of the Offering will be increased to [●] Shares.

In connection with the Offering, the Stabilising Manager (or persons acting on its behalf) may over-allot Shares or effect transactions which may stabilise or maintain the market price of our Shares at levels above those that might otherwise prevail in the open market. Such transactions may be effected on the SGX-ST and in other jurisdictions where it is permissible to do so, in each case in compliance with all applicable laws and regulations, including the Securities and Futures Act and any regulations thereunder. However, there is no assurance that the Stabilising Manager (or persons acting on its behalf) will undertake any such stabilisation action. Such transactions may commence on or after the Listing Date and, if commenced, may be discontinued at any time and shall not be effected after the earliest of (i) the date falling 30 days from the Listing Date, (ii) the date when the Stabilising Manager or its appointed agent has bought on the SGX-ST an aggregate of [●] Shares, representing not more than [●]% of the total Offering Shares, to undertake stabilising actions, or (iii) the date falling 30 days after the date of adequate public disclosure of the Offering Price.

NOTICE TO NEW HAMPSHIRE RESIDENTS

NEITHER THE FACT THAT A REGISTRATION STATEMENT OR AN APPLICATION FOR A LICENCE HAS BEEN FILED UNDER CHAPTER 421-B OF THE NEW HAMPSHIRE REVISED STATUTES WITH THE STATE OF NEW HAMPSHIRE NOR THE FACT THAT A SECURITY IS EFFECTIVELY REGISTERED OR A PERSON IS LICENSED IN THE STATE OF NEW HAMPSHIRE CONSTITUTES A FINDING BY THE SECRETARY OF STATE OF NEW HAMPSHIRE THAT ANY DOCUMENT FILED UNDER CHAPTER 421-B OF THE NEW HAMPSHIRE REVISED STATUTES IS TRUE, COMPLETE AND NOT MISLEADING. NEITHER ANY SUCH FACT NOR THE FACT THAT AN EXEMPTION OR EXCEPTION IS AVAILABLE FOR A SECURITY OR A TRANSACTION MEANS THAT THE SECRETARY OF STATE OF NEW HAMPSHIRE HAS PASSED IN ANY WAY UPON THE MERITS OR QUALIFICATIONS OF, OR RECOMMENDED OR GIVEN APPROVAL TO, ANY PERSON, SECURITY OR TRANSACTION. IT IS UNLAWFUL TO MAKE, OR CAUSE TO BE MADE, TO ANY PROSPECTIVE PURCHASER, CUSTOMER OR CLIENT, ANY REPRESENTATION INCONSISTENT WITH THE PROVISIONS OF THIS PARAGRAPH.

AVAILABLE INFORMATION

For so long as any Shares are “restricted securities” within the meaning of Rule 144(a)(3) under the U.S. Securities Act, we will, during any period in which we are neither subject to Section 13 or 15(d) of the U.S. Securities Exchange Act of 1934, as amended, nor exempt from reporting pursuant to Rule 12g3-2(b) thereunder, provide to any holder or beneficial owner of such restricted securities or to any prospective purchaser of such restricted securities designated by such holder or beneficial owner for delivery to such holder, beneficial owner or prospective purchaser, in each case upon the request of such holder, beneficial owner or prospective purchaser, the information required to be provided by Rule 144A(d)(4) under the U.S. Securities Act.

ENFORCEABILITY OF CIVIL LIABILITIES

We are a company incorporated with limited liability under the laws of the Australia. Many of our Directors, most of our Executive Officers, our auditors and certain of the other parties named in this document reside outside the United States. Some of our current operations are conducted outside the United States, and a substantial portion of our assets, and the assets of the persons referred to in the preceding sentence are located outside the United States. As a result, you may have difficulty serving legal process within the United States upon us or any of these persons. You may also have difficulty enforcing, both in and outside the United States, judgments you may obtain in courts in the United States against us, or any of such persons, including judgments based upon the civil liability provisions of U.S. federal or state securities laws.

There is uncertainty as to whether the courts of Australia would recognise and enforce judgments of the United States courts obtained against us or our Directors or Executive Officers predicated upon the civil liability provisions of the federal securities laws of the United States or the securities laws of any state in the United States or entertain original actions brought in Australian courts against us or our Directors or Executive Officers predicated upon the federal securities laws of the United States or the securities laws of any state in the United States, unless the facts surrounding such a violation would constitute or give rise to a cause of action under the laws of Australia.

PRESENTATION OF FINANCIAL AND STATISTICAL INFORMATION

This offering document contains our annual consolidated financial statements as at and for the years ended 30 June 2011, 2012 and 2013. References to our financial year refer to our Group's financial year ended or, as the case may be, ending 30 June of that year. Unless otherwise indicated, references to any other date or time or time period are references to the calendar year, as opposed to the financial year. Our annual consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**").

We have prepared our consolidated financial statements in Australian dollar. This offering document contains conversions of Australian dollar amounts into Singapore dollar and United States dollar solely for the convenience of the reader. Unless otherwise indicated, Australian dollar amounts in this offering document have been translated into Singapore dollar based on the exchange rate of A$1.00 = S$1.1648, into United States dollar based on the exchange rate of A$1.00 = US$0.9335, each as quoted by Bloomberg L.P. on the Latest Practicable Date. However, these translations should not be construed as representations that Australian dollar amounts have been, would have been or could be converted into Singapore dollar or United States dollar or that Singapore dollar or United States dollar amounts have been, would have been or could be converted into Australian dollar at those rates or any other rate or at all. See "Exchange Rates and Exchange Controls" for certain historical information on the exchange rates between Australian dollar, Singapore dollar and United States dollar.

We have included the exchange rates quoted above in its proper form and context in this offering document. Bloomberg L.P. has not provided its consent, for purposes of Section 249 of the Securities and Futures Act, to the inclusion of the exchange rates quoted above and in "Exchange Rates and Exchange Controls" in this offering document and is thereby not liable for such information under Sections 253 and 254 of the Securities and Futures Act. While we and the Joint Bookrunners and Joint Lead Managers have taken reasonable actions to ensure that the above exchange rates have been reproduced in their proper form and context, neither we nor the Joint Bookrunners and Joint Lead Managers, nor any other party has conducted an independent review of the information or verified the accuracy of the contents of the relevant information.

Certain numerical figures set out in this offering document, including financial data presented in millions or thousands, and percentages, have been subject to rounding adjustments and, as a result, the totals of the data in this offering document may vary slightly from the actual arithmetic totals of such information. Percentages and amounts reflecting changes over time periods relating to financial and other data set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations" are calculated using the numerical data in our consolidated financial statements or the tabular presentation of other data (subject to rounding) contained in this offering document, as applicable, and not using the numerical data in the narrative description thereof.

NON-IFRS FINANCIAL MEASURES

This offering document contains non-IFRS measures (which have not been audited or reviewed), including EBITDAX, that are not required by, or presented in accordance with, IFRS. EBITDAX as used herein represents net profit (loss) before income tax, non-controlling interest, interest income, finance costs, depreciation, depletion and amortisation, loss on sales of assets, impairment expense, accretion expense, unrealised commodity derivative loss, plug and abandonment and bad debt expense, in relation to our conventional oil and gas business in the United States. We believe that EBITDAX are useful to investors in evaluating our operating performance and our ability to incur and service our indebtedness because they:

- are widely used by investors in the oil and gas industry to measure a company's operating performance before depreciation and amortisation among other items, which can vary substantially from company to company depending upon accounting methods, book value of assets, capital structure and the method by which assets were acquired, among other factors; and
- help investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure.

EBITDAX is not a measurement of our financial performance under IFRS and should not be considered as an alternative to net income, operating income or any other performance measure derived in accordance with IFRS or as an alternative to net cash provided by operating activities as a measure of our profitability or liquidity. EBITDAX has significant limitations; it does not reflect our cash requirements for capital expenditures, contractual commitments, working capital or debt service. In addition, other companies in our industry may calculate EBITDAX differently than we do, limiting their usefulness as comparative measures. EBITDAX has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our operating results or cash flows as reported under IFRS. Some of these limitations are:

(a) it does not reflect our cash expenditures, or future requirements, for capital expenditures or contractual commitments;

(b) it does not reflect changes in, or cash requirements for, our working capital needs;

(c) it does not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on our debt;

(d) although depreciation is a non-cash charge, the assets being depreciated will often have to be replaced in the future, and EBITDAX does not reflect any cash requirements for such replacements; and

(e) it is not adjusted for all non-cash income or expense items that are reflected in our statements of cash flows.

Because of these limitations, EBITDAX should not be considered as a measure of discretionary cash available to us to invest in the growth of our business. We compensate for these limitations by relying primarily on our IFRS financial results and using EBITDAX only for supplemental purposes.

We present a reconciliation of each of the non-IFRS measures to the most directly comparable measure calculated and presented in accordance with IFRS in the sections headed "Selected Consolidated Financial Information and Other Data" and "Summary Consolidated Financial Information and Other Data".

FORWARD-LOOKING STATEMENTS

This offering document includes forward-looking statements. Investors can generally identify forward-looking statements by terminology such as “aim”, “anticipate”, “believe”, “continue”, “could”, “estimate”, “expect”, “intend”, “may”, “objective”, “plan”, “potential”, “project”, “pursue”, “shall”, “should”, “will”, “would”, or other words or phrases of similar import. All statements other than statements of historical facts included in this offering document, including, without limitation, those regarding our expected financial position and results of operations, our business plans and prospects, are forward-looking statements. These forward-looking statements include statements as to our business strategy and plans in future periods, revenue and profitability, forward-looking reserve estimates, oil, gas and coal reserves, planned exploration and development activities and other matters discussed in this offering document that are not historical facts. Information concerning the interpretation of exploration results and reserves and resource estimates also may be deemed to be forward-looking statements, as such information constitutes a prediction of what might be found to be present if and when a project is actually developed. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance or achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Important factors which could cause actual results to differ materially from our expectations include, among others:

- changes in the global oil, gas and coal industry;
- changes in prices and demand of oil, gas and coal;
- our ability to raise funds to finance our new projects, expansion and developments;
- our ability to successfully implement our strategy;
- our ability to generate sufficient cash flow to service our debt obligations;
- our recovery of proved undeveloped reserves;
- occurrence of natural calamities or disasters affecting the areas in which we have operations;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production;
- changes in laws and regulations that apply to the businesses of our Group;
- our ability to obtain and maintain the necessary governmental permits and approvals;
- changes in competitive conditions and our ability to compete under these conditions;
- increase in labour costs;
- labour unrest or other difficulties; and
- general global, regional and local political, economic and business conditions.

Additional factors that could cause actual results, performance or achievements to differ materially include, but are not limited to, those discussed elsewhere in “Risk Factors”, “Management’s Discussion and Analysis of Financial Condition and Results of Operations”, “Business” and “Appendix G—Industry Overview”. Neither us nor the Joint Bookrunners and Joint Lead Managers can give any assurance that the forward-looking statements made in this offering document will be realised. Such forward-looking statements are made only as at the date of this offering document. We expressly disclaim any obligation or undertaking to release publicly any updates or revisions to any forward-looking statement contained in this offering document to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any such statement is based.

ANY FINANCIAL AND OPERATING PROJECTIONS THAT MAY BE CONTAINED IN THIS OFFERING DOCUMENT REPRESENT OUR BEST ESTIMATES AS AT THE DATE OF THIS OFFERING DOCUMENT BASED ON INFORMATION AVAILABLE TO US. THE ASSUMPTIONS UPON WHICH ANY PROJECTIONS ARE BASED ARE DESCRIBED IN MORE DETAIL IN THIS OFFERING DOCUMENT. SOME OR ALL OF THESE ASSUMPTIONS MAY INEVITABLY NOT MATERIALISE, AND UNANTICIPATED EVENTS MAY OCCUR WHICH COULD AFFECT OUR RESULTS OR COULD CAUSE OUR RESULTS TO DIFFER MATERIALLY FROM THAT INDICATED BY ANY PROJECTION.

NO REPRESENTATION OR GUARANTEE IS MADE WITH RESPECT TO THE ACCURACY OR COMPLETENESS OF THE ASSUMPTIONS UNDERLYING ANY PROJECTIONS OR THAT THE RESULTS SET FORTH IN ANY PROJECTIONS WILL BE REALISED. PROSPECTIVE INVESTORS ARE CAUTIONED NOT TO PLACE UNDUE RELIANCE ON ANY PROJECTIONS INCLUDED HEREIN.

CERTAIN RESERVE AND RESOURCES INFORMATION

Unless otherwise indicated, the data on oil, gas and coal reserves and resources presented in this offering document are presented on a "net" basis (being the total or gross value multiplied by our Net Revenue Interest (as defined in "Presentation of Interests")) and have been audited and certified at our request by Haas Petroleum Engineering Services, Inc., Ryder Scott Company, L.P., DeGolyer and MacNaughton, Gustavson Associates LLC, Snowden Mining Industry Consultant Pty Ltd, Xenith Consulting Pty Ltd, and MineCraft Consulting Pty Ltd, as the case may be, whose reports on our oil, gas and coal assets are included in this offering document as "Appendix I—Qualified Persons' Reports" (each a "**Qualified Person**"). The Qualified Persons' Reports are subject to the assumptions and uncertainties and risks contained therein.

No material changes have occurred since the effective date of each of the Qualified Person's Reports.

PRESENTATION OF INTERESTS

Our working interest ("**Working Interest**") in respect of our conventional and unconventional oil and gas assets means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. Working Interests do not take into account the terms of any royalties, government shares of production or similar fiscal terms, and thus do not reflect net entitlement to any oil or gas produced.

Our net revenue interest ("**Net Revenue Interest**") in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest if any on petroleum under the relevant licence or lease, all royalty burdens and interests owned by others have been deducted.

Our equity interest ("**Equity Interest**") in respect of our coal assets refers to our ownership percentage of the asset. Our rights to a financial return from the assets are in proportion to the equity ownership once all other costs of the business have been met.

EXPERT QUALIFICATIONS

Haas Petroleum Engineering Services, Inc. ("**Haas Petroleum**") was founded in 1980 and incorporated in 1982 and performs petroleum engineering services. Haas Petroleum has provided services and expertise to hundreds of clients engaged in various aspects of the petroleum industry. The firm has highly experienced professionals and support staff who have conducted reserves evaluations in various countries of the world and in most of the producing areas of the United States. Haas Petroleum has prepared the Qualified Person's Report with respect to our oil and gas assets located in the Gulf Coast region of Texas and Louisiana (the "**Gulf Coast Region**"). Haas Petroleum's headquarters are located at 2100 Ross Avenue Suite 600 Dallas, Texas 75201, United States.

The report titled "The Appraisal of Certain Oil and Gas Interests owned by Linc Gulf Coast Petroleum, Inc. located in Louisiana and Texas as of 1 September 2013" prepared by Haas Petroleum dated 20 September 2013 (the "**Haas Petroleum Report**") has been supervised by Mr. Rodger L. Walker, an Associate Director of Engineering with Haas Petroleum and a member of the Society of Petroleum Engineers and is licensed and registered with the Texas Board of Registration for Professional Engineers. Mr. Walker has worked in various petroleum engineering capacities in the petroleum industry since 1976.

Ryder Scott Company, L.P. ("**Ryder Scott**") began operations in 1937 and is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott has prepared the Qualified Person's Report with respect to our oil and gas assets located in Wyoming and Alaska. Ryder Scott maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. Its Denver office is located at 621 Seventeenth Street Suite 1550 Denver, Colorado 80293, United States.

The reports titled "The Competent Person's Report on Linc Energy Umiat Field, Alaska" prepared by Ryder Scott dated 12 September 2013 in relation to our assets in Alaska (the "**Ryder Scott Alaska Report**") and the "Competent Person's Report on Linc Energy Petroleum (Wyoming), Inc" prepared by Ryder Scott dated 30 September 2013 in relation to our assets in Wyoming (the "**Ryder Scott Wyoming Report**", together with the Ryder Scott Alaska Report, the "**Ryder Scott Reports**") have been supervised by Mr. Scott James Wilson and Mr. James L. Baird, respectively. Mr. Scott James Wilson is a member and past chairman of the Denver section of the Society of Petroleum Evaluation Engineers. Mr. James L. Baird is a member of the Society of Petroleum Engineers.

DeGolyer and MacNaughton is an industry leader in the evaluation of prospective resources mineral prospects. It has been providing petroleum consultancy services throughout the world since 1936. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists are engaged in the independent appraisal of oil and gas properties. DeGolyer and MacNaughton has prepared the Qualified Person's Report with respect to our oil and gas assets located in the Arckaringa Basin, Australia. DeGolyer and MacNaughton's headquarters are located at 5001 Spring Valley Road Suite 800 East Dallas Texas 75244, United States.

The report titled "The Report as of 15 September 2013 on the Prospective Resources attributable to Certain Prospects owned by Linc Energy Ltd. in Various License Blocks in the Arckaringa Basin, South Australia" prepared by DeGolyer and MacNaughton dated 23 September 2013 (the "**DeGolyer and MacNaughton Report**") has been supervised by Mr. John W. Wallace, Executive Vice President with DeGolyer and MacNaughton, a Registered Professional Engineer in the State of Texas, and a member of the Society of Petroleum Engineers. He has over 30 years of oil and gas industry experience.

Gustavson Associates LLC ("**Gustavson Associates**") is a global consulting firm consisting of geologists, geophysicists, and petroleum engineers, as well as economists and financial experts dedicated to the business of problem solving in all aspects of natural resource evaluations. They have a track record of more than 30 years of experience in providing oil and gas support for their clients. Gustavson Associates has prepared the Qualified Person's Report with respect to our oil and gas assets located in the Arckaringa Basin, South Australia. Gustavson Associates' headquarters are located at 5757 Central Ave, Suite D, Boulder, Colorado 80301, United States.

The report titled "The Resource and Evaluation Report of the Arckaringa Basin, South Australia" prepared by Gustavson Associates dated 15 August 2013 (the "**Gustavson Report**") has been supervised by Ms. Michele G. Bishop, Chief Geologist of Gustavson Associates, a State of Wyoming Professional Geologist and a Certified Professional Geologist of the American Institute of Professional Geologists, with more than 30 years of experience in studies relating to oil and gas fields, including estimating quantities of reserves and resources.

Snowden Mining Industry Consultant Pty Ltd ("**Snowden**") is an independent mining consulting firm with engineers, geologists and geophysicists which provides specialist technical services to exploration and mining companies, diversified industrial groups, financial institutions, banks and legal firms. Snowden has prepared the Qualified Person's Report with respect to our coal assets in Queensland, Australia, which includes valuation on our conventional coal assets located in Australia. Snowden's office is located at 87 Colin Street, West Perth, WA 6005, Australia.

The report titled "The Independent Qualified Persons' Report on the Mineral Assets of New Emerald Coal Pty Ltd" prepared by Snowden Mining Industry Consultant Pty Ltd dated October 2013 (the "**Snowden Report**") has been supervised by Mr. Craig Morley, a director and full-time employee of Snowden and who is professionally registered with the Australasian Institute of Mining and Metallurgy.

Xenith Consulting Pty Ltd ("**Xenith**") is an independent mining consulting firm which provides mining technical services in areas such as geology, mine planning and business analysis. Xenith has prepared the Qualified Person's Reports with respect to our coal assets in Queensland, Australia, in particular on the coal resources and reserves for the Blair Athol mine, the coal resources for the Teresa Project, the coal resources for the Dalby Project and the coal resources for the Pentland Project. Xenith's office is located at Level 6, 40 Creek Street, Brisbane, Queensland 4000, Australia.

The report titled "The Blair Athol Resource QP Report dated October 2013" and the report titled "New Emerald Coal Pty Ltd Blair Athol Project Coal Resource Estimate dated August 2013" (together, the "**Blair Athol Resource Report**"), the report titled "Teresa Resource QP Report dated October 2013" and the report titled "New Emerald Coal Pty Ltd Resource Estimate Statement Teresa Project dated August 2012" (together, the "**Teresa Resource Report**"), the report titled "Dalby Resource QP Report dated October 2013", the report titled "The New Emerald Coal Pty Ltd Resource Statement Executive Summary Dalby Project" dated August 2013 and the report titled "New Emerald Coal Pty Ltd Independent Geological Appraisal Tipton Project dated August 2013" (together, the "**Dalby Resource Report**"), the report titled "Pentland Resource QP Report dated October 2013" the report titled "The New Emerald Coal Pty Ltd Resource Statement Executive Summary Pentland Project" dated August 2013 and the report titled "the New Emerald Coal Pty Ltd Independent Geological Appraisal Pentland Project dated August 2013" (together, the "**Pentland Resource Report**") prepared by Xenith Consulting Pty Ltd have been supervised by Mr. Troy Turner who is a member of the Australasian Institute of Mining and Metallurgy, and the Blair Athol Reserve QP Report dated October 2013 and the Reserve Estimate Blair Athol Coal Mine dated September 2013 prepared by Xenith Consulting Pty Ltd (together, the "**Blair Athol Reserve Report**") has been supervised by Mr. John Cawte who is a member of the Australasian Institute of Mining and Metallurgy with over 20 years of experience in mining in the open cut coal mining industry.

MineCraft Consulting Pty Ltd (“**Minecraft**”) is an independent mining engineering consultancy company which provides services to the coal mining industry. Minecraft has prepared the Qualified Person’s Report with respect to some of our coal assets in Queensland, Australia in particular on the coal reserves in the Teresa Project in Australia. Minecraft’s office is located at 18 Flinders Parade, North Lakes Business Park, Queensland 4509, Australia.

The report titled “The Teresa Project Underground Coal Reserves Qualified Person’s Report dated November 2013” and the The report titled “Teresa Project Underground Coal Reserves Report, dated November 2013” prepared by Minecraft (together, the “**Teresa Reserve Report**”) has been supervised by Mr. Jeremy Busfield who is a member of the Australasian Institute of Mining and Metallurgy and registered professional engineer of Queensland.

None of Haas Petroleum, Ryder Scott, DeGolyer and MacNaughton, Gustavson Associates, Snowden, Xenith or Minecraft owns any interest in the properties of our Company (save for certain individual employees of Snowden who may have immaterial shareholdings in our Company), are employed on a contingent basis and are officers, proposed officers, directors, proposed directors, or Substantial Shareholders of our Company or any holding or associated companies of our Company.

MARKET AND INDUSTRY INFORMATION

Unless stated otherwise, market data used in this offering document are as at the Latest Practicable Date. Market data used in this offering document under the sections “Summary” and “Business” have been extracted from official and industry sources and other sources we believe to be reliable. Sources of these data, statistics and information include information commissioned by Wood Mackenzie (Australia) Pty Ltd (the “**Industry Consultant**”).

We commissioned the Industry Consultant to prepare the market assessment of the global and regional oil and gas market overview covering aspects such as reserves, oil and gas demand and production and an overview of oil and gas industries in areas such as Australia, South East Asia and China. The Industry Overview also covers an overview of the underground coal gasification technology, industry and value chain and applications, and the sea-borne thermal coal market. The Industry Consultant has advised us that the statistical and graphical information contained herein under “Industry Overview” has been drawn from its databases and other sources.

The Industry Consultant is an independent company that carries out business research for the energy industry.

The Industry Consultant is aware of, and has consented to, the inclusion of its name and report in this offering document. The data, statistics and information under the sections “Summary” and “Business” have been accurately reproduced and, as far as we are aware and are able to ascertain from information published or provided by the Industry Consultant, no facts have been omitted that would render the reproduced information, data and statistics inaccurate or misleading. Reports and industry publication generally state that the information that they contain has been obtained from sources believed to be reliable, but that the accuracy and completeness of that information is not guaranteed. Although we believe the information that the Industry Consultant supplied is reliable, we and the Joint Bookrunners and Joint Lead Managers and our affiliates and advisors, have not independently verified and make no representation regarding the accuracy and completeness of this information. Similarly, internal surveys, industry forecasts and market research, which we believe to be reliable, have not been independently verified, and neither the Joint Bookrunners and Joint Lead Managers nor we make any representation as to the accuracy or completeness of this information.

CERTAIN DEFINED TERMS AND CONVENTIONS

In this offering document, references to our “**Company**” are to Linc Energy Ltd and unless the context otherwise requires, the terms “**we**”, “**us**”, “**our**” and “**our Group**” refer to Linc Energy

Ltd and its subsidiaries taken as a whole. Words importing the singular shall, where applicable, include the plural and *vice versa* and words importing the masculine gender shall, where applicable, include the feminine and neuter genders. References to persons shall include corporations.

In this offering document, references to "**S$**", "**Singapore dollar**" or "**cent**" are to the lawful currency of the Republic of Singapore, references to "**A$**" or "**Australian dollar**" or "**Australian cents**" or are to the lawful currency of the Commonwealth of Australia, references to "**US$**" or "**United States dollar**" or "**United States cents**" are to the lawful currency of the United States. Measurements in acres are converted to square kilometres ("**sq km**") and vice versa based on the conversion rate of 1 sq km = 247 acres.

The information on our websites or any website directly or indirectly linked to such websites is not incorporated by reference into this offering document and should not be relied on.

References to our "**executive officers**" and "**directors**" are to the Executive Officers and Directors of our Company; references to "**our Constitution**" are to the Constitution of our Company.

In addition, unless we indicate otherwise, all information in this offering document assumes (i) the Over-allotment Option has not been exercised, (ii) no Offering Shares have been re-allocated between the Placement and the Public Offer, (iii) none of the 2018 Convertible Notes (as defined herein) has been converted into Shares and (iv) none of the options and rights under the Employee Option Plan and the Performance Rights Plan have been exercised and/or converted into Shares.

The terms "**Depositor**", "**Depository Agent**" and "**Depository Register**" shall have the meanings ascribed to them respectively in Section 130A of the Companies Act, Chapter 50 of Singapore (the "**Singapore Companies Act**").

References to the "**Latest Practicable Date**" in this offering document are to 15 November 2013, being the latest practicable date prior to the lodgement of this offering document with the Authority.

Where names and characters, such as those of entities, properties, cities, governmental and regulatory authorities, laws and regulations and notices have been translated into English names, these translations are provided solely for your convenience. The English translations may not have been registered with the relevant authorities and should not be construed as representations that the English names actually represent the names in their original characters.

Any reference to dates or times of day in this offering document and, in connection with the Singapore Public Offer, the instructions booklet titled "Terms, Conditions and Procedures for Application for and Acceptance of the Offering Shares in Singapore", the Application Forms and, in relation to the Electronic Applications, the instructions appearing on the screens of the automated teller machines ("**ATMs**") or the relevant pages of the internet banking websites of the relevant Participating Banks, are to Singapore dates and times unless otherwise stated. Any reference in this offering document, the instructions booklet titled "Terms, Conditions and Procedures for Application for and Acceptance of the Offering Shares in Singapore", the Application Forms and, in relation to the Electronic Applications, the instructions appearing on the screens of the ATMs or the relevant pages of the internet banking websites of the relevant Participating Banks, to any statute or enactment is to that statute or enactment as amended or re-enacted. Any word defined in the Securities and Futures Act, the Singapore Companies Act, or any statutory modification thereof and used in this offering document has the meaning ascribed to it under the Securities and Futures Act, the Singapore Companies Act or any statutory modification thereof, as the case may be, unless otherwise indicated.

In this offering document, the accompanying Application Forms and, in relation to the Electronic Applications, the instructions appearing on the screens of the ATMs or the relevant pages of the internet banking websites of the relevant Participating Banks, the definitions and explanation of technical terms found in this section and the section "Definitions" in this offering document apply throughout where the context is applicable.

Copies of this offering document and the Application Forms may be obtained on request, subject to availability, during office hours from:

Credit Suisse (Singapore) Limited 1 Raffles Link #03/#04-01 South Lobby Singapore 039393	**DBS Bank Ltd.** 12 Marina Boulevard Marina Bay Financial Centre Tower 3 Singapore 018982	**J.P. Morgan (S.E.A.) Limited** 168 Robinson Road, Capital Tower, 17th Floor, Singapore 068912

A copy of this offering document is also available on the SGX-ST website: http://www.sgx.com.

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CORPORATE INFORMATION

Board of Directors	Mr. Kenneth Dark (*Chairman and Non-Executive Director*) Mr. Peter Bond (*Chief Executive Officer and Managing Director*) Mr. Craig Ricato (*Non-Executive Director*) Mr. Lim Ah Doo (*Non-Executive Lead Independent Director*) Mr. Jon Mathews (*Non-Executive Independent Director*) Mr. Koh Ban Heng (*Non-Executive Independent Director*)
Company Secretary	Mr. Brook Burke LL.B.
Registered Office and Principal Place of Business (Australia)	Smellie & Co Building 32 Edward Street Brisbane, Queensland, 4000, Australia Telephone no.: +61 7 3229 0800 Fax no.: +61 7 3229 6800
Principal Place of Business (United States)...............	1000 Louisiana Street, Suite 1500 Houston TX 77002 United States Telephone no.: 1 713 580 6600 Fax no.: 1 713 580 6650
Registration Number	076 157 045
Share Registrar and Share Transfer Agent	Boardroom Corporate & Advisory Services Pte. Ltd. 50 Raffles Place #32-01 Singapore Land Tower Singapore 048623
Joint Issue Managers, Joint Bookrunners and Joint Lead Managers	Credit Suisse (Singapore) Limited 1 Raffles Link #03/#04-01 South Lobby Singapore 039393 DBS Bank Ltd. 12 Marina Boulevard Marina Bay Financial Centre Tower 3 Singapore 018982 J.P. Morgan (S.E.A.) Limited 168 Robinson Road Capital Tower 17th Floor Singapore 068912

Legal Advisers to our Company as to Australian Law	HWL Ebsworth Lawyers Level 23, Riverside Centre 123 Eagle Street, Brisbane QLD 4000
Legal Advisers to our Company as to Singapore Law	WongPartnership LLP 12 Marina Boulevard Level 28 Marina Bay Financial Centre Tower 3 Singapore 018982
Legal Advisers to the Joint Issue Managers, Joint Bookrunners and Joint Lead Managers as to Singapore Law	Allen & Gledhill LLP One Marina Boulevard #28-00 Singapore 018989
Legal Advisers to the Joint Issue Managers, Joint Bookrunners and Joint Lead Managers as to U.S. Federal Securities Law and New York Law	Shearman & Sterling LLP 6 Battery Road #25-03 Singapore 049909
Independent Auditor	KPMG Australia Level 16, 71 Eagle Street Brisbane, Queensland, 4000 Australia Partner: Mr. Matthew McDonnell (a member of the Institute of Chartered Accountants Australia)
Principal Banker	National Australia Bank Limited Level 21, 100 Creek Street Brisbane, Queensland, 4000 Australia
Receiving Bank	DBS Bank Ltd. 12 Marina Boulevard Marina Bay Financial Centre Tower 3 Singapore 018982
Industry Consultant	Wood Mackenzie (Australia) Pty Ltd Level 13, 50 Pitt Street Sydney, New South Wales, 2000 Australia

Qualified Person with respect to our Oil and Gas assets in the Gulf Coast Region	Haas Petroleum Engineering Services, Inc. 2100 Ross Avenue Suite 600 Dallas, Texas 75201
Qualified Person with respect to our Oil and Gas assets in Wyoming and Alaska	Ryder Scott Company, L.P. 621 Seventeenth Street Suite 1550 Denver, Colorado 80293
Qualified Persons with respect to our Oil and Gas assets in the Arckaringa Basin, Australia	DeGolyer and MacNaughton 5001 Spring Valley Road Suite 800 East Dallas, Texas 75244 Gustavson Associates LLC 5757 Central Ave, Suite D Boulder, Colorado 80301
Qualified Persons with respect to our Coal assets in Queensland, Australia	Snowden Mining Industry Consultant Pty Ltd 87 Colin Street, West Perth, WA 6005, Australia Xenith Consulting Pty Ltd 6/40 Creek St Brisbane Queensland 4000, Australia MineCraft Consulting Pty Ltd 18 Flinders Parade North Lakes Business Park Queensland 4509, Australia

SUMMARY

This summary highlights information contained elsewhere in this offering document and may not contain all of the information that may be important to you, or that you should consider before deciding to invest in the Offering Shares. You should read this entire offering document, including, among others, our financial statements and related notes and the section titled "Risk Factors", before making a decision to invest in the Offering Shares.

OVERVIEW

We are focused on both conventional and unconventional oil and gas production. We own a diverse and substantial energy portfolio that includes oil, gas, shale oil and gas and coal.

We operate the following three key business divisions with offices headquartered in different geographic locations:

(a) conventional oil and gas, which consists of:

  (i) oil and gas producing assets located in two main areas in the United States, namely, the Gulf Coast Region and Wyoming, which contribute the bulk of our revenue; and

  (ii) the appraisal and development of the Umiat field located in Alaska, the United States;

(b) unconventional oil and gas, which consists of:

  (i) our Clean Energy business, which focuses on the commercialisation of our proprietary technology in underground coal gasification ("**UCG**"), the process of converting coal into valuable UCG synthetic gas ("**syngas**") in situ. Our Chinchilla demonstration facility, in Australia (the "**Chinchilla Demonstration Facility**"), is the only UCG to gas-to-liquids ("**GTL**") demonstration facility operating in the world. We also own and operate the world's longest running commercial UCG operation in Uzbekistan, having been in operation for over 50 years, and which supplies energy to a nearby power station. We hold coal interests for UCG in Wyoming and Alaska in the United States, Poland, Uzbekistan, and South Australia and Queensland in Australia; and

  (ii) our SAPEX business, which focuses on the exploration for shale oil and gas in the Arckaringa Basin in South Australia; and

(c) coal, which consists of:

  (i) a financial asset in the form of a contractual right to receive payments from coal production over the Carmichael Project in Queensland, Australia (the "**Carmichael Royalty**"); and

  (ii) our conventional coal mining business, which consists of our interests in our conventional coal mining assets in Queensland, Australia.

In respect of our oil and gas assets as of 1 September 2013, we had estimated net 1P reserves of 13.6 MMBOE (of which approximately 96% was oil) with an estimated PV-10 of US$614.5 million, estimated net 2P reserves of 168.2 MMBOE with an estimated PV-10 of US$3.1 billion, and estimated net 3P reserves of 274.6 MMBOE with an estimated PV-10 of US$4.6 billion. Since the acquisition of our producing assets in Wyoming and the Gulf Coast Region in February and October 2011, respectively, we have increased total production by approximately 85% from 2,711 BOEPD (gross) for the quarter ended 31 December 2011 to 5,010 BOEPD (gross) for the quarter ended 30 September 2013. From 1 October 2013 to the Latest Practicable Date, we had an average production rate of 5,858 BOEPD (gross).

Our Gulf Coast Region asset has estimated net 1P reserves of 12.8 MMBOE and net 2P reserves of 12.9 MMBOE. For the quarter ended 30 September 2013, our Gulf Coast Region asset produced 4,822 BOEPD. From 1 October 2013 to the Latest Practicable Date, we had an average production rate of 5,665 BOEPD (gross). Our near term development drilling programme is progressing, and we intend to continue focusing on the Gulf Coast Region.

Our Wyoming asset has estimated net 1P reserves of 0.8 MMBBL and net 3P reserves of 67.7 MMBBL. For the quarter ended 30 September 2013, our Wyoming asset produced 187 BOPD (gross). From 1 October 2013 to the Latest Practicable Date, our Wyoming asset had an average production rate of 193 BOPD (gross).

For FY2013, our net oil and gas production in the Gulf Coast Region and Wyoming was 1,157 MBOE at an average realised price of US$104.95 / BOE (excluding oil price hedges) with an average total operating expense, including oil and gas lease operating expenses, other production expenses, workover costs, production taxes and taxes, of US$25.09 / BOE.

Our Umiat field in Alaska, an asset under our conventional oil and gas business, is considered one of the largest, undeveloped conventional petroleum resources in North America with estimated net 2P reserves of 154.6 MMBBL and estimated net 3P reserves of 194.1 MMBBL. Based on estimated OOIP of approximately 1,200 MMBBL, capital expenditure of US$1.8 billion (prior to tax credits receipts from the Alaskan Government) and operating expenditure of US$589 million, we expect to target peak production of 50,000 BOPD (gross) from our Umiat field before 2020. We have in place a three-phase development plan for our Umiat field and have completed Phase 1 by drilling the Umiat #18 well at an approximate cost of US$70 million.

In respect of our Clean Energy business, we are focused on the generation of UCG syngas for GTL, power, urea, synthetic natural gas, hydrogen fuel cells and enhanced oil recovery ("**EOR**"). We believe we are the only company in the world that has successfully demonstrated UCG to GTL and to have produced diesel and jet fuel from UCG syngas. We are currently pursuing joint ventures with upstream asset owners for the monetisation of stranded coal assets. Through these strategic partnerships, we intend to acquire an equity participation in the relevant projects. We also plan to enter into licensing agreements with selected partners which will include either all or some of the following: (a) licensing fees, (b) royalty fees, (c) carried equity interests and/or (d) consulting and engineering fees. We have entered into a number of opportunity screening studies with third parties to evaluate potential commercial UCG opportunities. We entered into formal agreements to jointly pursue UCG as a commercial business to develop energy solutions in Sub-Saharan Africa with Exxaro Resources Limited ("**Exxaro Resources**") in May 2013. While our focus is currently through establishing strategic joint ventures, the opportunity to participate in projects on our own assets is still available in the future and, potentially, offers the greatest upside.

In respect of our SAPEX business, we hold interests in an area covering over 65,000 sq km (approximately 16 million acres) in the Arckaringa Basin in South Australia, Australia. In respect of such interests, Gustavson Associates estimated prospective resources for unconventional reservoirs to be 232.8 BNBOE, and prospective resources for conventional traps to be 125.0 BNBOE, on an unrisked best estimate basis. DeGolyer and MacNaughton estimated gross prospective oil, gas, condensate and solution gas prospective resources for various licences as of 15 September 2013 in the Arckaringa Basin. We have utilised these quantities in our estimate of 102,800 MMBOE based on the unrisked mean.

In respect of the Carmichael Royalty, we expect to receive payments of A$2 per tonne (indexed to the Consumer Price Index (Brisbane) All Groups number) of coal produced for the first 20 years of production at the Carmichael Project in Queensland, Australia. As at the

Latest Practicable Date, Adani Mining Pty Ltd ("**Adani**"), the existing owner and developer of the asset has reported that it expects to commence production in the first quarter of 2017.

Finally, in respect of our conventional coal mining business in Queensland, Australia, we acquired the Blair Athol Mine in October 2013 and expect to recommence production in June 2014. See "Business—Our Coal Business—Conventional Coal Mining" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors affecting our results of operations—Acquisitions and disposals of our assets" of this offering document for further details. The Blair Athol Mine has 8.7 Mt proved reserves and 2.6 Mt probable reserves as estimated in accordance with the JORC Code. In addition, we are presently in the pre-feasibility stage of the Teresa Project, and exploration and concept study of the Pentland Project and the Dalby Project.

The following table sets forth certain information regarding our assets as at the date of this offering document. We currently operate and manage all our oil, gas and coal assets.

Assets' Location	Gross Area (acres)	Working Interest Area[(1)] (acres)	Status
Conventional Oil and Gas			
United States			
Gulf Coast Region	13,629	13,537	Production
Wyoming	27,788	26,954	Production
Alaska	22,897	19,348	Exploration
Unconventional Oil and Gas			
UCG			
Australia			
Queensland	162,150	162,150	Exploration
South Australia	1,067,989	1,067,989	Exploration
Poland	53,374	53,374	Exploration
Uzbekistan	1,000	917	Production
United States			
Alaska	167,917	167,917	Exploration
Wyoming	180,651	180,651	Exploration
Shale Oil and Gas			
Australia			
South Australia[(2)]	21,121,826	21,121,826	Exploration
Coal			
Australia			
Queensland	28,454,679	NA	Various[(3)]

Notes:

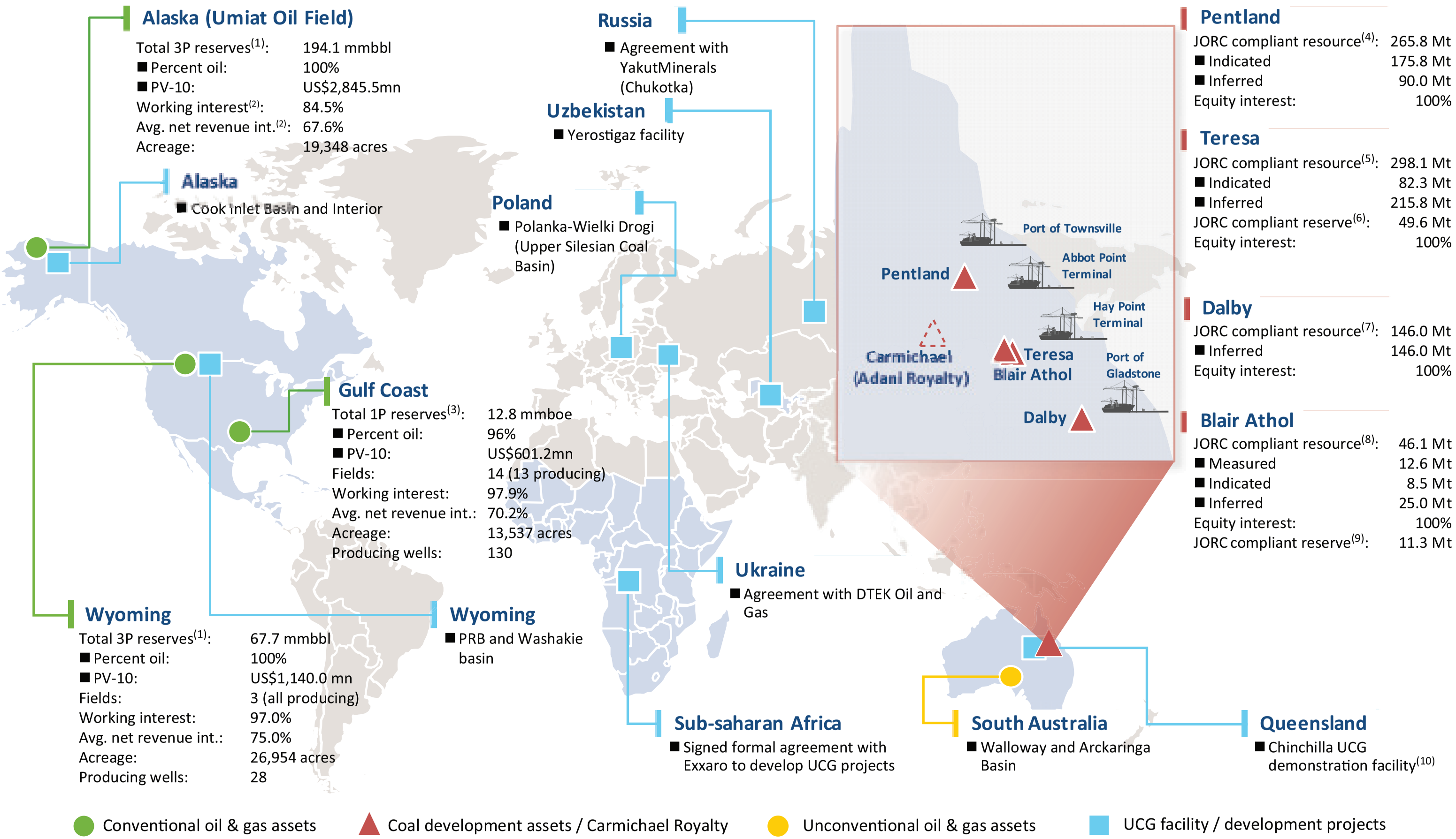
(1) In respect of our conventional and unconventional oil and gas assets our Working Interest area refers to our Working Interest multiplied by gross area. The concept of Working Interest area is not applicable to our conventional coal mining assets.

(2) The gross area and working interest area refers to our interests in the Arckaringa, Eromanga, Cooper and Walloway Basins.

(3) Our coal assets are at various stages of development. For example, we plan to recommence operations at the Blair Athol Mine by June 2014, while the Teresa Project is at the pre-feasibility study stage. See "Business—Coal" of this offering document for further details.

See "Appendix H—Our Oil, Gas and Coal Tenements and Leases" of this offering document for further details.

The map below shows the locations of our assets across the world:



Notes:
(1) Ryder Scott Reports
(2) Our wholly-owned subsidiary Linc Alaska Resources LLC owns an 84.5% interest in Renaissance Umiat LLC. Renaissance Umiat holds the entire Working Interest and a 80.0% Net Revenue Interest in our Umiat field in Alaska
(3) Haas Petroleum Report
(4) Pentland Resource Report
(5) Snowden Report and Teresa Resource Report
(6) Snowden Report and Teresa Reserve Report
(7) Dalby Resource Report
(8) Snowden Report and Blair Athol Resource Report
(9) Snowden Report and Blair Athol Reserve Report
(10) We have commenced decommissioning the Chinchilla Demonstration Facility

OUR STRENGTHS

We are a diversified energy company with operating control of a global portfolio of conventional and unconventional oil, gas and coal assets and proven UCG technology ready for commercialisation

We held oil and gas reserves with estimated net 1P reserves totalling 13.6 MMBOE as of 1 September 2013. For the quarter ended 30 September 2013, our average gross oil and gas production was 5,010 BOEPD. We operate all our oil, gas and coal assets.

We will be the largest listed independent upstream oil and gas exploration and production company in Singapore and one of the largest in South East Asia, in each case, by proved and probable reserves.

We believe we are also the only company in the world to have successfully demonstrated UCG to GTL and to have produced diesel and jet fuel from UCG syngas. Over the last nine years, we have invested approximately A$210.0 million (US$196.0 million) developing our proprietary UCG technology and, by 2012, we believe we had progressed our UCG technology to the stage of commercialisation.

In addition, we hold total coal resources of 756.0 Mt in accordance with the JORC Code (12.6 Mt measured, 266.6 Mt indicated and 476.8 Mt inferred). We will be the largest Singapore listed coal company by total coal resources.

Our physical asset base, which comprises assets that are all majority owned and operated by us, consists of a geographically and geologically diversified portfolio of conventional oil and gas assets in the Gulf Coast Region, Wyoming and Alaska, unconventional oil and gas assets in, among others, Queensland and South Australia, Australia and Uzbekistan and conventional coal mining assets in Queensland, Australia. Our assets are strategically located in regions near high energy demand centres across Asia Pacific and the United States. Within these regions, each of our assets have been selected through a rigorous evaluation process, based on in-depth knowledge derived from our management team's long-standing experience within the oil, gas and coal sectors.

High quality, low risk, oil levered production with potential for significant production upside from assets currently under development and from exploration

We believe our producing oil and gas assets in the Gulf Coast Region are of high quality and relatively low risk, mainly due to their location in one of the world's most well-known oil and gas producing regions that has a long history of oil and gas exploration and production. In addition, our oil and gas assets in the Gulf Coast Region are located within the largest oil and gas market globally, in close proximity to relevant infrastructure and the facilities of various potential off-takers. Furthermore, our net 2P reserves in the Gulf Coast Region consist of more than 95% oil. The oil from our Gulf Coast Region assets is considered high quality due to the fact that we receive Louisiana Light Sweet ("**LLS**") pricing, which has historically traded at a premium to West Texas Intermediate ("**WTI**") prices.

Our growth strategy combines production from existing fields and near-term asset developments complemented by a visible pipeline of mid-term development opportunities and the possibility of significant further upside from exploration in the longer-term.

Since we acquired our producing oil and gas assets in Wyoming and the Gulf Coast Region in February 2011 and October 2011, respectively, we have increased production by approximately 85% from 2,711 BOEPD (gross) for the quarter ended 31 December 2011 to 5,010 BOEPD (gross) for the quarter ended 30 September 2013. From 1 October 2013 to the Latest Practicable Date, we had an average production rate of 5,858 BOEPD (gross). Our continual near term development drilling will remained focused on the Gulf Coast Region.

Our Umiat field in Alaska has estimated net 2P reserves of 154.6 MMBBL and estimated net 3P reserves of 194.1 MMBBL. Based on estimated OOIP of approximately 1,200 MMBBL, capital expenditure of US$1.8 billion (prior to tax credits receipts from the Alaskan Government) and operating expenditure of US$589 million, we expect to target peak production of 50,000 BOPD (gross) from our Umiat field before 2020.

In Wyoming, we have the potential for significant increases in oil production in the mid-term (between three and five years) utilising a carbon dioxide (CO_2) EOR project, with potential peak gross production of 10,000 BOPD to 15,000 BOPD, subject to adequate availability of CO_2.

In addition to our conventional oil and gas assets, we also have potential shale oil and gas resources via our 100% Working Interest in a rare, large position of approximately 65,000 sq km (16 million acres) of contiguous acreage in South Australia that provides us access to the vast majority of the Arckaringa Basin. Estimated prospective resources for unconventional reservoirs in the Arckaringa Basin are 232.8 BNBOE, and prospective resources for conventional traps in the Arckaringa Basin are 125.0 BNBOE, on an unrisked best estimate basis. We also estimate gross oil, gas, condensate and solution gas prospective resources of 102,800 MMBOE on the unrisked mean. The various formations within the Arckaringa Basin have excellent shale oil and gas resource with total organic carbon levels, permeability, porosity and thickness comparing favourably to other high volume unconventional shale oil and gas geological basins such as the Eagle Ford and Bakken in the United States.

A leader in UCG technology

We believe we are the only company in the world to have demonstrated UCG to GTL and to have produced diesel and jet fuel from UCG syngas, which provides us with a first mover advantage in the UCG front for the production of valuable and cleaner energy solutions. In addition, we have invested approximately A$210.0 million (US$196.0 million) developing our proprietary UCG technology over the last nine years.

In March 2011, we demonstrated the success of the ultra-clean diesel fuel created from our UCG to GTL technology by driving a diesel engine motor vehicle for more than 5,000 km from our Chinchilla Demonstration Facility to Perth, Western Australia, and in May 2012, our management flew more than 4,200 km over three days across Australia in a jet aircraft powered by our very own Jet A1 fuel created from UCG to GTL technology.

We also own and operate the world's longest running commercial UCG operation in Uzbekistan, which has been in operation for over 50 years. It supplies energy to a nearby power station. In May 2013, we entered into formal agreements to jointly pursue a commercial UCG business developing energy solutions in Sub-Saharan Africa with Exxaro Resources. In addition, we have also entered into a number of opportunity screening studies with resource owners in Asia and North America to evaluate potential commercial UCG opportunities.

Our proprietary UCG technology is protected by intellectual property rights which we endeavour to register globally.

Strategically positioned and equipped to capitalise on robust demand for oil and gas in Asia, and, in particular, the switch from oil and coal to gas in regional markets

Our UCG technology provides a proven, cutting-edge solution for unlocking value in stranded coal deposits, and given the large number of potentially suitable coal resources in Asia, namely in China, Mongolia and Indonesia, we view our proprietary UCG technology to be highly relevant to the growing Asian energy market. In addition, supply constraints in Asia limit the amount of new oil coming on stream relative to demand. GTL technology can take advantage of these supply constraints, delivering to market a suite of UCG derived synthetic liquid fuels and syncrude products.

According to the Industry Consultant, from 2005 to 2012, oil and gas consumption in the Asia-Pacific region increased from 10,804 MMBOE to 13,826 MMBOE, representing a CAGR of 3.6%. This is expected to continue increasing, from 14,343 MMBOE in 2013 to 17,051 MMBOE in 2018. This robust growth in energy consumption is supported by consistent, rapid GDP increase and corresponding power demand. Gas consumption has increased at a CAGR of 7.2% from 2,376 MMCF in 2005 to 3,860 MMCF in 2012. Oil consumption has increased from 8,428 MBOPD in 2005 to 9,966 MBOPD in 2012. Imported thermal coal consumption has increased from 289 Mtpa in 2005 to 667 Mtpa in 2012.

The commercialisation of our UCG technology will allow us to benefit from the robust demand for gas in Asia. UCG syngas and its by-products can be used as feedstock for different downstream processes such as power generation, chemical production, liquid transport fuels, and reformation into substitute natural gas. Additionally, the application of GTL to transform UCG syngas to UCG syncrude can potentially address the oil supply deficit. The production of UCG syngas and its by-products will allow us to take advantage of the increasing demand for energy consumption in Asia.

Contracted royalty stream from the Carmichael coal tenement anticipated to provide stable medium to long-term cashflows

The Carmichael coal tenement is one of the largest coal tenements in Australia, located in the Galilee Basin of Queensland. In August 2010, we sold our interests in the Carmichael coal tenement to Adani for A$500.0 million (US$466.8 million) in cash. As part of that transaction, we expect to receive the Carmichael Royalty over coal produced for the first 20 years of production at the Carmichael Project in Queensland, Australia, which Adani, the existing owner and developer of the asset has reported is expected to commence in the first quarter of 2017.

Proven management team with development, operational and technical expertise

Our proven track record over the course of our operating history since 2005 is founded on our experienced management and technical teams, which have significant experience finding, developing and operating oil, gas and coal assets in our focus regions. Our management team has a track record of developing significant projects worldwide and across the oil, gas and coal value chains. Due to our management team's expertise, we have increased production of our oil and gas assets in Wyoming and the Gulf Coast Region by 85% from 2,711 BOEPD (gross) for the quarter ended 31 December 2011 to 5,010 BOEPD (gross) for the quarter ended 30 September 2013 since acquiring them in February 2011 and October 2011, respectively. In addition, our management team has an established base of relationships with domestic and foreign governments, national and international oil companies, service companies and independent oil and gas companies, all of which we believe enhance our competitiveness.

Our management team has focused on cost reduction through efficiency improvement, and maintaining long-term growth in reserves and production through continuing technological innovation. The management team is supported by a global team of 466 employees, which include multiple groups of technical staff, including geological, facilities and engineering and research and development professionals. In addition, our intellectual property rights are managed by a sophisticated intellectual property management plan and an experienced internal intellectual property legal team which ensures protection of our intellectual property and our ability to operate.

OUR STRATEGIES

Accelerate development and commercialisation of existing assets and increase our oil and gas reserves through further exploration

We will seek to fully develop our oil, gas and coal resources, to the extent such development is commercially viable, in order to accelerate and maximise production from our portfolio.

We are currently targeting to increase production to an exit rate of 8,000 to 9,000 BOEPD (gross) by end of December 2013 in the Gulf Coast Region. In addition, our Gulf Coast Region assets, such as Barber Hills, Black Bayou, Hoskins Mound and Port Neches, provide potential for sub-salt oil and gas. To date, we have identified a portfolio of approximately 60 prospects in the Gulf Coast Region. We plan to drill, as an operator, an aggregate of between 50 and 60 exploratory and appraisal wells in the Gulf Coast Region in the next 24 months, depending on drilling results.

We have in place a three-phase development plan for our Umiat field and have completed Phase 1 by drilling the Umiat #18 well and have extracted the core and subjected it to extensive evaluation. The preliminary results from the core analysis indicated good permeability and porosity, robust hydrocarbon geochemical signature, high quality reservoir rock and visible oil readily apparent in the core samples confirming saturation with hydrocarbons. We expect to commence Phase 2 at the end of 2013 which would involve drilling, completion and production testing of one horizontal well and if there is sufficient time, the drilling and testing of an additional well. We expect to commence Phase 3 in the spring of 2014 which would include a full Environmental Impact Statement review, procuring regulatory approvals and the commencement of drilling of up to 70 wells. Assuming success in Phase 2 and 3, we anticipate commencement of production prior to 2020.

In Wyoming, we intend to significantly increase production in the mid-term (between three and five years) via a CO_2 EOR technique, with an anticipated peak gross production of 10,000 BOPD to 15,000 BOPD subject to adequate availability of CO_2. We have completed all reservoir modelling, the facilities engineering and design is ongoing and we have completed a pre-feasibility study for a CO_2 pipeline. We are in discussions with several CO_2 suppliers in anticipation of securing a CO_2 pipeline within the next 18 months before a final investment decision in made.

With regard to our Australian shale oil and gas position in the Arckaringa Basin, we intend to enter into a joint venture with a strategic partner at the appropriate time when we believe we can receive the full value of our Australian shale oil and gas position. We intend to further appraise the unconventional oil resource as well as conduct further exploration of the deeper conventional oil potential.

Be a leader in the provision of clean energy through UCG and GTL, whilst deploying UCG technology to penetrate new markets and grow our asset base

Our Clean Energy business strategy is focused on the commercialisation of our proprietary UCG technology, which we have been developing over the last nine years. We are currently pursuing joint ventures with resource owners in Asia and North America for the monetisation of stranded coal assets. Through these strategic partnerships, we intend to acquire an equity participation in the relevant projects. We also plan to enter into licensing agreements with selected partners which will include either all or some of the following: (a) a licensing fee, (b) a royalty fee, (c) carried equity interests and/or (d) consulting and engineering fees.

We intend to continue entering into opportunity screening studies with third parties to evaluate potential commercial UCG opportunities. We undertake these studies for a fee. Upon completion of such studies, if the resource is suitable to be commercialised with our technology, the studies will form the basis of our negotiation for joint ventures for the commercialisation of the resource.

In addition to the formal agreements we signed with DTEK Oil and Gas, Exxaro Resources and LLC YakutMinerals in November 2012, May 2013 and June 2013, respectively, we continue to explore entering into other licence agreements and/or joint venture agreements in strategic locations. We also hold a global portfolio of coal resources acquired specifically to facilitate further development opportunities using our UCG technology.

Grow Asian footprint

According to the Industry Consultant, oil and gas consumption in the Asia Pacific region increased from 10,804 MMBOE to 13,826 MMBOE from 2005 to 2012, representing a CAGR of 3.6%. This is expected to continue increasing on the back of consistent, rapid GDP growth, and corresponding increase in power demand. The domestic gas demand in Asia is also expected to continue to grow, and the commercialisation of our UCG technology will allow us to benefit from the robust demand for gas.

We plan to leverage on our existing UCG technology through joint ventures with strategic partners to develop projects within the region, taking advantage of the region's robust oil and gas demand outlook and the large number of potentially suitable coal resources in Asia, namely in China, Mongolia and Indonesia.

Our technical teams have a deep understanding of the oil and gas and coal mining industries and related complexities, and it is our intention to use this knowledge to identify exploration, appraisal and development opportunities as well as execute projects efficiently and cost effectively in Asia. Furthermore, our management is experienced in building strong working relationships with government agencies and these relationships play an important role in the development of our assets and the acquisition of rights over future oil and gas reserves. To the extent that we enter into joint ventures to develop projects within the region, we intend to open local offices in Asia and recruit leading industry professionals with significant experience and relationships in these markets, while exporting our technical experience and know-how to the region.

Unlock value through strategic portfolio management

In order to maximise value for our Shareholders, we regularly review and evaluate our asset portfolio and engage in strategic portfolio management activities. As part of our portfolio management activities, for example, in August 2010, we sold our interests in the Carmichael coal tenement to Adani for A$500.0 million (US$466.8 million) in cash and we also expect to receive the Carmichael Royalty.

Going forward, we intend to further develop our coal assets and, at the appropriate time, establish a pure-play Australian coal company via a divestment and/or demerger, subject to our Shareholders' approval at an extraordinary general meeting, in 2014 or after. We have taken advantage of the current attractive valuations to make accretive acquisitions in order to increase the value of our coal business prior to any divestment and/or demerger. The acquisition of the Blair Athol Mine (which is currently pending completion) is expected to provide stable cash flow, has well-understood mine geology, and requires minimal working capital and as such, carries a low risk profile. Furthermore, our strategy centres around a strong management team with operational and turn-around experience in both underground and open-cut operations, the development of newly acquired and existing conventional coal assets to unlock underlying value, and a strong focus on efficient mining operations and turn-around opportunities. The long term monetisation plan of divesting or demerging the coal assets may include interim financing arrangements, such as the sale of individual assets, to ensure the best long-term outcome for our Shareholders.

Optimise capital base and maintain financial flexibility

We intend to use the net proceeds from the Offering to fund the further exploration, appraisal and development of our asset base, which includes, in respect of our projects in the Gulf Coast Region and Umiat, Alaska, the exploration for sub-salt oil and gas potential which we intend to evaluate by 2014 and the development of the CO_2 EOR project in Wyoming. See "Use of Proceeds". As some of our assets are developed and mature, we plan to utilise a broader range of financing alternatives and strategies to fund our business plan which will require substantial amounts of additional capital. For instance, given our current average Working Interest of approximately, 97.9%, 97.0% and 84.5% in our oil and gas assets in the Gulf Coast Region, Wyoming and Alaska, respectively, we have the option to farm-out a portion of our Working Interest on advantageous terms, including the ability to enter into agreements which allow us to bring in partners to fund a disproportionate share of risk capital. In addition, we also have the option of leasing production infrastructure which has been constructed by third parties from such third parties which would accordingly reduce our capital expenditure. With regards to our coal business, we have the option to enter into strategic partnerships with reputable third parties who, in order to secure an agreement to purchase our coal, may acquire a portion of our Equity Interest in any of our coal projects. In respect of the above, no arrangements have been entered into.

SUMMARY OF THE OFFERING

The Company	Linc Energy Ltd, a public company incorporated in the Commonwealth of Australia with limited liability.
The Offering	[●] Offering Shares consisting of the Placement and the Public Offer (subject to the Over-allotment Option). The completion of the Public Offer and the completion of the Placement are each conditional upon the completion of the other.
The Placement	The Placement comprises a placement of [●] Offering Shares at the Offering Price to investors, including institutional and other investors in Singapore, outside the United States in reliance on Regulation S and within the United States only to qualified institutional buyers in reliance on Rule 144A, on the terms and subject to the conditions contained in this offering document.
The Public Offer	The Public Offer comprises [●] Offering Shares offered by way of public offer in Singapore at the Offering Price, on the terms and subject to the conditions contained in this offering document.
Clawback and Re-allocation	Offering Shares may be re-allocated between the Placement and the Public Offer at the discretion of the Joint Bookrunners and Joint Lead Managers after consultation with us in the event of an excess of applications in one and a deficit in the other, subject to the minimum holding of shares and distribution requirements of the SGX-ST.
Offering Price	S$[●] for each Offering Share. Investors in the Placement may be required to pay a brokerage fee (and if so required, such brokerage fee will be up to 1.0% of the Offering Price).
Price Determination	The Offering Price was determined following a book-building process by agreement between the Joint Bookrunners and Joint Lead Managers and us.
Lock-ups	We have agreed with the Joint Bookrunners and Joint Lead Managers, subject to certain exceptions, that we will not issue, offer, sell, contract to sell, pledge, sell any option or otherwise transfer or dispose of, directly or indirectly, any Shares, without, in each case, the prior written consent of the Joint Bookrunners and Joint Lead Managers (such consent not to be unreasonably withheld), from the date of the Singapore Offer Agreement dated [●] (the "**Singapore Offer Agreement**") until six months after the Listing Date (both dates inclusive) (the "**First Lock-up Period**"). Each of Newtron Pty Ltd ("**Newtron**") and ISNY Pty Ltd ("**ISNY**") has agreed with the Joint Bookrunners and Joint Lead Managers that it will not, subject to certain exceptions

	as set out in "Plan of Distribution—Lock-up Arrangements", offer, sell, contract to sell, grant an option to purchase, grant security over, or otherwise transfer or dispose of, directly or indirectly, any Shares held by it as of the date of the Singapore Offer Agreement and any additional Shares that each of Newtron and/or ISNY may acquire between the date of the Singapore Offer Agreement and the Listing Date without, in each case, the prior written consent of the Joint Bookrunners and Joint Lead Managers (such consent not to be unreasonably withheld), for the First Lock-Up Period. Each of Newtron and ISNY has also agreed with the Joint Bookrunners and the Joint Lead Managers to a similar lock-up with respect to 50% of the Shares held by it as at the Listing Date, for the period commencing on the day immediately following the expiry of the First Lock-up Period until the date falling six months from such day (the "**Second Lock-up Period**"). Mr. Peter Bond, the sole shareholder of Newtron and ISNY, has also agreed with the Joint Bookrunners and Joint Lead Managers, subject to certain exceptions, that he will not, offer, sell, contract to sell, grant an option to purchase, grant security over, or otherwise transfer or dispose of, directly or indirectly, any Shares, any ordinary shares of Newtron ("**Newtron Shares**") or any ordinary shares of ISNY ("**ISNY Shares**") held by him as of the date of the Singapore Offer Agreement and the Listing Date, without, in each case, the prior written consent of the Joint Bookrunners and Joint Lead Managers (such consent not to be unreasonably withheld), for the First Lock-up Period and the Second Lock-up Period. See "Plan of Distribution—Lock-up Arrangements".
Use of Proceeds	We estimate that the net proceeds we will receive from the Offering (assuming the Over-allotment Option is not exercised) will be approximately S$[●] million (US$[●] million), after deduction of estimated expenses and commissions. We intend to use these proceeds for the following purposes: • approximately S$[●] million (US$[●] million) for the conventional oil and gas business, specifically towards developing our Umiat field in Alaska, developing the CO_2 EOR project with regard to our assets in Wyoming and also the sub-salt dome drilling and exploration programme in the Gulf Coast Region; • approximately S$[●] million (US$[●] million) for the Clean Energy business, specifically towards developing the UCG project in Poland and South Africa (in particular, developing the joint venture with Exxaro Resources), undertaking various other project development activities in Europe, Russia, North America and Asia, and to conduct additional exploration drilling and seismic programme for the SAPEX business; and

- the balance for funding working capital and other general corporate purposes.

See "Use of Proceeds".

Listing and Trading on SGX-ST .... Application has been made to the SGX-ST for permission to list all the issued Shares, the existing Shares, the Offering Shares, the Additional Shares, the Employee Option Plan Shares, the Performance Rights Plan Shares and the CN Shares on the Main Board of the SGX-ST. Such permission will be granted when we have been admitted to the Official List of the SGX-ST. Acceptance of applications for the Offering Shares will be conditional upon, among others, permission being granted to deal in and for quotation for all the issued Shares, the existing Shares, the Offering Shares, the Additional Shares, the Employee Option Shares, the Performance Rights Shares and the CN Shares.

Our Shares will, upon their listing and quotation on the SGX-ST, be traded on the SGX-ST under the book-entry (scripless) settlement system of CDP. Dealing in and quotation of our Shares will be in Singapore dollar. Our Shares will be traded in board lot sizes of 1,000 Shares.

Settlement and Delivery of our Offering Shares .... We expect to receive payment for all the Offering Shares in the Placement and the Public Offer on or about [●] 2013. We expect to deliver global share certificates representing the Offering Shares to CDP for deposit into the securities accounts of successful applicants on or about [●] 2013. See "Clearance and Settlement".

Application Procedures for the Public Offer............... Investors under the Public Offer must follow the application procedures set out in the instructions booklet titled "Terms, Conditions and Procedures for Application for and Acceptance of the Offering Shares in Singapore" which was registered by the Authority as part of the Singapore Prospectus. Applications must be paid for in Singapore dollar. The minimum initial application is for 1,000 Offering Shares. An applicant may apply for a larger number of Offering Shares in integral multiples of 1,000 Offering Shares.

Over-allotment Option ...... In connection with the Offering, we have granted the Stabilising Manager, on behalf of the Joint Bookrunners and Joint Lead Managers, the Over-allotment Option, to subscribe for up to an aggregate of the Additional Shares at the Offering Price, exercisable in full or in part on one or more occasions, from the Listing Date until the earliest of (i) the date falling 30 days from the Listing Date, (ii) the date when the Stabilising Manager or its appointed agent has bought on the SGX-ST, an aggregate of [●] Shares, representing not more than 10.0% of the total Offering Shares, to undertake stabilising actions, or (iii) the date falling 30 days after the date of adequate public disclosure of the Offering Price, solely to cover the over-allotment of the Offering Shares, if any, subject to any applicable laws and regulations. In the event the Over-allotment Option is exercised in full, the total number of issued Shares after the completion of the Offering will be increased to [●] Shares. See "Plan of Distribution—Over-allotment Option".

Stabilisation .... In connection with the Offering, the Stabilising Manager (or persons acting on its behalf) may over-allot Shares or effect transactions which may stabilise or maintain the market price of our Shares at levels above those that might otherwise prevail in the open market. Such transactions may be effected on the SGX-ST and in other jurisdictions where it is permissible to do so, in each case in compliance with all applicable laws and regulations, including the Securities and Futures Act and any regulations thereunder. However, there is no assurance that the Stabilising Manager (or persons acting on its behalf) will undertake any such stabilisation action. Such transactions may commence on or after the Listing Date and, if commenced, may be discontinued at any time and shall not be effected after the earliest of (i) the date falling 30 days from the Listing Date, (ii) the date when the Stabilising Manager or its appointed agent has bought on the SGX-ST an aggregate of [●] Shares, representing not more than [●]% of the total Offering Shares, to undertake stabilising actions, or (iii) the date falling 30 days after the date of adequate public disclosure of the Offering Price.

Transfer Restrictions........ The Offering Shares have not been, and will not be, registered under the U.S. Securities Act. Therefore, resales by subscribers of the Offering Shares will be subject to certain transfer restrictions described in "Transfer Restrictions".

Dividends...................... While we currently do not have a formal dividend policy, we intend to reinvest any profits generated from our operations in our business. The form, frequency and amount of future dividends on our Shares will depend on our earnings, general business and financial position, results of operations, capital requirements, cash flow, and other factors which our Directors may deem appropriate. Therefore, there can be no assurance that dividends will be paid in the future or of the amount or timing of any dividends that will be paid in future.

Risk Factors .... Prospective investors should carefully consider certain risks connected with an investment in our Shares, as discussed under "Risk Factors".

INDICATIVE TIMETABLE

An indicative timetable for trading in our Shares is set out below for the reference of applicants for our Shares:

Date and time (Singapore)	Event
[●] 2013, [●] [a.m./p.m.]	Opening date and time for the Public Offer.
[●] 2013, [●][a.m./p.m.]	Closing date and time of the Public Offer.
[●] 2013	Balloting of applications in the Public Offer, if necessary. Commence refunding of application monies to unsuccessful or partially successful applicants and commence returning or refunding of application monies to unsuccessful or partially successful applicants, if necessary.
[●] 2013, [●][a.m./p.m.]	Commence trading on a "ready" basis.
[●] 2013	Settlement date for all trades done on a "ready" basis on [●] 2013.

The above timetable is indicative only and is subject to change at our discretion, with the agreement of the Joint Bookrunners and Joint Lead Managers. The above timetable and procedure may also be subject to such modifications as the SGX-ST may in its discretion decide, including the commencement date of trading on a "ready" basis. It assumes that (i) the closing of the Public Offer is on [●] 2013, (ii) the date of admission of our Company to the Official List of the SGX-ST is [●] 2013, and (iii) compliance with the SGX-ST's shareholding spread requirement. All dates and times referred to above are Singapore dates and times.

We may at our discretion, with the agreement of the Joint Bookrunners and Joint Lead Managers, subject to all applicable laws and regulations and the rules of the SGX-ST, agree to extend or shorten the period during which the Offering is open, provided that the Public Offer may not be less than two Market Days.

In the event of the extension or shortening of the time period during which the Public Offer is open, we will publicly announce the same immediately:

(i) through a SGXNET announcement to be posted on the Internet at the SGX-ST website http://www.sgx.com; and

(ii) in one or more major Singapore newspapers, such as *The Straits Times*, *The Business Times* and *Lianhe Zaobao*.

Investors should consult the SGX-ST announcement on the "ready" listing date on the Internet (at the SGX-ST website) or in one or more major Singapore newspapers, or check with their brokers on the date on which trading on a "ready" basis will commence.

We will provide details of and the results of the Public Offer through SGXNET or in one or more major Singapore newspapers, such as *The Straits Times*, *The Business Times* and *Lianhe Zaobao*.

We reserve the right to reject or accept, in whole or in part, or to scale down or ballot any application for the Offering Shares, without assigning any reason therefore, and no enquiry and/or correspondence on our decision will be entertained. In deciding the basis of allocation, due consideration will be given to the desirability of allocating our Offering Shares to a reasonable number of applicants with a view to establishing an adequate market for our Shares.

In respect of an application made under the Public Offer, where an application is rejected, the full amount of the application monies will be refunded (without interest or any share of revenue or other benefit arising from such application) to the applicant at his own risk within 24 hours after balloting of applications (provided that such refunds are made in accordance with the procedures set out in the instructions booklet titled "Terms, Conditions and Procedures for Application for and Acceptance of the Offering Shares in Singapore").

In respect of an application made under the Public Offer, where an application is accepted in part only, any balance of the application monies will be refunded (without interest or any share of revenue or other benefit arising from such application) to the applicant, at his own risk, within 14 Market Days after the close of the Offering (provided that such refunds are made in accordance with the procedures set out in the instructions booklet titled "Terms, Conditions and Procedures for Application for and Acceptance of the Offering Shares in Singapore").

In respect of an application made under the Public Offer, if the Offering does not proceed for any reason, the full amount of application monies (without interest or any share of revenue or other benefit arising from such application) will be returned to the applicant, at his own risk, within three Market Days after the Offering is discontinued (provided that such refunds are made in accordance with the procedures set out in the instructions booklet titled "Terms, Conditions and Procedures for Application for and Acceptance of the Offering Shares in Singapore")

The manner and method for applications and acceptances under the Placement will be determined by the Joint Bookrunners and Joint Lead Managers in consultation with us.

SUMMARY CONSOLIDATED FINANCIAL INFORMATION AND OTHER DATA

You should read the following summary consolidated financial information for the periods and as at the dates indicated in conjunction with the section of this offering document titled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements, the accompanying notes and the related independent auditor's report included in this offering document. Our consolidated financial statements are reported in Australian dollars and are prepared and presented in accordance with IFRS as issued by the IASB, which may differ in certain significant respects from generally accepted accounting principles in other countries, including the United States.

The summary consolidated financial information as at and for the financial years ended 30 June 2011, 2012 and 2013 have been derived from our annual consolidated financial statements included elsewhere in this offering document. Our historical results for any prior or interim periods are not necessarily indicative of results to be expected for a full financial year or for any future period.

Summary Consolidated Statement of Comprehensive Income Data

	FY2011	FY2012	FY2013	FY2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Revenue	3,199	57,060	124,370	116,099
Cost of sales	(2,992)	(31,680)	(59,381)	(55,432)
Gross Profit	**207**	**25,380**	**64,989**	**60,667**
Gain on sale of coal tenement, net of costs	495,001	-	-	-
Gain on purchase of oil and gas assets	6,027	-	628	586
Other income	971	1,075	143	133
Expenses:				
Administration and corporate	(57,550)	(72,902)	(64,410)	(60,127)
Site operating costs	(12,666)	(12,367)	(9,075)	(8,472)
Exploration and evaluation	(2,455)	(3,326)	(3,245)	(3,029)
Technology development	(18,997)	(18,063)	(11,139)	(10,398)
Other expenses	-	(1,841)	(33,322)	(31,106)
Results from operating activities	**410,538**	**(82,044)**	**(55,431)**	**(51,746)**
Finance income	22,181	3,578	41,446	38,690
Finance expenses	(413)	(11,231)	(72,001)	(67,213)
Net finance costs	**21,768**	**(7,653)**	**(30,555)**	**(28,523)**
Profit / (loss) before income tax	**432,306**	**(89,697)**	**(85,986)**	**(80,269)**
Income tax benefit / (expense)	(135,865)	27,804	22,161	20,687
Profit / (loss) for the year	**296,441**	**(61,893)**	**(63,825)**	**(59,582)**
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss:				
Net change in the fair value of available-for-sale financial assets, net of transaction costs and tax	5,726	(7,895)	6,596	6,157
Foreign currency translation differences for foreign operations	554	(597)	31,620	29,517
Total other comprehensive income / (loss) for the year, net of income tax	**6,280**	**(8,492)**	**38,216**	**35,674**
Total comprehensive income / (loss) for the year	**302,721**	**(70,385)**	**(25,609)**	**(23,908)**

	Audited			
	FY2011	FY2012	FY2013	FY2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Profit / (loss) attributable to:				
Our equity holders	296,455	(61,891)	(63,805)	(59,562)
Non-controlling interest	(14)	(2)	(20)	(19)
Profit / (loss) for the year	**296,441**	**(61,893)**	**(63,825)**	**(59,581)**
Total comprehensive income / (loss) attributable to				
Our equity holders	302,757	(70,379)	(26,683)	(24,909)
Non-controlling interest	(36)	(6)	1,074	1,003
Total comprehensive income / (loss) for the year	**302,721**	**(70,385)**	**(25,609)**	**(23,908)**
	Australian cents	*Australian cents*	*Australian cents*	*United States cents*
Earnings / (loss) per Share attributable to our ordinary equity holders[(1)]:				
Basic[(2)]	59.27	(12.18)	(12.40)	(11.60)
Diluted[(3)]	57.71[(2)]	(12.18)	(12.40)	(11.60)
Adjusted[(4)]	[●]	[●]	[●]	[●]

Notes:

(1) The earnings / (loss) per Share excludes potential dilution from conversion of the 2018 Convertible Notes into CN Shares. Assuming conversion of the 2018 Convertible Notes fully into CN Shares, the basic earnings/(loss) per Share were [●] Australian cents for FY2011, [●] Australian cents for FY2012 and [●] Australian cents ([●] United States cents) for FY2013, calculated based on profit / (loss) for the year divided by the share capital of [●] Shares .

(2) The earnings per Share for FY2011 were computed based on the pre-Offering weighted average share capital of 500,204,247 Shares while the loss for FY2012 and FY2013 were computed based on the pre-Offering weighted average share capital of 508,143,132 and 514,712,468 Shares.

(3) The dilution in FY2011 was due to the effect of the conversion of then outstanding share options and share rights into a total of 13,513,284 additional Shares.

(4) The earnings / (loss) per Share as adjusted for the Offering is calculated based on profit / (loss) for the year divided by the post-Offering share capital of [●] Shares.

Summary Consolidated Statement of Financial Position Data

	As at 30 June			
	2011	2012	2013	2013
	(A$'000)	(A$'000)	(A$'000)	(US$'000)
Assets				
Cash and cash equivalents	310,343	25,680	124,007	115,761
Trade and other receivables	2,654	17,712	50,526	47,166
Inventories	936	2,773	2,935	2,740
Assets classified as held for sale	9,032	-	-	-
Other financial assets	15,814	-	958	894
Total current assets	**338,779**	**46,165**	**178,426**	**166,561**
Receivables	5,856	15,127	28,100	26,231
Intangibles	195,108	248,711	271,294	253,253
Property, plant and equipment	12,775	18,842	17,806	16,622
Oil and gas assets	25,288	384,581	555,538	518,595
Available-for-sale investments	23,128	13,652	16,220	15,141
Deferred tax assets	19	701	1,077	1,005
Other assets	-	-	30	28
Total non-current assets	**262,174**	**681,614**	**890,065**	**830,875**
Total assets	**600,953**	**727,779**	**1,068,491**	**997,436**
Liabilities				
Trade and other payables	14,927	38,851	94,097	87,840
Borrowings	2,786	185,678	1,632	1,523
Current tax liability	10,781	31	-	-
Provisions	2,894	3,702	8,574	8,004
Other financial liability	-	221	2,691	2,512
Total current liabilities	**31,388**	**228,483**	**106,994**	**99,879**
Payables	-	1,174	1,281	1,196
Borrowings	1,866	1,144	477,423	445,674
Deferred tax liability	48,331	18,922	894	835
Provisions	5,647	24,020	37,052	34,588
Other financial liability	-	162	-	-
Total non-current liabilities	**55,844**	**45,422**	**516,650**	**482,293**
Total liabilities	**87,232**	**273,905**	**623,644**	**582,172**
Net assets	**513,721**	**453,874**	**444,847**	**415,264**
Equity				
Share capital	309,493	310,606	325,388	303,750
Reserves	40,377	31,537	70,459	65,773
Retained earnings	163,794	101,903	38,098	35,564
Total equity attributable to our equity holders	**513,664**	**444,046**	**433,945**	**405,087**
Non-controlling interest	57	9,828	10,902	10,177
Total equity	**513,721**	**453,874**	**444,847**	**415,264**

Summary Consolidated Cash Flow Statement Data

	FY2011	FY2012	FY2013	FY2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Cash flows from operating activities				
Receipts from customers and other debtors (inclusive of goods and service tax)	3,756	48,208	121,998	113,885
Payments to suppliers and employees (inclusive of goods and service tax)	(53,023)	(110,654)	(102,612)	(95,788)
Interest and borrowing costs paid	(413)	(10,186)	(27,421)	(25,598)
Receipts from Alaskan tax credits	-	-	3,738	3,489
Payments for commodity swaps	-	(3,634)	(2,341)	(2,185)
Income taxes paid	(30,802)	(9,651)	987	921
Net cash used in operating activities	**(80,482)**	**(85,917)**	**(5,651)**	**(5,276)**
Cash flows from investing activities				
Payments for property, plant and equipment	(4,192)	(6,716)	(1,818)	(1,697)
Proceeds from disposal of property, plant and equipment	88	23	183	171
Proceeds from sale of coal tenement	500,000	-	-	-
Payments for software	(410)	(1,929)	(1,475)	(1,377)
Payments for exploration and evaluation (including tenement acquisitions)	(34,041)	(35,169)	(22,328)	(20,843)
Payments for exploration and development of oil and gas assets and coal-to-liquid assets	(8,807)	(32,550)	(156,139)	(145,756)
Payments for equity investments	(16,894)	(1,804)	-	-
Payment for acquisition of producing oil and gas assets	(18,268)	(254,697)	(2,977)	(2,779)
Payment for Umiat acquisition net of cash acquired	-	(44,660)	-	-
Loans to related parties	-	(250)	(260)	(243)
Proceeds from repayment of loans to related parties	-	-	12	11
Deposits paid on acquisitions in progress	(14,158)	-	-	-
Interest received	20,175	3,623	603	563
Net cash transferred (to)/from term deposits held as security for guarantees and bonds or held as investments	(3,150)	(4,862)	(12,156)	(11,348)
Net cash from / (used) in investing activities	**420,343**	**(378,991)**	**(196,355)**	**(183,298)**
Cash flows from financing activities				
Proceeds from the exercise of share options	7,555	2,133	3,234	3,019
Proceeds from the extinguishment of convertible loan facility	5,018	-	-	-
Proceeds from borrowings	775	191,433	103,397	96,521
Proceeds from notes issues	-	-	439,060	409,863
Repayment of borrowings	-	(1,800)	(257,047)	(239,953)
Payments associated with financing activities	-	-	(18,390)	(17,167)
Repayment of finance lease liabilities	(1,104)	(1,274)	(713)	(666)
Payment for share buy-backs net of costs	-	(12,093)	-	-
Dividends paid	(49,643)	-	-	-
Net cash from / (used) in financing activities	**(37,399)**	**178,399**	**269,541**	**251,617**
Net increase / (decrease) in cash and cash equivalents	**302,462**	**(286,509)**	**67,535**	**63,044**
Cash and cash equivalents at 1 July	7,365	310,343	25,680	23,972
Effect of exchange rate fluctuations on cash held	516	1,846	30,792	28,744
Cash and cash equivalents at 30 June	**310,343**	**25,680**	**124,007**	**115,760**

Other Financial Information and Non-IFRS Financial Data

	FY2011	FY2012	FY2013	FY2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Oil and gas sales revenue	1,785	55,098	118,259	110,395
Clean Energy				
UCG syngas revenue	1,414	1,962	2,267	2,116
Consulting revenue	-	-	3,844	3,588
	(US$'000)	*(US$'000)*	*(US$'000)*	
Other US Financial Data				
Drilling and development capital expenditures[1]	378	20,024	96,589	
Plant, property and equipment capital expenditures	433	4,965	4,001	
Exploration capital expenditure	5,589	-	57,319	
	(US$'000)	*(US$'000)*	*(US$'000)*	
US Oil & Gas Data[2]				
EBITDAX[3]	(1,820)	26,018	78,371	

Notes:

(1) Drilling and development capital expenditures as shown above differ from the amounts shown as payments for evaluation and development in the statement of cash flows in the combined financial statements because amounts above include changes in accrued capital expenditures from the previous reporting period, while the amounts in the statement of cash flows in the combined financial statements are presented on a cash basis.

(2) These US amounts are the actual amounts and were not restated based on the convenience translation of A$1 : US$0.9335.

(3) EBITDAX as used herein represents net profit (loss) before income tax, non-controlling interest, interest income, finance costs, depreciation, depletion and amortisation, loss on sales of assets, impairment expense, accretion expense, unrealised commodity derivative loss, plug and abandonment and bad debt expense, in relation to our conventional oil and gas business in the United States. We present EBITDAX because we believe it is an important supplemental measure of our performance that is frequently used by others in evaluating companies in our industry. EBITDAX is not a measurement of our financial performance under IFRS and should not be considered as an alternative to net income, operating income or any other performance measure derived in accordance with IFRS or as an alternative to net cash provided by operating activities as a measure of our profitability or liquidity. EBITDAX has significant limitations, including that it does not reflect our cash requirements for capital expenditures, contractual commitments, working capital or debt service. In addition, other companies may calculate EBITDAX differently from us, limiting its usefulness as comparative measures. The following table sets forth a reconciliation of EBITDAX to net profit (loss) before income tax as determined in accordance with IFRS for the periods indicated:

	FY2011	FY2012	FY2013
	(US$'000)	*(US$'000)*	*(US$'000)*
Net profit (loss) before income tax	**3,835**	**9,335**	**(4,912)**
Non-controlling interest	-	12	41
Interest income	(9)	(8)	(15)
Finance costs	7	3,538	30,073
Depreciation, depletion and amortisation	352	12,090	31,106
Gain on purchases and sales of assets	(6,005)	(78)	(614)
Impairment expense	-	-	17,225
Accretion expense[a]	-	740	1,064
Unrealised commodity derivative loss[b]	-	389	2,042
Plug and abandonment	-	-	1,821
Bad debt expense	-	-	540
EBITDAX	**(1,820)**	**26,018**	**78,371**

(a) Represents non-cash expenses for increases to the asset retirement obligation liability.

(b) Represents non-cash losses as a result of mark-to-market accounting of outstanding hedging contracts.

Operating Statistics

	FY2011[(1)]	FY2012[(2)]	FY2013
Total gross production (MBOE)	26.4	782.7	1,552.3
Net daily oil production volume (BOEPD)	151	2,062	3,170
Average realised price for oil and gas (excluding oil price hedges) (US$ / BOE)	95.84	97.97	104.95
Average lease operating expenses[(3)] (US$ / BOE)	40.28	20.02	13.77

Notes:

(1) These reflect the gross production volume, sales volumes, average realised price (excluding oil price hedges) and average lease operating expenses for our assets in Wyoming, which we acquired in February 2011.

(2) These reflect the gross production volume, sales volumes, average realised price (excluding oil price hedges) and average lease operating expenses for our assets in Wyoming for the full year and for our assets in the Gulf Coast Region from October 2011 when we acquired the relevant assets.

(3) Average lease operating expenses are calculated as oil and gas lease operating expenses in the period divided by total net production in the period.

RISK FACTORS

An investment in our Shares involves risk. Prospective investors should rely on their own evaluation and carefully consider the following risk factors, in addition to other information contained elsewhere in this offering document, before investing in our Shares. If any of the risks described herein actually occur, our performance, prospects, financial condition, results of operations and ability to make dividend payments could be negatively affected, the trading price of our Shares, could decline and you may lose all or part of your investment.

Unless quantified in the relevant risk factors set out herein, we are not in a position to quantify the financial or other implication of any of the risks described in this section. Any potential investor in, and purchaser of, our Shares should pay particular attention to the fact that we are governed in jurisdictions such as Australia and United States by a legal, regulatory and business environment which in some material respects may be different from that which prevails in Singapore and other countries. In addition, the following risk factors may not be exhaustive, and additional risks and uncertainties not presently known to us or which are currently deemed to be immaterial may become material in the future, which could have a material adverse effect on our performance, prospects, financial condition, results of operations and ability to make dividend payments or the trading price of our Shares, if any.

Investors should be aware that the price of our Shares may fluctuate. Investors should also note that they may not recoup all or any portion of their original investment.

RISKS RELATING TO OUR OPERATIONS

Exploration and development involves numerous risks and substantial and uncertain costs that may not yield desired results, resources or reserves for us

Our future financial condition and results of operations will be affected by the success of our exploration, development and production activities. Our exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling/mining will not result in commercially viable oil, gas and coal production. Our decision to explore and develop or otherwise drill or mine locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are subject to varying interpretations and may be inconclusive. The costs associated with drilling, completing and operating wells are often uncertain before drilling commences. Correspondingly, the costs associated with producing commercially viable volumes of coal are often uncertain before mining commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel scheduled drilling or mining projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions, drilling or mining hazards or environmental damage;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as flooding and storms;
- insufficient storage or transportation capacity;
- reductions in oil, gas and/or coal prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;

- limitations in the market for oil, gas and/or coal;
- costs and availability of contractual arrangements for properties or equipment associated with our activities; and
- title problems.

In terms of our oil and gas operations, our management team has identified and scheduled drilling locations on our acreage over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of equipment and capital, seasonal conditions, regulatory approvals, oil and/or gas prices, costs and drilling results. The final determination on whether to drill any of these drilling locations will be dependent upon the factors described elsewhere in this offering document as well as, to some degree, the results of our drilling activities with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe or at all or if we will be able to economically produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

In order to carry out EOR in Wyoming, we would require an adequate supply of CO_2, which is a valuable commodity in Wyoming. In addition, we need to ensure that wellbores are secured for the injection of CO_2. If we are unable to find a long-term source of CO_2 for the life of the asset and/or secure wellbores as required, this may adversely affect our ability to carry out CO_2 EOR in Wyoming.

Separately, our completed oil and gas wells and drill holes and correspondingly, our coal mines, may not produce reserves of oil, gas or coal that meet our earlier estimates of economically recoverable reserves. Even when drilling or mining does locate reserves, these may become uneconomic if other factors outside of our control impair or prevent the production of oil, gas or coal from those reserves. Further, in relation to our unconventional oil and gas operations, drilled resources or reserves may not be suitable for use in the production of syngas used for UCG to GTL production and power generation.

Our prospects are in various stages of evaluation, and may range from a prospect that is ready to be drilled or to be mined, to a prospect that will require substantial additional seismic data processing and interpretation and other technical analysis. We cannot predict in advance of drilling or mining whether any particular prospect will yield oil, gas or coal in sufficient quantities to recover drilling/mining or completion costs or to be economically viable. Moreover, the overall drilling/mining success rate within a particular project area may decline. Unsuccessful drilling/mining activities could result in a significant decline in our production and revenues and materially harm our operations and financial condition by reducing available cash and resources. Because of the risks and uncertainties of our business, the future performance in exploration and drilling/mining may not be comparable to the historical performance of our assets or ultimately result in the realisation of proved reserves, as the case may be.

In addition, the use of seismic data and other technologies and the study of producing fields or mines in the same area will not enable us to know conclusively prior to drilling or mining whether oil, gas or coal will be present or, if present, whether oil, gas or coal will be present in commercial quantities. Seismic data is a method used to determine the depth and orientation of subsurface rock formations. Even when properly used and interpreted, 2D and 3D seismic data and visualisation techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know definitively whether hydrocarbons are, in fact, present in those structures or the amount of hydrocarbons. We employ 3D seismic technology with respect to certain of our projects. The use of seismic and other advanced technologies requires greater pre-drilling/pre-mining expenditures than traditional drilling/mining strategies, and we might not be able to recover such expenditures. As such, our drilling/mining activities may not be successful or economical, and our overall drilling/mining success rate, or our drilling/mining success rate for activities in a particular area, could decline. We cannot assure investors that the analogies drawn from available data from other wells/mines, more fully explored prospects or producing fields/mines will be applicable to our drilling/mining prospects.

Our Company was in a net loss position for FY2012 and FY2013

For FY2012 and FY2013, we were in a net loss position of A$61.9 million and A$63.8 million, respectively. We also recorded negative operating cash flows of A$85.9 million and A$5.7 million for the same periods. There is no assurance we will not be in a net loss position or a negative operating cash flows in the future.

Our oil, gas and coal operations involve many operational risks, some of which could result in substantial losses and unforeseen interruptions to our operations

Our oil, gas and coal operations are subject to all the risks normally incidental to the oil, gas and coal development and production business, including:

- blowouts, cratering (catastrophic failure), explosions and fires;
- adverse weather effects and natural disasters;
- environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- uncontrolled flows of oil, gas or well fluids;
- high costs of drilling rigs and other essential equipment, supplies, personnel and oilfield services, shortages or delivery delays of equipment, materials (such as CO_2), labour or other services;
- facility or equipment malfunctions, failures or accidents;
- pipe or cement failures or casing collapses;
- reservoir damage;
- compliance with environmental and other governmental requirements as well as licensing or regulatory issues;
- lost or damaged oilfield workover and service tools;
- unusual or unexpected geological formations or pressure or irregularities in formations; and
- protests or disruptions caused by the local community, compensation claims for land acquisition and native title claims.

The cost to develop our projects has not been fixed and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs. Our construction and operation schedules may not proceed as planned and may experience delays or cost overruns. Any delay may increase the costs of the projects, requiring additional capital, and such capital may not be available in a timely and cost-effective fashion.

Our overall exposure to operational risks may increase as our operations expand. Any of these risks could result in substantial losses due to claims in relation to injury or loss of life, worker's compensation, production facilities or other property. Exposure to operational risks may subject us to clean-up responsibilities, regulatory investigations and penalties; suspension of operations and default in our obligations to third parties, which could have a material adverse effect on our results of operations and financial condition.

We rely on the discovery or acquisition and development of additional reserves that are economically recoverable to replace our reserves

The future success of our conventional oil, gas and coal business depends upon our ability to find, develop or acquire additional oil, gas and coal reserves that are economically recoverable. If we are unable to replace reserves through drilling or acquisitions, our level of production and cash flows will be adversely affected. In general, production from oil, gas and coal assets declines as reserves are depleted, with the rate of decline depending on the relevant reservoir characteristics. Our total reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire assets containing reserves that are economically recoverable. Our ability to make the necessary capital investment to maintain or expand our asset base of oil, gas and coal reserves could be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. As a result, we may not be successful in exploring, developing or acquiring additional reserves and we may also not be successful in raising funds to acquire additional reserves.

We may face difficulties obtaining financing for new projects, expansion and developments

Our business is capital intensive and we require substantial funds to explore and develop our assets prior to generating revenue. Our existing funds, available credit facilities and internally-generated funds may not be sufficient for expenditure that might be required for acquisitions, new projects and developments, further exploration and feasibility studies. We may need to raise additional debt or equity funds in the future to develop our projects, to place them in commercial production and to expand our operations. There is no assurance that we will be able to obtain additional debt or equity funding when required, or that the terms associated with that funding will be acceptable to us.

Our ability to secure funding for projects or other forms of financing for operations may depend on a number of factors, including commodity prices, interest rates, economic conditions, debt market conditions, share market conditions and country risk issues. Inability to obtain financing or refinancing could cause revisions or delays in planned capital expenditure, reduction in the scope of planned activities or increased financing costs and, thus, adversely affect our business, reputation, financial condition and results of operations of our Group.

Our future capital requirements will depend on many factors, including:

- the scope, rate of progress and cost of our exploration, development and production activities;
- oil, gas and coal prices;
- our ability to locate and acquire hydrocarbon and coal reserves;
- our ability to produce oil, gas and coal from those reserves;
- the terms and timing of any drilling and other production-related arrangements that we may enter into;
- the cost and timing of governmental approvals and/or concessions; and
- the effects of competition by larger companies operating in the oil, gas and coal industries.

Additionally, any debt financing we undertake could make us more vulnerable to changing exchange rates, interest rates, competitive pressure and economic downturns in our industry or the economy, in general. It could also require us to use a portion of our cash from operations for the repayment of debt or service interest expense, which will reduce the cash that would otherwise be available for our working capital needs, capital expenditures, acquisitions and other general requirements and reduce our flexibility to respond to changing business, regulatory and economic conditions.

The existing debt instruments and revolving credit facility of our Group have restrictions and financial covenants that may restrict our business and financing activities

We have entered into a senior secured revolving credit facility for US$65.0 million with an option to take an additional US$10.0 million subject to certain conditions dated 24 October 2013 (the "**2013 Credit Facility**") through our wholly-owned subsidiary, Linc Energy Resources, Inc. The obligations of Linc Energy Resources, Inc. under the 2013 Credit Facility are guaranteed by several of our subsidiaries in the United States including Linc USA GP, Linc Energy Finance (USA), Inc, Linc Gulf Coast Petroleum, Inc; Linc Alaska Resources, LLC, Linc Energy Petroleum (Wyoming), Inc, Paen Insula Holdings, LLC, Diasu Holdings, LLC and Diasu Oil & Gas Company, Inc. and secured by a first priority lien on all assets under Linc Energy Resources, Inc and Linc Energy Finance (USA), Inc which would cover our oil and gas assets in the Gulf Coast Region and Wyoming, as well as over certain other property interests which may be acquired by such subsidiaries thereafter. In addition, Linc USA GP and Linc Energy Finance (USA), Inc., also our wholly-owned subsidiaries, issued an aggregate principal amount of US$265.0 million 12.5% senior secured notes due 31 October 2017 (the "**2017 Senior Secured Notes**"). The 2017 Senior Secured Notes are guaranteed by all existing and future subsidiaries of Linc Energy Resources, Inc (other than immaterial subsidiaries of Linc Energy Resources, Inc, Renaissance Umiat, LLC as well as existing and future subsidiaries of Renaissance Umiat, LLC).

The terms under the 2017 Senior Secured Notes and the 2013 Credit Facility require us to comply with certain covenants and restrictions before dividends may be declared by certain of our subsidiaries. Such restrictions (including the satisfaction of the excess cash flow offer and payment being limited to 50% of the consolidated net income of Linc Energy Resources, Inc.) may limit our ability to receive dividends or cash from the relevant subsidiaries, which could adversely affect our financial condition and ability to execute our business plans or pay dividends. The credit agreement governing the 2013 Credit Facility contains financial and other covenants that require Linc Energy Resources, Inc, and its subsidiaries to achieve, amongst others, a specified maximum Debt to EBITDAX ratio. The indenture governing the 2017 Senior Secured Notes contains covenants that restrict, among others, the sale, lease or other disposition of any assets or rights of the issuers and guarantors, namely Linc USA GP and Linc Energy Finance (USA), Inc. and certain of their subsidiaries as well as the payment of dividends and other distributions and payments by them. For instance, to be able to declare dividends, a certain net leverage ratio, among others, would have to be maintained.

Any breach of such covenants or triggering of events of default relating to the 2017 Senior Secured Notes or the 2013 Credit Facility by our relevant subsidiaries for reasons such as a change in control and/or other customary events of default and/or the inability to attain operational targets or factors beyond our control, such as fluctuations in commodity prices, interest rates, credit ratings of our Company or our subsidiaries and competition for available debt financing could result in a loss of financing for our subsidiaries and may have a material adverse effect on our business, financial condition and results of operations.

In addition, we had on 10 April 2013 issued an aggregate principal amount of US$200.0 million 7.0% convertible, unsubordinated and unsecured notes due 10 April 2018 (the "**2018 Convertible Notes**") on the SGX-ST. Pursuant to the 2018 Convertible Notes, among other conditions, we shall not create or permit to subsist, any mortgage, charge, lien, pledge or other form of encumbrance or security interest upon the whole or any part of our present or future property or assets to secure any relevant indebtedness. Further, repayment of the 2018 Convertible Notes may be triggered by, but not limited to, a default in payment of the 2017 Senior Secured Notes or other indebtedness. In the event that the 2018 Convertible Notes have to be repaid, this would expose us to liability and could have a material adverse effect on our business, financial condition and results of operations.

As at 30 June 2012, we were in breach of one of the financial covenants in respect of the current ratio of Linc Energy Resources, Inc and its subsidiaries that comprise our producing oil and gas assets under our previous reserve based lending facility dated 6 October 2011 (the "**2011 Reserve Based Lending Facility**") which has since been repaid with the proceeds from the 2017 Senior Secured Notes. Subsequent to the reporting date we received a waiver in respect of the breach, and we were subsequently in compliance with all other covenant requirements under this facility.

We had previously entered into a senior secured revolving credit facility for US$50.0 million dated 12 October 2012 (the "**2012 Credit Facility**") through our wholly-owned subsidiary, Linc Energy Resources, Inc., which has been refinanced with the proceeds from the 2013 Credit Facility. We had in the past breached one of the covenants under the 2012 Credit Facility which stipulates that we must attain certain minimum amounts of net production for the month. These instances of non-compliance were resolved either by amendment to the terms of the agreement, or waivers from the lender. There is no minimum production covenant in the 2013 Credit Facility.

Due to the nature of our business, we cannot assure you that factors beyond our control, including the risks set out in this offering document, will not occur that will cause us to be in breach of any existing or future covenants which could have a material adverse effect on our business, financial condition, results of operations and prospects.

We may not be the operator on all of our future assets and therefore may not be in a position to control the timing of development efforts, the associated costs, or the rate of production of the reserves on such assets

In respect of our conventional oil and gas business, while we are the sole operator for our existing wells, we may not serve as operator of all planned wells in the future. In respect of our unconventional oil and gas business, we have entered into formal agreements with Exxaro Resources to jointly pursue UCG as a commercial business to develop energy solutions in Sub-Saharan Africa. As a result, we may have limited ability to exercise influence over the operations of some non-operated assets or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs could prevent the realisation of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploration activities on assets operated by others depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the timing and level of exploration activities;
- the availability of drilling or mining equipment, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources and condition;
- health and safety, environmental and other regulatory compliance practices;
- the prices at which and customers to whom products are sold;
- approval of other participants in the assets;

- selection of technology; and
- the rate of production.

In the event that our joint venture partners or third party operators do not meet their obligations under the requisite licences necessary to carry out operations, or they breach agreements governing our relationship, these violations may lead to fines, penalties, restrictions, withdrawals of licences and the termination of the agreements under which we operate. Notwithstanding that we will be entitled to seek certain recourse against our counter-parties in the event of such risk occuring, we may also be jointly and severally liable for such non-compliance with our obligations which could have a material adverse effect on our business, financial condition, results of operations and prospects.

We may pursue acquisitions which involve a number of risks, any of which could cause us not to realise the anticipated benefits

We may pursue acquisition opportunities in the future in various jurisdictions. In the process of such acquisitions, we may not be able to complete the transactions on terms which are most commercially advantageous to us. If we fail to accurately estimate the future results and value of an acquired business or are unable to successfully integrate the businesses or assets we acquire, our business, financial condition or results of operations could be negatively affected, and we may be unable to grow our business. Acquisition transactions involve various risks, including:

- uncertainties in assessing the strengths and potential profitability, and the related weaknesses, risks, contingent and other liabilities of acquisitions;
- changes in business, industry, market or general economic conditions that affect the assumptions underlying our rationale for pursuing the acquisition;
- the inability to achieve identified operating and financial synergies anticipated to result from an acquisition;
- diversion of our management's attention from other business concerns;
- regulatory challenges for completing and operating the acquired business, including opposition from environmental groups or regulatory agencies;
- environmental or geological problems in acquired assets;
- inability to acquire sufficient surface rights to enable extraction of resources;
- outstanding permit violations associated with acquired assets;
- difficulties or unexpected issues arising from our evaluation of internal control over financial reporting of the acquired business; and
- unanticipated liabilities associated with the acquired companies.

Even if we successfully complete an acquisition or an investment, we could face difficulties managing the investment or in the case of a business, integrating the acquisition with our existing operations. As such, we may not be able to achieve the strategic purpose of such an acquisition or investment. These difficulties could disrupt our ongoing business, distract our management and employees, and increase our expenses, any of which would materially and adversely affect our business and results of operations.

We may be unable to dispose of non-strategic assets on attractive terms, and may be required to retain liabilities for certain matters

We regularly review our asset base for the purpose of identifying non-strategic assets. Various factors could materially affect our ability to dispose of non-strategic assets or complete previously-publicised dispositions, including the availability of purchasers willing to purchase such non-strategic assets at acceptable prices.

Sellers typically retain certain liabilities or indemnify buyers for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestments, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations and/or indemnities guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

We may experience difficulty in achieving and managing future growth

Our ability to grow will depend on a number of factors, including, but not limited to:

- the ability to obtain leases or options on suitable assets;
- the ability to identify and acquire new exploratory prospects;
- the ability to develop existing prospects;
- the ability to continue to retain and attract skilled personnel;
- the ability to maintain or enter into new relationships with project partners and independent contractors;
- the results of our drilling programmes;
- commodity prices; and
- access to capital.

Future growth may place strains on our resources, which could have an adverse effect on our financial condition and results of operations.

We may not be successful in upgrading our technical, operations, and administrative resources or in increasing our ability to internally provide certain of the services currently provided by outside sources, and we may not be able to maintain or enter into new relationships with project partners and independent contractors. Our inability to achieve or manage growth may adversely affect our financial condition and results of operations.

We face significant competition

We operate in competitive industries and are subject to competition from various sources. Competition is based on many factors, including resources and reserves, product quality and characteristics, costs and transportation capability.

Key areas in which we face competition include:

- acquisition of exploration and production licenses through bidding processes run by governmental authorities;
- acquisition of other companies that may already own licenses or existing hydrocarbon assets;
- attracting and retaining experts and labour for our various stages of operations;
- engagement of third-party service providers whose capacity to provide key services may be limited;
- entering into commercial arrangements with customers;

- purchase of capital equipment that may be scarce;
- alternative energy sources such as hydroelectric, wind or solar energy, becoming more cost-competitive; and
- employment of highly skilled personnel and professional staff.

Many of our competitors are larger and have substantially greater financial and other resources. If we are unable to manage our product quality and price competitiveness, maintain our operational efficiency and control costs in connection with our expansion, we will experience an adverse effect on our business, reputation, growth opportunities, ability to obtain financing, financial condition and results of operation. In addition, if alternative energy sources, such as hydroelectric, wind or solar energy, become more cost-competitive, demand for traditional sources of energy such as oil, gas and coal could decrease.

Our operations are subject to various health, safety, environmental and operating risks

Due to the nature of our operations, we are exposed to various health, safety, environmental and operating risks. Such risks may include adverse weather conditions or natural disasters such as earthquakes or flooding, fires, unusual or unexpected variations in geological conditions, industrial accidents, critical failures in our exploration and production equipment, mishandling or loss of containment of dangerous substances, and technical problems. Factors influenced by geography, operational diversity and technical complexity of our activities at each site are beyond our control. In addition, we may also be subject to intentional acts of sabotage or vandalism on our facilities or production sites.

We cannot assure you that the risks described above will not occur in the course of our operations. The occurrence of any of these risks may expose us to legal or regulatory proceedings where we may have to incur substantial costs to rectify and rehabilitate. Any such occurrence could be detrimental to our reputation in respect of future operational opportunities or could even result in the loss or suspension of, among others, our licences or the termination of our agreements for our operations in the affected concessions and/or licences, which could affect our results of operations and financial position.

Climate change legislation or regulations restricting emissions of greenhouse gases ("GHG") could result in increased operating costs and reduced demand for our products

Our operations may result in the emission of GHG. As such, increased regulation of GHG emissions could adversely affect our business and may result in substantial capital, compliance, operating and maintenance costs. International agreements and national or regional legislation and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary depending on the laws enacted in each jurisdiction, our activities in such jurisdiction and market conditions. The GHG emissions that could be regulated include those arising from a company's exploration and production of oil, gas and coal; power generation; the processing, liquefaction and regasification of gas; the transportation of oil, gas, coal and related products and consumers' or customers' use of our products. Some of these activities, such as consumers' and customers' use of our products, as well as actions taken by our competitors in response to such laws and regulations, are beyond our control.

The effect of regulation on our financial performance will depend on a number of factors including, among others, the sectors covered, the GHG emissions reductions required by law, the extent which we would be entitled to receive emission allowance allocations or would need to purchase compliance instruments on the open market or through auctions, the price and availability of emission allowances and credits, and the impact of legislation or other regulation on our ability to recover the costs incurred through the pricing of our products. Material price increases or incentives to conserve or use alternative energy sources could reduce demand for products we currently sell and adversely affect our sales volumes, revenues and margins.

We may not have sufficient insurance coverage against potential operational risks

Our business is subject to environmental hazards that could expose us to substantial liability due to pollution and other environmental damage. We may incur material costs and liabilities resulting from claims for damage to property or injury to persons arising from risks associated with our operations. If we are pursued for sanctions, costs and liabilities in respect of these matters, our operations and, as a result, our profitability could be materially adversely affected.

We maintain general liability insurance, insurance coverage against certain losses resulting from physical damages, business interruption and certain pollution events, as well as directors' and officers' liability insurance. However, our insurance coverage does not provide 100% reimbursement of potential losses resulting from operational hazards, either because such insurance is not available to us or to other companies in our industry or because of the high premium costs and deductibles associated with obtaining such insurance.

While we have insurance that is typical for our operations, we are not fully insured against certain of the risks described in this offering document. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our profitability, financial condition and liquidity.

There can be no assurance that any insurance proceeds we receive would be sufficient to cover expenses relating to insured losses or liabilities. Further, depending on the severity of the damage, we may not be able to rebuild damaged property in a timely manner or at all. We are also subject to the risk of increased premiums or deductibles, reduced coverage, and additional or expanded exclusions in connection with our existing insurance policies and those of operators of those assets that we do not currently operate. The inability to rebuild damaged property and the increased insurance premium could have a material adverse effect on our business, results of operations, financial condition and prospects.

We may, from time to time, be involved in legal, regulatory and other proceedings arising out of our business and operations, and may incur substantial costs arising as a result

We have been, from time to time, and may in the future be, involved in disputes with various parties such as customers, contractors, suppliers and regulators. See "Business—Legal Proceedings". These disputes may lead to legal or other proceedings and may result in substantial costs, delays in our development schedule, and the diversion of resources and management's attention, regardless of the outcome. If we were to fail to win these disputes, we may incur substantial losses and face significant liabilities. Even if we were to succeed in these disputes, we may also incur substantial costs in mounting our claim or defence.

We may be subject to regulatory action in the course of our operations, which may subject us to administrative proceedings and unfavorable decisions that could result in penalties and/or delayed construction of new facilities. In such cases, our results of operations and cash flow could be materially and adversely affected.

We may also from time to time, be subject to regulatory audits. For example, as part of the sale of the Carmichael coal tenement to Adani in August 2010, we also entered into a deed to receive the Carmichael Royalty. We have been involved in discussions with the Australian Taxation Office (the "**ATO**") since 2011 regarding the income tax treatment of the deed. More specifically, the ATO are seeking to include the market value of the future income stream in the Company's taxable income in FY2011. Following these discussions, the ATO undertook a risk review of the specific issue and in October 2013 concluded that in their opinion the market value of the deed should be taxable in FY2011. Accordingly, in October 2013, the ATO advised that they intend to commence an audit of this specific issue in the future. As part of this process, we have received legal and tax advice to support the position taken in our FY2011 tax return lodged with the ATO that the future amounts receivable under the deed should not be taxable upfront. Furthermore, based on the opinions from our legal and tax advisers, we believe that our lodged tax return complies with the applicable tax laws in Australia and have not made a provision for this as a contingent liability. We will continue to work with the ATO to resolve this issue. Given the inherent uncertainty in estimating the ultimate quantum and timing of production from a mine in the Carmichael coal tenement as at the date of the transaction, it would have been and continues to be impracticable to prepare a market valuation of the deed as at that date. We cannot assure you that the ATO will ultimately agree with our position taken in the FY2011 tax return.

The credit risk of counterparties could have an adverse effect

We transact with different counterparties, including existing and potential joint venture partners, our customers, licensees of our UCG technology and counterparties in the financial services industry, such as commercial banks, insurance companies and other institutions. These transactions expose us to credit risk in the event of default of the counterparty. Deterioration in the credit markets may impact the credit ratings of current and potential counterparties and affect their ability to fulfil their existing obligations to us and/or their willingness to enter into future transactions with us which could have a material adverse effect on our business, financial condition, results of operations and prospects.

We are exposed to fluctuations in currency exchange rates

Our reporting currency is the Australian dollar. We operate in jurisdictions whose national currencies vary, including the United States. The majority of our products are priced in United States dollar. For financial reporting purposes, transactions in foreign currencies are converted in the functional currency of each entity using the exchange rates prevailing as at the transaction date. Monetary assets and liabilities outstanding at year end are converted at year-end rates. We do not have a policy of hedging against currency fluctuations. The translation and cash flow effect of fluctuations between relevant local currencies and the Australian dollar may have a material adverse effect on our business, financial condition and results of operations of our Company.

The reserves and resources data for our oil, gas and coal assets are estimates and may differ materially from the actual figures and may not ultimately be extracted at a profit

This offering document includes estimates of our shares of oil and gas reserves and prospective resources as well as coal reserves and resources made by Haas Petroleum, Ryder Scott, DeGolyer and MacNaughton, Gustavson Associates, Snowden, Xenith and Minecraft. Numerous uncertainties exist in estimating quantities of oil, gas and coal reserves and resources as well as net cash flows of our proved reserves. The estimates set forth herein are based on various assumptions, which may ultimately prove to be inaccurate. The determination of such data is a subjective process of estimating underground accumulations of oil, gas and coal that cannot be measured in an exact manner. Estimates of economically recoverable oil, gas and coal reserves and resources as well as estimated net cash flows of our proved reserves depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the quality and quantity of available data;

- the interpretation of that data;
- the assumed effects of regulations by governmental agencies;
- the production performance of our reserves;
- assumptions concerning prevailing and future commodity prices;
- extensive engineering, geological and geophysical judgments;
- individual geologic chance factors, such as trap, source, reservoir and migration; and
- assumptions concerning future operating costs, severance, ad valorem and excise taxes, development costs, transportation costs and workover and remedial costs.

In addition, subject to the assumptions, uncertainties and risks contained within the Qualified Persons' Reports, the estimated discounted future net cash flows from proved oil reserves set forth in this offering document are based on average prices preceding the date of the estimate and costs as at the date of the estimate, while actual future prices and costs may be materially higher or lower. Also, actual future net cash flows may be affected by factors such as the amount and timing of actual production, levels of future capital spending, increases or decreases in the supply of or demand for oil and gas, and changes in governmental regulations or taxation.

Moreover, the shale oil and gas estimates for the Arckaringa Basin provided in this offering document are for prospective resources. Unlike proved or probable reserves for oil and gas, there is no certainty that any portion of such prospective resources will be discovered. The estimates for prospective resources were calculated based on undiscovered accumulations of oil and were based on a mathematical model incorporating probability and inferences and limited drilling.

There are also numerous factors and assumptions inherent in estimating the quantities and qualities of, and costs to mine, coal reserves, any one of which may vary considerably from actual results. These factors and assumptions include: coal characteristics such as energy, ash and sulphur content, equipment and productivity, operating costs, including for critical supplies such as fuel, tires and explosives, capital expenditures and development and reclamation costs, the percentage of coal ultimately recoverable, the effects of regulation, including the issuance of required permits, and taxes, including severance and production taxes and royalties, and other payments to governmental agencies and timing for the development of the reserves.

Our actual production, revenues and expenditures with respect to our oil, gas and coal reserves and resources will likely be different from estimates, and the differences may be material. Any inaccuracy in our proven and probable reserves estimates could result in decreased profitability from lower than expected revenue and/or higher than expected costs and may affect the value of our Shares.

Our actual results of operations may differ significantly from certain information included in the Qualified Persons' Reports reproduced in Appendix I to this offering document

We have included, and also extracted certain information from, reports by the Qualified Persons because we believe that their evaluations are helpful to an investor's understanding of our business operations. These Qualified Persons' Reports are based on certain assumptions, including, among others, forward-looking assumptions about development time frames including government approvals and development of infrastructure, production capacities, fixed capital costs, operating costs, product prices, sales levels, inflation rates, exchange rates and financing costs. Investors should not place undue reliance on this information, which is provided for illustrative purposes only. Investors should in particular make their own assessment as to future prices for oil, gas and coal and as to the appropriate discount rate for projects of this size and type.

These forward-looking assumptions may differ from our development plans or may require revision in light of actual production experience, operating costs, world mineral prices and other factors. In particular, operating costs, product prices, exchange rates and financing costs have been assumed based on current market conditions which may or may not prove to be a stable medium to long-term indicators of demand. These costs and exchange rates have experienced significant fluctuations in the past and may fluctuate in the future. We cannot assure you that our actual net present value, operating costs and earnings, among other things, will not differ materially from our estimates in this offering document. If there is a significant change in the above factors, our actual results of operations may be materially and adversely affected. You are therefore cautioned not to rely on the conclusions stated in the Qualified Persons' Reports.

We may face supplies, equipment, materials or personnel shortages and operating cost pressures

The strong commodity cycle over recent years and large numbers of projects being developed in the resources industry has led to increased demand for, and shortages in, skilled personnel, contractors, materials and supplies that are required as critical inputs to our operations. In particular, the availability and cost of labour and construction materials will be critical to the growth and development of our business. A number of key cost inputs such as power and fuel, which are expected to constitute a significant part of our operating expenses, are commodity-linked and will be affected by unpredictable factors outside our control, such as a higher commodity price environment, government policies, exchange rates and inflation rates. Shortages and increases in the cost of inputs could lead to increased capital and operating costs and could impact the schedule of our exploration and development plans. Such changes may require us to seek additional funding and incur additional debt which may adversely affect our financial condition.

We depend on key personnel and a workforce with specialised technical skills

Our success will depend to a large extent upon the efforts and abilities of our executive officers and key operations personnel who have built our business and have been instrumental in our development. The loss of the services of one or more of these key employees could have a material adverse effect on us. In particular, we rely on the expertise and experience of our Executive Directors and Executive Officers who play a pivotal role in our daily operations. If we are unable to retain the services of these key individuals and are unable to suitably replace them in a timely manner, our business may be materially and adversely affected.

Our business is also dependent upon our ability to attract and retain qualified personnel. We require highly skilled personnel to provide technical and engineering services in the production and development of, and the exploration for, hydrocarbon resources. We also require specific personnel who have specialised experience working in adverse conditions, or have knowledge of our unconventional oil and gas businesses. For example, our plans to develop our Umiat asset require the identification and retention of personnel who have the specialised experience in drilling and developing natural resources under severe weather conditions. We also require personnel with EOR experience for our operations in Wyoming. As the demand for geoscientists, petroleum engineers and highly skilled persons from our competitors increase, shortages in professionals may occur, and thus acquiring and keeping these personnel could prove more difficult or cost substantially more than estimated. This could cause us to incur greater costs, or prevent us from pursuing our stated business objectives as quickly as we would otherwise wish to do. Limitations in our ability to hire and train the required number of skilled personnel and professional staff may reduce our capacity to expand our operations and may cause an adverse impact on our financial condition, results of operations and prospects.

Work stoppages and other personnel-related issues could materially adversely affect future operations

If our employees or the employees of one of our contractors were to engage in a work stoppage or other slowdown in the future, we could experience a significant disruption of our operations, which could have negative effects on our business, such as decreased productivity and increased labour costs. There also is the possibility that in the future we may be subject to charges, claims and/or lawsuits relating to our employees or use of independent contractors that may cause increased costs.

We may encounter difficulties with our assets, including title defects of our licences or the loss of our leases

We conduct due diligence to review title on significant assets that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in assets in which we hold an interest, we may suffer a financial loss.

In addition, our assets are held and our revenues are generated under and through leases held for exploration and production of our conventional and unconventional oil, gas and coal. If we fail to meet the specific requirements of the lease, including those regarding delay in rental payments, work programme obligations, environmental approvals, incurring a minimum exploration expenditure in relation to undeveloped interests, continuous production or development in relation to producing interests, or similar terms, the lease (or portions thereof) may terminate or expire. While most of our leases are held by production, our drilling plans for these areas are subject to change based upon various factors, including, drilling results, commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. There can be no assurance that any of the obligations required to maintain each lease will be met. The termination or expiration of our leases may reduce our opportunity to explore a given prospect for oil, gas and coal production and would otherwise have a material adverse effect on our business, financial condition and results of operations.

We do not possess security of tenure in all tenements in which we have interests and we may be subject to overlapping tenure or competing resources

All tenements in which we have interests (or which our commercial partners have interest) are subject to renewal conditions or are yet to be granted, which will be at the discretion of the relevant regulatory bodies in jurisdictions in which we have tenement interests. The maintenance of tenements, obtaining renewals, or getting tenements granted, often depends on us being successful in obtaining required statutory approvals for proposed activities. While we anticipate that subsequent renewals or mineral tenure grants will be given as and when sought, there is no assurance that such renewals or grants will be given as a matter of course and there is no assurance that new conditions will not be imposed in connection with such renewal. In addition, other oil, gas and/or coal companies may operate in the same basins as us or target the same resources and we may be subject to a competing claim from such companies which intend to mine the resources. Consequently, this may have a material adverse effect on our profitability, financial condition and liquidity.

Changes in our intangible assets may adversely affect our financial results and results of operations

As at 30 June 2013, we had A$271.3 million (US$253.3 million) in intangible assets, which includes exploration and evaluation costs related to our coal and unconventional oil and gas business, costs associated with the construction of our Chinchilla Demonstration Facility and software. The recoverability of the carrying amount of our intangible assets depends on the successful development, commercialisation or sale of these assets. Should we encounter difficulties in developing or commercialising such assets, they may be subject to impairment.

At 30 June 2013, we had A$555.5 million (US$518.6 million) in oil and gas assets. These are our conventional oil and gas assets in the United States. The recoverability of the carrying amount of the oil and gas assets depends on the successful development, commercialisation of sale of these assets. For example, we recognised an impairment expense of A$16.8 million (US$15.7 million) in respect of our oil and gas assets in the Gulf Coast Region for the year ended 30 June 2013.

At 30 June 2013, we had A$16.2 million (US$15.1 million) in available-for-sale investments which are listed equity securities. The recoverability of the carrying amount is determined by the active trading price of these assets. For example, an impairment expense of A$6.8 million (US$6.3 million) was recognised for write-downs in the value of two of our listed equity investments.

We may not be able to obtain access to infrastructure and transportation to market our products

The marketability of our products depends upon the proximity of our reserves to, and the capacity of, facilities and third party services, including oil, gas and coal gathering systems, pipelines, trucking or terminal facilities, and processing facilities, railroads, ports as well as the existence of adequate markets. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to carry out our UCG production, and store, process, transmit and sell our oil, gas and coal. Our plans to develop and sell our oil, gas and coal could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient transmission, storage or processing facilities, especially in areas of planned expansion for us, such as Alaska, where such facilities or access to such facilities do not currently exist.

Failure to obtain adequate storage facilities or any reduction in any storage facilities obtained arising from adverse weather conditions, or due to other emergencies and/or due to the need to protect the environment or to comply with the relevant legislations could adversely affect our financial condition and results of operations.

In the event of insufficient capacity available on these systems, or if these systems were unavailable to us, the price offered for our production could be materially adversely affected as we could be forced to reduce production or delay or discontinue drilling plans and commercial production following a discovery of reserves while we construct our own facility. In addition, regulation of oil, gas and coal production transportation in the countries in which we operate may affect our ability to produce and market our products on a profitable basis. A shut-in, delay or discontinuance could adversely affect our financial condition and results of operations.

In addition, transportation costs represent a significant portion of the total cost for our domestic and export customers. The cost and availability of transportation is a key factor in a customer’s purchasing decision and impacts our sales and the price we receive for our products.

RISKS RELATING TO OUR CONVENTIONAL OIL AND GAS AND SAPEX BUSINESSES

Our conventional oil and gas business has a limited operating history

A significant component of our revenue for FY2013, of 91.7%, was derived from oil sales revenue attributable to our conventional oil and gas business, in particular, in the Gulf Coast Region. We acquired our assets in the Gulf Coast Region in October 2011. Accordingly, our conventional oil and gas business has a limited operating history in its current form and our experience with drilling and developing certain complex geological structures in our conventional oil and gas business is relatively limited. As a result, there is a risk that we may not be able to develop our oil and gas asset base as expected.

Our operations are subject to hazards inherent in the oil and gas industry

Risks inherent to the oil and gas industry include the potential for significant losses associated with equipment design, operational failures or vehicle operator error. These risks can result in explosions and discharges of toxic gases, chemicals and hazardous substances, and, in rare cases, uncontrollable flows of gas or well fluids into environmental media, as well as personal injury, loss of life, long-term suspension or cessation of operations and interruption of our business or the businesses of third parties upon which we depend, and damage to geologic formations, environmental media and natural resources, equipment, facilities or property. In addition, we use and generate hazardous substances and waste in our operations and some of the assets that we currently lease are, or have in the past been, used for industrial purposes. If any of these assets contain unknown contamination, or if any of the hazardous substances that we generate are released into the environment at its leased assets or at off-site locations, we could be required to conduct expensive investigation and clean-up and may be exposed to liability for personal injury, wrongful death, property damage, loss of oil and gas production, pollution and other environmental damages. In an extreme case, such liabilities could materially impair our profitability, insurability, or competitive position.

Future price declines could result in a reduction in the carrying value of our proved oil and gas assets, which could adversely affect our results of operations

Declines in commodity prices may result in having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to impair, as a non-cash charge to earnings, the carrying value of our oil and gas assets. We are required to perform impairment tests on proved oil and gas assets whenever events or changes in circumstances indicate that the carrying value of proved assets may not be recoverable. To the extent such tests indicate a reduction in the estimated useful life or estimated future cash flows of our oil and gas assets, the carrying value may not be recoverable and therefore an impairment charge will be required to reduce the carrying value of the proved assets to their estimated fair value.

We periodically evaluate our unproved oil and gas assets and could be required to recognise non-cash charges in the earnings of future periods. These evaluations are affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases, contracts and permits pertaining to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognise non-cash charges in the earnings of future periods.

The geographic concentration of our producing assets is subject to an increased risk of loss of revenue or curtailment of production from factors affecting the Gulf Coast Region specifically

The geographic concentration of our producing assets in the Gulf Coast Region means that some or all of the assets could be affected should the region experience severe weather such as tropical storms and hurricanes, delays or decreases in production, the availability of equipment, facilities, services, capacity to transport, gather or process production; and/or changes in the regulatory environment.

Tropical storms, hurricanes and the threat of tropical storms and hurricanes often result in the shutdown of operations in the Gulf Coast Region as well as operations within the path and the projected path of the tropical storms or hurricanes. During a shutdown period, we may be unable to access well sites and our production services may be shut down. Additionally, tropical storms or hurricanes may cause evacuation of personnel and damage to drilling rigs and other equipment, which may result in suspension of our operations. The shutdowns, related evacuations and damage can create unpredictability in activity and utilisation rates, as well as delays and cost overruns, which may have a material adverse impact on our financial condition and results of operations.

There may be potential risks associated with our operations not covered by insurance. There also may be certain risks covered by insurance where the policy does not reimburse our Group for all of the costs related to a loss. Because all or a number of the assets could experience any of the same conditions at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other producers who have assets over a wider geographic area.

Our operations in Alaska are subject to risks that are specific to its location and climate

Our operations in our Umiat field in Alaska, which include drilling for conventional oil and gas, are located in a remote, environmentally sensitive area. Prior to an approved development plan being put in place, there is no permanent road access and limited infrastructure. Access to our assets is difficult, and we will incur significant costs in building the ice and snow roads required and in transporting equipment and personnel by fixed wing planes and helicopters. Adverse weather conditions can significantly delay our planned operations. For example, we did not manage to undertake a portion of our planned appraisal programme in winter 2012-2013 at our Umiat field in Alaska due to weather conditions and a subsequent delay in the mobilisation on site. The purpose of undertaking the winter appraisal programme was to progress the Alaskan development and production process. We are also subject to permit requirements and regulatory scrutiny from a variety of federal, state, and local entities. Delays in receipt of such permits could significantly impact our planned operations.

In addition, drilling and production equipment, capable contractors and experienced personnel and crews are scarce and in high demand. Operating costs, including wage costs, are significantly higher in Alaska as compared to the mainland United States. Full development of our Umiat field will require construction of a pipeline and access to the Trans-Alaska Pipeline System, which requires construction, regulatory and environmental issues to be resolved. Accordingly, our ability to conduct the drilling activities planned may be delayed or be more costly than currently anticipated, which could have a significant adverse effect on the proved reserves, financial condition and results of operations of our Company.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation

The 2014 Budget proposed in April 2013 by the President of the United States recommends elimination of certain key United States federal income tax incentives currently available to oil and gas exploration and production companies, and legislation has been introduced in Congress which would implement many of these proposals. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas assets, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortisation period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development.

We hedge our exposure to oil prices

In order to manage exposure to price risks in the marketing of oil production, we have entered into oil price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to manage downside oil price risk, such transactions may limit our potential gains if oil prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- actual production is less than hedged volumes;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our hedging agreements fail to perform under the contracts; or
- a sudden unexpected event materially impacts oil prices.

In addition, any new legislation to regulate the derivatives market could significantly increase the cost of derivative contracts such as our hedging contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against potential risks, reduce the ability to monetise or restructure its existing derivative contracts, and increase the exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of new legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect its ability to plan for and fund capital expenditures.

The Arckaringa Basin tenements partially overlap the Woomera Prohibited Area ("WPA") and as a result, our operations could be restricted

A portion of the Arckaringa Basin tenements coincide with the WPA in South Australia. Although the WPA is a military testing range, the Australian Federal and South Australia governments have commenced initiatives to gradually open the area for minerals exploration and resources development. For example, in October 2012, the Minister for Defence and Minister for Resources and Energy of Australia announced the lifting of a moratorium on granting access to non-defence entities in the minerals exploration and resources development industries. The Australian Federal and South Australia governments are now in the process of developing and implementing enabling legislation for resource exploration in the WPA.

Access to the WPA is divided into different use zones. A large portion of our tenements that overlap with the WPA are in the infrequent defence use zone, in which users may be required to evacuate for up to 56 days per year. A smaller portion of our tenements overlap in the periodic defence use zone 1 (evacuation required for blocks of seven to 140 days) and periodic defence use zone 2, (evacuation required for blocks of seven to 70 days). As at the date of this offering document, our exploration work has not been obstructed by WPA access procedures. However, changes in legislation and government policies could reverse the transition to opening up the lands for resource development, and, accordingly, may have an adverse effect on our business, financial condition and results of operation. Moreover, due to the location of some of the Arckaringa Basin tenements in the WPA, our selection of a partner to develop the tenements may require federal government approval, which could delay or restrict the establishment of the proposed partnership arrangement.

The potential adoption of federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Consideration of new regulations, increased oversight and regulatory uncertainty continue to arise in the jurisdictions in which we operate. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Moreover, some jurisdictions have already applied restrictions and/or moratoriums on the use of hydraulic fracturing. These restrictive actions can vary in duration. The timing and implementation and release of such restrictions can severely limit or prohibit economic development of unconventional shale resources, which requires hydraulic fracturing for economically viable operations. New or changes in legislation or regulation could also lead to operational delays or increased operating costs in the production of liquid hydrocarbons and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal or state laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells. The adoption of legislation or regulation which eliminates or severely limits the use of hydraulic fracturing may adversely affect the economic viability of developing unconventional shale deposits in the Arckaringa Basin.

Our ability to produce oil and gas economically and in commercial quantities in the Arckaringa Basin could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or if we are unable to dispose of or recycle the water we use economically and in an environmentally safe manner

Our proposed drilling activities in the Arckaringa Basin will require substantial use of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site. In situations where water is obtained from aquifers, the quantity of water which may be extracted may be subject to limitations.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of oil and gas. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on the operations and financial condition of our Company.

RISKS RELATING TO OUR CLEAN ENERGY BUSINESS

Our UCG technology has been proven only in our Chinchilla Demonstration Facility and the ability to develop this technology to a commercial scale will depend upon success in the financing, design, construction and operation of a commercial plant

As an emerging energy technology, UCG to GTL has reached the point of commercialisation without the need for additional capital investment. However, it is yet to be commercially deployed. We have successfully demonstrated the ability of our technology to produce fuels for a variety of applications at our Chinchilla Demonstration Facility and have made significant investments in conceptual, engineering and design work for a commercial plant. We have entered into a number of separate agreements with potential partners to develop a commercial scale UCG operation in various jurisdictions, such as our first commercial UCG project underway with Exxaro Resources signed in May 2013. These agreements typically involve the licensing of our proprietary technology to the joint venture, which we participate in, to allow the commercial development of a UCG facility. The value of our technology may, however, be diminished if these joint ventures are not able to develop a commercially viable project.

In addition, our licence agreements relating to the UCG technology, may under certain conditions, such as the breach of any material provisions including the representations given by us in favour of the licensee with regards to the validity/registration of our UCG intellectual property, be terminated by the licensee, with or without cause. Our licence agreements may also provide for certain exclusivity clauses, including the granting of a non-exclusive licence, such as the exclusive license provided to Exxaro Resources to use our UCG intellectual property in Sub-Saharan Africa. Such a breach and termination or an inability of our licensee to commercialise our UCG technology may have an adverse effect on our business, reputation and financial condition.

Our UCG technology competes with other conventional and unconventional energy sources

The development and commercialisation of alternative energy is highly competitive, and other technologies could be viewed as more commercially viable than our own. Our competitors include major integrated oil companies as well as independent technology providers that have developed or are developing competing technologies to UCG. Some of these companies may have significantly more financial resources than usual.

As competitors continue to develop competing technologies, one or more of our current technologies could become obsolete. Our ability to create and maintain technological advantages is critical to our future success. As new technologies develop, we may be placed at a competitive disadvantage, forcing us to implement new technologies at an increased cost.

Our UCG and UCG to GTL technology is a key competitive advantage and failure to adequately protect, or uncertainty regarding the validity, enforceability or scope of our intellectual property rights may undermine our competitive position

We regard our intellectual property as critical to the successful commercialisation of our UCG and UCG to GTL technology. We rely on a combination of patents, copyrights, trademarks, trade secrets and contractual restrictions to protect our proprietary rights with respect to our UCG process. We may not be able to successfully obtain patents or other intellectual property rights to protect our proprietary technologies in all of the countries or jurisdictions in which we intend to operate. Our existing patents might not provide commercial benefit or might be infringed upon, invalidated or circumvented by others. The availability of patents in foreign markets, and the nature of any protection against competition that may be afforded by those patents, and our ability to enforce our intellectual property rights is often difficult to predict and varies significantly from country to country. Third parties may use the technologies and proprietary processes that we have developed and compete against it, which may negatively affect any competitive advantage we enjoy, may lead to brand dilution and could materially and adversely affect our results of operations. We, our licensors, or our licensees may choose not to seek, or may be unable to obtain, patent protection in a country that could potentially be an important market for our proprietary technologies. The confidentiality agreements that are designed to protect our trade secrets could be breached, and we might not have adequate remedies for the breach. Additionally, our trade secrets and proprietary know-how might otherwise become known or be independently discovered by others.

In addition, the increased commercialisation of our proprietary technologies may give rise to claims that our technologies infringe upon the patents or proprietary rights of others. We may not become aware of patents or rights that may have applicability until after we have made a substantial investment in the development and commercialisation of our proprietary technologies. As a result, third parties may claim infringement and/or bring legal actions against us, our joint venture partners or our licensees. These claims could result in the payment of damages, fees to obtain certain licenses and injunctions or other court orders that would prevent us, our joint venture partners or our licensees to utilise the relevant technologies. Our investigation and response to such claims may require substantial time and expense and can distract management from focusing on the daily management and operation of the business. In addition, even if a claim against us is without merit, it could generate negative publicity and damage our reputation. Many possible claimants, such as the major energy companies that have competing technologies have significantly more resources to spend on litigation than we do.

RISKS RELATING TO OUR COAL BUSINESS

We may not receive royalty payments at the agreed-upon royalty rate or within the expected timeframe

In August 2010, we sold the Carmichael coal tenement in Queensland, Australia to Adani for a lump sum payment. We also expect to receive payments of A$2 per tonne (indexed to the Consumer Price Index (Brisbane) All Groups number) of coal over the first 20 years of production from the date of first production. Adani or the future acquirer of the Carmichael Project may experience unexpected delays in the development and production process including but not limited to inclement weather, natural disasters, delays in obtaining relevant government approval for permits and licences, transportation access including port access and other factors beyond the control of the operator of the Carmichael Project, currently Adani. In addition, the operator of the Carmichael Project may experience difficulties in financing the considerable capital expenditure required to ramp-up the mining operations, which may delay or restrict its abilities to develop the tenement. Furthermore, the operator of the Carmichael Project may experience difficulties in achieving forecast levels of production and face risks inherent in coal mining activities including commodity price exposure, recoverability of reserves, compliance with applicable legislation and operating risks. These factors may result in a reduction in the expected flow of royalty payments, which could adversely affect our financial condition and negatively affect our ability to execute our business strategies.

Our conventional coal mining business is at an early stage of development and we have no history of production or operating revenue and we may not develop our conventional coal mining business as planned or at all

We currently do not engage in, and have never recorded any revenue from the developments of our coal mining projects. In this respect, we have a limited operating history, upon which an evaluation of our future success or failure can be made, in respect of our conventional coal mining business.

We may seek financing for the development of some of our coal mining projects and as the case may be, bring some of projects to production, but we may not be able to obtain such financing at commercially viable terms or at all. In addition, we have not entered into all of the necessary agreements for the development of any of these projects and we do not have all our requisite approvals in place. In view of the risks identified in this section coupled with those arising from the additional factors identified below and elsewhere in this offering document, we may not develop any mines as planned or at all.

We entered into a sale and purchase agreement to acquire the Blair Athol Mine in October 2013 and we currently expect this mine to contribute to our operating revenue by June 2014. The Blair Athol Mine was a previously operating mine but has been dormant since November 2012 as the previous owner had ceased operations for commercial reasons. As the mining infrastructure is already in place and the Blair Athol Mine had been in operation before November 2012, we expect that minimal expenditure would be required to recommence commercial production.

We also face customary risks relating to the acquisition of new assets which could delay the recommencement of operations in the Blair Athol Mine or adversely affect our recoverability of coal from this mine. These include delays in allocations and approvals of requisite regulatory permits that are required to commence operations for mining, recruitment of the necessary personnel, initiation of contracts for logistical suppliers and equipment and any inclement weather conditions. While certain members of our Board of Directors and our Executive Officers have experience in mining projects, our Company, with our limited operating history in conventional coal mining, has not operated any mines. Separately, the Blair Athol Mine and its neighbouring mine, the Clermont Mine, which is owned by Mitsubishi Development Pty Ltd, Queensland Coal Pty Ltd, J-Power Australia Pty Ltd and J.C.D. Australia Pty Ltd (collectively, the "**Clermont Joint Venture Party**"), rely on each other for certain logistics and as such, we will need to enter into certain contracts in respect of coal handling, port and rail and the provision of water and electricity. The recommencement of operations of the Blair Athol Mine will require working capital expenditure, experienced personnel and regulatory approvals. We will therefore be subject to all the risks inherent in the establishment of new mining operations.

We do not expect to have any revenues from our conventional coal mining assets until after the recommencement of production of the Blair Athol Mine. Accordingly, we are subject to all of the risks inherent in companies which have businesses that may not have cash flow or earnings. This will make it difficult for prospective investors to assess the likely future performance of our conventional coal mining assets.

The development of our coal projects and the use and development of adequate and suitable infrastructure may be delayed, may exceed the expected budget or may not be developed at all

Our coal projects and our ability to use and develop adequate infrastructure may be delayed or adversely affected by a variety of factors, including:

- failure to obtain the necessary tenure or access rights;
- failure to obtain sufficient funding;
- shortages of or delays in obtaining equipment and qualified personnel to undertake specific works;
- difficulties or delays in the construction of infrastructure required for our projects;
- facility or equipment malfunctions;
- costs and availability of contractual arrangements for properties or equipment associated with our activities;
- resource constraints, particularly in Queensland, where for example, there is limited access to fuel to generate electricity for mining operations in rural areas and access to the fresh water resources require for our operations can be difficult to procure and may be potentially quite costly;
- pressure or irregularities in geological formations;
- availability of labour and problems associated with the workforce such as labour disputes;
- adverse weather conditions, such as flooding;
- reductions in coal prices;
- limitations in the market for coal; and
- defects or challenges on title.

Costs of our coal projects and the necessary infrastructure may also exceed our planned investment budget because of such delays, unforeseen geological, engineering and/or environmental problems, changes to plans and specifications and shortages of, and price increases in, energy, materials, equipment and labour.

We will be dependent on external contractors over whom we have no control

We intend to outsource a portion of our coal exploration, mining and development activities pursuant to service contracts with third-party contractors. We intend to enter into contracts with subcontractors for the construction of infrastructure relating to our projects.

Such contractors may have economic or other interests or goals that are inconsistent with our interests or goals or may be unable or unwilling to fulfil their obligations or comply with our instructions or requests. Their performance may be constrained by labour disputes or actions, shortages in the supply of plant capacity, equipment, facilities, services, materials or supplies or damage to or failure of plants, equipment and machinery. In the event of such problems, we may not be able to find a suitable replacement contractor within a reasonable time, or at all, and our business and results of operations would be materially and adversely affected. We may not be able to control the quality, safety and environmental standards of the work done by third-party contractors to the same extent as when the work is performed by our own employees.

Our coal operations are exposed to risks in relation to the mishandling of dangerous articles

Our coal exploration, mining and coal production operations will involve the handling and storage of explosive, toxic and other dangerous articles. Accidents arising from the mishandling of dangerous articles may occur in the future. If we fail to comply with any relevant laws, regulations or policies or should any accident occur as a result of the mishandling of dangerous articles, our business and results of operations may be adversely affected, and we may be subject to penalties and/or civil and/or criminal liabilities. More stringent laws, regulations and policies may be implemented by the relevant Australian authorities, and we may not be able to comply with any future laws, regulations and policies in relation to the handling of dangerous articles in an economically viable manner, or at all.

Extensive environmental laws, including existing and potential future legislation, treaties and regulatory requirements relating to air emissions, may affect our customers and could reduce the demand for coal as a fuel source and cause coal prices and sales of our coal to materially decline

The operations of our potential customers are subject to extensive environmental regulation particularly with respect to air emissions. Coal contains impurities, including sulphur, mercury, chlorine and other elements and compounds, many of which are released into the air when coal is burned. Stricter environmental regulations of emissions from coal-fired electricity generation plans and other industrial plants could increase the costs of using coal. As a result, these power plants may switch to other fuels that generate fewer of these emissions or may install more effective pollution control equipment that reduces the need for low-sulphur coal. Any switching of fuel sources away from coal, closure of existing coal-fired power plants, or reduced construction of new coal-fired power plants could have a material adverse effect on demand for, and prices received for, our coal. Alternatively, less stringent air emissions limitations, particularly related to sulphur, to the extent enacted, could make low-sulphur coal less attractive, which could also have a material adverse effect on the demand for, and prices received for, our coal.

Australia and 191 other signatories to the 1992 United Nations Framework Convention on Climate Change ("**UNFCC**") intended to limit or capture emissions of greenhouse gases such as CO_2. In December 1997, in Kyoto, Japan, signatories to UNFCC established a potentially binding set of emissions targets for developed nations (the "**Kyoto Protocol**"). The Kyoto Protocol came into effect on 16 February 2005. The specific emissions targets vary from country to country. The enactment of the Kyoto Protocol or other comprehensive legislation focusing on greenhouse gas emissions could have the effect of restricting the use of coal in our primary target markets. Other efforts to reduce emissions of greenhouse gases and initiatives in various countries to encourage the use of natural gas may also affect the use of coal as an energy source and could adversely affect our business, financial condition, results of operations and prospects.

We have not obtained a number of licences and approvals required for our coal projects and whether we obtain these licences and approvals on a timely basis or at all is dependent on factors beyond our control (including the consent of relevant Government ministers and agencies). Further, the licences and approvals we have obtained are subject to ongoing conditions and/or renewal

We require various licences, permits, authorisations and approvals before mining and infrastructure development can commence, but have not yet obtained a number of them. There are well established approval regimes in Australia which govern the manner in which a project is taken from the exploration phase to development. The relevant licences, permits, authorisations and approvals will be applied for in accordance with the procedures set out in the relevant approvals regimes as and when required, with the approvals process varying depending on the stage of development of the project. Many factors will influence the timing of the grant of the licences, permits, authorisations and approvals required for our operations, including without limitation, the following: (i) many of the relevant approvals are not subject to any time limits within the relevant government department; (ii) it is possible that adverse decisions can be made by Ministers for purely political reasons; and (iii) rights of appeal exist in favour of third parties, which can add delay to the project timetable. Accordingly, these may not be granted in a timely manner or at all. Failure to obtain all necessary licences, permits, authorisations and approvals may prevent us from being able to develop our projects or may result in additional expenses or delays.

We will also require various approvals including general corporate, mining, capital investment, manpower, environmental, land utilisation, mining tenement and Ministerial Statements and other licences to commence development of our projects, and there is no guarantee that we will receive these on a timely basis, or at all.

The licences, permits, authorisations and approvals may also be granted subject to conditions which impose material restrictions on our ability to carry out the relevant project as planned or which require certain expenditures or activities in order to retain such licences. Any licences granted or approvals given to us are subject to periodic renewal. While we anticipate that renewals will be given as and when sought, there is no assurance that such renewals will be given as a matter of course and there can be no assurance that new conditions will not be imposed.

We may not be able to sell all or any of our coal products at the price or quantity that we expect

We may enter into supply agreements with certain coal customers under which they would agree to purchase and take, or pay if not taken, an aggregate quantity of thermal coal produced from the Blair Athol Mine. The supply agreements would be conditional upon the recommencement of operations of the Blair Athol Mine, which is dependent on obtaining all approvals of requisite regulatory permits that are required to commence operations for mining, recruitment of necessary personnel, initiation of contracts for logistical supplies and equipment and any inclement weather conditions. If any of these conditions are not satisfied, then the obligations of our coal customers under the supply agreements may be affected. The pricing for the coal supplied under the agreement may be calculated as a base price (which will be agreed between the parties on an annual basis having regard to, among other considerations, the relevant benchmark price, to reflect the prevailing market price for thermal coal) adjusted for actual coal quality (as measured by moisture, calorific value, sulphur content and ash content). There may be some uncertainty over how these terms will be agreed upon and this could result in our customer's purchase obligation being unenforceable. If our customers' obligations under the agreement do not come into force, our customers' purchase obligation is unenforceable or we are unable to recover our losses for a breach of contract, then this could adversely affect our business and results of operations.

Significant increases in taxes we pay on the coal we produce, such as royalties or severance and production taxes, including as a result of governmental audits or regulatory or interpretive changes, could materially adversely affect our profitability

We are required under Australian law to pay certain taxes in relation to our coal production activities. If the royalty rates in Queensland were to significantly increase, or if the methodology by which the government agencies assess royalties materially changes, our results of operations could be materially adversely affected. Examples of this could include:

- if the Australian federal government were to materially alter the method for valuing royalty payments for our non-arms' length sales, our profitability and cash flows could be materially adversely affected;
- if an Australian state government was to increase royalties or severance and production taxes or any other tax applicable to our operations in that state, our profitability could be reduced and our results of operations may be adversely affected; and
- if we are required to make additional payments (including related interest and penalties) as a result of pending or future governmental audits, our results of operations would be adversely affected.

Political, economic and legal developments in Australia could materially and adversely affect our business and results of operations of our conventional coal mining business

Certain of our projects are currently located in Australia. Accordingly, our result of operations, financial position and prospects are subject to economic, political and legal developments in Australia. Political instability in the areas which we operate can result in civil unrest, expropriation, nationalisation, renegotiation or nullification of existing agreements, mining leases and permits, changes in laws, or currency restrictions. Commercial instability caused by bribery and corruption can lead to similar consequences. Any of these can have a material adverse effect on the profitability or, in extreme cases, the viability of a project.

Some of our current and potential projects are located in or near communities that may now, or in the future, regard such a project as having a detrimental effect on their economic and social circumstances. Should this occur, it may have a material adverse impact on the profitability or viability of the project.

RISKS RELATING TO OUR INDUSTRY AND THE JURISDICTIONS IN WHICH WE OPERATE

Fluctuations in commodity prices could adversely affect our financial condition and results of operations

Our revenues, profitability, cash flow and future rate of growth are highly dependent on commodity prices including oil, gas and coal. Commodity prices may fluctuate widely in response to changes in the supply of and demand for commodities including oil, gas and coal, market uncertainty, and a variety of additional factors relating to such commodities that are beyond our control, such as:

- domestic and worldwide over-supply of or demand for the commodities;

- volatile movements in trading patterns in the commodity-futures markets including as a result of speculative trading;
- the cost of exploring for, developing, producing, transporting, and marketing the commodities;
- weather conditions and natural disasters;
- the ability of the members of the Organisation of Petroleum Exporting Countries and other producing nations to agree to and maintain production levels and prices;
- the effect of worldwide energy conservation and environmental protection efforts to the extent it constrains demand;
- the price and availability of alternative and competing fuels and other energy sources;
- domestic and foreign governmental regulations and taxes;
- the proximity to, and capacity of, transportation facilities;
- general economic and political conditions worldwide to the extent this constrains demand;
- technological advances affecting energy consumption and energy supply; and
- the production quality of such commodities.

The long-term effect of these and other factors on commodity prices are uncertain. Prolonged or substantial declines in commodity prices may have the following effects on our business:

- an adverse effect on our financial condition, liquidity, ability to finance planned capital expenditures, and results of operations;
- a reduction in the amount that we can produce economically;
- the delay or postponement of some of our planned capital projects;
- a reduction in our revenues, operating income, or cash flows;
- a reduction in the amounts of our estimated reserves and resources;
- a reduction in the carrying value of our assets; and
- a limitation in our access to sources of capital, such as equity and long-term debt.

On the other hand, increases in commodity prices could lead to increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon. It may also result in increased demand for labour, services and materials as drilling activity increases, and increased taxes. Any of these would result in increased costs for us.

We make price assumptions that are used for planning purposes and this includes a portion of our cash outlays, including rent, salaries and non-cancellable capital commitments which are largely fixed in nature. Accordingly, if commodity prices vary from expectations upon which these commitments were based, our financial results may be adversely and disproportionately affected.

Concerns over the worldwide economic outlook, geopolitical issues and the availability and cost of credit could have a significant adverse effect on global financial markets. If the global economic climate were to deteriorate, demand for energy products could diminish, which could adversely affect our business, financial condition and results of operations.

We have geographically diverse operations and are subject to various political and sovereign immunity risks

We operate in several geographic locations and jurisdictions, including Australia, the United States, Poland and Uzbekistan, and we expect to continue to develop operations in countries that expose us to additional regulatory, economic and investment risks as the political, economic and legal systems in these other countries may differ. These risks include difficulties in enforcing agreements through some of the legal systems, the protection of intellectual property, rising labour costs, disruptions in the infrastructure of the countries where we operate, difficulties in staffing and managing our operations, the burden of complying with foreign and international laws and treaties and the burden of compliance with, and changes in, international taxation policies.

In particular, some of the countries in which we operate have constitutions and laws which entrench and vest all the rights over their natural resources in the state, including its oil, gas and coal resources, which are regarded as sovereign state assets.

Natural disasters in Australia could have a negative impact on the Australian economy and cause our business to suffer

The occurrence of natural disasters, including floods (for example, heavy flooding in Queensland in late 2010 and early 2011), cyclones, bushfires and drought in Australia could adversely affect the Australian economy, which in turn may impact on our results of operations or financial condition. Beginning in December 2010, Queensland experienced severe flooding which caused widespread damage to housing, businesses and infrastructure as well as a food shortage in the State. For instance, the Australian coal industry was directly affected and several coal mines as well as coal railway lines in Queensland were forced to close, resulting in several billion Australian dollar in estimated losses due to cessation of coal production and costs of recovery.

The re-occurrence of flooding on a similar or greater scale as that experienced in Queensland in 2010 may adversely impact the Australian economy and would consequently adversely affect our business, results of operations and financial condition.

Our tenements in Australia may be affected by native title rights

In the context of interests of native and/or indigenous peoples in Australia, the *Native Title Act 1993* (Cth) recognises and protects the rights and interests in Australia of Aboriginal and Torres Strait Islander people in land and waters, according to their traditional laws and customs. The risks arising because of native title and aboriginal land rights may affect our ability to gain access to prospective exploration areas to obtain production titles. Existing tenements may be affected by native title claims or procedures (which may preclude or delay the granting of exploration and mining tenements), with the possibility of considerable expenses and delays involved in negotiating and resolving issues or obtaining clearances. Compensatory obligations may be necessary in settling native title claims lodged over any of the tenements held or acquired by us. The level of impact of these matters will depend, in part, on the location and status of our tenements. The location of our tenements in Queensland and South Australia overlap in certain instances with areas the subject of current approved determinations of native title, native title claimant applications (both registered and unregistered) and registered and unregistered indigenous land use agreements. Where a tenement has already been granted, it would have been the case that the relevant Queensland or South Australian government agency was satisfied that it could validly do so following compliance with the relevant future act regime under the Native Title Act 1993 (Cth) (if applicable). For future tenements that might be applied for in areas where native title has not been extinguished, it may affect the timeframe for the granting of those future tenements as agreements with the relevant Native Title parties (if any) will be required as a precondition for granting.

We are subject to risks associated with community relations

Our ongoing and future success depends on securing and maintaining a ‘social license to operate’ from impacted communities and other stakeholders in respect of the jurisdictions in which we operate. We believe our operations can provide valuable benefits to surrounding communities, in terms of direct employment, training and skills development, creation of demand for products and services and other community benefits associated with ongoing payment of taxes and contribution to community development funds. Notwithstanding, communities can become dissatisfied with our activities. Such dissatisfaction may result in civil unrest, protests, direct action, or campaigns against us, Any such actions may have a material adverse impact on project costs or production, or in extremis, project viability.

We may incur significant costs and liabilities as a result of environmental, health and safety laws and regulations that govern our operations

Our operations are subject to a variety of environmental, health and safety laws and regulations in the jurisdictions in which we operate, including Australia, the United States, Poland and Uzbekistan. We must obtain and maintain numerous permits, approvals, consents and certificates from various governmental authorities before commencing drilling or other regulated activities. In addition, we may need to make significant capital and operating expenditures to control emissions or perform corrective actions at our wells, mines and assets to meet the requirements of these laws and regulations or the terms or conditions of the permits issued pursuant to such laws.

We may incur significant environmental costs and liabilities in the performance of our operations due to our handling of various materials including petroleum hydrocarbons and wastes such as air emissions and wastewater discharges related to our operations and as a result of historical operations and waste disposal practices. Under certain environmental laws and regulations that impose strict joint and several liability, we may be required to remediate contamination on our assets and provide indemnification regardless of whether such contamination resulted from our own actions or the actions of the previous owners, regardless of whether such actions were in compliance with all applicable laws and regulations at the time they were taken. For example, upon completion of the acquisition of the Blair Athol Mine, we will be responsible for the reclamation and rehabilitation of all areas being mined within our concession area relating to the Blair Athol Mine. Our mine reclamation and rehabilitation liabilities can change significantly if our actual costs vary from our assumptions or if governmental regulations change. We expect to provide up to A$90 million (US$84.0 million) towards environmental rehabilitation bonds in order to recommence production of the Blair Athol Mine. Any significant unanticipated increase in our reclamation and rehabilitation costs could materially and adversely affect our business, financial condition and results of operations.

Furthermore, higher environmental protection standards may be imposed in the future, which could increase our costs of compliance. Moreover, future spills or releases of regulated substances or accidents or the discovery of currently unknown contamination could expose us to material losses, expenditures and environmental, health and safety liabilities. Such liabilities could include penalties, sanctions or claims for damages to persons, property or natural resources brought on behalf of the government or private litigants that could cause us to incur substantial costs or losses, of which we may not be able to recover some or any of these costs from insurance and this would have a material adverse effect on our business, financial condition and results of operations.

We may from time to time be subject to regulatory action in the course of our operations, which may subject us to, among others, administrative proceedings and unfavourable decisions that could result in penalties. In particular, failure to comply with applicable laws and regulations related to environmental, health and safety matters, or the terms or conditions of required environmental permits, could result in the assessment of significant administrative, civil and/or criminal penalties, the imposition of investigatory or remedial obligations and corrective actions, the revocation of required permits, or the issuance of injunctions limiting or prohibiting some or all of our operations. In such cases, our results of operations and cash flows could be materially adversely affected.

Laws protecting the environment generally have become more stringent over time we expect this trend to continue. The costs of complying with applicable environmental laws and regulations are likely to increase over time and we cannot assure you that we will be able to remain in compliance with respect to existing or new laws and regulations or that the cost of such compliance will not have a material adverse effect on our business, financial condition and results of operations.

Implementation of any one or more of any various proposed responses to any disaster, past or future, could materially adversely affect our financial results by raising operating costs, increasing insurance premiums, delaying drilling operations and increasing regulatory costs, in addition to a wide variety of other unforeseeable consequences.

The integration of the UCG to GTL processes is a unique proprietary technology and requires a range of permits in the relevant jurisdictions where we operate or plan to operate. These permits may vary in requirement in the different jurisdictions. For example, there are several environmental issues that require careful management in the exploration, testing and operational phases of a UCG project including fracturing and surface subsidence and potential impacts on ground water. If we are unable to obtain or maintain the necessary regulatory approvals in the relevant jurisdictions, the successful commercialisation of our UCG to GTL process may be delayed.

In October 2013, we received a notice from the Department of Environment and Heritage Protection ("**DEHP**") in Queensland requiring us to make available certain information so as to enable the DEHP to conduct an investigation into allegations regarding the unlawful release of contaminants at our Chinchilla Demonstration Facility in contravention of the Environmental Protection Act 1994 ("**EPA**") and the conditions of our Environmental Authorities. We intend to and have been cooperating with all proper and reasonable requests from the DEHP in connection with the subject matter of their investigation. Although we believe that these allegations are without merit, there can be no assurance that we will not be found to be in breach of the requirements of the EPA or in contravention of the conditions of our Environmental Authorities. In the event that we are found to be in such breach of the requirements of the EPA or in contravention of the conditions of our Environmental Authorities, the maximum aggregate financial penalty under the EPA for the potential offences is approximately A$3.4 million (US$3.2 million). In the event that an unfavourable decision is made against us, we believe that the more likely potential implications are that we may have to pay a nominal fine, undertake some form of rehabilitation and engage in regular compliance monitoring and reporting to DEHP, which should not have a material impact on our operations.

We are subject to governmental regulations relating to the oil, gas and coal industry and the procurement of relevant government permits, licences and approvals

Our current operations are, and our future operations will be, subject to the various government's considerable influence over their respective economies, including the oil, gas and coal industry, in terms of, among others, the granting of licences for drilling/mining operations, implementing regulations and approval for the exploration, drilling bonds, placement of environment rehabilitation bond, the sharing of information on natural resources and reports concerning operations, the spacing of wells, unitisation of oil, gas and coal accumulations, taxation, development, construction, operation, production, marketing and pricing, transportation and storage of oil, gas and coal. For instance, each time we undertake drilling of new wells for exploration or production we will be required to obtain new permits and licences which we may not obtain in a timing manner, or at all. Failure to obtain such permits would have an adverse effect on our drilling plans. In respect of drilling in Queensland, Wyoming, Alaska, Africa and Poland with a view to commercialising UCG, regulatory and royalty frameworks in these jurisdictions continue to be developing. We cannot assure you that any development in these matters will not be adverse to us. Under these laws and regulations, we may also be liable for personal injuries, property damage and other types of damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties.

Further, any governmental action concerning the conventional and unconventional oil and gas industry and conventional coal industry, such as a change in oil, gas or coal pricing policy, expropriation, nationalisation, renegotiation or nullification of existing concessions, licences and contracts, taxation policies, foreign exchange and repatriation restrictions and currency controls could have a material adverse effect on us. There is no assurance that these governments will not postpone or review projects or will not make any changes to government policies which, in each case, could adversely affect our financial position, results of operations or prospects.

Some of the countries in which we operate suffer from terrorism and militant activity

We operate and conduct business in countries which have experienced terrorist and militant activity. There can be no assurance that further terrorist acts will not occur in the future. The fear of terrorist actions, either against our assets or generally, could have an adverse effect on our ability to adequately staff and/or manage our operations or could substantially increase the costs of doing so. Any future terrorist acts in the countries in which we operate, could destabilise those countries and increase internal divisions within their governments, and might result in concerns about stability in the region and negatively affect investors' confidence. Violent acts arising from and leading to instability and unrest have in the past had, and could continue to have, a material adverse effect on investment and confidence in, and the performance of, and in turn on our business. Any terrorist attack, including those targeting our assets, could interrupt parts of our business and materially and adversely affect our business, results of operations, financial condition and prospects.

RISKS RELATING TO OUR SHARES AND THIS OFFERING

The sale or possible sale of a substantial number of our Shares in the public market by us, our major Shareholders following the Offering, and the availability of large amounts of our Shares for sale, could adversely affect the price of our Shares and ability to raise capital in the future

Sales of a substantial number of our Shares in the public market following the Offering, or the perception that these sales could occur, may depress the market price for our Shares. These sales could also impair our ability to raise additional capital through the sale of our equity securities in the future.

Following the Offering, we will have [●] issued Shares, of which [●] Shares or approximately [●]% will be owned indirectly by Mr. Peter Bond. If Mr. Peter Bond sells or is perceived as intending to sell a substantial amount of Shares, this could have a material adverse impact on the market price of our Shares. As at the Latest Practicable Date, Mr. Peter Bond through his wholly-owned company, Newtron, has pledged an aggregate of 71,000,000 Shares (the "**Pledged Collateral**") to Equities First Holdings, LCC ("**Equities**") pursuant to the terms of the master loan agreement entered into between both parties. Accordingly, any breach of the terms of the master loan agreement could lead to Equities being able to claim the Pledged Collateral and any subsequent sale of the Pledged Collateral by Equities in the market may adversely affect the price of our Shares. Furthermore, 37,453,184 Shares indirectly held by Mr. Peter Bond are the subject matter of a securities lending agreement (the "**SLA**") entered into between Newtron as lender, and Credit Suisse Equities (Australia) Limited ("**CS**

Equities") as borrower. For the duration of the arrangements provided for under the SLA, such Shares when borrowed, are not subject to any moratorium otherwise imposed on Mr. Peter Bond and other Shares directly and/or indirectly held by him. Hence, if any or all of these Shares are borrowed and subsequently sold into the market, the market price for our Shares may be adversely affected.

Upon completion of the Offering and the listing of our Shares on the SGX-ST, we also estimate that a total of [●] of our Shares, comprising approximately [●]% of our outstanding Shares, will be freely tradable on the SGX-ST.

In addition, we have agreed with the Joint Bookrunners and Joint Lead Managers that from the date of the Singapore Offer Agreement until the date that is six months after the Listing Date, we and they will not, without the respective written consent of the initial purchasers and the Joint Bookrunners and Joint Lead Managers, offer, sell or otherwise dispose of any securities of the same class as the Shares offered in this Offering or any securities convertible into or exchangeable for our securities of the same class as the Shares offered in this Offering.

We cannot predict the effect, if any, that future sales, or the availability of Shares for future sale, will have on the market price of our Shares prevailing from time to time. Sales of a substantial number of Shares in the public market following the Offering, or the perception that such sales may occur, could adversely affect the market price of our Shares.

Any depreciation in the value of the Singapore dollar could adversely affect the equivalent in other currencies of the value of our Shares in Singapore dollar and of any gains or losses realised by investors on a sale of our Shares. Any depreciation in the value of the Australian dollar and United State dollar could adversely affect the value in other currencies of any dividends distributed by us

Transactions in our Shares on the SGX-ST will be settled in Singapore dollar. Fluctuations in the exchange rate between the Singapore dollar and other currencies will affect the equivalent in other currencies of the Singapore dollar price of our Shares on the SGX-ST and the Singapore dollar amount of any gains or losses realised by investors on a sale of our Shares. Any dividends we declare in respect of our Shares will be payable in Australian dollar. Our financial statements are prepared in Australian dollar. Fluctuations in the exchange rate between the Australian dollar and United State dollar and other currencies will affect the equivalent in other currencies of the Australian dollar amount of any dividends distributed by us. See "Exchange Rate and Exchange Controls" for further information regarding fluctuations in the value of the United States dollar and Australian dollar relative to the Singapore dollar.

In relation to our business generally, we may have currency exposure in the procurement of capital equipment for the construction of infrastructure and in the sale of coal, as the international trade in these products is generally denominated in United States dollar.

The price of our Shares in the secondary market may fall below the Offering Price

The Offering Price of our Shares is determined by agreement between us and the Joint Bookrunners and Joint Lead Managers and may not be indicative of the market price for our Shares after the completion of the Offering.

The price of our Shares after the Offering may trade at prices significantly below the price at which new Shares may be issued pursuant to the Offering.

The price of our Shares will depend on many factors, including:

- variations in our operating results;

- the perceived prospects of our performance and investments and the Australian mining industry;
- gain or loss of an important business relationship;
- differences between our actual financial and operating results and those expected by investors and analysts;
- changes in accounting principles or other developments affecting us, our customers or our competitors;
- additions or departures of key personnel;
- changes in analysts' recommendations, perceptions or estimates of our financial performance;
- changes in conditions affecting the industry (including commodity prices), general economic conditions or other events or factors;
- the market value of our assets;
- amount of our reserves;
- the time needed to reach commercial production;
- the perceived attractiveness of our Shares against those of other equity securities, including those not in the mining industry;
- the balance of buyers and sellers of our Shares;
- any sale or intended sale of a substantial amount of Shares by existing Shareholders (including Shareholders who may decide to sell their Shares in connection with the delisting of our Shares from the ASX);
- broad market fluctuations, including any weakness of the equity market and increases in interest rates; and
- involvement in litigation.

These fluctuations may be exaggerated if the trading volume of our Shares is low. In recent years, the securities markets have experienced a high level of price and volume volatility and have exerted extreme downward pressure on stock prices, particularly in the mining industry. the market price of many companies, particularly those considered to be development stage companies, has experienced wide fluctuations which have not necessarily been related to the operating performance, underlying asset values or prospects of such companies. If these increased levels of volatility and market turmoil continue, the trading price of our Shares could be adversely affected.

For these reasons, among others, our Shares may trade in the secondary market at prices that are higher or lower than the NAV per Share. Any failure on our part to meet market expectations with regard to future earnings and dividends may adversely affect the market price for our Shares.

If any of the contracts we entered into are not honoured, or any of their conditions are not complied with, we may incur losses and be unable to declare dividends

We have entered into numerous contracts in connection with our business. Further details of our contracts are described in this offering document. In the event that one or more of our contracts is not honoured or any of the conditions contained in our contracts are not observed by a contracting party, we may incur a loss in relation to such contract thereby adversely affecting our business, financial condition and results of operations. If the loss incurred in relation to such contract is significant, we may not achieve a profit, in which case we may be unable to declare dividends.

Subject to the Corporations Act, our Constitution and the terms or rights of any shares with special rights to dividends, our Board may from time to time resolve to pay dividends to Shareholders. This being said, we may be unable to pay a dividend unless we have profits out of which a dividend can be paid. Under the Corporations Act, we must not pay a dividend unless (i) our assets exceed our liabilities immediately before the dividend is declared and the excess is sufficient for the payment of the dividend (ii) the payment of the dividend is fair and reasonable to our Shareholders as a whole and (iii) the payment of the dividend does not materially prejudice our ability to pay our creditors. If any of the aforementioned criteria cannot be satisfied due to our profitability, we may be unable to declare dividends.

We may not be able to pay dividends in the future

Our Company is incorporated in Australia and we operate our business through our subsidiaries. Therefore, the availability of funds to us to pay dividends to our Shareholders depends in part on dividends received from these subsidiaries.

Our ability to declare dividends in relation to our Shares is subject to our Constitution and will depend on our earning, financial condition and capital requirements. As such, we cannot assure that we will generate sufficient income to cover operating expenses and pay dividends to our Shareholders, or at all.

Our business is capital intensive and we may need to make additional capital expenditures to carry out our exploration and development activities. Our ability to make dividends could also be restricted to certain financial arrangements that we may enter into. For example, the indenture governing the 2017 Senior Secured Notes contains covenants that restrict, among others, the sale, lease or other disposition of any assets or rights of the issuers and the guarantors as well as the payment of dividends by them. We may be unable to pay dividends in the near or medium term, and our future dividend policy will depend on capital requirements and financing arrangements for our exploration and production activities, financial condition and results of operations.

Singapore laws and Australian laws contain provisions that could discourage a take-over of our Company

We are registered under the Corporations Act and governed by Australian laws and regulations. Australian laws and regulations may differ in some respects from comparable Singapore laws and regulations. We may be therefore be subject to different obligations in each jurisdiction and this may result in increased compliance costs for our Company.

We are subject to the Singapore Code of Take-Overs and Mergers (the "**Singapore Take-Over Code**"). The Singapore Take-Over Code contains provisions that may delay, deter or prevent a future take-over or change in control of our Company. Under the Take-Over Code, any person acquiring an interest, either individually or together with parties acting in concert, in 30.0% or more of our voting shares must extend, except with the consent of the Securities Industry Council a take-over offer for our remaining voting shares in accordance with the Take-Over Code. Except with the consent of the Securities Industry Council, a take-over offer is also required to be made if a person holding between 30.0% and 50.0% inclusive of the voting rights in our Company, either individually or in concert, acquires more than 1.0% of our voting shares in any six-month period under the Take-Over Code. While the Singapore Take-Over Code seeks to ensure an equality of treatment among shareholders, its provisions could substantially impede the ability of shareholders to benefit from a change of control and, as a result, may adversely affect the market price of our Shares and the ability to realise any benefit from a potential change of control.

Similarly, the acquisition of interests in our Company is regulated by the takeover provisions in Chapter 6 of the Corporations Act. These provisions prohibit (with the sanction of penalties) the acquisition of relevant interests in Shares, if as a result of the acquisition the acquirer's (or another party's) "voting power" in our Company would increase to above 20.0%, or would increase from a starting point that is above 20.0% and below 90.0%. That prohibition is subject to a number of exceptions, including for acquisitions pursuant to a regulated takeover bid.

In addition, the acquisition of interests in our Company is also regulated by the Australian Foreign Acquisitions and Takeovers Act 1975 (the "**FATA**"). Pursuant to the FATA, where a "foreign person" acquires certain interests in our Company, as a consequence of which such person would have an interest in 15.0% or more of our Shares, or a number of foreign persons would have in aggregate an interest in 40.0% or more of our Shares, and such acquisition is considered by the Treasurer of the Commonwealth of Australia to be contrary to Australia's national interest, the acquisition may be prohibited. See "Appendix D—Description of our Shares—Ownership Restrictions" for further details.

The above provisions may discourage or prevent such transactions from taking place at all. Some of our Shareholders may therefore be disadvantaged as such a transaction may have allowed the sale of Shares at a price above the then prevailing market price.

In addition to the aforementioned, our Company, the offeror and other parties will need to consider regulatory obligations in both jurisdictions which may involve significant increases to time and cost when compared to a takeover bid in a single jurisdiction.

The Offering may not result in an active or liquid market for our Shares

We have received an eligibility-to-list letter from the SGX-ST to have our Shares listed and quoted on the SGX-ST, listing and quotation does not guarantee that a trading market for our Shares will develop or, if a market does develop, the liquidity of that market for our Shares. Although we currently intend that our Shares will remain listed on the SGX-ST, there is no guarantee of the continued listing of our Shares.

The Offering Price of our Shares under the Offering was determined following a book-building process by agreement between the Joint Bookrunners and Joint Lead Managers and us and may not be indicative of prices that will prevail in the trading market. An investor may not be able to resell our Shares at a price that is attractive to such investor.

The trading prices of our Shares could be subject to fluctuations in response to variations in our results of operations, changes in general economic conditions, changes in accounting principles or other developments affecting us, our clients or our competitors, changes in financial estimates by securities analysts, the operating and stock price performance of other companies and other events or factors, many of which are beyond our control. Volatility in the price of our Shares may be caused by factors outside of our control or may be unrelated or disproportionate to our results of operations. It may be difficult to assess our performance against either domestic or international benchmarks.

Investors may face difficulty in enforcing any judgment obtained outside Australia against us or our Management

Our Company is an Australian registered company. A number of our Directors and officers are residents of Australia. A substantial portion of our assets and the assets of our Directors and officers, at any one time, may be located in jurisdictions outside Singapore. Investors may face difficulties in lawfully effecting service of process on our Directors and officers who reside outside Singapore, or to recover against our Company or our Directors and officers on judgments of Singapore courts predicated upon the laws of Singapore.

If a judgment is obtained against us or our Directors in a Singapore court, additional requirements need to be satisfied in order to attempt to enforce the judgment in Australia. An Australian court will only enforce such a judgment if, among other things, an application is made to register the judgment in Australia within six years of the date of judgment (or date of latest appeal), it is a judgment of the Court of Appeal or the High Court in Singapore, and the judgment is final and conclusive, even if an appeal can be made. In addition, an Australian court may set aside registration of a judgment of the Singapore courts where, for example (without limitation), the judgment debtor did not appear in the proceedings in Singapore, the judgment has been reversed or set aside on appeal, or enforcement of the judgment would be contrary to public policy in Australia.

Overseas shareholders may not be able to participate in future rights offerings or certain other equity issues by us

If we offer to our Shareholders rights to subscribe for additional Shares or any right of any other nature, we will have discretion as to the procedure to be followed in making the rights available to our Shareholders or in disposing of the rights for the benefit of our Shareholders and making the net proceeds available to our Shareholders. We may choose not to offer the rights to our Shareholders who have a registered address outside Singapore. In addition, we may be prohibited by applicable law from extending such rights offering or similar event to holders in certain jurisdictions unless certain procedures are followed. For example, we would not be permitted to offer such rights to our Shareholders having a registered address in the United States unless (i) we file a registration statement under the U.S. Securities Act in order for us to offer such rights to Shareholders and sell the securities represented by such rights, or (ii) the offering and sale of such rights or the underlying securities to such Shareholders are exempt from registration under the U.S. Securities Act. We have no obligation to prepare or file any registration statement under the U.S. Securities Act. Accordingly, Shareholders who have a registered address in the United States may be unable to participate in rights offerings and may experience a dilution in their holdings as a result.

USE OF PROCEEDS

Based on the Offering Price of S$[●] for each Offering Share, we estimate that the aggregate net proceeds we will receive from the Offering (assuming the Over-allotment Option is not exercised) will be approximately S$[●] million (US$[●] million), after deducting underwriting commissions and other estimated transaction expenses payable in relation to the Offering.

We intend to use the net proceeds of S$[●] million (US$[●] million) from the subscription of Offering Shares for the following purposes:

- approximately S$[●] million (US$[●] million) for the conventional oil and gas business, specifically towards developing our Umiat field in Alaska, developing the CO_2 EOR project with regard to our assets in Wyoming and also the sub-salt dome drilling and exploration programme in the Gulf Coast Region;
- approximately S$[●] million (US$[●] million) for the Clean Energy business, specifically towards developing the UCG project in Poland and South Africa (in particular developing the joint venture with Exxaro Resources), undertaking various other project development activities in Europe, Russia, North America and Asia, and to conduct additional exploration drilling and seismic programme for our SAPEX business; and
- the balance for funding working capital and other general corporate purposes.

For each Singapore dollar of our gross proceeds from the Offering, we intend to use the following amounts for each purpose:

- approximately S$[●] for the conventional oil and gas business;
- approximately S$[●] for the unconventional oil and gas business;
- approximately S$[●] for funding working capital and other general corporate purposes; and
- approximately S$[●] for expenses in connection with the Offering.

None of the proceeds from the Offering will be used to discharge, reduce or retire the indebtedness of our Group.

If the Over-allotment Option is exercised by the Stabilising Manager, we shall use the net proceeds from the issue and sale of the Additional Shares for working capital purposes.

The foregoing represents our best estimate of our allocation of our proceeds from the Offering based on our current plans and estimates regarding our anticipated expenditures. Actual expenditures may vary from these estimates, and we may find it necessary or advisable to re-allocate our net proceeds within the categories described above or to use portions of our net proceeds for other purposes. In the event that we decide to re-allocate our net proceeds from the Offering for other purposes, we will publicly announce our intention to do so through a SGXNET announcement to be posted on the internet at the SGX-ST website, http://www.sgx.com.

Pending the deployment of the net proceeds as aforesaid, we may place the funds in fixed deposits with banks and financial institutions or use the funds for investment in short-term money market instruments, as our Directors may deem appropriate in their absolute discretion.

We intend to make periodic announcements on the use of proceeds as and when material amounts of proceeds from the Offering are disbursed, and provide a status report on the use of proceeds in our annual report.

EXPENSES

We estimate that the expenses payable by our Company in connection with the Offering as well as the application for listing, including the underwriting and placement commission, and all other incidental expenses relating to the Offering (assuming the Over-allotment Option is not exercised), will amount to approximately S$[●] million (US$[●] million). A breakdown of these expenses is set out below:

Estimated Expense(1)	S$ (in millions)	As a percentage of gross proceeds from the Offering (%)
Underwriting, selling and management commission	[●]	[●]
Professional fees and accounting fees(2)	[●]	[●]
Other Offering-related expenses(3)	[●]	[●]
Advertising and printing expenses	[●]	[●]
Total	**[●]**	**[●]**

Notes:

(1) Assuming the Over-allotment Option is not exercised.

(2) Includes legal counsel's fees and fees for the Independent Auditors, the Independent Tax Advisor, the Qualified Persons, the Industry Consultant and other professionals' fees as well as the cost of production of this offering document, road expenses and certain other expenses incurred or to be incurred in connection with the Offering.

(3) Includes the fees payable to the SGX-ST and the Authority in connection with the Offering and the listing of our Company on the SGX-ST.

Subscribers for the Offering Shares may be required to pay brokerage or other similar fees (and if so required, such brokerage will be up to 1.0% of the Offering Price), any stamp duties and other similar charges in accordance with the laws and practices of the country of subscription, in addition to the Offering Price.

We will pay the Joint Bookrunners and Joint Lead Managers, as compensation for their services in connection with the Offering, a combined underwriting and selling commission amounting to 3.5% of the total gross proceeds from the sale of Offering Shares, the Additional Shares (if the Over-allotment Option is exercised).

We may, at our sole discretion, pay one or more of the Joint Bookrunners and Joint Lead Managers an incentive fee of up to [●]% of the total gross proceeds from the offering of the Offering Shares, the Additional Shares (if the Over-allotment Option is exercised).

See "Plan of Distribution—The Offering" for a description of the commissions payable in connection with the Offering.

DIVIDEND POLICY

Statements contained in this section that are not historical facts are forward-looking statements. Such statements are subject to certain risks and uncertainties which could cause actual results to differ materially from those which may be forecasted and projected. Under no circumstances should the inclusion of such information herein be regarded as a representation, warranty or prediction with respect to the accuracy of the underlying assumptions by us and the Joint Bookrunners and Joint Lead Managers, or any other person. Prospective investors are cautioned not to place undue reliance on these forward-looking statements that speak only as at the date hereof. See "Notice to Investors—Forward-looking Statements".

On 31 August 2010, our Company declared a fully franked special dividend of A$0.10 (US$0.10) per Share which we paid on 8 October 2010. Since 9 October 2010, we have not declared or paid any further dividends.

While we currently do not have a formal dividend policy, we intend to reinvest any profits generated from our operations in our business. Subject to the Corporations Act, our Constitution and the terms or rights of any Shares with special rights to dividends, our Board may from time to time resolve to pay dividends to Shareholders. The form, frequency and amount of future dividends on our Shares will depend on our retained earnings and expected future earnings, general business and financial position, results of operations, capital requirements, cash flow, general financing condition, and other factors which our Directors may deem appropriate. Therefore, there can be no assurance that dividends will be paid in the future or of the amount or timing of any dividends that will be paid in future.

The terms under the 2017 Senior Secured Notes and the 2013 Credit Facility specify scheduled debt repayments and require us to comply with certain covenants and restrictions before dividends may be declared by our subsidiaries. Such restrictions may limit our ability to receive dividends or cash from the relevant subsidiaries, which could adversely affect our financial condition and ability to execute our business plans or pay dividends. The indenture governing the 2017 Senior Secured Notes contains covenants that restrict, among others, the sale, lease or other disposition of any assets or rights of the issuers and the guarantors as well as the payment of dividends by them. Further details as to the restrictions under such facilities are set out in the "Risk Factors—We may not be able to pay dividends in the future" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Borrowings and other indebtedness" of this offering document.

Information relating to taxes payable on dividends is set out under "Taxation" in this offering document.

No inference should or can be made from any of the foregoing statements as to our actual future profitability or our ability to pay dividends in any of the periods discussed.

CAPITALISATION AND INDEBTEDNESS

The following table sets forth our consolidated short-term debt, long-term debt and capitalisation as at 30 September 2013, on an actual basis and as adjusted to give effect to the entry by our Company into the 2013 Credit Facility on 24 October 2013 to refinance the 2012 Credit Facility and the issue and offer of the Offering Shares at the Offering Price of S$[●] per Offering Share and the application of our net proceeds from the Offering in the manner described in "Use of Proceeds".

The information in this table should be read in conjunction with "Use of Proceeds", "Selected Consolidated Financial Information and Other Data", "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our historical consolidated financial statements and the notes thereto included in this offering document.

	As at 30 September 2013 (Unaudited / Unreviewed)					
	Actual		As adjusted for the 2013 Credit Facility(1)		As Adjusted for the Offering	
	(A$'000)	*(US$'000)*	*(A$'000)*	*(US$'000)*	*(A$'000)*	*(US$'000)*
Current borrowings:						
Secured and guaranteed	37,422	34,933	454	424	[●]	[●]
Unsecured and non-guaranteed	1,074	1,003	1,074	1,003	[●]	[●]
Total Current Borrowings	38,496	35,847	1,528	1,427	[●]	[●]
Non-current borrowings:						
Secured and guaranteed(2)	265,238	247,600	325,525	303,878	[●]	[●]
Unsecured and non-guaranteed(3)	178,903	167,006	178,903	167,006	[●]	[●]
Total Borrowings	**482,637**	**450,052**	**505,956**	**472,310**	**[●]**	**[●]**
Shareholders' Equity:						
Share capital	329,675	307,752	329,675	307,752	[●]	[●]
Reserves	56,741	52,968	56,741	52,968	[●]	[●]
Retained Earnings	(2,837)	(2,648)	(3,604)	(3,364)	[●]	[●]
Total Shareholders' Equity	**383,579**	**358,071**	**382,812**	**357,355**	**[●]**	**[●]**
Total Capitalisation	**866,216**	**806,620**	**888,168**	**829,665**	**[●]**	**[●]**

Notes:

(1) On 24 October 2013, we entered into the 2013 Credit Facility. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources—Borrowings and other indebtedness—2013 Credit Facility" for further details on the 2013 Credit Facility.

(2) On 1 October 2012, Linc USA GP and Linc Energy Finance (USA), Inc. issued the 2017 Senior Secured Notes. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources—Borrowings and other indebtedness—2017 Senior Secured Notes" for further details on the 2017 Senior Secured Notes".

(3) On 10 April 2013, we issued the 2018 Convertible Notes. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources—Borrowings and other indebtedness—2018 Convertible Notes" for further details on the 2018 Convertible Notes.

DILUTION

Dilution created by the Offering represents the amount by which the initial public offering price paid by the purchasers of Shares in the Offering exceeds the book value of net assets per Share after the Offering. We have determined book value of net assets per Share by subtracting our total liabilities from the total book value of our assets and dividing the difference by the number of Shares outstanding on 30 June 2013.

As at 30 June 2013, our book value, expressed in terms of consolidated net assets per Share, was A$0.86 (based on the 519,468,416 Shares issued and outstanding on that date and the issued share capital of A$444,847,000). After giving effect to the sale of the [●] Offering Shares offered in the Offering at the Offering Price of S$[●] per Offering Share, and after payment of underwriting commissions and other estimated expenses of the Offering resulting in net proceeds to us of S$[●], but without taking into account any other changes in book value of net assets after 30 June 2013, the book value of net assets is S$[●] per Share, and there will be an immediate dilution of S$[●] (i.e. [●]%) per Share to new investors purchasing Shares at the price of S$[●] per Share.

The following table illustrates the per Share dilution (based on the Offering Price of S$[●] per Offering Share) described above (in S$):

Offering Price per Offering Share of S$[●] in the Offering	[●]
Book value of net assets per Share as at 30 June 2013(1)	A$0.86
Increase in book value of net assets per Share attributable to the sale of Shares in the Offering(2)	[●]
Pro forma book value of net assets per Share after the Offering ([●] Shares outstanding as adjusted)(2)	[●]
Dilution per share to new investors of Shares in the Offering	[●]

Notes:

(1) Book value of net assets per Share is calculated based on total net assets of A$444,847,000 divided by 519,468,416 Shares as at 30 June 2013.

(2) Assumes the Over-allotment Option is not exercised.

The issuance of the Employee Option Plan Shares and/or the Performance Rights Plan Shares pursuant to the vesting of awards which may be granted and/or the exercise of options which have been granted under the Performance Rights Plan and Employee Option Plans, respectively (each as defined in "**Share-Based Incentive Plans**") as well as the issuance of the CN Shares pursuant to the conversion of the 2018 Convertible Notes would have a further dilutive effect on new investors in the Offering. The total number of the Employee Option Plan Shares and/or the Performance Rights Plan Shares that may be issued pursuant to awards granted under our Share-Based Incentive Plans may not exceed 15.0% of our total issued share capital on the day preceding the relevant date of the award. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—2018 Convertible Notes" for the dilutive effect of the 2018 Convertible Notes.

The following table summarises the total number of Shares acquired by our Directors, Substantial Shareholders or their respective associates during the three years prior to the date of lodgement of this offering document, as well as by new investors in the Offering the total consideration paid by them and the effective cash cost per Share to them and to our new Shareholders pursuant to the Offering. Except as disclosed in the table, none of our Directors, Substantial Shareholders or their associates has acquired any Shares during the three years prior to the date of lodgement of this offering document.

Directors	**No. of Shares acquired[1]**	**Total Consideration (A$'000)**	**Effective Cash Cost per Share (A$)**	**Effective Cash Cost per Share (US$)**
Kenneth Dark	2,000,000	500	0.25	0.23
Peter Bond	855,862[2]	2,251	2.63	2.43
	500,000	585	1.17	1.08
	145,252	419	2.88	2.66
	171,939	499	2.90	2.68
	24,071	70	2.90	2.68
Craig Ricato	500,000[3]	585	1.17	1.08
Substantial Shareholders				
Affiliates of Credit Suisse Group AG[4]	49,768,726	-	-	-
New Investors in the Offering	**[●]**	**[●]**	**[●]**	**[●]**

Notes:

(1) For the avoidance of doubt, the number of Shares acquired and total consideration in the table reflects the acquisition by our Directors and Substantial Shareholders between 17 September 2010 and 19 September 2013.

(2) Out of these Shares acquired, 500,000 Shares have been disposed for a total consideration of A$585,000 (US$546,098).

(3) Subsequently sold to Mr. Peter Bond.

(4) Four affiliates of Credit Suisse Group AG acquired an aggregate of approximately 9.5% of the issued share capital of our company, pursuant to the provision of services related to securities activities. Of these affiliates, Credit Suisse Equities (Australia) Limited holds 49,019,688 shares representing 9.4% of the issued share capital of our company.

EXCHANGE RATES AND EXCHANGE CONTROLS

EXCHANGE RATES

The following table sets forth the average, high, low and period end exchange rate between Australian dollar and Singapore dollar (in Singapore dollar per Australian dollar) for the periods indicated. We make no representation that the converted Singapore dollar amounts referred to in this document actually represent such Australian dollar amounts or could have been or could be converted into Australian dollar at the rate indicated, any other rate or at all. The high and low amounts and the average rates for the annual figures were determined using the respective exchange rates at the end of each month during the year indicated; the high and low amounts and the average rates for the monthly figures were determined using the respective exchange rates for each day during the month indicated.

	Australian dollar / Singapore dollar(1)			
Period	**Low**	**High**	**Average**	**Period End/Closing Rate**
FY2011	0.7446	0.8557	0.7826	0.7592
FY2012	0.7375	0.8050	0.7696	0.7720
FY2013	0.7593	0.8629	0.7865	0.8629
May 2013	0.7470	0.7617	0.7563	0.7597
June 2013	0.8174	0.8629	0.8418	0.8629
July 2013	0.8513	0.8758	0.8607	0.8758
August 2013	0.8571	0.8830	0.8701	0.8809
September 2013	0.8427	0.8743	0.8526	0.8546
October 2013	0.8337	0.8535	0.8452	0.8516
November 2013 (through to the Latest Practicable Date)	0.8447	0.8605	0.8533	0.8585

Note:

(1) Bloomberg L.P. has not consented to the inclusion of this statement, table or compilation, as the case may be, for the purposes of Section 249 of the Securities and Futures Act and is thereby not liable for this statement under Sections 253 and 254 of the Securities and Futures Act. While our Directors and the Joint Bookrunners and Joint Lead Managers have taken reasonable actions to ensure that the information from the relevant report published by Bloomberg L.P. is reproduced in its proper form and context, and that the information is extracted accurately and fairly from that report, none of our Directors, the Joint Bookrunners and Joint Lead Managers or any other party has conducted an independent review of the information contained in that report or verified the accuracy of the contents of the relevant information.

The exchange rate for Australian dollar as at the Latest Practicable Date was S$1.00 = A$0.86. Fluctuations in the exchange rate between the Singapore dollar and the Australian dollar will affect the Australian dollar equivalent of the Singapore dollar price of our Shares on the SGX-ST and the Australian dollar equivalent of our cash dividends, if any, paid by us in Singapore dollars.

The following table sets forth the average, high, low and period end exchange rate between Singapore dollar and United States dollar (in Singapore dollar per United States dollar) for the periods indicated. We make no representation that the converted Singapore dollar amounts referred to in this document actually represent such United States dollar amounts or could have been or could be converted into United States dollar at the rate indicated, any other rate or at all. The high and low amounts and the average rates for the annual figures were determined using the respective exchange rates at the end of each month during the year indicated; the high and low amounts and the average rates for the monthly figures were determined using the respective exchange rates for each day during the month indicated.

	United States dollar / Singapore dollar[(1)]			
Period	**Low**	**High**	**Average**	**Period End/Closing Rate**
FY2011	0.7174	0.8176	0.7738	0.8141
FY2012	0.7581	0.8329	0.7939	0.7904
FY2013	0.7835	0.8223	0.8072	0.7888
May 2013	0.7995	0.8176	0.8073	0.8107
June 2013	0.7835	0.8036	0.7936	0.7888
July 2013	0.7802	0.7943	0.7889	0.7868
August 2013	0.7790	0.7953	0.7859	0.7845
September 2013	0.7807	0.8022	0.7921	0.7964
October 2013	0.7988	0.8093	0.8044	0.8056
November 2013 (through to the Latest Practicable Date)	0.8003	0.8050	0.8027	0.8014

Note:

(1) Bloomberg L.P. has not consented to the inclusion of this statement, table or compilation, as the case may be, for the purposes of Section 249 of the Securities and Futures Act and is thereby not liable for this statement under Sections 253 and 254 of the Securities and Futures Act. While our Directors and the Joint Bookrunners and Joint Lead Managers have taken reasonable actions to ensure that the information from the relevant report published by Bloomberg L.P. is reproduced in its proper form and context, and that the information is extracted accurately and fairly from that report, none of our Directors nor the Joint Bookrunners and Joint Lead Managers or any other party has conducted an independent review of the information contained in that report or verified the accuracy of the contents of the relevant information.

The exchange rate for United States dollar as at the Latest Practicable Date was S$1.00 = US$0.80. Fluctuations in the exchange rate between the Singapore dollar and the United States dollar will affect the United States dollar equivalent of the Singapore dollar price of our Shares on the SGX-ST and the United States dollar equivalent of our cash dividends, if any, paid by us in Singapore dollars.

EXCHANGE CONTROLS

Singapore

There are no exchange controls in Singapore.

United States

There are no exchange controls in the United States.

Australia

Australia has liberal foreign exchange laws permitting the free transfer of both Australian and foreign currencies into and out of Australia. There is currently no Australian law, decree or regulatory requirement which would affect the repatriation of capital and the remittance of profits, including any dividends, by or to our Company.

MARKET PRICE INFORMATION

The following table shows certain pricing and trading volume information for our Shares on the ASX for the periods indicated. Investors should take note that our Share price may vary from our past market performance due to various reasons including, in particular, that our Shares were listed on the ASX but will now be listed on the SGX-ST. Investors are therefore cautioned not to rely on the historical data presented above to evaluate the future performance of our Shares.

Period	High(1) (A$)	Low(1) (A$)	Average daily trading volume (Number of Shares)
2011	3.28	1.00	2,473,107
2012	2.99	0.59	2,733,893
2013	2.95	0.48	5,293,430
May 2013	1.88	1.40	4,551,169
June 2013	1.53	0.82	8,159,865
July 2013	1.95	0.81	9,533,625
August 2013	1.84	1.50	4,136,556
September 2013	1.61	1.39	4,519,278
October 2013	1.74	1.09	8,186,060
November 2013 (through to the Latest Practicable Date)	1.37	1.00	12,167,393

Note:

(1) Bloomberg L.P. has not consented to the inclusion of this statement, table or compilation, as the case may be, for the purposes of Section 249 of the Securities and Futures Act and is thereby not liable for this statement under Sections 253 and 254 of the Securities and Futures Act. While our Directors and the Joint Bookrunners and Joint Lead Managers have taken reasonable actions to ensure that the information from the relevant report published by Bloomberg L.P. is reproduced in its proper form and context, and that the information is extracted accurately and fairly from that report, none of our Directors nor the Joint Bookrunners and Joint Lead Managers or any other party has conducted an independent review of the information contained in that report or verified the accuracy of the contents of the relevant information.

The table below shows the highest and lowest prices of our Shares for each financial quarter in each of the financial years ended 30 June 2012 and 2013 as well as for the financial quarter ended 30 September 2013.

Period	High(1) (A$)	Low(1) (A$)
1 July 2011 to 30 September 2011	2.99	1.68
1 October 2011 to 31 December 2011	2.15	1.02
1 January 2012 to 31 March 2012	1.51	1.08
1 April 2012 to 30 June 2012	1.27	0.59
1 July 2012 to 30 September 2012	0.78	0.48
1 October 2012 to 31 December 2012	1.30	0.54
1 January 2013 to 31 March 2013	2.95	1.25
1 April 2013 to 30 June 2013	2.12	0.82
1 July 2013 to 30 September 2013	1.95	0.81

Note:

(1) Bloomberg L.P. has not consented to the inclusion of this statement, table or compilation, as the case may be, for the purposes of Section 249 of the Securities and Futures Act and is thereby not liable for this statement under Sections 253 and 254 of the Securities and Futures Act. While our Directors and the Joint Bookrunners and Joint Lead Managers have taken reasonable actions to ensure that the information from the relevant report published by Bloomberg L.P. is reproduced in its proper form and context, and that the information is extracted accurately and fairly from that report, none of our Directors nor the Joint Bookrunners and Joint Lead Managers or any other party has conducted an independent review of the information contained in that report or verified the accuracy of the contents of the relevant information.

The closing price of our Shares on the ASX as at the Latest Practicable Date was A$0.995 (US$0.93) and the closing price of our Shares as at 1 October 2013, which was the last trading date before the announcement of the Offering was A$1.405 (US$1.31).

SELECTED CONSOLIDATED FINANCIAL INFORMATION DATA AND OTHER DATA

You should read the following selected historical consolidated financial data for the periods and as at the dates indicated in conjunction with the section of this offering document titled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements, the accompanying notes and the related auditors' report included in this offering document. Our consolidated financial statements are reported in Australian dollars and are prepared and presented in accordance with IFRS as issued by the IASB, which may differ in certain significant respects from generally accepted accounting principles in other countries, including the United States.

The selected consolidated financial data as at and for the financial years ended 30 June 2011, 2012 and 2013 has been derived from our annual historical consolidated financial statements included elsewhere in this offering document and should be read together with those financial statements and the notes thereto. Our historical results for any prior periods are not necessarily indicative of results to be expected for a full financial year or for any future period.

Selected Consolidated Statement of Comprehensive Income Data

	FY2011	FY2012	FY2013	FY2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Revenue	3,199	57,060	124,370	116,099
Cost of sales	(2,992)	(31,680)	(59,381)	(55,432)
Gross Profit	**207**	**25,380**	**64,989**	**60,667**
Gain on sale of coal tenement, net of costs	495,001	-	-	-
Gain on purchase of oil and gas assets	6,027	-	628	586
Other income	971	1,075	143	133
Expenses:				
Administration and corporate	(57,550)	(72,902)	(64,410)	(60,127)
Site operating costs	(12,666)	(12,367)	(9,075)	(8,472)
Exploration and evaluation	(2,455)	(3,326)	(3,245)	(3,029)
Technology development	(18,997)	(18,063)	(11,139)	(10,398)
Other expenses	-	(1,841)	(33,322)	(31,106)
Results from operating activities	**410,538**	**(82,044)**	**(55,431)**	**(51,746)**
Finance income	22,181	3,578	41,446	38,690
Finance expenses	(413)	(11,231)	(72,001)	(67,213)
Net finance costs	**21,768**	**(7,653)**	**(30,555)**	**(28,523)**
Profit / (loss) before income tax	**432,306**	**(89,697)**	**(85,986)**	**(80,269)**
Income tax benefit / (expense)	(135,865)	27,804	22,161	20,687
Profit / (loss) for the year	**296,441**	**(61,893)**	**(63,825)**	**(59,582)**
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss:				
Net change in the fair value of available-for-sale financial assets, net of transaction costs and tax	5,726	(7,895)	6,596	6,157
Foreign currency translation differences for foreign operations	554	(597)	31,620	29,517
Total other comprehensive income / (loss) for the year, net of income tax	**6,280**	**(8,492)**	**38,216**	**35,674**
Total comprehensive income / (loss) for the year	**302,721**	**(70,385)**	**(25,609)**	**(23,908)**

	FY2011	FY2012	FY2013	FY2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Profit / (loss) attributable to:				
Our equity holders	296,455	(61,891)	(63,805)	(59,562)
Non-controlling interest	(14)	(2)	(20)	(19)
Profit / (loss) for the year	**296,441**	**(61,893)**	**(63,825)**	**(59,581)**
Total comprehensive income / (loss) attributable to				
Our equity holders	302,757	(70,379)	(26,683)	(24,909)
Non-controlling interest	(36)	(6)	1,074	1,003
Total comprehensive income / (loss) for the year	**302,721**	**(70,385)**	**(25,609)**	**(23,908)**
	Australian cents	*Australian cents*	*Australian cents*	*United States cents*
Earnings / (loss) per Share attributable to our ordinary equity holders(1):				
Basic(2)	59.27	(12.18)	(12.40)	(11.60)
Diluted(3)	57.71(2)	(12.18)	(12.40)	(11.59)
Adjusted(4)	[●]	[●]	[●]	[●]

Notes:

(1) The earnings / (loss) per Share excludes potential dilution from conversion of the 2018 Convertible Notes into CN Shares. Assuming conversion of the 2018 Convertible Notes fully into CN Shares, the basic earnings/(loss) per Share were [●] Australian cents for FY2011, [●] Australian cents for FY2012 and [●] Australian cents ([●] United States cents) for FY2013, calculated based on profit / (loss) for the year divided by the share capital of [●] shares.

(2) The earnings per Share for FY2011 were computed based on the pre-Offering weighted average share capital of 500,204,247 Shares while the loss for FY2012 and FY2013 were computed based on the pre-Offering weighted average share capital of 508,143,132 and 514,712,468 Shares.

(3) The dilution in FY2011 was due to the effect of the conversion of then outstanding share options and share rights into a total of 13,513,284 additional Shares.

(4) The earnings / (loss) per Share as adjusted for the Offering is calculated based on profit / (loss) for the year divided by the post-Offering share capital of [●] Shares.

Selected Consolidated Statement of Financial Position Data

	As at 30 June			
	2011	2012	2013	2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Assets				
Cash and cash equivalents	310,343	25,680	124,007	115,761
Trade and other receivables	2,654	17,712	50,526	47,166
Inventories	936	2,773	2,935	2,740
Assets classified as held for sale	9,032	-	-	-
Other financial assets	15,814	-	958	894
Total current assets	**338,779**	**46,165**	**178,426**	**166,561**
Receivables	5,856	15,127	28,100	26,231
Intangibles	195,108	248,711	271,294	253,253
Property, plant and equipment	12,775	18,842	17,806	16,622
Oil and gas assets	25,288	384,581	555,538	518,595
Available-for-sale investments	23,128	13,652	16,220	15,141
Deferred tax assets	19	701	1,077	1,005
Other assets	-	-	30	28
Total non-current assets	**262,174**	**681,614**	**890,065**	**830,875**
Total assets	**600,953**	**727,779**	**1,068,491**	**997,436**
Liabilities				
Trade and other payables	14,927	38,851	94,097	87,840
Borrowings	2,786	185,678	1,632	1,523
Current tax liability	10,781	31	-	-
Provisions	2,894	3,702	8,574	8,004
Other financial liability	-	221	2,691	2,512
Total current liabilities	**31,388**	**228,483**	**106,994**	**99,879**
Payables	-	1,174	1,281	1,196
Borrowings	1,866	1,144	477,423	445,674
Deferred tax liability	48,331	18,922	894	835
Provisions	5,647	24,020	37,052	34,588
Other financial liability	-	162	-	-
Total non-current liabilities	**55,844**	**45,422**	**516,650**	**482,293**
Total liabilities	**87,232**	**273,905**	**623,644**	**582,172**
Net assets	**513,721**	**453,874**	**444,847**	**415,264**
Equity				
Share capital	309,493	310,606	325,388	303,750
Reserves	40,377	31,537	70,459	65,773
Retained earnings	163,794	101,903	38,098	35,564
Total equity attributable to our equity holders	**513,664**	**444,046**	**433,945**	**405,087**
Non-controlling interest	57	9,828	10,902	10,177
Total equity	**513,721**	**453,874**	**444,847**	**415,264**

Selected Consolidated Cash Flow Statement Data

	FY2011	FY2012	FY2013	FY2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Cash flows from operating activities				
Receipts from customers and other debtors (inclusive of goods and service tax)	3,756	48,208	121,998	113,885
Payments to suppliers and employees (inclusive of goods and service tax)	(53,023)	(110,654)	(102,612)	(95,788)
Interest and borrowing costs paid	(413)	(10,186)	(27,421)	(25,598)
Receipts from Alaskan tax credits	-	-	3,738	3,489
Payments for commodity swaps	-	(3,634)	(2,341)	(2,185)
Income taxes paid	(30,802)	(9,651)	987	921
Net cash used in operating activities	**(80,482)**	**(85,917)**	**(5,651)**	**(5,276)**
Cash flows from investing activities				
Payments for property, plant and equipment	(4,192)	(6,716)	(1,818)	(1,697)
Proceeds from disposal of property, plant and equipment	88	23	183	171
Proceeds from sale of coal tenement	500,000	-	-	-
Payments for software	(410)	(1,929)	(1,475)	(1,377)
Payments for exploration and evaluation (including tenement acquisitions)	(34,041)	(35,169)	(22,328)	(20,843)
Payments for exploration and development of oil and gas assets and coal-to-liquid assets	(8,807)	(32,550)	(156,139)	(145,756)
Payments for equity investments	(16,894)	(1,804)	-	-
Payment for acquisition of producing oil and gas assets	(18,268)	(254,697)	(2,977)	(2,779)
Payment for Umiat acquisition net of cash acquired	-	(44,660)	-	-
Loans to related parties	-	(250)	(260)	(243)
Proceeds from repayment of loans to related parties	-	-	12	11
Deposits paid on acquisitions in progress	(14,158)	-	-	-
Interest received	20,175	3,623	603	563
Net cash transferred (to)/from term deposits held as security for guarantees and bonds or held as investments	(3,150)	(4,862)	(12,156)	(11,348)
Net cash from / (used) in investing activities	**420,343**	**(378,991)**	**(196,355)**	**(183,298)**
Cash flows from financing activities				
Proceeds from the exercise of share options	7,555	2,133	3,234	3,019
Proceeds from the extinguishment of convertible loan facility	5,018	-	-	-
Proceeds from borrowings	775	191,433	103,397	96,521
Proceeds from notes issues	-	-	439,060	409,863
Repayment of borrowings	-	(1,800)	(257,047)	(239,953)
Payments associated with financing activities	-	-	(18,390)	(17,167)
Repayment of finance lease liabilities	(1,104)	(1,274)	(713)	(666)
Payment for share buy-backs net of costs	-	(12,093)	-	-
Dividends paid	(49,643)	-	-	-
Net cash from / (used) in financing activities	**(37,399)**	**178,399**	**269,541**	**251,617**
Net increase / (decrease) in cash and cash equivalents	**302,462**	**(286,509)**	**67,535**	**63,044**
Cash and cash equivalents at 1 July	7,365	310,343	25,680	23,972
Effect of exchange rate fluctuations on cash held	516	1,846	30,792	28,744
Cash and cash equivalents at 30 June	**310,343**	**25,680**	**124,007**	**115,760**

Other Financial Information and Non-IFRS Financial Data

	FY2011	FY2012	FY2013	FY2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Oil and gas sales revenue	1,785	55,098	118,259	110,395
Clean Energy				
UCG syngas revenue	1,414	1,962	2,267	2,116
Consulting revenue	-	-	3,844	3,588
	(US$'000)	*(US$'000)*	*(US$'000)*	
Other US Financial Data				
Drilling and development capital expenditures[1]	378	20,024	96,589	
Plant, property and equipment capital expenditures	433	4,965	4,001	
Exploration capital expenditure	5,589	-	57,319	
	(US$'000)	*(US$'000)*	*(US$'000)*	
US Oil & Gas Data[2]				
EBITDAX[3]	(1,820)	26,018	78,371	

Notes:

(1) Drilling and development capital expenditures as shown above differ from the amounts shown as payments for evaluation and development in the statement of cash flows in the combined financial statements because amounts above include changes in accrued capital expenditures from the previous reporting period, while the amounts in the statement of cash flows in the combined financial statements are presented on a cash basis.

(2) These US amounts are the actual amounts and were not restated based on the convenience translation of A$1 : US$0.9553.

(3) EBITDAX as used herein represents net profit (loss) before income tax, non-controlling interest, interest income, finance costs, depreciation, depletion and amortisation, loss on sales of assets, impairment expense, accretion expense, unrealised commodity derivative loss, plug and abandonment and bad debt expense, in relation to our conventional oil and gas business in the United States. We present EBITDAX because we believe it is an important supplemental measure of our performance that is frequently used by others in evaluating companies in our industry. EBITDAX is not a measurement of our financial performance under IFRS and should not be considered as an alternative to net income, operating income or any other performance measure derived in accordance with IFRS or as an alternative to net cash provided by operating activities as a measure of our profitability or liquidity. EBITDAX has significant limitations, including that it does not reflect our cash requirements for capital expenditures, contractual commitments, working capital or debt service. In addition, other companies may calculate EBITDAX differently from us, limiting their usefulness as comparative measures. The following table sets forth a reconciliation of EBITDAX to net profit (loss) before income tax as determined in accordance with IFRS for the periods indicated:

	FY2011	FY2012	FY2013
	(US$'000)	*(US$'000)*	*(US$'000)*
Net profit (loss) before income tax	**3,835**	**9,335**	**(4,912)**
Non-controlling interest	-	12	41
Interest income	(9)	(8)	(15)
Finance costs	7	3,538	30,073
Depreciation, depletion and amortisation	352	12,090	31,106
Grain on purchases and sales of assets	(6,005)	(78)	(614)
Impairment expense	-	-	17,225
Accretion expense[a]	-	740	1,064
Unrealised commodity derivative loss[b]	-	389	2,042
Plug and abandonment	-	-	1,821
Bad debt expense	-	-	540
EBITDAX	**(1,820)**	**26,018**	**78,371**

(a) Represents non-cash expenses for increases to the asset retirement obligation liability.

(b) Represents non-cash gains or losses as a result of mark-to-market accounting of outstanding hedging contracts.

Operating Statistics

	FY2011[(1)]	FY2012[(2)]	FY2013
Total gross production (MBOE)	26.4	782.7	1,552.3
Net daily oil production volume (BOEPD)	151	2,062	3,170
Average realised price for oil and gas (excluding oil price hedges) (US$ / BOE)	95.84	97.97	104.95
Average lease operating expenses[(3)] (US$ / BOE)	40.28	20.02	13.77

Notes:

(1) These reflect the gross production volume, sales volumes, average realised price (excluding oil price hedges) and average lease operating expenses for our assets in Wyoming, which we acquired in February 2011.

(2) These reflect the gross production volume, sales volumes, average realised price (excluding oil price hedges) and average lease operating expenses for our assets in Wyoming for the full year and for our assets in the Gulf Coast Region from October 2011 when we acquired the relevant assets.

(3) Average lease operating expenses are calculated as oil and gas lease operating expenses in the period divided by total net production in the period.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion of our results of operations and financial position has been prepared by our management and should be read in conjunction with the "Independent Auditors' Report on the Consolidated Financial Statements for the Financial Years Ended 30 June 2011, 2012 and 2013" and the related notes as set out in the F-pages of this offering document. This discussion contains forward-looking statements that involve risks and uncertainties. Our actual results may differ significantly from those anticipated in these forward-looking statements as a result of various factors including those discussed below and elsewhere in this offering document, particularly in "Forward-Looking Statements" and "Risk Factors". Our consolidated financial statements have been prepared in accordance with IFRS.

OVERVIEW

We are focused on both conventional and unconventional oil and gas production. We own a diverse and substantial energy portfolio that includes oil, gas, shale oil and gas and coal.

In the last three financial years, we have focused on production growth from both conventional and unconventional oil and gas assets, exploring and evaluating our asset portfolio and developing and commercialising our proprietary UCG technology. Our consolidated revenue was A$3.2 million in FY2011, A$57.1 million in FY2012 and A$124.4 million (US$116.1 million) in FY2013 and our gross profit increased from A$0.2 million in FY2011 to A$65.0 million in FY2013. Substantially all of our revenue has been derived from our conventional oil and gas assets in the Gulf Coast Region and Wyoming. We recorded a net profit of A$296.4 million in FY2011 (primarily due to the sale of the Carmichael coal tenement), a net loss of A$61.9 million in FY2012 and a net loss of A$63.8 million (US$59.6 million) in FY2013. A significant portion of our growth has been achieved through recent acquisitions and strategic divestments so our historical results of operations may not be comparable from year to year.

In respect of our oil and gas assets as of 1 September 2013, we had estimated net 1P reserves of 13.6 MMBOE (of which approximately 96% was oil) with an estimated PV-10 of US$614.5 million, estimated net 2P reserves of 168.2 MMBOE with an estimated PV-10 of US$3.1 billion, and estimated net 3P reserves of 274.6 MMBOE with an estimated PV-10 of US$4.6 billion.

Since the acquisition of our producing assets in Wyoming and the Gulf Coast Region in February and October 2011, respectively, we have increased total production by approximately 85% from 2,711 BOEPD (gross) for the quarter ended 31 December 2011 to 5,010 BOEPD (gross) for the quarter ended 30 September 2013. From 1 October 2013 to the Latest Practicable Date, we had an average production rate of 5,858 BOEPD (gross). We expect this production rate to grow in FY2014 although our capital expenditure to support this growth is discretionary. Our near term development drilling programme is continuing, focusing on the Gulf Coast Region. It is focused on well defined prospects within existing oil fields onshore and in the shallow waters of the Gulf of Mexico, United States. We target and specialise in the exploration, development and production from salt domes. Our management team has focused on cost reduction through efficiency improvement, and maintaining long-term growth in reserves and production through continuing technological innovation.

Our Gulf Coast Region asset has estimated net 1P reserves of 12.8 MMBOE and net 2P reserves of 12.9 MMBOE. For the quarter ended 30 September 2013, our Gulf Coast Region asset produced 4,822 BOEPD. From 1 October 2013 to the Latest Practicable Date, we had an average production rate of 5,665 BOEPD (gross). Our near term development drilling programme is progressing, and we intend to continue focusing on the Gulf Coast Region.

Our Wyoming asset has estimated net 1P reserves of 0.8 MMBBL and net 3P reserves of 67.7 MMBBL. For the quarter ended 30 September 2013, our Wyoming asset produced

187 BOPD (gross). From 1 October 2013 to the Latest Practicable Date, our Wyoming asset had an average production rate of 193 BOPD (gross).

For FY2013, our net oil and gas production in the Gulf Coast Region and Wyoming was 1,157 MBOEs at an average realised price of US$104.95 / BOE (excluding oil price hedges) with an average total operating expense, including oil and gas lease operating expense, other production expenses, workover costs, production taxes and taxes, of US$25.09 / BOE.

Our Umiat field in Alaska is considered one of the largest, undeveloped conventional petroleum resources in North America, which has, estimated net 2P reserves of 154.6 MMBBL and estimated net 3P reserves of 194.1 MMBBL. Based on estimated OOIP of approximately 1,200 MMBBL, capital expenditure of US$1.8 billion (prior to tax credits receipts from the Alaskan Government) and operating expenditure of US$589 million, we target peak production of 50,000 BOPD (gross) from our Umiat field before 2020. We have in place a three-phase development plan for our Umiat field and have completed Phase 1 by drilling the Umiat #18 well at an approximate cost of US$70 million.

Our conventional oil and gas business in the United States has achieved revenue growth from US$1.7 million in FY2011 to US$51.3 million in FY2012 to US$110.4 million. Our EBITDAX in relation to our conventional oil and gas business in the United States was US$(1.8) million, US$26.0 million and US$78.4 million for FY2011, FY2012 and FY2013, respectively. See "Selected Consolidated Financial Information and Other Data" for a reconciliation of EBITDAX to our consolidated financial statements. These EBITDAX amounts which are expressed in United States dollar are the actual amounts and have not been restated based on the convenience translation of A$1 : US$0.9335.

For further details, see "Business—Our Oil and Gas Reserves and Resources" of this offering document.

In respect of our unconventional oil and gas business, in particular our Clean Energy business, we are focused on the generation of UCG syngas for GTL, power, urea, synthetic natural gas, hydrogen fuel cells and EOR. We believe we are the only company in the world that has successfully demonstrated UCG to GTL and to have produced diesel and jet fuel from UCG syngas.

Our business model for commercialising our UCG technology is through strategic joint ventures where we will receive either all or some of the following: (a) licensing fees, (b) royalty fees, (c) carried equity interests and/or (d) consulting and engineering fees. We have entered into a number of opportunity screening studies with third parties to evaluate potential commercial UCG opportunities. We entered into formal agreements to jointly pursue UCG as a commercial business to develop energy solutions in Sub-Saharan Africa with Exxaro Resources in May 2013. While our focus is currently through establishing strategic joint ventures, the opportunity to participate in a project on our own assets is still available in the future and, potentially, offers the greatest return on investment for our Shareholders. In FY2013, we recorded a new revenue stream of A$3.8 million comprising consulting revenue from the opportunity screening studies we entered into with resource owners in Asia and North America.

For our SAPEX business, we hold interests in an area covering over 65,000 sq km (approximately 16 million acres) in the Arckaringa Basin in South Australia, Australia. In respect of such interests, Gustavson Associates estimated prospective resources for unconventional reservoirs to be 232.8 BNBOE, and prospective resources for conventional traps to be 125.0 BNBOE, on an unrisked best estimate basis. DeGolyer and MacNaughton estimated gross prospective oil, gas, condensate and solution gas prospective resources for various licences as of 15 September 2013 in the Arckaringa Basin. We have utilised these quantities in our estimate of 102,800 MMBOE based on the unrisked mean.

In respect of our coal business, we expect to receive the Carmichael Royalty for the first 20 years of production at the Carmichael Project in Queensland, Australia, which Adani, the existing owner and developer of the asset has reported is expected to commence in the first quarter of 2017.

Finally, in respect of our conventional coal mining business in Queensland, Australia, we are presently in the pre-feasibility study stage in respect of our Teresa Project, and exploration and concept study of the Pentland Project and the Dalby Project. In October 2013, we entered into a sale and purchase agreement to acquire the Blair Athol Mine and we expect to recommence mining operations at the Blair Athol Mine by June 2014. The Blair Athol Mine has estimated 8.7 Mt proved reserves and 2.6 Mt probable reserves in accordance with the JORC Code.

In order to maximise value for our Shareholders, we regularly review and evaluate our asset portfolio and engage in strategic portfolio management activities. In addition, we may in the future make acquisitions of further assets as and when opportunities arise.

FACTORS AFFECTING OUR RESULTS OF OPERATIONS

Our results of operations are affected by a number of factors, including:

Commodity price fluctuations

Historically, oil, gas and coal prices have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil, gas or coal could materially and adversely affect our financial position, our results of operations, the quantities of oil, gas and coal reserves that we can economically produce and our access to capital.

Our financial performance is largely dependent on prevailing market prices for oil and gas which are impacted by several global economic, demand and supply factors including:

- worldwide economic activity;
- demand for oil and gas, especially in the United States, Europe, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- the effect of regulations on oil and gas operations, particularly in the regions in which we operate;
- actions taken by the Organisation of Petroleum Exporting Countries;
- the availability and discovery rate of new oil and gas reserves;
- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- technological advances affecting energy exploration, production, transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- tax policies.

Our revenue is derived primarily from the sale of our oil and gas production from our fields in the Gulf Coast Region and Wyoming. In the Gulf Coast Region, we sell our oil production to Shell Trading (US) Company at prices based on LLS, adjusted for location, quality and transportation. In recent history, LLS has exhibited a premium to the WTI oil benchmark. In Wyoming, we sell our oil production to Enterprise Crude Oil LLC at prices based on a discount to WTI, adjusted for location, quality and transportation. Historically we have had minimal gas production. Since June 2013, we have increased gas production primarily as a result of drilling in our Cedar Point field in the Gulf Coast Region. We sell our gas production based on a discount to the Henry Hub benchmark price.

LLS, WTI and Henry Hub prices fluctuate from period to period, sometimes significantly, and this affects our oil and gas revenue. The table below shows the high and low LLS, WTI and Henry Hub prices for FY2011, FY2012 and FY2013.

	FY2011 (US$ / BBL)	FY2012 (US$ / BBL)	FY2013 (US$ / BBL)
Oil			
LLS (high)	129.64	129.61	118.93
LLS (low)	74.77	89.69	99.03
WTI (high)	113.56	106.41	97.50
WTI (low)	70.95	75.19	66.36
	(US$ / MMBtu)	**(US$ / MMBtu)**	**(US$ / MMBtu)**
Gas			
Henry Hub (high)	4.9427	4.6414	4.3764
Henry Hub (low)	3.1765	1.8523	2.6347

Source: Bloomberg L.P.

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The following table shows our average realised price for oil and gas (excluding oil price hedges) for FY2011, FY2012 and FY2013.

Average realised price(1)

	FY2011 (US$ / BOE)	FY2012 (US$ / BOE)	FY2013 (US$ / BOE)
Gulf Coast Region and Wyoming(2)	95.84	97.97	104.95

Notes:

(1) Our revenue for each period is a product of our average realised price and our Net Revenue Interest production for the particular period for the asset.

(2) The average realised price of oil and gas from our assets in the Gulf Coast Region are calculated from October 2011 when we acquired the relevant assets and the average realised price of oil and gas from our assets in Wyoming is calculated from February 2011 when we acquired the relevant assets.

We generally hedge our expected future oil production to reduce our exposure to fluctuations in oil prices. By removing a portion of oil price volatility, we expect to reduce some of the variability in our cash flow from operations. See "—Derivative Instruments" for discussion of our hedging policy and hedge positions.

Accordingly, our statement of profit or loss and other comprehensive income reflect (a) the recognition of unrealised gains and losses associated with our open derivative contracts as oil prices change and oil derivatives contracts expire or new ones are entered into, and (b) our realised gains or losses on the settlement of these oil derivative contracts. Unrealised gains and losses result from changes in market valuations of derivatives as future oil price expectations change compared to the contract prices on the derivatives. If the expected future oil prices increase compared to the contract prices on the derivatives, unrealised losses are recognised. Conversely, if expected future oil prices decrease compared to the contract prices on the derivatives, unrealised gains are recognised. Since we have elected not to apply hedge accounting to our derivatives, we reflect the unrealised and realised gains and losses in our current statement of profit or loss and other comprehensive income periods based on the mark-to-market value at the end of each month. Cash flows associated with derivative financial instruments are reflected in cash flow from operations in our consolidated statement of cash flows.

We entered into a sale and purchase agreement to acquire the Blair Athol Mine located in Queensland in October 2013 but we have not commenced commercial production of coal. We expect to recommence production of coal from the Blair Athol Mine by June 2014. In the future, we will be affected by fluctuations in coal prices.

We also expect to receive the Carmichael Royalty from the date of first production which Adani, the existing owner and developer, has reported that it expects to commence production in the first quarter of 2017. The payments consist of A$2 per tonne (indexed to the Consumer Price Index (Brisbane) All Groups number). Consequently, our future results in relation to the Carmichael Royalty from FY2017 and beyond are only impacted by coal price fluctuations to the extent that this leads to production fluctuations from the Carmichael Project.

Production volumes and oil and gas lease operating expenses

We face the challenge of natural production declines like other businesses engaged in the exploration and production of resources.

As oil and gas is produced, initial reservoir pressure usually reduces and production from any given well is normally expected to decline. As a result, oil and gas exploration and production companies deplete their asset base with each unit of oil or gas they produce. We attempt to overcome this production decline by developing additional reserves through our drilling operations, recompleting, where possible, to a shallower reservoir in an existing wellbore and acquisitions of additional producing or greenfield oil and gas fields or exploration rights. Our future growth will depend on our ability to maintain or grow production levels from our existing reserves and at the same time to replace reserves at a rate which is in excess of production.

In addition, the volume of oil and gas that we produce is also affected by facility or equipment availability and unexpected downtime and delays imposed by or resulting from compliance with regulatory requirements. Our production volume may hence be lower than estimated or expected.

The following table sets forth our total production and sales volume for the financial years ended 30 June 2011, 2012 and 2013 and three months ending 30 September 2013.

	FY2011		**FY2012**		**FY2013**		**For the three months ended 30 September 2013**	
	Gross (MBOE)	**Net Revenue Interest[1] (MBOE)**	**Gross (MBOE)**	**Net Revenue Interest[1] (MBOE)**	**Gross (MBOE)**	**Net Revenue Interest[1] (MBOE)**	**Gross (MBOE)**	**Net Revenue Interest (MBOE)**
Gulf Coast Region[2] ...	-	-	694.4	519.0	1,489.5	1,113.3	443.7	338.7
Wyoming[3]	26.4	18.4	88.3	61.6	62.8	43.8	17.2	12.4
Total	**26.4**	**18.4**	**782.7**	**580.6**	**1,552.3**	**1,157.2**	**460.9**	**351.1**

Notes:

(1) Our average Net Revenue Interest in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest, if any, on petroleum under the relevant licence or lease, all royalty burdens and interests owned by others have been deducted.

(2) The total production and sales volume from our assets in the Gulf Coast Region are calculated from October 2011 when we acquired the relevant assets.

(3) The total production and sales volume from our assets in Wyoming are calculated from February 2011 when we acquired the relevant assets.

Oil and gas lease operating expenses impact the profitability of our operations. The following table sets forth our oil and gas lease operating expenses, total gross production and average lease operating expenses of our operations for the financial years ended 30 June 2011, 2012 and 2013.

	FY2011(2)	FY2012(3)	FY2013
Oil and gas lease operating expenses(1) (US$'000)	691	11,609	15,929
Average lease operating expenses(4) (US$ / BOE)	40.28	20.02	13.77

Notes:

(1) See Note 3 of the notes to the consolidated financial statements included elsewhere in this offering document.

(2) These reflect the oil and gas lease operating expenses, total gross production and average lease operating expenses for our assets in Wyoming, which we acquired in February 2011.

(3) These reflect the oil and gas lease operating expenses, total gross production and average lease operating expenses for our assets in Wyoming for the full year and for our assets in the Gulf Coast Region from October 2011 when we acquired the relevant assets.

(4) Average lease operating expenses are calculated as oil and gas lease operating expenses in the period divided by total net production in the period.

Exploration and development activities

Our future growth is dependent on the success of our exploration and development activities for our current assets as well as our ability to acquire additional producing or non-producing oil and gas fields or coal mines or exploration rights. We will maintain our focus on the capital investments necessary to produce our reserves as well as to add to our reserves through exploration and acquisition opportunities.

Our ability to make the necessary capital expenditures is dependent on cash flow from operations as well as our ability to obtain additional debt and equity financing, which can, in turn, be limited by many factors, including the cost of such capital and operational considerations. In addition, we also raise funds through other means. For instance, pursuant to the Alaskan Government's exploration and development incentive programmes to encourage the active exploration and timely development of Alaska's oil and gas resources, we have obtained capital cost rebates amounting to US$29.5 million for expenditures incurred to 30 June 2013. In August 2013, we sold our rights to receive such rebates from the Alaskan Government to Apollo Investment Corporation for a consideration of US$25.0 million, arrived at on a willing-buyer, willing-seller basis. We used the proceeds to fund oil and gas costs in Alaska and the Gulf Coast Region. We are also currently in the process of negotiating with third parties to sell our rights to receive rebates from the Alaskan Government in order to fund our development costs in respect of our Umiat asset by April 2014. We may, in future, also continue to consider the sale of our receivables such as rebates as a potential funding option. We may also seek to obtain potential infrastructure financing for pipelines and roads from various sources such as the Alaska Industrial Development and Export Authority, which was established with a view to promote development, advance economic growth and diversification in Alaska by providing various means of financing, though we cannot assure you that this can be obtained at reasonable rates or at all.

Our efficiency, safety, production technology and consistency in our drilling and extraction activities affect our costs as well as our level of production. Our capital expenditure is dependent on the number of wells or mines that we drill, our efficiency in drilling such wells or mines and our need for vehicles, drilling rigs and other facilities and equipment, which may be impacted by geological conditions and environmental and other factors.

There are risks inherent in our acquisition of new exploration and development assets. Our success or failure in our exploration and appraisal activities will affect the level of our reserves and resources. Successful exploration and appraisal activities result in an increase in our resources and reserves, whereas unsuccessful exploration and appraisal activities result in an impairment of our oil and gas assets (for producing assets) and/or goodwill and expenditure incurred for exploration and appraisal activities that do not translate to operating revenue. The value of our developments and producing fields are reviewed at least annually to compare the expected value of the asset (based on discounted cash flows) with the carried value on our statement of financial position. If the expected value is lower than the carried value, any impairment is recognised as impairment loss in the financial period.

Changes to oil, gas and coal reserves

We adopt the successful efforts method of accounting for oil, gas and coal operations whereby the costs to acquire mineral investments in oil, gas and coal assets, to drill successful exploratory wells, to drill and equip development wells, to operate our coal mines and to install production facilities are capitalised. Our acquisition and development costs of proved oil, gas and coal assets are amortised using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively, as estimated by independent petroleum and mining engineers. If there is a significant change in the estimated net reserves for a producing well or mine, the total costs incurred will be spread over the revised reserves amount which could therefore significantly increase or decrease the cost recognised during any particular financial period. A substantial decline in the amount of reserves could also result in an impairment write-down of the relevant asset if the valuation of the asset is reduced.

Acquisitions and disposals of our assets

We acquire and dispose of our interests in oil, gas and coal assets from time to time as part of our strategy to unlock value through strategic portfolio management. This can also involve partial sales of assets to provide funding and/or to reduce our risk exposure to major exploration or development plays. Such acquisitions and disposals, if significant, will have a material effect on our results of operations and financial condition. Consequently, our historical financial results before the acquisition or disposal may not be comparable with future results.

In August 2010, we sold the Carmichael coal tenement in the Galilee Basin in North-west Queensland to Adani for A$500.0 million (US$466.8 million). At the time of the sale, there was no mining and commercial production of coal from the coal tenement and accordingly, we had not recorded any sales or revenue from coal in the Carmichael coal tenement. We expect to receive the Carmichael Royalty upon commencement of coal production at the Carmichael Project.

In February 2011, we acquired from Rancher Energy Corp., an unrelated third party in Wyoming, its producing oil fields, for a consideration of US$20 million which was determined based on a willing-buyer, willing-seller basis and funded by internal cash reserves. With the completion of this acquisition, we were able to produce oil which accordingly contributed to our oil sales and revenue. Prior to February 2011, we did not have any significant operating revenue.

We acquired our Umiat field in July 2011 from Renaissance Alaska LLC, an unrelated third party, for a consideration of US$50 million (plus adjustments for working capital, deposits and inventory) on a willing-buyer, willing-seller basis and funded by internal cash reserves. We have in place a three-phase development plan. In early 2013, we completed Phase 1 of our drilling and development plan. Assuming success in Phase 2 and Phase 3, we are anticipating commencing production prior to 2020.

With a portion of the proceeds from the sale of the Carmichael coal tenement, together with a US$130.0 million secured credit facility, in October 2011, we acquired our producing oil and gas assets in the Gulf Coast Region from ERG Resources, LLC, an unrelated third party, for a consideration of US$236 million (plus adjustments of US$25.4 million) on a willing-buyer, wiling-seller basis and funded by internal cash reserves and monies from a US$300 million credit facility with BNP Paribas. These assets consist of 14 fields in Texas and Louisiana.

In October 2013, we entered into a sale and purchase agreement to acquire the Blair Athol Mine from the Blair Athol Joint Venture Party for a nominal consideration, arrived at on a willing-buyer, willing-seller basis. The acquisition cost was funded from our internally-generated funds. As part of the acquisition, we have assumed all the rehabilitation liabilities associated with the mine and will receive fixed cash compensation over a period of years from the Blair Athol Joint Venture Party to defray the rehabilitation obligation. We expect to recommence mining operations at the Blair Athol Mine by June 2014, which would contribute to our revenue from FY2014 and subsequent future periods. See "Business—Our Conventional Oil and Gas Business", "Business—Our Unconventional Oil and Gas Business" and "Business—Our Coal Business" for further details of these acquisitions and disposal.

As part of our strategy to maximise value for our Shareholders in 2014 or after, we intend to establish a pure-play Australian coal company via a divestment and/or demerger. This divestment and/or demerger may result in a loss of revenue and corresponding cost savings from coal production at the time of the divestment and/or demerger.

From time to time, we may acquire other non-producing fields, mines or exploration rights which could contribute no revenue or result in a net loss. We may also direct significant resources to identifying and evaluating potential acquisition opportunities, without any assurance that an acquisition will be completed successfully. To the extent that the purchase price for any acquisition is paid in cash, such acquisition would affect our cash balance in the relevant period.

Royalties and production taxes

Royalties and production taxes are paid on produced oil and gas based on a percentage of revenue from products sold at market prices or at fixed rates established by federal, state or local taxing authorities. We attempt to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in amount of oil and gas revenue.

Finance expenses

We operate in a capital intensive industry and require significant capital expenditure to fund existing and future oil, gas and coal exploration, development and production activities. We rely on a combination of cash flow from operations, debt and equity financing as well as farm-out or joint venture arrangements to finance these expenditures. Our debt financing, comprises our 2017 Senior Secured Notes, the 2013 Credit Facility and our 2018 Convertible Notes (each as defined below). The terms for the 2017 Senior Secured Notes and the 2018 Convertible Notes are based on fixed interest rates while the 2013 Credit Facility is based on a floating rate. US$57.4 million was outstanding under the 2013 Credit Facility as at the Latest Practicable Date. Our interest expense has and will continue to affect our results of operations. Our finance expenses were A$0.4 million in FY2011, A$11.2 million in FY2012 and A$72.0 million (US$67.2 million) in FY2013. The finance expenses for FY2013 included an unrealised foreign exchange loss of A$20.1 million (US$18.8 million).

Our 2018 Convertible Notes are considered compound financial instruments issued by our Group which can be converted to share capital at the option of the noteholder. We can settle the conversion by making a cash payment to the noteholder or issuing new shares. The liability component of the notes is initially recognised at fair value and subsequently recognised at amortised cost using the effective interest rate method. The embedded derivative component is initially measured at fair value and subsequently measured at fair value through profit or loss at the end of each reporting period. The embedded derivative fair value calculation reflected through profit or loss is primarily impacted by our Company's share price on the reporting date (being the last day of the period for which the profit and loss statements are prepared). If the share price moves down relative to the previous reporting date, then the fair value amount of the embedded derivative will fall; conversely, if the share price increases compared to the previous reporting date, then the fair value of the equity component will increase. The changes reflect that the equity value of the embedded derivative will increase or decrease in accordance with the relative proximity of the share price to the conversion price at different reporting dates. On 16 October 2013, the noteholders of our 2018 Convertible Notes approved changes to the terms of the 2018 Convertible Notes, including a resolution that, unless previously redeemed or purchased and cancelled, noteholders will have the right commencing 21 May 2013 until their redemption or maturity to convert the 2018 Convertible Notes into CN Shares at the conversion price of S$[●], being the lower of (i) A$3.40 per Share or (ii) the arithmetic average of the volume weighted average price of Shares traded on the ASX for each day during the 20 consecutive trading days ended on 15 November 2013, translated into Singapore dollar at the prevailing rate multiplied by 1.35 or the Offering Price multiplied by 1.35, depending on the amount of the gross proceeds of the Offering, which is lower than the original conversion price provided in the 2018 Convertible Notes. The reduction in the conversion price could lead to an increased expense through profit or loss for reporting periods after 16 October 2013 as compared to a position had the conversion price not been adjusted. Changes in fair value adjustment are non-cash movements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with IASB and IFRS. The preparation of financial statements in conformity with IASB and IFRS requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide a discussion of our more significant accounting policies which require estimates and judgments below. See Note 1 of the notes to the consolidated financial statements included elsewhere in this offering document for a discussion of our significant accounting policies, including those identified below.

Successful efforts method of accounting

We follow the successful efforts method of accounting for oil and gas operations whereby the costs to acquire mineral investments in oil and gas assets, to drill successful exploratory wells, to drill and equip development wells, and to install production facilities are capitalised. Our acquisition and development costs of proved oil and gas assets are amortised using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively, as estimated by independent petroleum engineers. Unproved assets consist of costs incurred to acquire undeveloped leases as well as the cost to acquire unproved reserves. Undeveloped lease costs and unproved reserve acquisition costs are capitalised. Unproved costs related to successful exploratory drilling are reclassified to proved assets and depleted on a unit-of production basis.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in anticipation of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial, which will result in additional exploration expenses when incurred. Additionally, the application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

Estimated oil, gas and coal reserves

The amount of proved and probable reserves is reassessed at each reporting date for the purposes of assessing possible impairment of assets and calculating depletion of assets and capitalised exploration, evaluation and development costs. Reserves are determined by independent third party reserve certification consultants and conform to guidelines issued by the Society of Petroleum Engineers and Australasian Joint Ore Reserves Committee. Estimated reserve quantities incorporate assumptions about future development and production costs and expected commodity prices. These estimates can change from period to period due to changes in these assumptions and as additional geological data is generated through drilling operations.

Impairment of assets

The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sale prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk associated with realising the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for our assets will be recorded.

In the absence of quoted market prices, estimates of the recoverable amount of our assets are based on the present value of future cash flows. Expected future cash flows are based on reserves, future production profiles, commodity prices and costs.

Exploration and evaluation

We currently capitalise exploration costs. Our policy for exploration and evaluation assets requires certain estimates and assumptions as to future events and circumstances, particularly in relation to the assessments of whether economic quantities of reserves have been found. Estimates and assumptions may change as new information becomes available. If, after capitalising expenditure, management concludes that it is unlikely to recover expenditure through future exploration or sale, then the relevant capitalised amount will be written off the statement of comprehensive income.

Income tax—research and development

We provide for the amount of tax payable on our estimated assessable income for the year. A significant component in determining the amount payable is the estimate of research and development expenditure offset in respect of current and prior years.

Provision for site restoration

We have provided for site restoration costs to allow for any necessary decommissioning and rehabilitation work at our coal-to-liquids technology development sites in Chinchilla and Wyoming in the event of cessation of all activities at these sites and in the Blair Athol Mine. This provision is based on our best estimate of the costs of this work, which is consistent with estimates submitted to and approved by the relevant regulatory authorities in each jurisdiction.

We have also provided for the costs associated with rehabilitating disturbance caused by our exploration drilling in prior years. This provision is based on quotes received from third parties to undertake the required work. We have also provided for the costs associated with rehabilitation and decommissioning in respect of our oil and gas production activities in the United States. Increases in the provision are capitalised to our oil and gas assets and amortised over the life of the field using the units of production method based on economically recoverable reserves.

PRINCIPAL COMPONENTS OF STATEMENT OF COMPREHENSIVE INCOME

Revenue

We derive substantially all our revenue from the sale of oil and gas in the United States. The balance of our revenue are attributable to our Clean Energy business, comprising revenue from the sale of UCG syngas in Uzbekistan and consulting revenue from the opportunity screening studies we entered into with resource owners in Asia and North America, both of which are not material in FY2013. The revenue from the sale of UCG syngas is reinvested in the operations.

For our oil sales, revenue is recognised when the significant risks and rewards of ownership of the goods have passed to the buyer and can be measure reliably. For gas sales, revenue is recognised when the gas is delivered to the purchaser.

The following tables set out our revenue by business and geographical segments and such revenue as a percentage of our total revenue for the financial years ended 30 June 2011, 2012 and 2013, net oil production volumes and average realised price (excluding oil price hedges) for the relevant years:

Business segments

	FY2011		FY2012		FY2013		
	(A$'000)	*(%)*	*(A$'000)*	*(%)*	*(A$'000)*	*(US$'000)*	*(%)*
Oil and gas sales revenue	1,785	55.8	55,098	96.6	118,259	110,395	95.1
Clean Energy:							
UCG syngas revenue	1,414	44.2	1,962	3.4	2,267	2,116	1.8
Consulting revenue	-	-	-	-	3,844	3,588	3.1
Total	**3,199**	**100.0**	**57,060**	**100.0**	**124,370**	**116,099**	**100.0**

Geographical segments

	FY2011		FY2012		FY2013		
	(A$'000)	*(%)*	*(A$'000)*	*(%)*	*(A$'000)*	*(US$'000)*	*(%)*
United States	1,785	55.8	55,098	96.6	118,259	110,395	95.1
Uzbekistan	1,414	44.2	1,962	3.4	2,267	2,116	1.8
South Africa and others	-	-	-	-	3,844	3,588	3.1
Total	**3,199**	**100.0**	**57,060**	**100.0**	**124,370**	**116,099**	**100.0**

	FY2011	FY2012	FY2013
Net daily oil production volume (BOEPD)	151	2,062	3,170
Average realised price for oil and gas (excluding oil price hedges) (US$ / BOE)	95.84	97.97	104.95

Cost of sales

The major components of cost of sales comprise the following:

(a) oil and gas lease operating expenses;

(b) other oil and gas production expenses;

(c) royalties and production taxes;

(d) workover expenses;

(e) depletion and accretion expense of oil and gas assets; and

(f) production costs—Uzbekistan.

Oil and gas lease operating expenses are daily costs incurred to bring oil and gas out of the ground and to the market, together with the daily costs incurred to maintain our producing assets. Such costs also include gas transportation and treating expenses, as well as maintenance and repair expenses related to our oil and gas assets. Oil and gas lease operating expenses include both a portion of costs that are fixed in nature, such as infrastructure costs, as well as variable costs resulting from additional wells and production. As production increases, our average lease operating expense per BOE will typically be reduced because the fixed portion of this expense does not increase proportionately with production.

Other oil and gas production expenses are other miscellaneous expenses related to our oil and gas operations and production costs—Uzbekistan relate to the Yerostigaz facility in Uzbekistan.

Royalties and production taxes are paid on produced oil and gas based on a percentage of revenue from products sold at market prices or at fixed rates established by federal, state, or local taxing authorities. In general, the production taxes we pay correlate to changes in the amount of oil and gas revenue.

Workover projects are pursued on an as needed basis and are not regularly scheduled. Consequently, workover expense is not necessarily comparable from period to period.

Depletion and accretion expense measures and incorporates changes due to production and the passage of time into the carrying amount of the liability. Such accretion expense representing changes in the liability for an asset retirement obligation due to passage of time is the result of applying an interest method of allocation to the amount of the liability at the beginning of the period. The interest rate used to measure that change is the credit-adjusted risk-free rate that existed when the liability, or portion thereof, was initially measured. That amount is recognised as an increase in the carrying amount of the liability and as an expense classified as an operating item in the statement of income.

We follow the successful efforts method of accounting for oil and gas operations whereby the costs to acquire mineral investments in oil and gas assets, to drill successful exploratory wells, to drill and equip development wells, and to install production facilities are capitalised. Our acquisition and development costs of proved and producing oil and gas assets are amortised using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively, as estimated by independent petroleum engineers and reflected as depletion and accretion expense of oil and gas assets.

The major components of our cost of sales for the financial years ended 30 June 2011, 2012 and 2013 and such costs as a percentage of our total cost of sales for the relevant periods are set out below:

	FY2011		FY2012		FY2013		
	(A$'000)	*(%)*	*(A$'000)*	*(%)*	*(A$'000)*	*(US$'000)*	*(%)*
Components of cost of sales							
Oil and gas lease operating expenses	698	23.3	11,246	35.5	15,511	14,480	26.1
Other oil and gas production expenses	-	-	14	0.0	8	7	0.0
Royalties and production taxes	219	7.3	3,419	10.8	6,870	6,413	11.6
Workover expenses	262	8.8	3,946	12.5	5,884	5,493	9.9
Depletion and accretion expense of oil and gas assets	330	11.0	11,087	35.0	29,253	27,308	49.3
Production costs—Uzbekistan	1,483	49.6	1,968	6.2	1,855	1,732	3.1
Total	**2,992**	**100.0**	**31,680**	**100.0**	**59,381**	**55,433**	**100.0**

Gain on sale of coal tenement, net of cost

Gain on sale of coal tenement, net of cost was from gain from sale of Carmichael coal tenement, net of sale costs and costs capitalised between the period of acquisition to disposal, if any.

Gain on purchase of oil and gas assets

Gain on purchase of oil and gas assets reflects a bargain purchase gain if the cost of an acquisition is less than our share of the net fair value of the assets acquired.

Other income

Other income comprises lease income, being income from the sub-lease of an Australian drilling rig to a third-party drilling contractor, and sundry income.

Expenses

Our expenses reflect expenses by function and consist of administration and corporate expenses, site operating costs, exploration and evaluation costs, technology and development expenses and other expenses.

The major components of our expenses for the financial years ended 30 June 2011, 2012 and 2013 and such costs as a percentage of our total expenses for the relevant periods are set out below:

	FY2011		FY2012		FY2013		
	(A$'000)	*(%)*	*(A$'000)*	*(%)*	*(A$'000)*	*(US$'000)*	*(%)*
Administration and corporate	57,550	62.8	72,902	67.2	64,410	60,127	53.1
Site operating costs	12,666	13.8	12,367	11.4	9,075	8,472	7.5
Exploration and evaluation	2,455	2.7	3,326	3.1	3,245	3,029	2.7
Technology and development	18,997	20.7	18,063	16.6	11,139	10,398	9.2
Other expenses	-	-	1,841	1.7	33,322	31,106	27.5(1)
Total	**91,668**	**100.0**	**108,499**	**100.0**	**121,191**	**113,132**	**100.0**

Note:

(1) In FY2013, the majority of our other expenses were the impairment of our oil and gas assets in the United States and other investments as well as the port commitments in relation to our conventional coal mining business.

Administration and corporate expense consists of overheads, including payroll and benefits for our corporate staff, foreign exchange gain / (loss), costs of maintaining our headquarters, franchise taxes, audit and other professional fees and legal compliance. The major components of our administration and corporate expense for FY2011, FY2012 and FY2013 and such costs as a percentage of our total administration and corporate expense for the relevant periods are set out below:

	FY2011		FY2012		FY2013		
	(A$'000)	*(%)*	*(A$'000)*	*(%)*	*(A$'000)*	*(US$'000)*	*(%)*
Employee benefits and directors' fees	29,047	50.5	38,786	53.2	39,838	37,189	61.9
Payment to consultants, contractors and/ or professionals	6,946	12.1	15,869	21.8	12,484	11,654	19.4
Depreciation and amortisation	1,276	2.2	3,689	5.1	5,159	4,816	7.8
Foreign exchange gain / (loss)	7,661	13.3	(4,630)	(6.4)	(8,973)	(8,376)	(13.9)
Overheads	2,073	3.6	4,541	6.2	4,746	4,430	7.4
Others[1]	10,547	18.3	14,646	20.1	11,156	10,414	17.4
Total	**57,550**	**100.0**	**72,902**	**100.0**	**64,410**	**60,127**	**100.0**

Note:

(1) Other refers to, among others, insurance costs, vehicle costs and training.

Site operating costs are primarily for the maintenance and the running cost of our Chinchilla Demonstration Facility and plug and abandonment costs for our oil and gas assets in the United States.

Exploration and evaluation costs primarily capture exploration and evaluation costs that are not reflected in cost of sales or costs that are not permitted to be capitalised as intangible assets in our statement of financial position and include site operating costs, salaries and wages and contractor costs.

Technology and development expenses are costs relating to developing our UCG and GTL technologies and include site operating costs, salaries and wages and amortisation of our Chinchilla Demonstration Facility.

Other expenses are the impairment for certain of our oil and gas assets in the United States and other investments as well as the port commitments, being the take or pay arrangement we entered into with Gladstone Port Authority.

Finance income and expenses

Our finance income is mainly derived from interest income on cash and cash equivalents while our finance costs comprise interest and finance charges paid or payable, net loss on derivative financial instruments and borrowing costs.

A breakdown of our finance income and expenses and the relevant component items as a percentage of total finance income or expense is set out below:

	FY2011		FY2012		FY2013		
	(A$'000)	*(%)*	*(A$'000)*	*(%)*	*(A$'000)*	*(US$'000)*	*(%)*
Finance income recognised in profit and loss							
Interest income on cash and cash equivalents	22,181	100.0	3,564	99.6	632	590	1.5
Interest income on loans	-	-	14	0.4	44	41	0.1
Net gain on foreign currency options	-	-	-	-	958	894	2.3
Net change in fair value of embedded derivative at fair value through profit and loss	-	-	-	-	39,812	37,165	96.1
Total finance income	**22,181**	**100.0**	**3,578**	**100.0**	**41,446**	**38,690**	**100.0**
Finance expenses recognised in profit and loss							
Interest and borrowing costs paid or payable	(413)	100.0	(7,220)	64.3	(45,378)	(42,360)	63.0
Net loss on commodity swaps	-	-	(4,011)	35.7	(4,329)	(4,041)	6.0
Unwind of discount on notes	-	-	-	-	(2,202)	(2,056)	3.1
Unrealised foreign exchange loss on convertible notes	-	-	-	-	(20,092)	(18,756)	27.9
Total financing expenses	**(413)**	**100.0**	**(11,231)**	**100.0**	**(72,001)**	**(67,213)**	**100.0**
Net financing costs	**21,768**		**(7,653)**		**(30,555)**	**(28,523)**	

Income tax expense or benefit

We are taxed in accordance with the applicable statutory tax rates and prevailing tax regulations in the United States, Australia, Poland, United Kingdom and South Africa. Our subsidiaries in the United States are part of a consolidated group for United States tax purposes and therefore are treated as a single tax payer. Similarly, our Australian entities are also part of a consolidated group for Australian tax purposes.

Income tax expense or benefit consists of both current income tax as well as deferred income tax.

As at 30 June 2013, our United States tax consolidated group had a combined net operating loss carry forwards of US$180.3 million while in Australia, our total carried forward tax losses was A$130.2 million (US$121.5 million) and our total carried forward research and development tax offset was A$22.1 million (US$20.6 million). The deferred tax assets relate primarily to net operating loss carry forwards and tax losses and deferred tax liabilities relate primarily to our oil and gas assets as well as our Chinchilla Demonstration Facility. Currently, there is a 100.0% valuation allowance booked against the net operating loss deferred tax asset of our United States tax consolidated group.

In assessing the realisability of deferred tax assets, our management considers whether some or all of the deferred tax assets will be realised based on a more likely than not standard of judgment. The ultimate realisation of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Management believes that is more likely than not that both the United States and the Australian tax consolidated groups will be able to utilise their deferred tax assets in the future.

As part of the sale of the Carmichael coal tenement to Adani in August 2010, we also entered into a deed to receive the Carmichael Royalty. We have been involved in discussions with the ATO since 2011 regarding the income tax treatment of the deed. More specifically, the ATO are seeking to include the market value of the future income stream in the Company's taxable income in FY2011. Following these discussions, the ATO undertook a risk review of the specific issue and in October 2013 concluded that in their opinion the market value of the deed should be taxable in FY2011. Accordingly, in October 2013, the ATO advised that they intend to commence an audit of this specific issue in the future.

As part of this process, we have received legal and tax advice to support the position taken in our FY2011 tax return lodged with the ATO that the future amounts receivable under the deed should not be taxable upfront. Furthermore, based on these opinions we believe that our lodged tax return complies with the applicable tax laws in Australia and have not made a provision for this as a contingent liability. We will continue to work with the ATO to resolve this issue.

Given the inherent uncertainty in estimating the ultimate quantum and timing of production from a mine in the Carmichael coal tenement as at the date of the transaction, it would have been and continues to be impracticable to prepare a market valuation of the deed as at that date.

Comprehensive income or loss

Comprehensive income or loss consists of net change in the fair value of available-for-sale financial assets, net of transaction costs and tax and foreign currency translation differences for foreign operations.

RESULTS OF OPERATIONS

The following table sets forth certain income and expense items of our consolidated statement of comprehensive income for the periods indicated.

	FY2011	FY2012	FY2013	FY2013
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Revenue	3,199	57,060	124,370	116,099
Cost of sales	(2,992)	(31,680)	(59,381)	(55,432)
Gross profit	**207**	**25,380**	**64,989**	**60,667**
Gain on sale of coal tenements, net of costs	495,001	-	-	-
Gain on purchase of oil and gas assets	6,027	-	628	586
Other income	971	1,075	143	133
Expenses	(91,668)	(108,499)	(121,191)	(113,132)
Results from operating activities	410,538	(82,044)	(55,431)	(51,746)
Net finance cost	21,768	(7,653)	(30,555)	(28,523)
Income tax benefit / (expense)	(135,865)	27,804	22,161	20,687
Profit / (loss) for the year	**296,411**	**(61,893)**	**(63,825)**	**(59,582)**

FY2012 vs FY2013

Revenue

Our revenue increased by A$67.3 million or 117.9% from A$57.1 million in FY2012 to A$124.4 million (US$116.1 million) in FY2013.

This was primarily attributable to a substantial increase in the oil sales revenue in the United States, which increased from A$55.1 million in FY2012 to A$118.3 million (US$110.4 million) in FY2013 due primarily to an increase in production volumes from our oil and gas assets in the Gulf Coast Region from 2,534 BOEPD (gross) to 4,081 BOEPD (gross). The increase was a result of the drilling of additional new wells and the recompleting of existing wells over the periods.

In October 2011, we acquired our oil and gas assets in the Gulf Coast Region, which contributed to our revenue for a period of nine months in FY2012 as opposed to a full year in FY2013. From October 2011 through June 2012, these oil and gas assets produced 694,358 BBLs (gross) of oil, with an average realised price of US$101.09 / BOE (excluding oil price hedges). For FY2013, we produced 1,489,514 BBLs (gross) with an average realised price of US$104.95 / BOE (excluding oil price hedges).

We realised higher average realised prices per barrel from the Gulf Coast Region than from Wyoming primarily because our wells are located nearer to infrastructure, and also because the quality of the oil produced is pegged to LLS which generally trades at a premium to WTI.

The sale of gas in the United States and the sale of UCG syngas in Uzbekistan for both FY2012 and FY2013 were not material. We also recorded a new revenue stream in FY2013 comprising consulting revenue from our Clean Energy business amounting to A$3.8 million (US$3.5 million).

Cost of Sales

Our cost of sales increased by A$27.7 million or 87.4% from A$31.7 million in FY2012 to A$59.4 million (US$55.4 million) in FY2013.

Our cost of sales increased from FY2012 to FY2013 in line with the increase in production volumes. Our oil and gas lease operating expenses increased from A$11.2 million to A$15.5 million (US$14.5 million) while our depletion and accretion expense of oil and gas assets, increased from A$11.1 million to A$29.3 million (US$27.4 million). Our oil and gas lease operating expenses did not increase as much as our revenue as a portion of our oil and gas lease operating expenses was fixed overhead costs and we benefited from the economies of scale of a significantly higher number of producing wells in FY2013 as compared with FY2012 as well as improved efficiency as we continue the operation of our assets.

Gain on sale of coal tenement, net of cost

There was no sale of coal tenement in both FY2012 and FY2013.

Gain on purchase of oil and gas assets

On July 2012, we acquired the Gasrock net profit interest of 10.0% in exchange for a 0.5% overriding royalty interest for A$3.0 million (US$2.8 million). The net profit interest covers selected leases in certain of our leases in our Glenrock field in Wyoming. The net worth of the Gasrock net profit interest was estimated at A$3.7 million (US$3.5 million) based on an economic reserve analysis report. As the estimated value of the 10.0% net profit interest received was in excess of the cash consideration paid, the difference resulted in a bargain purchase gain of A$0.6 million (US$0.6 million). There was no gain on purchase of oil and gas assets in FY2012.

Other income

Other income decreased by A$1.0 million or ten-fold from A$1.1 million in FY2012 to A$0.1 million (US$0.1 million) in FY2013.

The decrease in our other income was primarily attributed to a decrease in sundry income from A$0.9 million to A$0.1 million (US$0.1 million). In addition, there was no lease income in FY2013 as opposed to a lease income of A$0.2 million in FY2012.

Expenses

Our expenses increased by A$12.7 million or 11.7% from A$108.5 million in FY2012 to A$121.2 million (US$113.1 million) in FY2013.

This was primarily attributable to an increase in other expenses from A$1.8 million in FY2012 to A$33.3 million (US$31.1 million) arising from an impairment expense of A$16.8 million (US$15.7 million) in respect of our oil and gas assets in the Gulf Coast Region, an impairment expense of A$6.8 million (US$6.4 million) for write-downs in the value of two of our listed equity investments and A$9.7 million (US$9.1 million) for our port commitments under the take or pay arrangement with Gladstone Port Authority. The increase in our expenses was partially offset by a reduction in administration and corporate expenses from A$72.9 million in FY2012 to A$64.4 million (US$60.1 million) in FY2013 as well as a reduction in technology and development expense from A$18.1 million in FY2012 to A$11.1 million (US$10.4 million) in FY2013. The reduction in administration and corporate expenses was a direct result of a continued focus on cost reductions across our Group including redundancies and salary stabilisation. The reduction in technology and development expenses was directly attributable to a reduction in the amortisation in our Chinchilla Demonstration Facility arising from a revision of the useful life of the asset in FY2012.

Net finance income or expense

Our net finance expense increased by A$22.9 million or 297.4% from A$7.7 million in FY2012 to A$30.6 million (US$28.5 million) in FY2013 as a result of interest payable on the increased borrowings.

Income tax benefit or expense

Our income tax benefit decreased by A$5.7 million or 20.0% from A$27.8 million in FY2012 to A$22.2 million (US$20.7 million) in FY2013 largely due to the revaluation of the embedded derivative contained within the 2018 Convertible Note.

Loss for the year

As a result of the above, our loss for the year increased from a net loss of A$61.9 million in FY2012 to a net loss of A$63.9 million (US$59.6 million) in FY2013.

Other comprehensive income

We had other comprehensive loss of A$8.5 million in FY2012, which became other comprehensive income of A$38.2 million (US$35.7 million) in FY2013.

This was primarily attributable to foreign currency translation differences for foreign operations.

FY2011 vs FY2012

Revenue

Our revenue increased by A$53.9 million or approximately 18-fold from A$3.2 million in FY2011 to A$57.1 million (US$53.3 million) in FY2012.

This was primarily attributable to a substantial increase in the oil sales revenue in the United States, which increased from A$1.8 million in FY2011 to A$55.1 million in FY2012 due primarily to an increase in production volumes as a result of acquisitions of producing oil and gas assets and also as a result of the drilling of additional new wells as well as the recompleting of existing wells over the periods.

In February 2011, we acquired our oil and gas assets in Wyoming, which contributed to our revenue for a period of five months in FY2011 as opposed to a full year in FY2012. From February 2011 through June 2011, these oil and gas assets produced 26,398 BBLs (gross) of oil, with an average realised price of US$95.84 per BBL (excluding oil price hedges). For FY2012, we produced 88,308 BBLs (gross) of oil, with an average realised price of

US$71.68 per BBL (excluding oil price hedges). In addition, we acquired our oil and gas assets in the Gulf Coast Region in October 2011, which contributed to our revenue for a period of nine months in FY2012. During the nine months in FY2012, our assets in the Gulf Coast Region produced 694,358 BBLs (gross), with an average realised price of US$101.09 per BOE (excluding oil price hedges).

The average realised price of oil and gas (excluding oil price hedges) increased from US$95.84 / BOE in FY2011 to US$97.97 / BOE in FY2012. We realised higher average realised prices per BOE from the Gulf Coast Region than from Wyoming primarily because our wells are located nearer to infrastructure, and also because the quality of the oil produced is pegged to LLS which generally trades at a premium to WTI.

The sale of gas in the United States for both FY2011 and FY2012 was not material.

Our increase in revenue from FY2011 to FY2012 was also attributable to an increase in revenue from the sale of UCG syngas in Uzbekistan from A$1.4 million in FY2011 to A$2.0 million (US$1.9 million) in FY2012.

Cost of Sales

Our cost of sales increased by A$28.7 million or 11-fold from A$3.0 million in FY2011 to A$31.7 million (US$29.6 million) in FY2012.

All components of our cost of sales increased from FY2011 to FY2012 in line with the increase in production volumes. Our oil and gas lease operating expenses increased from A$0.7 million to A$11.2 million (US$10.5 million) while our depletion and accretion expense of oil and gas assets, increased from A$0.3 million to A$11.1 million (US$10.4 million). Our oil and gas lease operating expenses did not increase as much as our revenue as a portion of our oil and gas lease operating expenses was fixed overhead costs and we benefited from the economies of scale of a significantly higher number of producing wells in FY2012 as compared with FY2011 as well as improved efficiency as we continue the operation of our assets.

Gain on sale of coal tenement, net of cost

In FY2011, we sold the Carmichael coal tenement, net of cost for an amount of A$495.0 million (US$462.1 million). There was no sale of other coal tenement in FY2012.

Gain on purchase of oil and gas assets

On March 2011, we acquired our oil and gas assets in Wyoming, which resulted in a bargain purchase gain of A$6.0 million (US$5.6 million). This gain resulted from the fair value of unproved oil and gas assets previously written off by the vendor who was in bankruptcy. The unproved reserves were valued per acre based on comparable transactions in Wyoming in 2011. There was no gain on purchase of oil and gas assets in FY2012.

Other income

Other income increased by A$0.1 million or 10.7% from A$1.0 million in FY2011 to A$1.1 million (US$1.0 million) in FY2012.

Expenses

Our expenses increased by A$16.8 million or 18.4% from A$91.7 million in FY2011 to A$108.5 million (US$101.3 million) in FY2012.

This was primarily attributable to an increase in administration and corporate expenses from A$57.6 million in FY2011 to A$72.9 million (US$68.1 million) in FY2012 as a result of an increase in employee benefits and directors' fees from A$29.0 million in FY2011 to

A$38.8 million (US$36.2 million), which is partially offset by a foreign exchange loss of A$4.6 million in FY2012 as opposed to a foreign exchange loss of A$7.7 million in FY2011.

Net finance income or expense

We had a net finance income of A$21.8 million in FY2011, which became a net finance expense of A$7.7 million (US$7.2 million).

Finance income decreased from A$22.2 million to A$3.6 million (US$3.4 million) primarily as a result of a decrease in interest income on cash and cash equivalents, which we received from cash invested following the sale of Carmichael coal tenement to Adani in August 2010 and which was also utilised for the acquisitions of our oil and gas assets in the United States in February 2011 and October 2011. Finance expense increased from A$0.4 million to A$11.2 million (US$10.5 million). This was mainly as a result of interest payable on the increased borrowings and the recognition of an accounting loss of A$4.0 million (US$3.7 million) on the net change in the fair value of derivative financial instruments. The accounting loss of A$4.0 million reflects both the realised (A$3.6 million (US$3.4 million)) and unrealised (A$0.4 million (US$0.4 million)) loss on oil hedges taken out by our subsidiary as a requirement of its 2011 Reserve Based Lending Facility.

Income tax benefit or expense

We had an income tax expense of A$135.9 million in FY2011, which became an income tax benefit of A$27.8 million (US$26.0 million).

The current income tax expense in FY2011 was largely due to the gain on sale of the Carmichael coal tenement. Our current income tax expense then decreased from A$41.6 million to current income tax benefit of A$25.6 million (US$23.9 million). Deferred income tax expense similarly decreased from A$94.3 million to deferred income tax benefit of A$27.8 million (US$26.0 million) primarily due to the utilisation of carried forward tax losses in FY2011.

Profit / loss for the year

As a result of the above, our profit for the year decreased from a net profit of A$296.4 million in FY2011 to a net loss of A$61.9 million (US$57.8 million) in FY2012.

Other comprehensive income

We had other comprehensive income of A$6.3 million in FY2011, which became other comprehensive loss of A$8.5 million (US$7.9 million) in FY2012.

This was primarily attributable to a reduction in net change in the fair value of available-for-sale financial assets from a gain of A$5.7 million to a loss of A$7.9 million (US$7.4 million) arising from a reduction in value for the listed investments from FY2011 to FY2012.

LIQUIDITY AND CAPITAL RESOURCES

We have historically met our working capital and other capital requirements from cash flows from operating activities, borrowings from banks and financial institutions and bond financing.

The following table sets forth a summary of our cash flows for FY2011, FY2012 and FY2013.

	FY2011	FY2012	FY2013	
	(A$'000)	*(A$'000)*	*(A$'000)*	*(US$'000)*
Net cash used in operating activities	(80,482)	(85,917)	(5,651)	(5,275)
Net cash from / (used) in investing activities	420,343	(378,991)	(196,355)	(183,297)
Net cash from / (used) in financing activities	(37,399)	178,399	269,541	251,617
Net increase / (decrease) in cash and cash equivalents	**302,462**	**(286,509)**	**67,535**	**63,045**
Cash and cash equivalents at beginning of year	7,365	310,343	25,680	23,972
Effect of exchange rate fluctuations on cash held	516	1,846	30,792	28,744
Cash and cash equivalents at end of year	**310,343**	**25,680**	**124,007**	**115,761**

FY2013

For FY2013, we had a total of A$25.7 million (US$24.0 million) cash and cash equivalents at the start of the financial year. During the period, a net cash inflow of A$67.5 million (US$63.0 million) increased the cash and cash equivalents balance to A$124.0 million (US$115.8 million) at the financial year end.

This net cash inflow was due to the issuance of the 2017 Senior Secured Notes (US$265.0 million) and the 2018 Convertible Notes (US$200.0 million) classified as cash flow from financing activities, which were off-set by cash outflows of A$196.3 million (US$183.2 million) from investing activities in conjunction with exchange rate movements.

Receipts from customers which were predominantly related to oil sales in the United States amounted to A$122.0 million (US$113.9 million) and payments to suppliers and employees amounted to A$102.6 million (US$95.8 million).

Other material cash inflows and outflows during the year include:

(a) payment of A$50,207 million (US$45,854 million) for the exploration and evaluation of our Umiat field, Alaska;

(b) payment of A$156.1 million (US$145.7 million) for development activities, predominantly in respect of our oil and gas asset at the Gulf Coast Region;

(c) proceeds from both the bond issues of A$439.1 million (US$409.8 million) being the 2017 Senior Secured Notes and the 2018 Convertible Notes;

(d) proceed from borrowings of A$103.4 million (US$96.5 million) being A$65.0 million from Fortress Line of Credit Facility and A$38.4 million from 2012 Asset based Lending Facility; and

(e) repayment of borrowings of A$257.0 million (US$239.9 million) being the 2011 Reserve Based Lending Facility and the A$120.0 million (US$112.0 million) line of credit facility agreement with an affiliate of Fortress Investment Group, LLC (the "**Line of Credit Facility**");

FY2012

For FY2012, we had a total of A$310.3 million cash and cash equivalents at the start of the financial year. During the period, a net cash outflow of A$286.5 million and a A$1.9 million in exchange rate movement reduced the cash and cash equivalents balance to A$25.7 million at the financial year end.

This net cash outflow was due to cash outflows of A$86.0 million and A$379.0 million for operating and investing activities respectively, which were off-set by cash inflows of A$178.4 million from financing activities.

The substantial increase in outstanding borrowings in FY2012 was due to two new facility agreements—the Line of Credit Facility and the 2011 Reserve Based Lending Facility. Amounts drawn under both credit facilities were secured with certain assets of our Group. The Line of Credit Facility was secured against the Carmichael Royalty and the Teresa Project and the 2011 Reserve Based Lending Facility was secured against our oil and gas assets in the Gulf Coast Region and Wyoming.

Receipts from customers which were predominantly related to oil sales in the United States amounted to A$48.2 million and payments to suppliers and employees amounted to A$110.7 million. There was also a final 2011 tax-instalment of A$9.7 million paid during the period but relating to the coal tenement sale that occurred in the preceding period.

Other material cash inflows and outflows during the year include:

(a) payment of A$254.7 million for the acquisition of our oil and gas assets in the Gulf Coast Region;

(b) payment of A$44.7 million for the completion of the acquisition of our assets in Umiat, Alaska;

(c) payment of A$35.2 million for the exploration and evaluation, including drilling and seismic acquisition in South Australia (A$15.0 million), exploration drilling at Teresa (A$9.0 million), exploration in Wyoming (A$5.3 million), exploration in Alaska (A$4.3 million) and the Great Northern Leases (A$1.0 million);

(d) payment of A$32.6 million for development activities, predominantly technology development costs including Gasifier 5 at our Chinchilla Demonstration Facility (A$12.8 million), Gulf Coast oil and gas (A$15.6 million) and Wyoming oil and gas (A$3.4 million);

(e) receipt of A$128.0 million received from the 2011 Reserve Based Lending Facility; and

(f) payment of A$12.1 million for Shares purchased under our on-market share buy-back.

FY2011

For FY2011, we had a total of A$7.4 million cash and cash equivalents at the start of the financial year. During the period, a net cash inflow of A$302.5 million increased the cash and cash equivalents balance to A$310.3 million at the financial year end.

This net cash inflow was due to the cash inflow of A$420.3 million from investing activities, which were off-set by cash outflows of A$80.5 million and A$37.4 million from operating and financing activities respectively.

Other material cash inflows and outflows during the year include:

(a) receipt of A$500.0 million from the sale of the Carmichael coal tenement to Adani;

(b) payment of A$18.3 million for the acquisition of our oil and gas assets in Wyoming;

(c) payment of A$14.2 million for deposits on acquisitions of Umiat field and ERG Resources;

(d) payment of A$30.8 million in income tax predominately due to the sale of the Carmichael coal tenement;

(e) payment of A$32.9 million for exploration activities comprising predominantly A$15.3 million for the purchase of coal tenements in Wyoming, A$9.1 million for the exploration drilling in the Arckaringa Basin and A$5.2 million for the exploration drilling in Alaska;

(f) payment of A$16.9 million for the investments in listed equity; and

(g) receipt of A$20.2 million in interest revenue.

Financial resources

As at 30 June 2013, we had aggregate cash and cash equivalents of A$124.0 million (US$115.8 million), compared to A$25.7 million as at 30 June 2012, and A$310.3 million as at 30 June 2011.

We expect to receive approximately S$[●] million (US$[●] million) from the net proceeds of the Offering. See "Use of Proceeds" for a description of the proceeds we expect to receive and how we intend to use them.

As at the Latest Practicable Date, the total banking facilities available to our Group amounted to US$530.0 million, of which US$522.4 million was drawn down, and our material unused sources of liquidity include our cash and cash equivalents, which amounted to A$39.1 million (US$36.1 million) plus undrawn amounts under the 2013 Credit Facility.

We have on 24 October 2013 entered into the 2013 Credit Facility with a debt availability of US$65.0 million plus an additional US$10.0 million at our option subject to certain conditions which had been used in part to refinance the 2012 Credit Facility. Subsequent to entering into the 2013 Credit Facility, the total banking facilities of our Group will amount to US$530.0 million.

Borrowings and other indebtedness

Our third party borrowings consist of the 2017 Senior Secured Notes, the 2013 Credit Facility and the 2018 Convertible Notes. As at 30 June 2013, our total borrowings was A$479.1 million (US$447.2 million). As at the Latest Practicable Date, our liability, being principal outstanding, on the 2017 Senior Secured Notes was US$265.0 million, the amount drawn on the 2013 Credit Facility was US$57.4 million and our liability on the 2018 Convertible Notes was US$200.0 million. None of the 2013 Credit Facility, the 2017 Senior Secured Notes nor the 2018 Convertible Notes contains any provisions which make references to the shareholding interest of our controlling shareholder.

2013 Credit Facility

On 24 October 2013, Linc Energy Resources, Inc., our wholly-owned subsidiary entered into the 2013 Credit Facility for US$65.0 million plus up to an additional amount of US$10 million available at our option subject to certain conditions. The 2013 Credit Facility has an interest rate of a base rate plus a margin ranging from 2.25% to 3.25%. An aggregate of A$36,138,971 was drawn down from the 2013 Credit Facility to refinance the 2012 Credit Facility. In addition, the 2013 Credit Facility was also drawn down for general corporate purposes as and when applicable.

The 2013 Credit Facility ranks *pari passu* with and is secured by the same security and guaranteed by the same guarantors as the 2017 Senior Secured Notes pursuant to an intercreditor agreement. The 2013 Credit Facility benefits from a first lien priority ranking. The guarantors under the 2013 Credit Facility are all United States-based subsidiaries. The debt facilities are not guaranteed by our Company.

The 2013 Credit Facility contains usual and customary covenants for a facility of this nature. In particular, the credit agreement governing the 2013 Credit Facility contains financial covenants that require Linc Energy Resources, Inc, and its subsidiaries to achieve, amongst others, a specified maximum Debt to EBITDAX ratio, minimum current ratio and minimum EBITDAX to interest ratio.

US$57.4 million has been drawn down under the 2013 Credit Facility as at the Latest Practicable Date.

2017 Senior Secured Notes

Linc USA GP and Linc Energy Finance (USA), Inc., our wholly-owned subsidiaries (each an "**Issuer**" and together, the "**Issuers**"), issued the 2017 Senior Secured Notes, being an aggregate principal amount of US$265.0 million 12.5% senior secured notes due 31 October 2017. Interest on the 2017 Senior Secured Notes accrues at the rate of 12.5% per annum and is payable semi-annually in arrears on 30 April and 31 October in each year, which commenced on 30 April 2013. The net proceeds from the issue of the notes were used to repay existing indebtedness, fund capital expenditures and for general corporate purposes.

As at the Latest Practicable Date, the total amount outstanding in relation to the 2017 Senior Secured Notes amounted to US$266.4 million comprising US$265.0 million in principal and US$1.4 million in interest and none of the notes were redeemed or purchased and cancelled.

The 2017 Senior Secured Notes include an option for the Issuers, on or after 30 April 2015, to redeem some or all of the 2017 Senior Secured Notes at the redemption price that will decrease over time, plus accrued and unpaid interest, if any, to the date of redemption. Prior to 30 April 2015, the Issuers may, at their option, redeem up to 35.0% of the aggregate principal amount of the notes using the net proceeds of certain equity offerings at a redemption price equal to 112.5% of the principal amount thereof, plus accrued and unpaid interest, if any. In addition, the Issuers may, at their option, redeem some or all of the notes at any time and from time to time prior to 30 April 2015, at a redemption price equal to 100.0% of the principal amount of notes redeemed plus premium as of, and accrued and unpaid interest, if any. Pursuant to its terms, the Issuers are required to use 75.0% of the annual excess cash flow (after all interest expenditure, capital expenditure, consolidated taxes paid, exploration expenses, among others) to make an offer to repurchase the 2017 Senior Secured Notes (to the limit of any excess cashflow calculated as described) at a price equal to 100.0% of their aggregate principal amount, plus accrued and unpaid interest, if any.

All obligations with respect to the 2017 Senior Secured Notes are guaranteed fully and unconditionally, jointly and severally, by Linc Energy Resources, Inc., our wholly-owned subsidiary, and all of its existing and future United Stated-based subsidiaries (other than immaterial subsidiaries, Renaissance Umiat, LLC and each existing and future subsidiary of Renaissance Umiat, LLC), which hold our oil and gas assets in the Gulf Coast Region and Wyoming. The 2017 Senior Secured Notes and the guarantees are secured by liens on substantially all of the Issuers' and the guarantors' assets, subject to certain exceptions. The liens on the collateral securing the notes and the guarantees will be contractually subordinated to the liens on the collateral that secure the 2012 Credit Facility.

The indenture governing the 2017 Senior Secured Notes contains covenants that restrict, among others (unless specifically permitted), the sale, lease or other disposition of any assets or rights of the Issuers and the guarantors as well as the payment of dividends and other distributions and payments by them. In addition, if the Issuers experience certain kinds of changes of control, which is defined as, among others:

(a) the direct or indirect sale, lease, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the properties or assets of the restricted subsidiaries (as defined in the indenture);

(b) other than in connection with (i) any consolidation or merger (i) between an Issuer and/ with an affiliate solely for the purpose of reincorporating such Issuer in another jurisdiction or (ii) any consolidation or merger, or any sale, assignment, transfer, conveyance, lease or other disposition of assets between or among the Issuer and any guarantor, the adoption of a plan in relation to the liquidation or dissolution of Linc USA GP or Linc Energy Resources, Inc.;

(c) the consummation of any transaction the result of which a new beneficial owner will hold more than 50% of the voting stock of Linc USA GP or Linc Energy Resources, Inc.;

(d) Linc USA GP or Linc Energy Resources, Inc. consolidating with, or merging with, any person or any person consolidating with, or merging with or into Linc USA GP or Linc Energy Resources, Inc., pursuant to a transaction in which any of the outstanding voting stock of Linc USA GP or Linc Energy Resources, Inc. or such person is converted into or exchanged into cash, securities or other property;

(e) the first day on which a majority of the members of the board of directors of Linc USA GP or Linc Energy Resources, Inc. are not continuing directors (as defined in the indenture); or

(f) the first day on which Linc USA GP or Linc Energy Resources, Inc. fails to be the beneficial owner of 100% of the issued and outstanding equity interests of Linc Energy Finance (USA),

Each holder of the 2017 Senior Secured Notes will have the right to require the Issuers to repurchase all or any part of their notes at an offer price in cash equal to 101.0% of the aggregate principal amount thereof, plus accrued and unpaid interest, if any, to the date of purchase pursuant to the terms of the indenture.

The maturity date of the 2013 Credit Facility shall be the earlier of (i) 24 October 2016 and (ii) 180 days prior to the scheduled maturity of the 2017 Senior Secured Notes, such maturity date being 31 October 2017.

2018 Convertible Notes

We issued the 2018 Convertible Notes, being an aggregate principal amount of US$200.0 million 7.0% convertible, unsubordinated and unsecured notes due 10 April 2018. Interest on the 2018 Convertible Notes accrues at the rate of 7.0% per annum and is payable semi-annually in arrears on 10 April and 10 October in each year, commencing on 10 October 2013. The net proceeds received from the issue of the notes were used for the repayment of debt (including the Fortress Line of Credit Facility), general corporate purposes and to support the commercialisation of our key assets. We have also granted an affiliate of Credit Suisse (Singapore) Limited, Credit Suisse (Hong Kong) Limited, an option in relation to the 2018 Convertible Notes to purchase up to an additional US$50.0 million in principal amount of notes on or about 10 May 2014. As of the Latest Practicable Date, Credit Suisse (Hong Kong) Limited has yet to exercise this option. If Credit Suisse (Hong Kong) Limited were to exercise such option, any additional notes issued pursuant to the exercise of the option would be placed out to third party investors and not be held by Credit Suisse (Hong Kong) Limited. Consequently, the Shares which these notes are converted into would be held by such third party investors. The new third party investors' percentage shareholding corresponding to the shares underlying these additional options will depend on the prevailing conversion price at the time of conversion.

As at the Latest Practicable Date, the total amount outstanding in relation to the 2018 Convertible Notes was US$201.4 million comprising US$200.0 million in principal and US$1.4 million in interest and none of the notes were redeemed or purchased and cancelled.

Unless previously redeemed or purchased and cancelled, noteholders will have the right following the meeting on 16 October 2013 (the "**CB Noteholders Meeting**") to convert the 2018 Convertible Notes into CN Shares at the conversion price of S$[●], being the lower of (i) A$3.40 per Share or (ii) the arithmetic average of the volume weighted average price of Shares traded on the ASX for each day during the 20 consecutive trading days ended on

15 November 2013, translated into Singapore dollar at the prevailing rate multiplied by 1.35 or the Offering Price multiplied by 1.35, depending on the amount of the gross proceeds of the Offering.

The 2018 Convertible Notes are convertible at any time on and after 21 May 2013 up to and including the tenth day prior to the stated maturity date, being 10 April 2018, pursuant to the terms of the trust deed. The conversion right of a noteholder may be settled in Shares or in cash, at our option. We may make an election to settle in cash by making payment to the relevant noteholders of the cash amount in lieu of delivering or issuing specific amount of Shares to such noteholders.

We will, at the option of any noteholder, redeem all or some of such notes subject to certain conditions on 10 April 2015 (the "**Put-Option Date**") at their principal amount, together with interest accrued to the Put Option Date. Subject to certain conditions, we may redeem in whole but not in part the notes on any date on or after 10 April 2015 at their principal amount together with accrued but unpaid interest.

Based on the post-Offering share capital of [●] Shares (assuming the Over-allotment Option is not exercised and none of the options granted under the Share-Based Incentive Plans are exercised), if all the CN Shares are issued pursuant to the full conversion of the 2018 Convertible Notes, the dilutive effect on the existing shareholders of the Company will be [●]%.

We will not, as long as the notes remain outstanding, among others, create or permit to subsist, and will ensure that none of our subsidiaries will create or permit to subsist, any mortgage, charge, lien, pledge or other form of encumbrance or security interest upon the whole or any part of our present or future property or assets to secure any past or future indebtedness or to secure any guarantee of or indemnity in respect of any past or future indebtedness.

If we experience a change of control, which is defined as, among others, (a) an offeror having acquired more than a 50% interest in our Shares pursuant to an offering which has been made to all shareholders and/or associate and such offer having been declared unconditional in all respects; or (b) any person having acquired more than a 50% interest in our Shares pursuant to a proposed scheme of arrangement, each holder of the 2018 Convertible Notes will have the right to require us to redeem all or some of their notes at the principal amount, plus accrued and unpaid interest and convert any outstanding notes into Shares at the applicable conversion price.

Our Directors are of the reasonable opinion that, after taking into account our cash and bank balance, existing banking facilities, net proceeds raised from the Offering and cash generated from our operating activities, our targeted production schedule, our planned capital expenditure for our assets, our working capital as at the date of this offering document is sufficient for our present requirements and for 18 months after Listing which includes (i) operating, general and administrative and financing costs; (ii) property holding costs; and (iii) costs of any proposed exploration and/or development.

Covenant Compliance

We have implemented procedures to monitor compliance with our loan covenants. We hold monitoring meetings on a weekly basis involving key financial personnel such as our Chief Financial Officer, our financial controllers and corporate finance managers of our Australian and US operations, our treasurer, senior management accountant involved in forecasting, and our tax and risk manager. Any material issues that arise will be reported to our Chief Executive Officer who will raise material issues with our Board of Directors. Based on our latest financial position, we do not foresee any difficulty with complying with the financial covenants under our existing loan facilities.

DERIVATIVE INSTRUMENTS

We enter into various oil hedging contracts, primarily swaps, in an effort to manage our exposure to product price volatility. Historically, prices received for oil production have been volatile because of supply and demand factors, worldwide political factors, general economic conditions and weather conditions. See "Factors Affecting our Results of Operations—Commodity price fluctuations" for further details. Swaps are designed so that we receive or make payments based on a differential between fixed and variable prices for oil. While the use of derivative instruments limits the downside risk of adverse price movements, they also limit future revenue from favourable price movements. We do not enter into commodity derivative instruments for speculative or trading purposes.

For FY2013, we recognised realised losses of A$2.3 million (US$2.1 million) and unrealised losses of A$2.0 million (US$1.9 million) in profit and loss.

During October 2011, we entered into five oil swaps. The first two oil swaps have expired. The third oil swap has a term of January 2013 through December 2013 and provides for 30,247 BBLs per month. The swap has a fixed price of US$86.89 per BBL. The fourth oil swap has a term of January 2014 through December 2014 and provides for 24,207 BBLs per month. The swap has a fixed price of US$87.05 per BBL. The fifth oil swap has a term of January 2015 through December 2015 and provides for 20,082 BBLs per month. The swap has a fixed price of US$87.55 per BBL.

At 30 June 2013, we have hedged our exposure to the variability in future cash flows from forecasted oil production as follows:

Year	Total Remaining Volume (BBLs)	Swap Price (US$ / BBL)
Financial year ending 30 June 2014	487,724	88.95
Financial year ending 30 June 2015	265,734	86.73
Financial year ending 30 June 2016	120,492	87.01

The fair market value of our oil hedge contracts in place at 30 June 2013 was a net liability of A$2.3 million (US$2.1 million).

On 29 May 2013, we entered into a series of foreign exchange hedge contracts to convert a known amount of United States dollar to Australian dollar each month to cover our Australian dollar costs through to December 2013. The hedge provides a collar structure with a minimum and maximum conversion price of the United States dollar back to Australian dollar. This structure provides certainty within a known range for our Australian dollar working capital.

Hedging policy

The management of financial risk, including the hedging policy, is undertaken by our Group Treasury, which will be the responsibility of our Chief Financial Officer, under delegated authority from our Board. We have established internal control procedures to be followed for derivative instruments and this hedging policy is approved by our Audit and Risk Management Committee. Any deviation from such policy requires the approval of our Audit and Risk Management Committee.

Our current policy allows us to enter into various swap and option contracts to hedge against changes in price of oil up to 48 months forward, and to hedge up to 80.0% of our expected oil production. Entry into derivative contracts requires the approval of our President, Oil and Gas, Chief Financial Officer and our Chief Executive Officer and Managing Director. We expect to continuously review our hedging policy, taking into account the economic and oil market outlook, current, forward and forecast oil prices, available hedging lines and counter-party risks as well as liquidity risk. Our Audit and Risk Management Committee monitors the implementation of the policy. Our Chief Financial Officer has overall oversight and keeps track of exposure to derivative contracts on a daily basis.

In addition, under of 2013 Credit Facility, Linc Energy Resources, Inc., our wholly-owned subsidiary had covenanted, among others that it will not, and it will not permit its subsidiaries to, enter into any swap agreements that exceed 80.0% of the reasonably anticipated projected production from proved, developed, producing oil and gas assets for each month during the period during which such swap agreement is in effect.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

We lease a number of office premises under operating leases. These leases generally provide for additional rental payments that are based on consumer price indices or market reviews with minimum escalation rates and are not recognised as liabilities. Tenement commitments refer to the rental and expenditure components of the agreements we enter into while port commitments relate to the take or pay arrangement with Gladstone Port Authority contracted for but not recognised as liabilities payable. We intend to offset the port commitment prior to commencing production at the Teresa project through allocation of capacities to third parties. The following table summarises our contractual cash obligations and commitments as at the Latest Practicable Date.

	Total	Less than 1 year	1 – 2 years	3 – 5 years	> 5 years
	(A$'000)	*(A$'000)*	*(A$'000)*	*(A$'000)*	*(A$'000)*
Operating lease commitments as lessee	2,729	1,213	490	386	640
Tenement commitments	29,651	3,574	10,732	15,345	-
Port commitments	183,859	14,537	21,806	32,069	115,447

The following table summarises commitments by geographic location:

	Total	Less than 1 year	1 – 2 years	3 – 5 years	> 5 years
	(A$'000)	*(A$'000)*	*(A$'000)*	*(A$'000)*	*(A$'000)*
Australia	212,472	18,592	31,383	47,520	115,447
United States	3,219	224	1,429	641	642
Europe	548	224	216	108	-

We plan to fund these contractual commitments through our internal cash flows, debt financing, capital markets transactions and the net proceeds from the Offering.

CAPITAL EXPENDITURES, DIVESTMENTS AND PLANNED CAPITAL EXPENDITURES

We incurred the following major capital expenditures and divestments for FY2011, FY2012 and FY2013 and from 1 July 2013 to the Latest Practicable Date:

Capital expenditures

	FY2011	FY2012	FY2013	1 July 2013 to the Latest Practicable Date
	(A$'000)	*(A$'000)*	*(A$'000)*	*(A$'000)*
Acquisition of Umiat field, Alaska	4,719	44,660	-	-
Acquisition of assets in the Gulf Coast Region	9,438	254,697	-	-
Acquisition of assets in Wyoming	18,268	-	-	-
Drilling and development expenditure in the Gulf Coast Region	-	15,621	102,741	62,230
Umiat field, Alaska appraisal and development	-	-	50,208	6,533
Cook Inlet exploration	-	4,313	4,506	-
Wyoming UCG project	6,619	5,308	-	-
Wyoming oil and gas	-	3,426	-	-
Teresa Project, Queensland	-	9,038	15,605	1,076
SAPEX exploration, Arckaringa Basin	-	14,960	-	-
Chinchilla Demonstration Facility, Queensland	2,396	12,840	-	-
Total	**41,440**	**364,863**	**173,060**	**69,839**

The above material capital expenditures were mainly financed by internally generated cash flows, the proceeds from the divestment of the Carmichael coal tenement and bank borrowings.

Divestments

	FY2011	FY2012	FY2013	1 July 2013 to the Latest Practicable Date
	(A$'000)	*(A$'000)*	*(A$'000)*	*(A$'000)*
Disposal of property, plant and equipment	88	23	183	-
Sale of coal tenement	500,000	-	-	-
Total	**500,088**	**23**	**183**	**-**

Planned capital expenditures

In budgeting for our activities, we have relied on a number of assumptions, including with regard to our oil and gas production rate, our exploration discovery success rate, the number of wells we plan to drill, our Working Interests in our conventional and unconventional projects, the costs involved in developing these conventional and unconventional projects and the availability of both suitable equipment and qualified personnel. Most of the planned capital expenditure is discretionary and is subject to change. Our current planned capital expenditures for the nine months ending 30 June 2014 and FY2015 are as follows:

	Nine months ending 30 June 2014 and FY2015
	(A$'000)
Conventional Oil and Gas	
Development of Umiat field, Wyoming CO_2 EOR project and the exploitation and exploration of Gulf Coast assets including sub-salt opportunities	190,148
Unconventional Oil and Gas	
Development of UCG projects in South Africa, other UCG development activities in Asia, Europe, Russia and North America, decommissioning of our Chinchilla Demonstration Facility and exploration drilling and seismic in the Arckaringa Basin	22,057
Other	
Planned capital expenditures relating to the development of conventional coal mining assets assuming non-divestment	20,686
Total	**232,891**

We plan to fund these capital expenditure through a combination of our internal cash flows, debt financing, capital markets transactions and the net proceeds from the Offering.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTINGENT LIABILITIES

As at the Latest Practicable Date, save for those set out below, we do not have any material off-balance sheet arrangements or contingent liabilities.

Acquisition of Powder River Basin coal leases from Gastech Inc.

On 24 December 2009, we acquired an aggregate 81,268 acres of coal lease tenements in Powder River Basin (Wyoming) and Williston Basin (Montana) from Gastech Inc. and Wold Oil Properties Inc, respectively. Gastech Inc. and Wold Oil Properties are related to each other but unrelated to our Company. Gastech Inc. retains a royalty interest in an amount equal to one quarter of the coal production royalties payable, but not greater than 2.0%, to the

State of Wyoming under the Wyoming leases. The acquisition cost relating to our acquisition of Powder River Basin (Wyoming) was $20 million by way of equity.

Acquisition of oil and gas leases in Alaska from GeoPetro Alaska LLC

On 2 March 2010, we acquired 123,000 acres of oil and gas leases in the Cook Inlet Basin in Alaska from GeoPetro Alaska LLC. An additional A$3.9 million (US$3.6 million) will be payable from the proceeds of any successful production from the acquired leases. Following such payment, GeoPetro Alaska LLC will also be entitled to an overriding royalty from 7.0% to 10.0% of the value of commercial production from the leases.

Legal claims and other assets or liabilities

There was one legal claim pending against us in relation to the assets acquired from ERG Resources LLC. See "Business—Legal Proceedings" for more information.

CHANGES IN ACCOUNTING POLICIES

We have not made any significant changes in our accounting policies during the last three financial years ended 30 June 2011, 2012 and 2013.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

As a result of our global operating and financing activities, we are exposed to various types of market risks, including changes in commodity prices, foreign currency exchange rates, interest rates and liquidity risk. We use certain financial instruments to hedge the risk of commercial exposures in respect of oil prices and we do not hold such financial instruments for trade or speculative purposes. Our general approach is to hedge our exposure to oil prices to achieve certainty of results.

Our risk management strategy aims to minimise the adverse effects from the unpredictability of financial markets risk and commodity price fluctuations on our financial performance.

Our risk governance structure consists of responsible staff in each operational group reporting to our Chief Financial Officer, in our Brisbane office, who is responsible for, among others, identifying and monitoring the specific risks that are identified. Once a risk is identified and our exposure is certain, approval is sought of our Chief Executive Officer and Managing Director and our Board to implement a strategy to eliminate this risk or reduce its impact.

Our borrowing agreements in relation to producing assets may require us to maintain a certain level of hedge cover to protect against downside price movements in the relevant commodity prices.

Commodity price risk

We periodically enter into derivative instruments such as swap agreements to moderate the effects of fluctuations in commodity prices on our cash flow and to manage exposure to commodity price risk. Our commodity derivative instruments generally serve as effective economic hedges of commodity price exposure; however, we have elected not to designate our derivatives as hedging instruments. As such, we recognise all changes in fair values of our derivative instruments as unrealised gains or losses in profit and loss. See "—Derivative Instruments" for discussion of our hedging policy and hedge positions.

For FY2013, we recognised realised losses of A$2.3 million (US$2.1 million) and unrealised losses of A$2.0 million (US$1.9 million) in profit and loss.

Foreign exchange risk

Our functional and reporting currency is the Australian dollar although operational currency is predominantly the United States dollar.

Foreign currency risk is associated with international procurement and operational activities. This risk arises when future commercial transactions and recognised assets and liabilities are denominated in a currency that is not our functional currency. The establishment and settlement of foreign exchange transactions require approval from our Chief Financial Officer to minimise exposures to currency fluctuations.

As at 30 June 2013, we held a material amount of cash and cash equivalents. The distribution of this cash, by currency is set out in the table below:

	FY2013	
	(A$'000)	*(US$'000)*
Australian dollar	19,741	18,428
United States dollar	103,877	96,969
Pounds Sterling	314	293
Uzbekistan Soms	36	34
Polish Zloty	39	36
Total cash and cash equivalents	**124,007**	**115,761**

For FY2013, we recognised unrealised gains of A$0.9 million (US$0.8 million) in profit and loss.

Our revenue streams are substantially in United States dollar along with all of our debt liabilities and the majority of our cash assets.

From a working capital perspective, our main exposure is to United States dollar depreciation against the Australian dollar. To mitigate this, on 29 May 2013, we entered into a series of foreign exchange hedge contracts to convert a known amount of United States dollar to Australian dollar each month to cover our Australian dollar costs through to December 2013. The hedge provides a collar structure with a minimum and maximum conversion price of the United States dollar back to Australian dollar. This structure provides certainty within a known range for our Australian dollar working capital.

We are subject to foreign currency exposure with our United States dollar denominated trade receivables, predominately oil sales totalling A$13.4 million (US$12.5 million) in the United States and the Alaskan tax credit receivable A$32.6 million (US$30.4 million). Minimal exposures exist in relation to other receivables and other financial assets.

A portion of our available-for-sale assets are also exposed to foreign currency risk. A$14.8 million (US$13.8 million) of the balance represents investments in companies listed on the London Stock Exchange AIM which are denominated in Pounds Sterling. We hold a material amount of borrowings taken out in currency other than functional currency which is subject to foreign currency risk. The 2018 Convertible Notes are denominated in United States dollar whereas our functional currency is Australian dollar.

As at 30 June 2013, a 10.0% change in the United State dollar foreign currency rates would have increase / (decreased) the 2018 Convertible Notes and embedded derivatives and profit and loss by the amounts shown below, assuming all other variables remain constant:

	Profit or loss	
	10.0% Increase	**10.0% Decrease**
	(A$'000)	
Borrowings—2018 Convertible Notes component	15,512	(15,512)
Borrowings—embedded derivatives	1,752	(1,861)
Foreign currency options	5,627	(1,421)
Net sensitivity	22,891	(18,794)

Movement of a 10.0% increase in foreign currency exchange rates as at 30 June 2013 would have no impact on our equity.

Interest rate risk

Interest rate risk occurs with respect to cash and deposits and borrowings to the extent they are subject to movements in floating interest rates. Cash is usually placed on deposit at fixed interest rates for periods of between 30 and 180 days. At 30 June 2013, the majority of cash held by us was held at floating interest rates.

As at 30 June 2013, a change in interest rates would have increased/(decreased) financial assets and liabilities and profit and loss by the amounts shown below, assuming all other variables remain constant:

	Profit or loss	
	100bp Increase	100bp Decrease
	(A$'000)	
Financial assets	653	(653)
Financial liabilities	(376)	376
Borrowings—embedded derivatives	876	(766)
Net cash flow sensitivity	(1,153)	(1,043)

Movement of 100 basis points as at 30 June 2013 would have no impact on our equity.

SEASONALITY

Seasonal weather conditions can limit our exploration, drilling and production activities and other oil and gas operations in certain areas. We typically do not experience and have not experienced any other significant seasonality in our business in the last three financial years.

ORDER BOOK

Due to the nature of our business, we do not maintain an order book.

RECENT DEVELOPMENTS

The following table sets out selected information on our consolidated statement of comprehensive income, consolidated statement of financial position and consolidated cash flow statement as of and for the quarter ended 30 September 2013.

Consolidated Statement of Comprehensive Income

	Three months ended 30 September 2012	Three months ended 30 September 2013
	(A$'000)	(A$'000)
	(Unaudited / Unreviewed)	
Revenue	24,239	38,362
Gross Profit	13,088	20,404
Total comprehensive loss for the period	(18,531)	(44,508)

Consolidated Statement of Financial Position

	Three months ended 30 September 2012
	(A$'000) (Unaudited /Unreviewed)
Cash and cash equivalent	63,628
Total assets	1,010,314
Current Borrowings	38,496
Non-Current Borrowings	444,141
Total liabilities	616,891
Net assets	393,423
Total equity	393,423

Consolidated Cash Flow Statement

	Three months ended 30 September 2013
	(A$'000) *(Unaudited / Unreviewed)*
Net operating cash flows	24,975
Net investing cash flows	(72,378)
Net financing cash flows	(10,695)
Net increase (decrease) in cash held	(58,098)
Cash at end of quarter	63,628

Revenue in the three months ended 30 September 2013 increased by A$14.1 million over the corresponding period in FY2013, primarily due to an increase in oil and gas revenue which was driven by an increase in production volume as well as average selling prices. However, total comprehensive loss for the three months ended 30 September 2013 increased by A$26.0 million over the corresponding period in the prior year (despite the increase in gross profit of A$7.3 million). The increase in comprehensive loss was primarily due to a A$22 million increase in finance expense (which included increases in interest expense from the 2017 Senior Secured Notes and 2018 Convertible Notes and a fair value adjustment to the value of the embedded derivative component of the 2018 Convertible Notes, a A$10.4 million increase in administration and corporate expense, a A$5.9 million loss on the sale of the Alaskan tax credit receivable and a A$5 million decrease in income tax benefit (due to a decrease in research and development tax concessions available as a result of decreased research and development expenditure). See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting our Results of Operation—Finance expenses" for more information on the fair value adjustment to the value of the embedded derivative component of our compound financial instruments and Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting our Results of Operation—Exploration and development activities" for more information on the Alaskan tax credit.

Production at Cedar Point in the Gulf Coast Region is currently lower than capacity across the newly drilled wells due to minor operational issues. We commenced a remediation programme to restore production to its anticipated level prior to the end of the three months ending 31 December 2013.

For the three months ended 30 September 2013, we had a total of A$124.0 million (US$115.8 million) cash and cash equivalents at the start of the period. During the period, a net cash outflow of A$58.0 million (US$54.1 million) decreased the cash and cash equivalents balance to A$63.6 million (US$59.4 million) at quarter end.

The net cash inflow from operating activities of A$25.0 million (US$23.3 million) was offset by cash outflows of A$72.4 million (US$67.6 million) classified as cash flow for investing activities and A$10.7 million (US$10.0 million) for financing activities.

Receipts from customers which were predominantly related to oil sales in the United States amounted to A$36.2 million (US$33.8 million) and payments to suppliers and employees amounted to A$36.3 million (US$33.9 million).

Other material cash inflows and outflows during the three months ended 30 September 2013 include:

(a) proceeds from the sale of the Alaskan tax credit receivable of A$26.7 million (US$24.9 million);

(b) payment of A$9.8 million (US$9.1 million) to settle the termination of the Fortress Line of Credit Facility Warrant Deed with FCCD (Australia) Pty Ltd;

(c) payment of A$5.2 million (US$4.9 million) for the exploration and evaluation of our Umiat field, Alaska;

(d) payment of A$64.8 million (US$60.5 million) for development activities, predominantly in respect of our oil and gas asset at the Gulf Coast Region; and

(e) payment of A$10.6 million (US$10.0 million) to Gladstone Ports Corporation Ltd for six months of port access to the RG Tanna Coal Export Terminal at the Port of Gladstone.

In addition, we also estimate the following cash outflow in respect of the three months ending 31 December 2013 which forms part of the planned capital expenditure we expect to spend in FY2014. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources—Borrowings and other indebtedness—2013 Credit Facility" for further details on the 2013 Credit Facility:

	Three months ending 31 December 2013
	(A$'000)
Exploration and evaluation[(1)]	16,876
Development[(2)]	24,807
Production[(3)]	10,302
Administration[(4)]	14,445
Technology development and site operations[(5)]	7,703
Total[(6)]	**74,133**

Notes:

(1) Includes payment in respect of Phase 2 Umiat of our drilling programme costs in Alaska.

(2) Includes payment of accrued creditors and scheduled payments for development of our conventional oil and gas assets.

(3) The total includes payments for all costs directly attributable to our conventional oil and gas production.

(4) Administration payments scheduled for the three months ended 31 December 2013 include overheads and costs that are attributable to the listing of our Company on the Main Board of the SGX-ST.

(5) The expected licence fee receipt of A$20 million from Exxaro Resources in respect of the three months ended 30 September 2013 has been assumed to be received within the three months ending 31 March 2014 and will cover our Clean Energy business operating and overhead costs.

(6) The table excludes revenues from our conventional oil and gas assets and Clean Energy business, and other funds inflows, including the increased drawing capacity under the 2013 Credit Facility. Some of these revenue sources have already been received or are expected to be received within the three months ending 31 December 2013.

RECENT ACCOUNTING PRONOUNCEMENTS

Our annual consolidated financial statements included in this offering document have been prepared in accordance with Australian Accounting Standards as adopted by the Australian Accounting Standards Board ("**AASB**"). The consolidated financial statements comply with IFRS as issued by the IASB. Our Group has adopted the following new standards and amendments to standards, including any consequential amendments to other standards, with a date of initial application of 1 July 2013.

- AASB 10/IAS 10 Consolidated Financial Statements (2011) (see (a))
- AASB 11/IAS 11 Joint Arrangements (see (b))
- AASB 13/IAS 13 Fair Value Measurement (see (c))
- AASB 119/IAS 19 Employee Benefits (2011) (see (d))
- Annual Improvements to the Australian Accounting Standards 2009-2011

The nature and the effect of the changes are further explained below. There is no difference between the foregoing accounting pronouncements under AASB and IFRS.

(a) Consolidated Financial Statements

As a result of AASB 10 (2011), our group has changed our accounting policy for determining whether we have control over and consequently whether we consolidate our investees. AASB 10 (2011) introduces a new control model that is applicable to all investees, by focusing on whether our Group has power over an investee, exposure or rights to variable returns from our involvement with our investee and ability to use our power to affect those returns. In particular, AASB 10 (2011) requires the Group consolidate investees that we control on the basis of de facto circumstances. There was no impact on the statement of financial position or the profit or loss associated with the initial application of this standard.

(b) Joint arrangements

As a result of AASB 11, our Group has changed our accounting policy for our interests in joint arrangements. Under AASB 11, our Group classifies our interest in joint arrangements as either joint operations or joint ventures depending on our Group's rights to the assets and obligations for the liabilities of the arrangements. When making this assessment, our Group considers the structure of the arrangements, the legal form of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances. Previously, the structure of the arrangement was the sole focus of classification. There was no impact on the statement of financial position or the profit or loss associated with the initial application of this standard.

(c) Fair value measurement

AASB 13 establishes a single framework for measuring fair value and making disclosures about fair value measurements, when such measurements are required or permitted by other AASBs. In particular, it unifies the definition of fair value as the price at which an orderly transaction to sell an asset or to transfer a liability would take place between market participants at the measurement date. It also replaces and expands the disclosure requirements about fair value measurements in other AASBs, including AASB 7 Financial Instruments: Disclosures. Some of these disclosures are specifically required in interim financial statements for financial instruments; accordingly, our Group has included additional disclosures in this regard (see Note 11). There was no impact on the statement of financial position or the profit or loss associated with the initial application of this standard.

(d) Employee Benefits

As a result of AASB 119/ IAS 19, the definition of short-term and other long-term employee benefits have been amended to affecting the measurement of the obligations. Under the amended standard, the distinction between short-term and other long-term employee benefits depends on when the benefit is expected to be wholly settled. Previously, the distinction was based on timing of contractual settlement. The adoption of the amendments resulted in our reclassifying some employee benefits from short-term to other long-term and they have been remeasured accordingly.

There was no significant impact on the statement of financial position or the profit or loss associated with the initial application of this standard.

(e) Segment information

The amendment to AASB 134 clarifies that our Group needs to disclose the measures of total assets and liabilities for a particular reportable segment only if the amounts are regularly provided to our Group's chief operating decision maker, and there has been a material change from the amount disclosed in the last annual financial statements for that reportable segment. There was no impact on the segment disclosure with the initial application of this amendment to the standard.

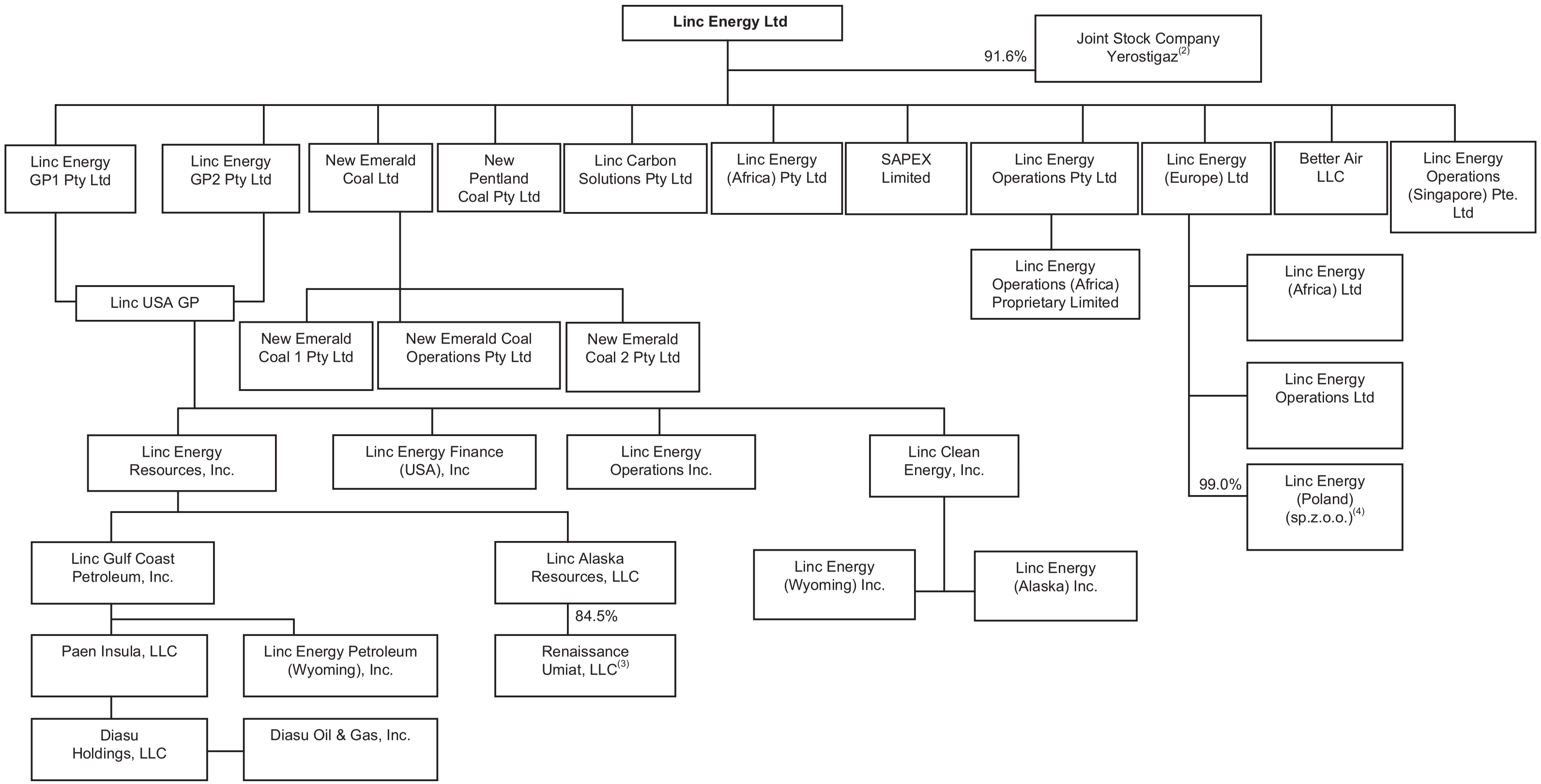
(f) Summary of quantitative impacts

There is no quantitative impact resulting from the above changes in accounting policies on our Group's financial position, comprehensive income and cash flows.

We currently recognise a number of financial assets and liabilities. All of these except for the available-for-sale financial assets are currently recognised at fair value or amortised cost. However, all of the available-for-sale assets are listed equity securities which are currently recognised at their fair value based on the last trading price of the period. Any movement in the fair value of the available-for–sale-assets will be reflected in the profit and loss or other comprehensive income rather than the available-for-sale reserve. The impact of this may be significant depending on the change in value of these assets during future periods.

CORPORATE STRUCTURE

Linc Energy Ltd (formerly known as Linc Energy N.L.) was incorporated in Australia on 29 October 1996. As at the Latest Practicable Date, we have 33 subsidiaries. We own 100.0% of the shares in our subsidiaries except as indicated otherwise in our Group structure below[1]:



Notes:

(1) Entities in which our Company holds less than 20% interest in have not been included in this chart.

(2) Our interest in Joint Stock Company Yerostigaz is held by Mr. Peter Bond on trust for our Company. The remaining shareholders of Joint Stock Company Yerostigaz are other unrelated third parties comprising of the management of the Yerostigaz facility.

(3) The remaining shareholders of Renaissance Umiat, LLC Rutter and Wilbanks Corporation and Arctic Falcon Exploration Inc. The ownership interest of Arctic Falcon Exploration is the subject of litigation between Linc Alaska Resources, LLC and Arctic Falcon Exploration. See “Legal Proceedings” of this offering document for further information.

(4) The remaining shareholder of Linc Energy (Poland) (sp z.o.o) is JP Weber Dudarski sp. k. On 6 November 2013, we acquired the remaining shares from JP Weber Dudarski sp. k. We would own 100.0% of the shares in Linc Energy (Poland) (sp z.o.o) once the change is registered with the relevant Poland court register.

The details of our subsidiaries are as follows:

No	Company Name	Date of Incorporation/ Formation	Country of Incorporation/ Formation	Principal place of Business	General Nature of Business	Effective Ownership interest (%)
1.	Linc Energy GP1 Pty Ltd	3 September 2012	Queensland, Australia	Queensland, Australia	Holding entity	100.0
2.	Linc Energy GP2 Pty Ltd	3 September 2012	Queensland, Australia	Queensland, Australia	Holding entity	100.0
3.	Linc USA GP	13 September 2012	Texas, United States	Texas, United States	Holding entity	100.0
4.	Linc Energy Resources, Inc	4 June 2012	Delaware, United States	Texas, United States	Holding entity	100.0
5.	Linc Gulf Coast Petroleum, Inc	14 September 2010	Delaware, United States	Texas, United States	Oil and Gas	100.0
6.	Linc Energy Petroleum (Wyoming), Inc	8 December 2010	Delaware, United States	Texas, United States	Oil and Gas	100.0
7.	Pean Insula, LLC	8 June 2009	Texas, United States	Texas, United States	Holding entity	100.0
8.	Diasu Holdings, LLC	23 April 2009	Texas, United States	Texas, United States	Oil and Gas	100.0
9.	Diasu Oil & Gas, Inc	30 October 1978	Texas, United States	Texas, United States	Oil and Gas	100.0
10.	Linc Alaska Resources, LLC	14 November 2006	Delaware, United States	Anchorage, United States	Oil and Gas	100.0
11.	Renaissance Umiat, LLC	1 March 2007	Alaska, United States	Alaska, United States	Oil and Gas	84.5[(1)]
12.	Linc Energy Finance (USA) Inc.	21 August 2012	Delaware, United States	Texas, United States	Holding entity	100.0
13.	Linc Energy Operations Inc.	11 August 2009	Delaware, United States	Texas, United States	Oil and gas	100.0
14.	Linc Clean Energy, Inc	4 June 2012	Delaware, United States	Colorado, United States	UCG	100.0
15.	Linc Energy (Wyoming), Inc	9 February 2009	Delaware, United States	Wyoming, United States	UCG	100.0
16.	Linc Energy (Alaska), Inc	15 October 2009	Delaware, United States	Anchorage, United States	UCG	100.0
17.	New Emerald Coal Ltd	20 January 2011	Queensland, Australia	Queensland, Australia	Conventional coal mining	100.0
18.	New Emerald Coal 1 Pty Ltd	23 July 2013	Queensland, Australia	Queensland, Australia	Conventional coal mining	100.0
19.	New Emerald Coal Operations Pty Ltd	18 May 2012	Victoria, Australia	Queensland, Australia	Conventional coal mining	100.0
20.	New Emerald Coal 2 Pty Ltd	23 July 2013	Queensland, Australia	Queensland, Australia	Conventional coal mining	100.0
21.	New Pentland Coal Pty Ltd	6 March 2012	Victoria, Australia	Queensland, Australia	Conventional coal mining	100.0
22.	Linc Carbon Solutions Pty Ltd	21 May 2008	Queensland, Australia	Queensland, Australia	UCG	100.0
23.	Linc Energy (Africa) Pty Ltd	3 August 2011	Queensland, Australia	Queensland, Australia	Holding entity	100.0
24.	SAPEX Limited	6 July 2000	New South Wales, Australia	New South Wales, Australia	Shale oil and gas	100.0
25.	Linc Energy Operations Pty Ltd	23 February 2011	Queensland, Australia	Queensland, Australia	Holding entity	100.0
26.	Linc Energy Operations (Africa) Proprietary Limited	8 February 2013	South Africa	South Africa	UCG	100.0

No	Company Name	Date of Incorporation/ Formation	Country of Incorporation/ Formation	Principal place of Business	General Nature of Business	Effective Ownership interest (%)
27.	Linc Energy (Europe) Ltd	27 January 2011	United Kingdom	United Kingdom	UCG	100.0
28.	Linc Energy (Africa) Ltd	27 January 2011	United Kingdom	United Kingdom	UCG	100.0
29.	Linc Energy (Operations) Ltd	27 January 2011	United Kingdom	United Kingdom	UCG	100.0
30.	Linc Energy (Poland) (Sp.z.o.o.)	8 March 2011	Poland	Poland	UCG	99.0(2)
31.	Joint Stock Company Yerostigaz	30 June 1995	Uzbekistan	Uzbekistan	UCG	91.6(3)
32.	Better Air LLC	26 July 2010	Uzbekistan	Uzbekistan	UCG	100.0
33.	Linc Energy Operations (Singapore) Pte. Ltd.	8 November 2013	Singapore	Singapore	Business support services	100.0

Notes:

(1) The remaining shareholders of Renaissance Umiat, LLC are Rutter and Wilbanks Corporation and Arctic Falcon Exploration, Inc. The ownership interest of Arctic Falcon Exploration Inc is the subject of litigation between Linc Alaska Resources, LLC and Arctic Falcon Exploration. See "Legal Proceedings" of this offering document for further information.

(2) The remaining shareholder of Linc Energy (Poland) (sp.z.o.o.) is JP Weber Dudarski sp. k. On 6 November 2013, we acquired the remaining share from JP Weber Dudarski sp. k. We would own 100% of the shares in Linc Energy (Poland) (Sp.z.o.o) once the change is registered with the relevant Poland court register.

(3) Joint Stock Company Yerostigaz was privatised on 30 June 1995. Our interest in Joint Stock Company Yerostigaz is held by Mr. Peter Bond on trust for our Company. The remaining shareholders of Joint Stock Company Yerostigaz are unrelated third parties comprising management of the Yerostigaz facility. Under the Uzbekistan Company Law, the Cabinet of Ministers of the Republic of Uzbekistan may introduce special rights in the form of "Golden Shares" of the Uzbekistan Government to participate in and manage certain joint stock companies which has less than 25% state-owned shares. The Golden Share is implemented through appointment of a state representative who is obligated to participate in, among others, the general shareholders meetings, and enjoys the right to set aside a veto on decisions on issues such as amendments to constitutive documents, reorganisation of company and changing of charter capital. As at the Latest Practicable Date, no Golden Shares have been issued by the Joint Stock Company Yerostigaz.

OVERVIEW

We are focused on both conventional and unconventional oil and gas production. We own a diverse and substantial energy portfolio that includes oil, gas, shale oil and gas and coal.

We operate the following three key business divisions with offices headquartered in different geographic locations:

(a) conventional oil and gas which consists of:

  (i) oil and gas producing assets located in two main areas in the United States, namely, the Gulf Coast Region and Wyoming, which contribute the bulk of our revenue; and

  (ii) the appraisal and development of our Umiat field located in Alaska, the United States;

(b) unconventional oil and gas, which consists of:

  (i) our Clean Energy business, which focuses on the commercialisation of our proprietary technology in UCG, the process of converting coal into a valuable UCG syngas in situ. Our Chinchilla Demonstration Facility is the only UCG to GTL demonstration facility operating in the world. We also own and operate the world's longest running commercial UCG operation in Uzbekistan, which has been in operation for over 50 years, and which supplies energy to a nearby power station. We hold coal interests for UCG in Wyoming and Alaska in the United States, Poland, Uzbekistan, and South Australia and Queensland in Australia; and

  (ii) our SAPEX business, which focuses on the exploration for shale oil and gas in the Arckaringa Basin in South Australia; and

(c) coal, which consists of:

  (i) the Carmichael Royalty; and

  (ii) our conventional coal mining business, which consists of our interests in our conventional coal mining assets in Queensland, Australia.

In respect of our oil and gas assets as of 1 September 2013, we had estimated net 1P reserves of 13.6 MMBOE (of which approximately 96% was oil) with an estimated PV-10 of US$614.5 million, estimated net 2P reserves of 168.2 MMBOE with an estimated PV-10 of US$3.1 billion, and estimated net 3P reserves of 274.6 MMBOE with an estimated PV-10 of US$4.6 billion. Since the acquisition of our producing assets in Wyoming and the Gulf Coast Region in February and October 2011, respectively, we have increased total production by 85% from 2,711 BOEPD (gross) for the quarter ended 31 December 2011 to 5,010 BOEPD (gross) for the quarter ended 30 September 2013. From 1 October 2013 to the Latest Practicable Date, we had an average production rate of 5,858 BOEPD (gross).

Our Gulf Coast Region asset has estimated net 1P reserves of 12.8 MMBOE and net 2P reserves of 12.9 MMBOE. For the three months ended 30 September 2013, our Gulf Coast Region asset produced 4,822 BOEPD. From 1 October 2013 to the Latest Practicable Date, we had an average production rate of 5,665 BOEPD (gross). Our near term development drilling programme is progressing, and we intend to continue focusing on the Gulf Coast Region.

Our Wyoming asset has estimated net 1P reserves of 0.8 MMBBL and net 3P reserves of 67.7 MMBBL. For the three months ended 30 September 2013, our Wyoming asset produced 187 BOPD (gross). From 1 October 2013 to the Latest Practicable Date, our Wyoming asset had an average production rate of 193 BOPD (gross).

For FY2013, our net oil and gas production in the Gulf Coast Region and Wyoming was 1,157 MBOEs at an average realised price of US$104.95 / BOE with an average total operating expense, including oil and gas lease operating expenses, other production expenses, workover costs, production taxes and taxes, of US$25.09 / BOE.

Our Umiat field in Alaska, an asset under our conventional oil and gas business, is considered one of the largest, undeveloped conventional petroleum resources in North America with estimated net 2P reserves of 154.6 MMBBL and estimated net 3P reserves of 194.1 MMBBL. Based on estimated OOIP of approximately 1,200 MMBBL, capital expenditure of US$1.8 billion (prior to tax credits receipts from the Alaskan Government) and operating expenditure of US$589 million we expect to target peak production of 50,000 BOPD (gross) from our Umiat field before 2020. We have in place a three-phase development plan for our Umiat field and have completed Phase 1 by drilling the Umiat #18 well at an approximate cost of US$70 million.

In respect of our Clean Energy business, we are focused on the generation of UCG syngas for GTL, power, urea, synthetic natural gas, hydrogen fuel cells and EOR. We believe we are the only company in the world that has successfully demonstrated UCG to GTL and to have produced diesel and jet fuel from UCG syngas. We are currently pursuing joint ventures with upstream asset owners for the monetisation of stranded coal assets. Through these strategic partnerships, we intend to acquire an equity participation in the relevant projects. We also plan to enter into licensing agreements with selected partners which will include either all or some of the following: (a) licensing fees, (b) royalty fees, (c) carried equity interests and/or (d) consulting and engineering fees. We have entered into a number of opportunity screening studies with third parties to evaluate potential commercial UCG opportunities. We entered into formal agreements to jointly pursue UCG as a commercial business to develop energy solutions in Sub-Saharan Africa with Exxaro Resources in May 2013. While our focus is currently through establishing strategic joint ventures, the opportunity to participate in projects on our own assets is still available in the future and, potentially, offers the greatest upside.

In respect of our SAPEX business, we hold interests in an area covering over 65,000 sq km (approximately 16 million acres) in the Arckaringa Basin in South Australia, Australia. In respect of such interests, Gustavson Associates estimated prospective resources for unconventional reservoirs to be 232.8 BNBOE, and prospective resources for conventional traps to be 125.0 BNBOE, on an unrisked best estimate basis. DeGolyer and MacNaughton estimated gross prospective oil, gas, condensate and solution gas prospective resources for various licences as of 15 September 2013 in the Arckaringa Basin. We have utilised these quantities in our estimate of 102,800 MMBOE based on the unrisked mean.

In respect of the Carmichael Royalty, we expect to receive payments of A$2 per tonne (indexed to the Consumer Price Index (Brisbane) All Groups number) of coal produced for the first 20 years of production at the Carmichael Project in Queensland, Australia. As at the Latest Practicable Date, Adani, the existing owner and developer of the asset, has reported that it expects to commence production in the first quarter of 2017.

Finally, in respect of our conventional coal mining business in Queensland, Australia, we entered into a sale and purchase agreement to acquire the Blair Athol Mine in October 2013 and expect to recommence production in June 2014. See "Business—Conventional Coal Mining" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors affecting our results of operations—Acquisitions and disposals of our assets" of this offering document for further details. The Blair Athol Mine has 8.7 Mt proved reserves and 2.6 Mt probable reserves in accordance with the JORC Code. We are presently in the pre-feasibility stage of the Teresa Project, and exploration and concept study of the Pentland Project and the Dalby Project.

The following table sets forth certain information regarding our assets as at the date of this offering document. We currently operate and manage all our oil, gas and coal assets.

Assets' Location	Gross Area (acres)	Working Interest Area(1) (acres)	Status
Conventional Oil and Gas			
United States			
Gulf Coast Region	13,629	13,537	Production
Wyoming	27,788	26,954	Production
Alaska	22,897	19,348	Exploration
Unconventional Oil and Gas			
UCG			
Australia			
Queensland	162,150	162,150	Exploration
South Australia	1,067,989	1,067,989	Exploration
Poland	53,374	53,374	Exploration
Uzbekistan	1,000	917	Production
United States			
Alaska	167,917	167,917	Exploration
Wyoming	180,651	180,651	Exploration
Shale Oil and Gas			
Australia			
South Australia(2)	21,121,826	21,121,826	Exploration
Coal			
Australia			
Queensland	28,454,679	NA	Various(3)

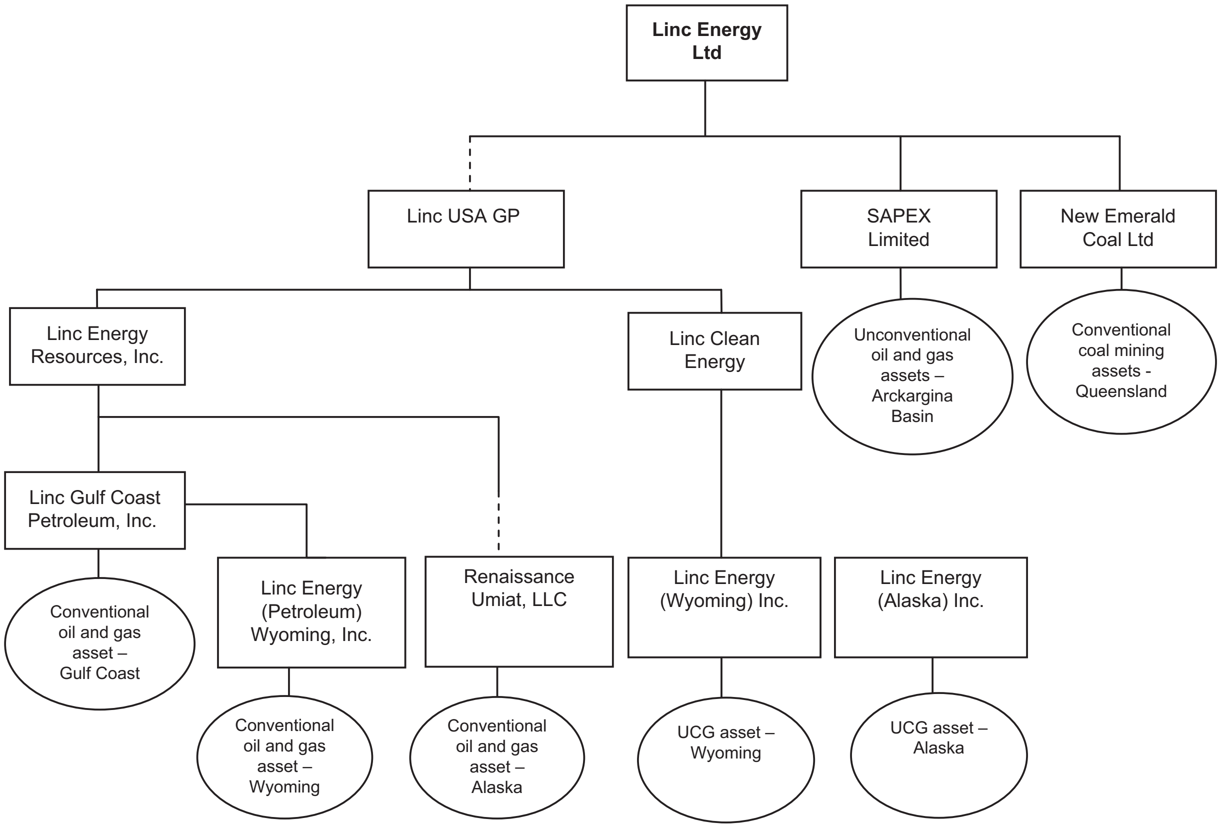
Notes:

(1) In respect of our conventional and unconventional oil and gas assets our Working Interest area refers to our Working Interest multiplied by gross area. The concept of Working Interest area is not applicable to our conventional coal mining assets.

(2) The gross area and working interest area refers to our interests in the Arckaringa, Eromanga, Cooper and Walloway Basins.

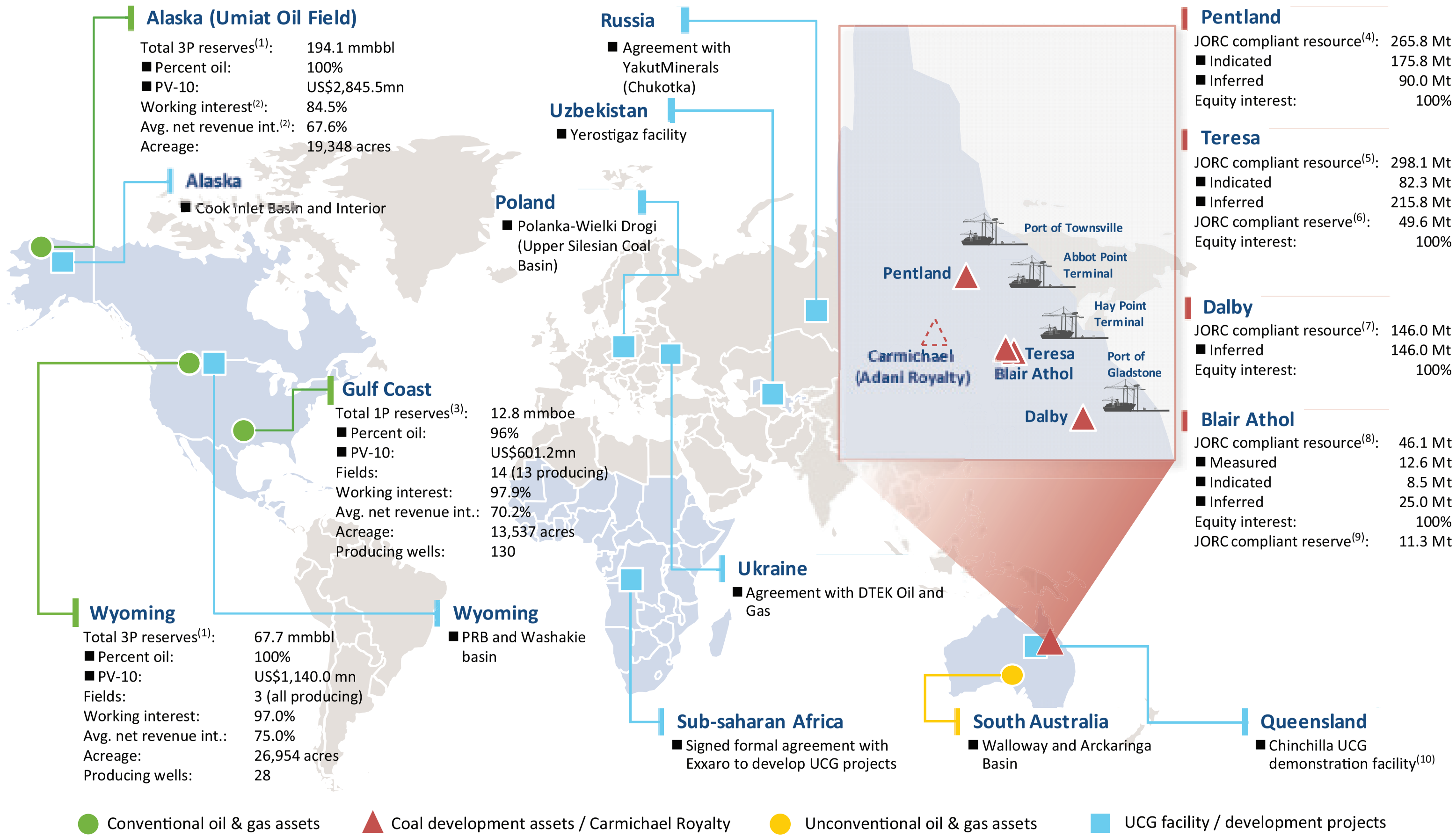
(3) Our coal assets are at various stages of development. For example, we plan to recommence operations at the Blair Athol Mine by June 2014, while the Teresa Project is at the pre-feasibility study stage. See "Business—Coal" of this offering document for further details.

The following diagram illustrates the relationship between our Company and our key subsidiaries as at the Latest Practicable Date. For further details on our complete group structure, please see "Corporate Structure" of this offering document.



See "Appendix H—Our Oil, Gas and Coal Tenements and Leases" of this offering document for further details.

The map below shows the locations of our assets across the world:



Notes:
(1) Ryder Scott Reports
(2) Our wholly-owned subsidiary Linc Alaska Resources LLC owns an 84.5% interest in Renaissance Umiat LLC. Renaissance Umiat holds the entire Working Interest and a 80.0% Net Revenue Interest in our Umiat field in Alaska
(3) Haas Petroleum Report
(4) Pentland Resource Report
(5) Snowden Report and Teresa Resource Report
(6) Snowden Report and Teresa Reserve Report
(7) Dalby Resource Report
(8) Snowden Report and Blair Athol Resource Report
(9) Snowden Report and Blair Athol Reserve Report
(10) We have commenced decommissioning the Chinchilla Demonstration Facility

OUR STRENGTHS

We are a diversified energy company with operating control of a global portfolio of conventional and unconventional oil, gas and coal assets and proven UCG technology ready for commercialisation

We held oil and gas reserves with estimated net 1P reserves totalling 13.6 MMBOE as of 1 September 2013. For the three months ended 30 September 2013, our average gross oil and gas production was 5,010 BOEPD. We operate all our oil, gas and coal assets.

We will be the largest listed independent upstream oil and gas exploration and production company in Singapore and one of the largest in South East Asia, in each case, by proved and probable reserves.

We believe we are also the only company in the world to have successfully demonstrated UCG to GTL and to have produced diesel and jet fuel from UCG syngas. Over the last nine years, we have invested approximately A$210.0 million (US$196.0 million) developing our proprietary UCG technology and, by 2012, we believe we had progressed our UCG technology to the stage of commercialisation.

In addition, we hold total coal resources of 756.0 Mt in accordance with the JORC Code (12.6 Mt measured, 266.6 Mt indicated and 476.8 Mt inferred). We will be the largest Singapore listed coal company by total coal resources.

Our physical asset base, which comprises assets that are all majority owned and operated by us, consists of a geographically and geologically diversified portfolio of conventional oil and gas assets in the Gulf Coast Region, Wyoming and Alaska, unconventional oil and gas assets in, among others, Queensland and South Australia, Australia and Uzbekistan and conventional coal mining assets in Queensland, Australia. Our assets are strategically located in regions near high energy demand centres across Asia Pacific and the United States. Within these regions, each of our assets have been selected through a rigorous evaluation process, based on in-depth knowledge derived from our management team's long-standing experience within the oil, gas and coal sectors.

High quality, low risk, oil levered production with potential significant production upside from assets currently under development and from exploration

We believe our producing oil and gas assets in the Gulf Coast Region are of high quality and relatively low risk, mainly due to their location in one of the world's most well-known oil and gas producing regions that has a long history of oil and gas exploration and production. In addition, our oil and gas assets in the Gulf Coast Region are located within the largest oil and gas market globally, in close proximity to relevant infrastructure and the facilities of various potential off-takers. Furthermore, our net 2P reserves in the Gulf Coast Region consist of more than 95% oil. The oil from our Gulf Coast Region assets is considered high quality due to the fact that we receive LLS pricing, which has historically traded at a premium to WTI prices.

Our growth strategy combines production from existing fields and near-term asset developments complemented by a visible pipeline of mid-term development opportunities and the possibility of significant further upside from exploration in the longer-term.

Since acquisition of our producing oil and gas assets in Wyoming and the Gulf Coast Region in February and October 2011, respectively, we have increased total production by approximately 85% from 2,711 BOEPD (gross) for the quarter ended 31 December 2011 to 5,010 BOEPD (gross) for the quarter ended 30 September 2013. From 1 October 2013 to the Latest Practicable Date, we had an average production rate of 5,858 BOEPD (gross). Our continual near term development drilling will remained focused on the Gulf Coast Region.

Our Umiat field in Alaska has estimated net 2P reserves of 154.6 MMBBL and estimated net 3P reserves of 194.1 MMBBL. Based on estimated OOIP of approximately 1,200 MMBBL, capital expenditure of US$1.8 billion (prior to tax credits receipts from the Alaskan Government) and operating expenditure of US$589 million, we expect to target peak production of 50,000 BOPD (gross) from our Umiat field before 2020.

In Wyoming, we have the potential for significant increases in oil production in the mid-term (between three and five years) utilising a CO_2 EOR project, with potential peak gross production of 10,000 BOPD to 15,000 BOPD, subject to adequate availability of CO_2.

In addition to our conventional oil and gas assets, we also have potential shale oil and gas resources via our 100.0% Working Interest in a rare, large position of approximately 65,000 sq km (16 million acres) of contiguous acreage in South Australia that provides us access to the vast majority of the Arckaringa Basin. Estimated prospective resources for unconventional reservoirs in the Arckaringa Basin are 232.8 BNBOE, and prospective resources for conventional traps are 125.0 BNBOE, on an unrisked best estimate basis. We also estimate gross oil, gas, condensate and solution gas prospective resources of 102,800 MMBOE on the unrisked mean. The various formations within the Arckaringa Basin have excellent shale oil and gas resource with total organic carbon levels, permeability, porosity and thickness comparing favourably to other high volume unconventional shale oil and gas geological basins such as the Eagle Ford and Bakken in the United States.

A leader in UCG technology

We believe we are the only company in the world to have demonstrated UCG to GTL and to have produced diesel and jet fuel from UCG syngas, which provides us with a first mover advantage in the UCG front for the production of valuable and cleaner energy solutions. In addition, we have invested approximately A$210.0 million (US$196.0 million) developing our proprietary UCG technology over the last nine years.

In March 2011, we demonstrated the success of the ultra-clean diesel fuel created from our UCG to GTL technology by driving a diesel engine motor vehicle for more than 5,000 km from our Chinchilla Demonstration Facility to Perth, Western Australia, and in May 2012, our management flew more than 4,200 km over three days across Australia in a jet aircraft powered by our very own Jet A1 fuel created from UCG to GTL technology.

We also own and operate the world's longest running commercial UCG operation in Uzbekistan, which has been in operation for over 50 years. It supplies energy to a nearby power station. In May 2013, we entered into formal agreements to jointly pursue a commercial business developing energy solutions in Sub-Saharan Africa with Exxaro Resources. In addition, we have also entered into a number of opportunity screening studies with resource owners in Asia and North America to evaluate potential commercial UCG opportunities.

Our proprietary UCG technology is protected by intellectual property rights which we endeavour to register globally.

Strategically positioned and equipped to capitalise on robust demand for oil and gas in Asia, and, in particular, the switch from oil and coal to gas in regional markets

Our UCG technology provides a proven, cutting-edge solution for unlocking value in stranded coal deposits, and given the large number of potentially suitable coal resources in Asia, namely in China, Mongolia and Indonesia, we view our proprietary UCG technology to be highly relevant to the growing Asian energy market. In addition, supply constraints in Asia limit the amount of new oil coming on stream relative to demand. GTL technology can take advantage of these supply constraints, delivering to market a suite of UCG derived synthetic liquid fuels and syncrude products.

According to the Industry Consultant, from 2005 to 2012, oil and gas consumption in the Asia-Pacific region increased from 10,804 MMBOE to 13,826 MMBOE, representing a CAGR of 3.6%. This is expected to continue increasing, from 14,343 MMBOE in 2013 to 17,051 MMBOE in 2018. This robust growth in energy consumption is supported by consistent, rapid GDP increase and corresponding power demand. Gas consumption has increased at a CAGR of 7.2% from 2,376 MMCF in 2005 to 3,860 MMCF in 2012. Oil consumption has increased from 8,428 MBOPD in 2005 to 9,966 MBOPD in 2012. Imported thermal coal consumption has increased from 289 Mtpa in 2005 to 667 Mtpa in 2012.

The commercialisation of our UCG technology will allow us to benefit from the robust demand for gas in Asia. UCG syngas and its by-products can be used as feedstock for different downstream processes such as power generation, chemical production, liquid transport fuels, and reformation into substitute natural gas. Additionally, the application of GTL to transform UCG syngas to UCG syncrude can potentially address the oil supply deficit. The production of UCG syngas and its by-products will allow us to take advantage of the increasing demand for energy consumption in Asia.

Contracted royalty stream from Carmichael coal tenement anticipated to provide stable medium to long-term cashflows

The Carmichael coal tenement is one of the largest coal tenements in Australia, located in the Galilee Basin of Queensland. In August 2010, we sold our interests in the Carmichael coal tenement to Adani for A$500.0 million (US$466.8 million) in cash. As part of that transaction, we expect to receive the Carmichael Royalty over coal produced for the first 20 years of production at the Carmichael Project in Queensland, Australia, which Adani, the existing owner and developer of the asset has reported is expected to commence in the first quarter of 2017.

Proven management team with development, operational and technical expertise

Our proven track record over the course of our operating history since 2005 is founded on our experienced management and technical teams, which have significant experience finding, developing and operating oil, gas and coal assets in our focus regions. Our management team has a track record of developing significant projects worldwide and across the oil, gas and coal value chains. Due to our management team's expertise, we have increased production of our oil and gas assets in Wyoming and the Gulf Coast Region by 85% from 2,711 BOEPD (gross) for the quarter ended 31 December 2011 to 5,010 BOEPD (gross) for the quarter ended 30 September 2013 since acquiring them in February 2011 and October 2011, respectively. In addition, our management team has an established base of relationships with domestic and foreign governments, national and international oil companies, service companies and independent oil and gas companies, all of which we believe enhance our competitiveness.

Our management team has focused on cost reduction through efficiency improvement, and maintaining long-term growth in reserves and production through continuing technological innovation. The management team is supported by a global team of 466 employees, which include multiple groups of technical staff, including geological, facilities and engineering and research and development professionals. In addition, our intellectual property rights are managed by a sophisticated intellectual property management plan and an experienced internal intellectual property legal team which ensures protection of our intellectual property and our ability to operate.

OUR STRATEGIES

Accelerate development and commercialisation of existing assets and increase our oil and gas reserves through further exploration

We will seek to fully develop our oil, gas and coal resources, to the extent such development is commercially viable, in order to accelerate and maximise production from our portfolio.

We are currently targeting to increase production to an exit rate of 8,000 to 9,000 BOEPD (gross) by end of December 2013 in the Gulf Coast Region. In addition, our Gulf Coast Region assets, such as Barber Hills, Black Bayou, Hoskins Mound and Port Neches, provide potential for sub-salt oil and gas. To date, we have identified a portfolio of approximately 60 prospects in the Gulf Coast Region. We plan to drill, as an operator, an aggregate of between 50 and 60 exploratory and appraisal wells in the Gulf Coast Region in the next 24 months, depending on drilling results.

We have in place a three-phase development plan for our Umiat field and have completed Phase 1 by drilling the Umiat #18 well and have extracted the core and subjected it to extensive evaluation. The preliminary results from the core analysis indicated good permeability and porosity, robust hydrocarbon geochemical signature, high quality reservoir rock and visible oil readily apparent in the core samples confirming saturation with hydrocarbons. We expect to commence Phase 2 at the end of 2013 which would involve drilling, completion and production testing of one horizontal well and if there is sufficient time, the drilling and testing of an additional well. We expect to commence Phase 3 in the spring of 2014 which would include a full Environmental Impact Statement review, procuring regulatory approvals and the commencement of drilling of up to 70 wells. Assuming success in Phase 2 and 3, we anticipate commencement of production prior to 2020.

In Wyoming, we intend to significantly increase production in the mid-term (between three and five years) via a CO_2 EOR technique, with an anticipated peak gross production of 10,000 to 15,000 BOPD subject to adequate availability of CO_2. We have completed all reservoir modelling, the facilities engineering and design is ongoing and we have completed a pre-feasibility study for a CO_2 pipeline. We are in discussions with several CO_2 suppliers in anticipation of securing a CO_2 pipeline within the next 18 months before a final investment decision is made.

With regard to our Australian shale oil and gas position in the Arckaringa Basin, we intend to enter into a joint venture with a strategic partner at the appropriate time when we believe we can receive the full value of our Australian shale oil and gas position. We intend to further appraise the unconventional oil resource as well as conduct further exploration of the deeper conventional oil potential.

Be a leader in the provision of clean energy through UCG and GTL, whilst deploying UCG technology to penetrate new markets and grow our asset base

Our Clean Energy business strategy is focused on the commercialisation of our proprietary UCG technology, which we have been developing over the last nine years. We are currently pursuing joint ventures with resource owners in Asia and North America for the monetisation of stranded coal assets. Through these strategic partnerships, we intend to acquire an equity participation in the relevant projects. We also plan to enter into licensing agreements with selected partners which will include either all or some of the following: (a) a licensing fee, (b) a royalty fee, (c) carried equity interests and/or (d) consulting and engineering fees.

We intend to continue entering into opportunity screening studies with third parties to evaluate potential commercial UCG opportunities. We undertake these studies for a fee. Upon completion of such studies, if the resource is suitable to be commercialised with our technology, the studies will form the basis of our negotiation for joint ventures for the commercialisation of the resource.

In addition to the formal agreements we signed with DTEK Oil and Gas, Exxaro Resources and LLC YakutMinerals in November 2012, May 2013 and June 2013, respectively, we continue to explore entering into other licence agreements and/or joint venture agreements in strategic locations. We also hold a global portfolio of coal resources acquired specifically to facilitate further development opportunities using our UCG technology.

Grow Asian footprint

According to the Industry Consultant, oil and gas consumption in the Asia Pacific region increased from 10,804 MMBOE to 13,826 MMBOE from 2005 to 2012, representing a CAGR of 3.6%. This is expected to continue increasing on the back of consistent, rapid GDP growth, and corresponding increase in power demand. The domestic gas demand in Asia is also expected to continue to grow, and the commercialisation of our UCG technology will allow us to benefit from the robust demand for gas.

We plan to leverage on our existing UCG technology through joint ventures with strategic partners to develop projects within the region, taking advantage of the region's robust oil and gas demand outlook and the large number of potentially suitable coal resources in Asia, namely in China, Mongolia and Indonesia.

Our technical teams have a deep understanding of the oil and gas and coal mining industries and related complexities, and it is our intention to use this knowledge to identify exploration, appraisal and development opportunities as well as execute projects efficiently and cost effectively in Asia. Furthermore, our management is experienced in building strong working relationships with government agencies and these relationships play an important role in the development of our assets and the acquisition of rights over future oil and gas reserves. To the extent that we enter into joint ventures to develop projects within the region, we intend to open local offices in Asia and recruit leading industry professionals with significant experience and relationships in these markets, while exporting our technical experience and know-how to the region.

Unlock value through strategic portfolio management

In order to maximise value for our Shareholders, we regularly review and evaluate our asset portfolio and engage in strategic portfolio management activities. As part of our portfolio management activities, for example, in August 2010, we sold our interests in the Carmichael coal tenement to Adani for A$500.0 million (US$466.8 million) in cash and we also expect to receive the Carmichael Royalty.

Going forward, we intend to further develop our coal assets and, at the appropriate time, establish a pure-play Australian coal company via a divestment and/or demerger, subject to our Shareholders' approval at an extraordinary general meeting, in 2014 or after. We have taken advantage of the current attractive valuations to make accretive acquisitions in order to increase the value of our coal business prior to any divestment and/or demerger. The acquisition of the Blair Athol Mine is expected to provide stable cash flow, has well-understood mine geology, and requires minimal working capital and as such, carries a low risk profile. Furthermore, our strategy centres around a strong management team with operational and turn-around experience in both underground and open-cut operations, the development of newly acquired and existing conventional coal assets to unlock underlying value, and a strong focus on efficient mining operations and turn-around opportunities. The long term monetisation plan of divesting or demerging the coal assets many include interim financing arrangements, such as the sale of individual assets, to ensure the best long-term outcome for our Shareholders.

Optimise capital base and maintain financial flexibility

We intend to use the net proceeds from the Offering to fund the further exploration, appraisal and development of our asset base, which includes, in respect of our projects in the Gulf Coast Region and Umiat, Alaska, the exploration for sub-salt oil and gas potential which we intend to evaluate by 2014 and the development of the CO_2 EOR project in Wyoming. See "Use of Proceeds". As our some of our assets are developed and mature, we plan to utilise a broader range of financing alternatives and strategies to fund our business plan which will require substantial amounts of additional capital. For instance, given our current average Working Interest of approximately, 97.9%, 97.0% and 84.5%, in our oil and gas assets in the

Gulf Coast Region, Wyoming and Alaska, respectively, we have the option to farm-out a portion of our Working Interests on advantageous terms, including the ability to enter into agreements which allow us to bring in partners to fund a disproportionate share of risk capital. In addition, we also have the option of leasing production infrastructure which has been constructed by third parties from such third parties which would accordingly reduce our capital expenditure. With regards to our coal business, we have the option to enter into strategic partnerships with reputable third parties who, in order to secure an agreement to purchase our coal, may acquire a portion of our Equity Interest in any of our coal projects. In respect of the above, no arrangements have been entered into.

HISTORY

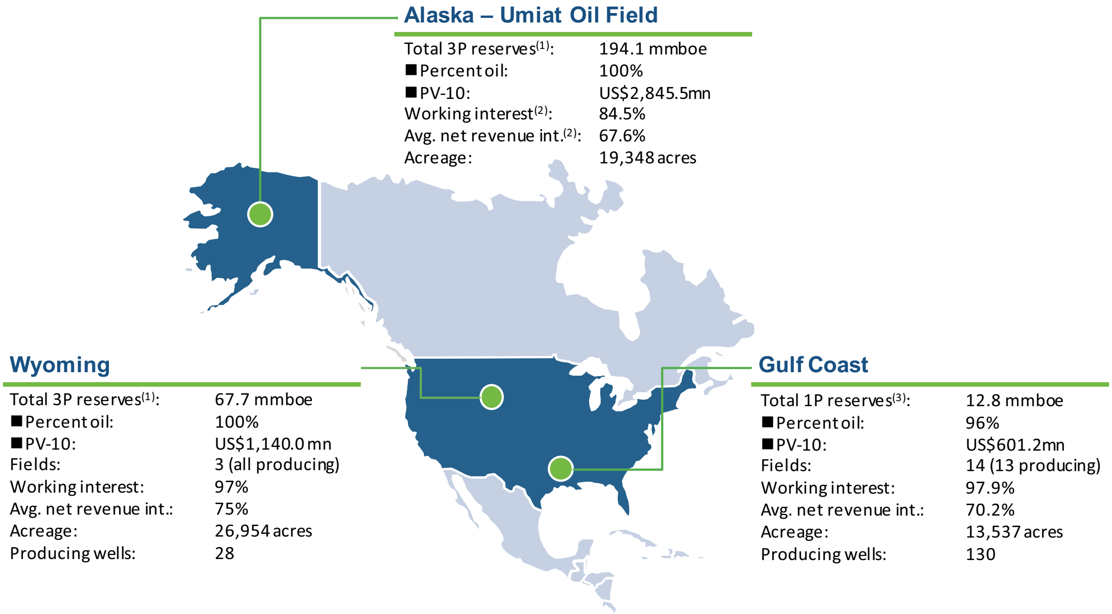
The following are key events in our history and business development:

October 1996	:	Incorporation of our Company (formerly known as Linc Energy N.L.)
July 1999	:	Commenced development of our Chinchilla Demonstration Facility for our Clean Energy business in Queensland, Australia
May 2004	:	Mr. Peter Bond, our Managing Director and Chief Executive Officer, acquired a controlling interest in our Company
August 2004	:	Original exploration tenure over the Carmichael coal asset in Queensland, Australia was granted to us
May 2006	:	Listed on the ASX
October 2007	:	Acquired a controlling interest in Yerostigaz facility in Uzbekistan for our unconventional oil and gas business
October 2008	:	Acquired SAPEX Limited, a South Australia petroleum and gas explorer, through which we gained access to PELs and ELs across the Arckaringa, St Vincent and Walloway Basins in South Australia, Australia
October 2008	:	First production of liquids at our Chinchilla Demonstration Facility through the successful combination of the UCG to GTL processes for our unconventional oil and gas business
September 2009	:	Expanded into the United States through acquisition of coal leases of approximately 372 sq km (92,000 acres) in Powder River Basin in Wyoming, United States for our unconventional oil and gas business
July 2010	:	Acquired oil and gas leases of approximately 494 sq km (122,000 acres) in the Cook Inlet Basin, Alaska for our unconventional oil and gas business
August 2010	:	Sold Carmichael coal tenement in Queensland, Australia to Adani for A$500.0 million (US$466.8 million) and retain payments over production from the Carmichael coal tenement of A$2 per tonne
January 2011	:	Granted approximately 732 sq km (181,000 acres) of UCG coal exploration licences in Alaska
January 2011	:	Incorporated New Emerald Coal Ltd (formerly known as New Emerald Coal Pty Ltd and Teresa Coal Pty Ltd) to operate our conventional coal mining business in Queensland
February 2011	:	Acquired the Glenrock Field, in Wyoming for our conventional oil and gas business
March 2011	:	We demonstrated the success of the ultra-clean diesel fuel created from our UCG to GTL technology by driving a diesel engine motor vehicle for more than 5,000 km from our demonstration facility in Chinchilla, Queensland to Perth, Western Australia

June 2011	:	Commenced drilling the first oil exploration well in the Arckaringa Basin, South Australia for our unconventional oil and gas business
July 2011	:	Acquired Renaissance Alaska LLC (now known as “Linc Alaska Resources, LLC”), which owns an 84.5% interest in Renaissance Umiat LLC. Renaissance Umiat LLC holds the entire Working Interest and a 80.0% Net Revenue Interest in our Umiat field in Alaska
October 2011	:	Acquired our oil and gas assets in the Gulf Coast Region
November 2011	:	Granted coal exploration lease for our Clean Energy business over approximately 214.4 sq km (53,000 acres) in south-eastern part of Upper Silesia Coal Basin, Poland
May 2012	:	Our management flew more than 4,200 km over three days across Australia in a jet aircraft powered by our own Jet A1 fuel created from UCG to GTL technology
June 2012	:	Underwent a corporate restructuring to form the current group structure and separation of business divisions
October 2012	:	Issued the 2017 Senior Secured Notes for the repayment of borrowings, and general corporate purposes
December 2012	:	Commenced drilling of the first exploration well in our Umiat field, Alaska for the winter 2012-2013 drilling programme
March 2013	:	Issued the 2018 Convertible Notes for repayment of borrowings, general corporate purposes and to support key commercialisation of our key assets
May 2013	:	Entered into formal agreements with Exxaro Resources for the development of a commercial UCG project in Sub-Saharan Africa
June 2013	:	Entered into formal agreement with LLC YakutMinerals to jointly evaluate commercial UCG to GTL opportunities in the Chukotka region in north-eastern Russia
October 2013	:	Entered into a sale and purchase agreement to acquire the Blair Athol Mine in Queensland, Australia

OUR CONVENTIONAL OIL AND GAS BUSINESS

Our conventional oil and gas assets are located across three areas in the United States, namely the Gulf Coast Region, Alaska and Wyoming:



Notes:

(1) The Ryder Scott Reports.

(2) Our wholly-owned subsidiary Linc Alaska Resources LLC owns an 84.5% interest in Renaissance Umiat LLC. Renaissance Umiat LLC holds the entire Working Interest and 80% Net Revenue Interest in our Umiat field.

(3) The Haas Petroleum Report.

Our total oil and gas net 1P reserves in the United States was 13.6 MMBOE, consisting of 13.1 MMBBL of oil and 3.0 BCF of gas as of 1 September 2013. Additionally, we had oil and gas net 2P reserves of 168.2 MMBOE, and net 3P reserves of 274.6 MMBOE. Our oil and gas reserve base includes significant undeveloped and exploratory drilling opportunities, which we believe are relatively low risk developments given the historical production from the Gulf Coast Region as well as the significant drill hole data and information we have on the Gulf Coast Region assets. See section titled "Business—Our Reserves—Our Conventional Oil and Gas Reserves" for further information.

Production within our Conventional Oil and Gas Assets

Our producing assets are located in the Gulf Coast Region and Wyoming, which we acquired in October 2011 and February 2011, respectively. The following table sets forth our gross and net production from each of the regions for the financial years ended 30 June 2011, 2012, 2013 and the three months ending 30 September 2013.

	FY2011		FY2012		FY2013		For the three months ended 30 September 2013	
Location	**Gross (MBOE)**	**Net Revenue Interest(1) (MBOE)**	**Gross (MBOE)**	**Net Revenue Interest(1) (MBOE)**	**Gross (MBOE)**	**Net Revenue Interest(1) (MBOE)**	**Gross (MBOE)**	**Net Revenue Interest(1) (MBOE)**
Gulf Coast Region(2)	-	-	694.4	519.0	1,489.5	1,113.3	443.7	338.7
Wyoming(3)	26.4	18.4	88.3	61.6	62.8	43.8	17.2	12.4
Total	**26.4**	**18.4**	**782.7**	**580.6**	**1,552.3**	**1,157.2**	**460.9**	**351.1**

Notes:

(1) Our average Net Revenue Interest in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest, if any, on petroleum under the relevant licence or lease, all royalty burdens and interests owned by others have been deducted.

(2) The total production and sales volume from our assets in the Gulf Coast Region are calculated from October 2011 when we acquired the relevant assets.
(3) The total production and sales volume from our assets in Wyoming are calculated from February 2011 when we acquired the relevant assets.

Drilling and Data Acquisition

As part of our exploration and development process in our assets in the Gulf Coast Region, Wyoming and Alaska, we participate in the acquisition of geological data relating to our petroleum licences and the drilling of exploration and appraisal wells, as well as development wells. The following table summarises our exploration and drilling activities for the financial years ended 30 June 2011, 2012, 2013 and the three months ending 30 September 2013.

Wells	FY2011	FY2012	FY2013	For the three months ended 30 September 2013
Exploration and appraisal wells	-	1	1	-
Development wells	-	14	29	13
Data acquisition				
3D seismic data (area in sq km)	-	176.5	45.5	-

The number of exploration and development wells we participate in drilling and the amount of seismic data acquisition we participate in acquiring in any particular year varies based upon the status of our projects and the availability of equipment and government and joint-venture approval, and no such trend should be inferred from the annual changes in our drilling and data acquisition activity. As at 30 September 2013, we are drilling three development wells in the Gulf Coast Region.

Gulf Coast Region

Description of the assets

We operate 14 fields in Texas and Louisiana, of which 13 are in production, through our wholly-owned subsidiary. These fields lie within the onshore Gulf Coast Region and inland waters regions with a total area of approximately 57.6 sq km (13,537 Working Interest acres) spread across numerous oil and gas leases. Our key fields in these regions include Barber Hills, Black Bayou, High Island, Atkinson Island, Cedar Point, Hoskins Mound and Port Neches. All of the fields are either salt domes or geological structures related to deep-seated salt movement, which have been a significant source of the domestic oil production in the United States. With the appropriate application of available technologies, we have been able to increase its extraction and production from these features. Certain of our Gulf Coast Region assets, such as Barber Hills, Black Bayou, Hoskins Mound and Port Neches, provide potential for sub-salt oil and gas and we intend to undertake evaluation of such potential plays by 2014.

The following map illustrates the location of our assets in the Gulf Coast Region:

Reserves

Based on the Haas Petroleum Report, our estimated net 1P oil and gas reserves in the Gulf Coast Region were approximately 12.8 MMBOE, approximately 96% of which were oil reserves. Our estimated 2P oil and gas reserves were approximately 12.9 MMBOE. The following table sets forth certain details of our oil and gas reserves in the Gulf Coast Region as at 1 September 2013 which has been extracted from the Haas Petroleum Report:

	Gross attributable to Licence	Net Revenue Interest(1)	
	(MMBBL)	(MMBBL)	Change from previous update (%)
Oil Reserves			
1P	16.3	12.3	N/A
2P	16.3	12.4	N/A
3P	-	-	N/A
Gas Reserves	**(BCF)**	**(BCF)**	
1P	11.3	3.0	N/A
2P	11.5	3.2	N/A
3P	-	-	N/A

Note:

(1) Our average Net Revenue Interest in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest, if any, on petroleum under the relevant licence or lease, all royalty burdens and interests owned by others have been deducted.

In particular, the following table sets forth further details of our proved and probable reserves from our oil fields in the Gulf Coast Region as at 20 September 2013 which has been extracted from the Haas Petroleum Report.

Reserves category	Oil (MMBBLs)	Gas (BCF)	Total (MMBOE)
Proved Developed			
Producing	2.8	0.2	2.9
Non-producing	4.8	1.0	4.9
Shut-in	-	-	-
Total Proved Developed	7.6	1.3	7.9
Undeveloped	4.7	1.7	5.0
Total Proved	**12.3**	**3.0**	**12.8**
Probable Undeveloped	0.1	0.2	0.1
Total Probable	**0.1**	**0.2**	**0.1**
Grand Total	**12.4**	**3.2**	**12.9**

Further details of our 1P and 2P reserves from our key oil fields in the Gulf Coast Region as at 1 September 2013 which has been extracted from the Haas Petroleum Report are also set out below.

	Working Interest Area(1) (acres)	Working Interest(2) (%)	Average Net Revenue Interest(3) (%)	1P Reserves (MBOE)	1P Reserves % Oil	1P Reserves %PDP	1P Reserves PV-10 (US$'000)	2P Reserves (MBOE)	2P Reserves % Oil	2P Reserves %PDP	2P Reserves PV-10 (US$'000)
Texas											
Barbers Hill	1,302	100.0	78	5,547	100	9	228,093	5,547	100	9	228,093
Black Bayou	2,435	100.0	65	161	100	35	7,813	161	100	35	7,813
High Island	826	100.0	74	1,249	100	20	57,969	1,249	100	20	57,969
Atkinson Island / Cedar Point	1,280	100.0	57.8	3,751	90	38	236,970	3,817	90	37	237,232
Hoskins Mound	2,500	100.0	73	700	73	6	18,760	700	73	6	18,760
Port Neches	3,202	100.0	83	312	98	16	16,151	312	98	16	16,151
Others	1,992	85.3	60.8	1,116	99	73	35,408	1,182	99	73	35,408
Total / Average	13,537	97.9	70.2	12,835	96	22	601,164	12,967	96	22	601,426

Notes:

(1) Our Working Interest Area refers to our Working Interest multiplied by gross area.

(2) Our Working Interest in respect of our conventional and unconventional oil and gas assets means an interest in an oil and gas lease that does not take into account the terms of any royalties, government shares of production or similar fiscal terms, and thus do not reflect net entitlement to any oil or gas produced.
(3) Our average Net Revenue Interest in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest, if any, on petroleum under the relevant licence or lease, all royalty burdens and interests owned by others have been deducted.

Background

The fields in the Gulf Coast Region have over 80 years of development and production history. We purchased the Gulf Coast Region assets from ERG Resources L.L.C. ("**ERG**") in October 2011, in which we acquired oil and gas leases, property interests (including all related infrastructure such as pipelines, tank batteries and processing facilities) and wells (including shut-ins) upon Gulf Coast Region oil fields which were held directly by ERG and its subsidiaries. As all the fields exhibit multiple stacked pay sands, on-going development is a mix of recompletion of behind pipe opportunities and drilling new wells into previously unexploited or up-dip reservoir compartments.

Drilling, Development and Production

As at 30 September 2013, we had 130 producing wells in the Gulf Coast Region. Our gross oil and gas production was 443.7 MBOE for the three months ended 30 September 2013 and our average daily production for the same period was 4,822 BOEPD (gross). Our gross production of oil and gas in the past three financial years and the three months ending 30 September 2013 is as follows:

Operating data	FY2011	FY2012[1]	FY2013	For the three months ended 30 September 2013
Sales volumes				
Oil (MBBLs)	-	684.5	1,485.6	397.7
Gas (MMCF)	-	59.0	23.5	275.9
Total (MBOE)	-	694.4	1,489.5	443.7
Average daily production (BOEPD)	-	2,534	4,081	4,822

Note:
(1) The Gulf Coast Region assets in production for 274 days.

From 1 October 2013 to the Latest Practicable Date, we had an average production rate of 5,858 BOEPD (gross).

Since our acquisition of the Gulf Coast assets, the majority of our drilling and recompletion activity has been in our Barbers Hill Field. The wells drilled in Barbers Hill generally have multiple producing horizons which set up multiple low cost recompletion opportunities. The wells provide robust economics, but individual reservoirs are relatively small in size (1-2 acres) and exhibit steep initial declines. During the three months ended 30 September 2013, we drilled 13 wells and completed eight of those well. The remaining four wells are awaiting completion, with the final well temporarily abandoned for future sidetrack opportunity. Eight of these 13 wells were drilled at our Barbers Hill Field, and the remaining five wells at Cedar Point. We also recompleted seven existing wells during the three months ended 30 September 2013.

During the past 18 months, we have acquired 3D Seismic data over our Cedar Point, Atkinson Island, Barbers Hill, Port Neches, High Island, and Black Bayou fields. We have also undertaken an extensive seismic reprocessing programme across our data. This process enhances the data imaging beyond its original quality and allows our Geoscientists to better interpret the seismic data and to calibrate it to historical well data. As a result of the 3D Seismic reprocessing data, we have generated a significant sub-salt prospect which we intend to undertake evaluation of by 2014. In addition, we are assessing an extension recompletion programme in our Port Neches field which is expected to commence on or around January 2014.

The first field where we have applied this newly reprocessed data is our Cedar Point Field, which is located in Galveston Bay near Houston, Texas. Cedar Point Field was a historically prolific field with producing horizons in three distinct geologic ages: Vicksburg, Frio, and Miocene. We have encountered reservoirs at depths of up to 7,500 feet, in all three producing horizons. Minimal historical drilling at depths beyond 7,500 feet has been undertaken. The wells have substantiated our seismic interpretation with reservoir sizes ranging from 25 to 50 acres which translates to much shallower declines than our Barbers Hill wells. This will result in stable production over a longer period of time. Our two initial completions had good results. The first well exhibited initial production rates of 400 BOPD and 3.3 MMCF of gas per day, with the second testing at 435 BOPD and 3.1 MMCF of gas per day. The other six wells are in various stages of completion. The number of wells and expected production ramp-up has required an upgrade to our facilities and pipeline system which we are currently undertaking. We are currently completing an additional vertical well and a second horizontal well in the field, which will conclude our seasonal drilling programme in Cedar Point until the spring of 2014. As at the Latest Practicable Date, we had initiated production on nine new Cedar Point wells and performed two recompletions in the field, and we are currently drilling an additional Cedar Point horizontal well.

We believe that the Cedar Point field has mean 1P reserve potential of 2.9 MMBOE of oil and gas as at 1 September 2013. We continue to analyse and interpret our reprocessed 3D seismic data over Atkinson Island, High Island and Black Bayou seeking similar opportunities to enhance production. We expect deeper drilling potential at the Yegua, Hackberry and Wilcox formations.

Sales and marketing

We sell our oil and gas to third-party purchasers such as Shell Trading (US) Company under contracts with prices based on market indices, adjusted for location, quality and transportation. The contracts entered into with Shell Trading (US) Company are on a fixed term basis of one a year and continue thereafter on a monthly evergreen basis.

Interests

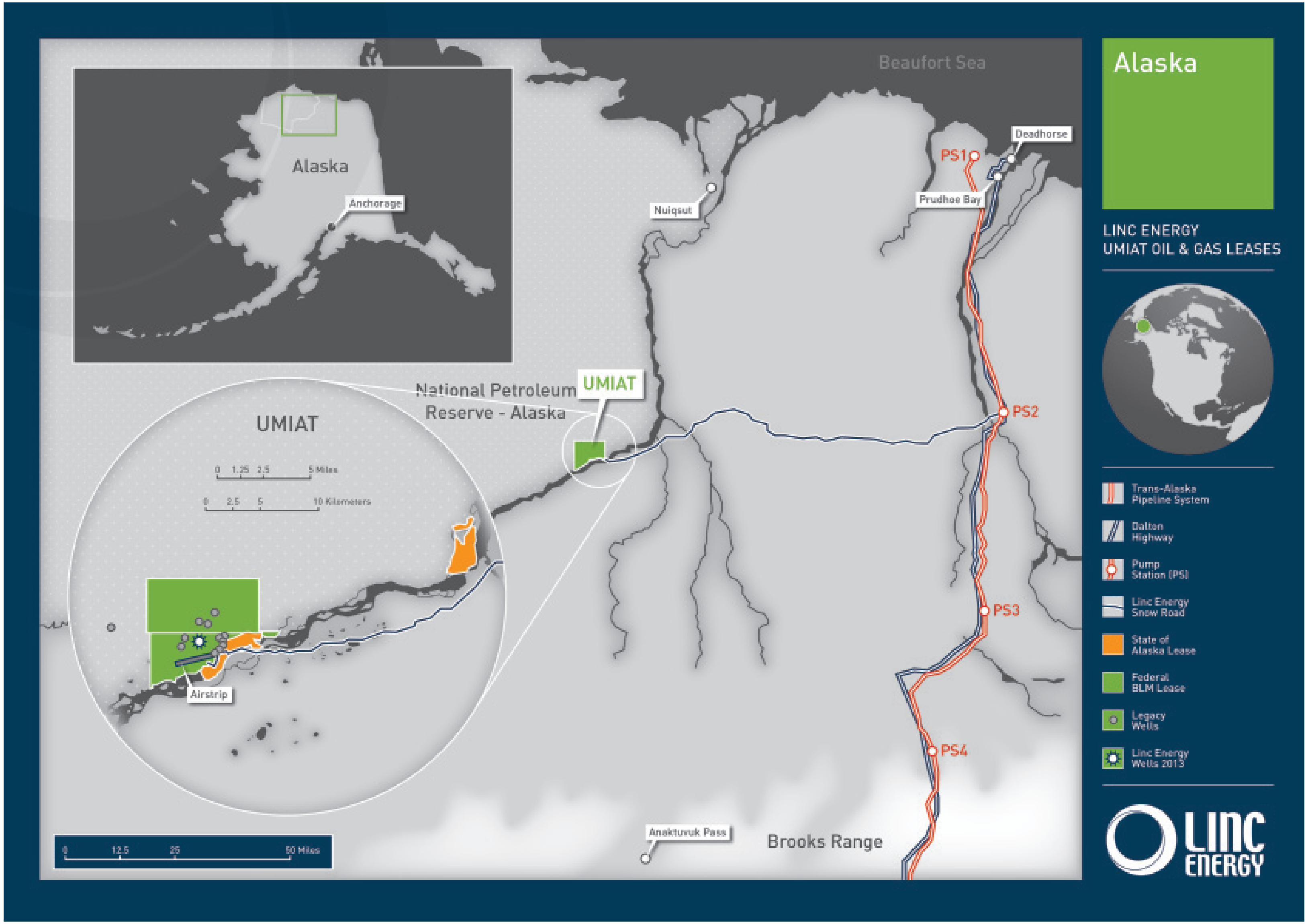
We have an average Working Interest of approximately 97.9% and an approximate average Net Revenue Interest of 70.2% in our assets in the Gulf Coast Region. We are also the operator for all of our assets in the Gulf Coast Region.

Alaska

Description of the asset

Our Umiat field, which covers approximately 78 sq km (19,348 Working Interest acres) spread across three oil and gas leases. It is located in the south-eastern portion of the National Petroleum Reserve of Alaska on the central part of the Alaskan North Slope on the leading edge of the Brooks Range Fold Belt. It is north of the Arctic circle and approximately 92 miles due west of the Trans-Alaskan Pipeline System ("**TAPS**") and is considered to be one of the largest undeveloped conventional petroleum resources in North America. Our interests in our Umiat field are held through Renaissance Umiat, LLC. We hold 84.5% of the shares in Renaissance Umiat, LLC. In addition to our interest in Umiat field, Alaska, we also own Angel Unit which is located at the Matanuska-Susitna Borough in Alaska.

The following map illustrates the location of the Umiat field in Alaska:



Reserves

Based on the Ryder Scott Alaska Report, the Umiat field consists of approximately 154.6 MMBOE of probable and 39.5 MMBOE of possible conventional oil reserves. The following table sets forth certain details of our oil reserves in Alaska as at 1 September 2013 which has been extracted from the Ryder Scott Alaska Report.

	Gross attributable to Licence	Net Revenue Interest[(1)]	
	(MMBBL)	(MMBBL)	Change from previous update (%)
Oil Reserves			
1P	-	-	N/A
2P	193	154.6	N/A
3P	243	194.1	N/A

Note:

(1) Our Net Revenue Interest in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest, if any, on petroleum under the relevant licence or lease, all royalty burdens and interests owned by others have been deducted.

The following table sets forth further details of the Umiat field in Alaska as at 1 September 2013 which has been extracted from the Ryder Scott Alaska Report.

	Working Interest Area[(1)] (acres)	Working Interest[(2)] (%)	Average Net Revenue Interest[(3)] (%)	2P Reserves (MBBL)	2P Reserves % Oil	2P Reserves %PDP	2P Reserves PV-10 (US$'000)	3P Reserves (MBBL)	3P Reserves % Oil	3P Reserves %PDP	3P Reserves PV-10 (US$'000)
Umiat field	19,348	84.5[(4)]	67.6	154,562.8	100.0	-	2,465,333	194,057.1	100	-	2,845,477

Notes:

(1) Our Working Interest Area refers to our Working Interest multiplied by gross area.

(2) Our wholly-owned subsidiary Linc Alaska Resources LLC owns an 84.5% interest in Renaissance Umiat LLC. Renaissance Umiat LLC holds the entire Working Interest and a 80.0% Net Revenue Interest in our Umiat field in Alaska. Our Working Interest in respect of our conventional and unconventional oil and gas assets means an interest in an oil and gas lease that does not take into account the terms of any royalties, government shares of production or similar fiscal terms, and thus do not reflect net entitlement to any oil or gas produced.

(3) Our wholly-owned subsidiary Linc Alaska Resources LLC owns an 84.5% interest in Renaissance Umiat LLC. Renaissance Umiat LLC holds the entire Working Interest and a 80.0% Net Revenue Interest in our Umiat field in Alaska. Our Net Revenue Interest in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest, if any, on petroleum under the relevant licence or lease, all royalty burdens and interests owned by others have been deducted.

(4) The remaining minority Working Interest in these wells is owned by Arctic Falcon.

Background

The Umiat reservoirs were discovered by the United States Navy in the mid-1940s as part of the exploration of land known as the National Petroleum Reserve in Alaska and adjacent areas. A total of 12 "legacy wells" were drilled within the field between 1944 and 1979. We acquired our interests in the Umiat field in July 2011 through our acquisition of our now wholly-owned subsidiary, Linc Alaska Resources, LLC, and we concluded our initial winter appraisal programme at the Umiat field in the first three months of 2013. Linc Alaska Resources, LLC, owns 84.5% of Renaissance Umiat, LLC, and thus has 84.5% Working Interest in the Umiat field. That was the first drilling at the Umiat field since 1979 and the first time modern arctic drilling techniques and horizontal drilling was applied to the Umiat field.

Pursuant to the Alaskan Government's exploration and development incentive programmes to encourage the active exploration and timely development of Alaska's oil and gas resources, we have obtained capital cost rebates for expenditures incurred to 30 June 2013. In August 2013, we sold our rights to receive rebates from the Alaskan Government to a third party on competitive terms, and we used the proceeds to fund oil and gas costs in Alaska and the Gulf Coast Region. We may, in future, also consider selling our rights to rebates as a potential funding option to fund future development costs in respect of our Umiat asset. We may also seek to obtain potential infrastructure financing for pipelines and roads from various sources such as the Alaska Industrial Development and Export Authority. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors affecting our results of operations—Exploration and development activities" for further details.

Drilling and Development

Based on Ryder Scott's estimation on OOIP of approximately 1,200 MMBBL, capital expenditure of US$1.8 billion (prior to tax credits receipts from the Alaskan Government) and operating expenditure of US$589 million, we expect to target peak production of 50,000 BOPD gross from the Umiat field before 2020. We have in place a three-phase development plan, which includes extensive environmental studies and regulatory compliance initiatives that will help reconfirm and delineate the reserve potential of the Umiat field and prepare the property for future production. Generally, prior to an approved development plan, drilling and development activity at the Umiat field in Alaska can only be conducted during winter. Accordingly, during the exploration phase before the approval of the development plan is obtained and production begins, activities are also restricted to winter which is approximately six to eight months of the year. After an approved development plan is in place, permanent infield infrastructure can be put in place allowing activities to be conducted all year round.

We have completed the first phase of the development plan. Prior to commencing our winter drilling programme in December 2012, we completed the construction of a 100 mile snow-packed access road to facilitate transportation for the project.

In early 2013, we completed Phase 1 of our drilling and development plan by drilling the Umiat #18 to the core point of 710 ft. (216m), logged with Logging While Drilling (LWD) tools, and extracted a 300 ft. (91.5m) conventional core through the entire Lower Grandstand (LGS) formation with 100% recovery. The core was transported in a frozen state to Houston, Texas where it has gone through extensive evaluation.

Preliminary results from the core analysis have been received and indicate:

- good permeability and porosity—permeability and porosity analyses reveal good 16 – 18% porosity, 70-270 millidarcies air permeability in the main reservoir sands. For the light crude (37° API gravity) found at Umiat, these are outstanding rock properties;

- robust hydrocarbon geochemical signature confirmed;

- 98% of the sandstones are shallow marine, indicative of high quality reservoir rock;

- Visible oil is readily apparent in the core samples under ultraviolet light, confirming that the Lower Grandstand reservoir is completely saturated with hydrocarbons.

Additionally, we commenced our environmental data acquisition for our Environmental Impact Study ("**EIS**") which is required for our eventual Development Plan to be submitted to the Bureau of Land Management ("**BLM**") which is the lead United States federal agency for the Umiat Project.

We will construct a snow road of approximately 100 miles, from Dalton Highway to Umiat to support winter operations of approximately 100 miles in Phase 2, which we expect will commence in late 2013. Concurrent to this construction, Kuukpik #5 will also be mobilised from Seabee pad to the 23H drilling pad. The drilling rig is currently stacked on location as is the required equipment and supplies allowing for commencement of an earlier drilling season this winter. In-field ice roads will be constructed concurrently with the snow road, allowing movement of the rig to the 23H drilling pad. The proposed minimum programme will include the drilling, completion, and production testing of two horizontal wells (23H and 25H). After the completion of the 23H drilling pad, if there is sufficient time remaining in the Alaska winter drilling season, the drilling rig may be moved to an additional location to drill and test the

24H horizontal well in a similar fashion to the 23H drilling pad. The completion and flow rate testing of a horizontal well is critical in proving the economic viability of the development.

Following the completion of Phase 2, Phase 3, commencing in spring 2014, will include a full Environmental Impact Statement review, application for certain master plan approvals, construction of roads and pipelines, receipt of relevant air permit, facilities construction, the commencement of development drilling of up to 70 wells, and entering into Trans-Alaska Pipeline System tie-in facility. Phase 3 capital expenditure relates to the total project costs to enable delivery of oil into the TAPS. We currently estimate total project costs to be in the range of US$1.3 billion to US$1.5 billion. We have performed initial scoping on production facilities at Umiat to develop the field infrastructure. We expect to finalise these plans after completing the current drilling programme and after we have a better understanding of our reservoir parameters. Assuming success, we are anticipating commencing production prior to 2020.

Interests

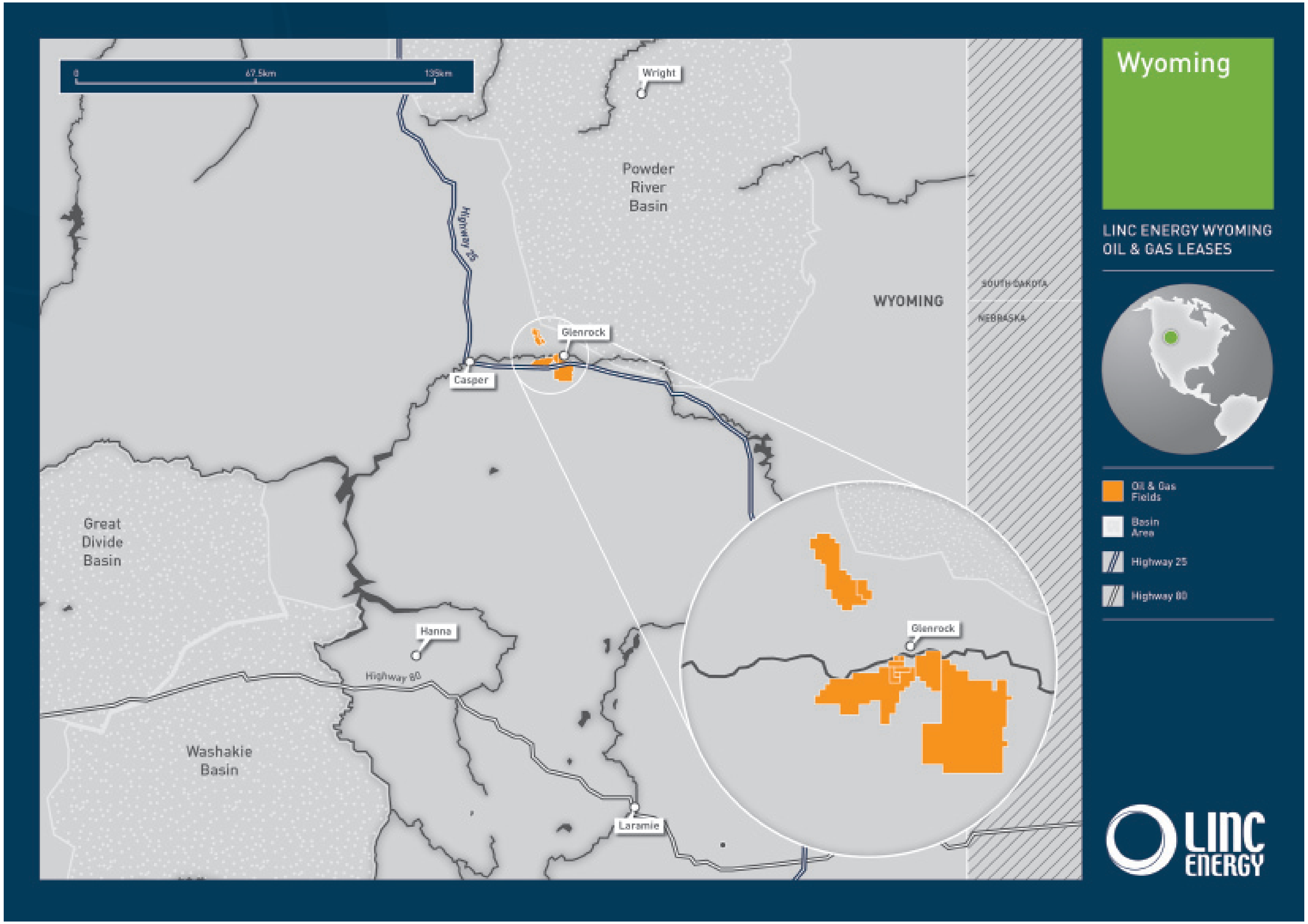
Our subsidiary Linc Alaska Resources LLC owns an 84.5% interest in Renaissance Umiat LLC. Renaissance Umiat LLC holds the entire Working Interest and a 80% Net Revenue Interest in Umiat field, Alaska. We are also the operator of all of our assets in Alaska.

Wyoming

Description of the assets

We operate three fields in Wyoming, namely Big Muddy field, the South Glenrock (A and B Units75) field and the South Cole Creek field, all of which are in production through our wholly-owned subsidiary. These fields are located in the Powder River Basin, approximately 15 miles east of Casper, Wyoming. The total area of these three fields is approximately 109.1 sq km (26,954 Working Interest acres) spread across numerous oil and gas leases which are currently held by production.

The following map illustrates the location of our assets in Wyoming:



Reserves

Our Wyoming assets consist of approximately 0.77 MMBBL of proved net reserves and 66.9 MMBBL of possible net reserves based on the Ryder Scott Wyoming Report. The following table sets forth certain details of our oil reserves in Wyoming as at 31 August 2013 which has been extracted from the Ryder Scott Wyoming Report.

	Gross attributable to Licence	Net Revenue Interest[(1)]	
	(MMBBL)	(MMBBL)	Change from previous update (%)
Oil Reserves			
1P	1.0	0.8	N/A
2P	1.0	0.8	N/A
3P	90.3	67.7	N/A

Note:

(1) Our Net Revenue Interest in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest, if any, on petroleum under the relevant licence or lease, all royalty burdens and interests owned by others have been deducted.

In particular, the following table sets forth further details of our proved and possible reserves from our oil fields in Wyoming as at 31 August 2013 which has been extracted from the Ryder Scott Wyoming Report.

Reserves category	Oil (MMBBL)	Gas (MCF)	Total (MBOE)
Proved Developed			
Producing	0.8	-	0.8
Non-producing	-	-	-
Shut-in	-	-	-
Total Proved Developed	0.8	-	0.8
Undeveloped	-	-	-
Total Proved	**0.8**	**-**	**0.8**
Total Possible	**66.9**	**-**	**66.9**
Grand Total	**67.7**	**-**	**67.7**

The following table sets forth details of our key oil fields in Wyoming as at 31 August 2013 which the economic and reserve data has been extracted from the Ryder Scott Wyoming Report.

	Working Interest Area[(1)] (acres)	Working Interest[(2)] (%)	Average Net Revenue Interest[(3)] (%)	1P Reserves (MBOE)	1P Reserves % Oil	1P Reserves %PDP	1P Reserves PV-10 (US$'000)	3P Reserves (MBOE)	3P Reserves % Oil	3P Reserves %PDP	3P Reserves PV-10 (US$'000)
Big Muddy field	7,950	100.0	77	92	100.0	100	1,744	36,450	100	-	743,163
South Glenrock field	13,071	95.0	74	511	100.0	100	8,596	31,046	100	-	393,811
South Cole Creek field	5,933	100.0	77	163	100.0	100	3,030	163	100	-	3,030
Total / Average	**26,954**	**97.0**	**75**	**766**	**100.0**	**100**	**13,370**	**67,658**	**100**	**-**	**1,140,004**

Notes:

(1) Our Working Interest Area refers to our Working Interest multiplied by gross area.

(2) Our Working Interest in respect of our conventional and unconventional oil and gas assets means an interest in an oil and gas lease that does not take into account the terms of any royalties, government shares of production or similar fiscal terms, and thus do not reflect net entitlement to any oil or gas produced.

(3) Our Net Revenue Interest in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest, if any, on petroleum under the relevant licence or lease, all royalty burdens and interests owned by others have been deducted.

Background

Big Muddy field, South Glenrock field and South Cole Creek field were respectively discovered in 1917, 1950 and 1948. Our fields in Wyoming have an estimated OOIP of approximately 466.6 MMBBL. Each of Big Muddy field, South Glenrock field and South Cole Creek field has OOIP of approximately 255 MMBBL, 170 MMBBL and 42 MMBBL, respectively, and three fields have produced approximately 146.6 MMBBL of oil throughout primary and secondary production. We acquired our Wyoming assets in March 2011 from Rancher Energy Corp., a Nevada corporation. Our acquisition was approved by the United States Bankruptcy Court on 24 February 2011.

Drilling, Development and Production

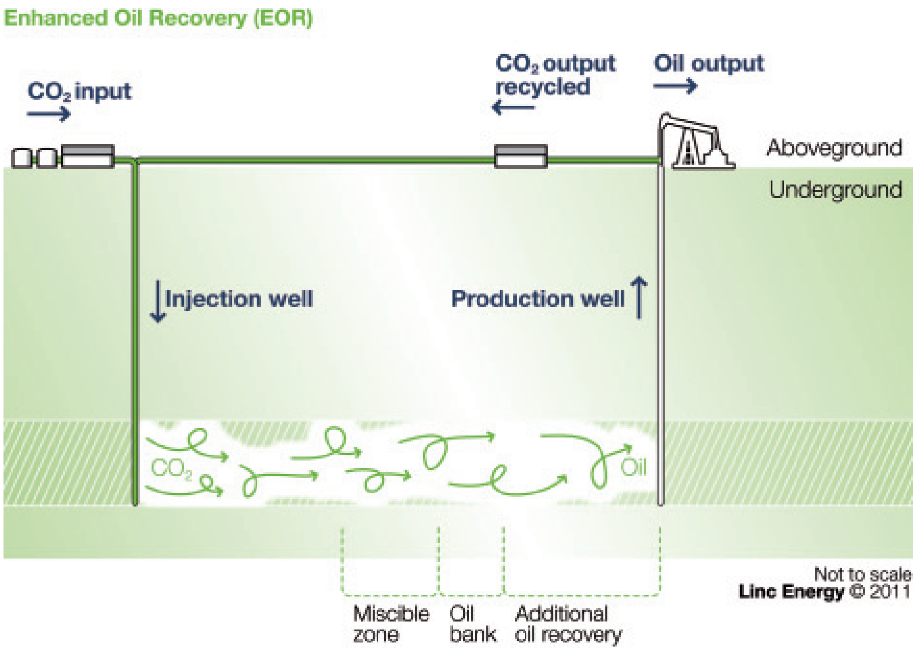
As at 30 September 2013, we had 30 producing wells in Wyoming. Our gross oil production was approximately 17.2 MBOE for the three months ended 30 September 2013 and our average daily gross production for the same period was 187 BOPD. These fields have the potential to increase recoverable oil by approximately 80 MMBBLs (gross) from EOR techniques utilising CO_2 flooding operations. Our gross production of oil and gas in the past three financial years and the three months ended 30 September 2013 is as follows:

Operating data:	**FY2011[(1)]**	**FY2012**	**FY2013**	**For the three months ended 30 September 2013**
Sales volumes:				
Oil (MBBLs)	26.4	88.3	62.8	17.2
Gas (MMCF)	-	-	-	-
Total (MBOE)	26.4	88.3	62.8	17.2
Average daily production (BOPD)	216	241	172	187

Note:

(1) Based on 122 days of production.

EOR involves the injection of a fluid into an established oil reservoir to extract as much oil, if not more, from the preceding production phases. The fluid we will use in the application of the EOR process will be CO_2. This is considered one of the best options as it acts as a solvent to sweep the majority of the remaining oil to the surface. We have completed reservoir modelling, the facilities engineering and design is ongoing and we have completed a pre-feasibility study for a CO_2 pipeline. Evaluations are taking place to determine the feasibility of using new 3D seismic studies for conventional exploitation at our South Cole Creek field. The diagram below illustrates the EOR process:



See "Business—Intellectual Property—Patents" on the list of patents we have to protect our EOR technology.

Our Wyoming EOR Project will ultimately include CO_2 injection into four distinct reservoirs associated with producing units. These are indicated below with estimated recoverable oil reserves:

Reservoirs	Fields	(MMBBL)
Dakota	South Glenrock B Unit	19.7
Upper Muddy	South Glenrock B Unit	6.0
Lower Muddy	South Glenrock B Unit	8.1
Frontier	Big Muddy River Unit	47.4

We have completed reservoir modelling studies with Nitec Engineering and have also commenced facilities engineering and completed a pre-feasibility study of CO_2 pipeline routes. We have entered into an agreement with Exxon-Mobil to provide up to 25 MMCF/D of CO_2 on an interruptible basis. Additionally, we are in discussions with several other CO_2 suppliers in anticipation of securing a CO_2 pipeline within the next 18 months before a final investment decision is made. We intend to finalise the commercialisation strategy for the EOR project by the first quarter of 2014.

The project will consist of multiple phases of injecting CO_2 into new or existing injection wells while producing from new or existing producers. The full field development is still in its planning phase. The plan is ultimately dependent on timing amount of available CO_2.

Sales and marketing

We sell our oil to third-party purchasers such as Enterprise Crude Oil LLC and our gas to third-party purchasers such as Enterprise Products Operating LLC under contracts with prices based on market indices, adjusted for location, quality and transportation. We have a month-to-month contract with both Enterprise Crude Oil LLC and Enterprise Products Operating LLC which is terminable by either party upon 30 days' notice.

Interests

We have an average Working Interest of 97.0% and an average Net Revenue Interest of 75.0% in our assets in Wyoming. We are the operator on all our assets in Wyoming.

OUR UNCONVENTIONAL OIL AND GAS BUSINESS

Our unconventional oil and gas division comprises two distinct businesses:

(a) the Clean Energy business in various locations such as Brisbane, Chinchilla in Queensland, Poland, South Africa and Uzbekistan; and

(b) the SAPEX business, in the Arckaringa Basin in South Australia.

Clean Energy

Our Clean Energy business is focused on the commercialisation of our proprietary UCG technology, which we have been developing over the last nine years. There is abundant deep and stranded coal which, based on existing technology and infrastructure, is currently not economic or unsafe to mine. We have the ability to carry out the UCG to GTL process, and we believe we are the only company in the world to have produced diesel and jet fuel from UCG syngas. In March 2011, we demonstrated the success of the ultra-clean diesel fuel created from our UCG to GTL technology by driving a diesel engine motor vehicle for more than 5,000 km from our demonstration facility in Chinchilla, Queensland to Perth, Western Australia. Subsequent to that, our management flew more than 4,200 km over three days across Australia in a jet aircraft powered by our own Jet A1 fuel created from UCG to GTL technology in May 2012. Production of our UCG syngas has enabled us to produce valuable and cleaner energy solutions, such as power generation, fuel production and petrochemical processes.

The UCG process

UCG is the process of gasifying coal in-situ, that is, where it lies under the ground to produce UCG syngas, which includes hydrogen (H_2), carbon monoxide (CO) and methane (CH_4) and other gases. This process enables us to access 'stranded' coal and eliminates the need for mining coal in a conventional sense and processing it through a surface gasification plant. The UCG process can be broadly broken into the following four steps:

(1) Well construction and linkage: Wells are drilled into the coal to allow for injection of air or oxygen and production gas extraction. Concrete and steel lining is added to the well to ensure isolation from any groundwater. The wells are linked and are extended to form an in-seam channel to facilitate injection of air or oxygen, cavity development and UCG syngas flow.

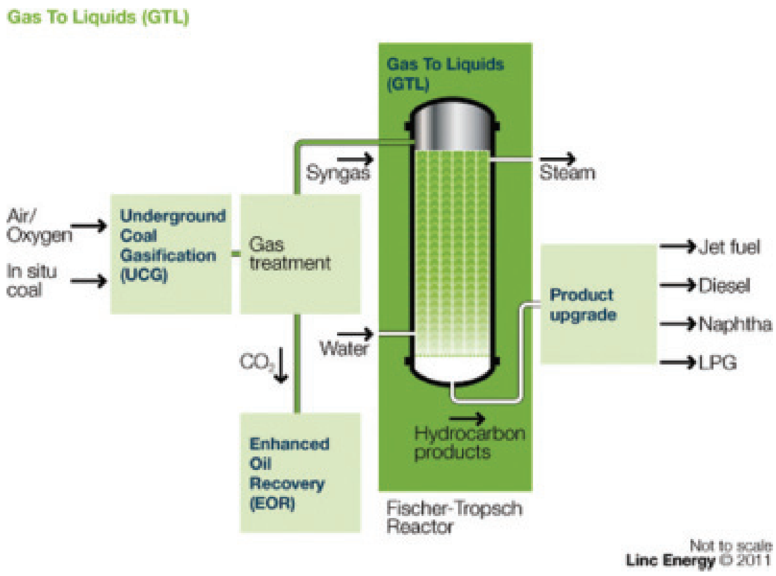
(2) Ignition: The coal seam is dried and then ignited at ignition points along the in-seam horizontal channel using proprietary down-well ignition tools.

(3) Gas production: UCG syngas is produced through combustion and gasification reactions. Combustion produces heat, CO_2 and some UCG syngas (through partial combustion). Following which, gasification reactions then take place, involving heat and CO_2 from combustion, pressure, steam and carbon from the coal. The UCG syngas then flows from the gasification zone, through constructed or formed horizontal channels to the gas production well where it flows to the surface for treatment.

(4) Decommissioning: Once all the available coal has been extracted as a gaseous product, the gasification process is shut down according to known and demonstrated shut down procedures.

The diagram below illustrates the overview process of UCG process.

We are able to convert UCG syngas into synthetic crude ("**syncrude**"), using traditional gas treatment and the Fischer-Tropsch GTL synthesis process. Produced syncrude can then be refined using traditional methods to produce cleaner diesel and jet fuels. The diagram below illustrates the UCG to GTL process:



See "Business—Technology, Research and Development" and "Business—Intellectual Property" on our research development as well as our intellectual property in respect of our UCG and GTL processes. Research is currently in progress on producing synthetic unleaded petrol.

UCG syngas is a form of cleaner fuel. UCG syngas and by-products can be used as feedstock for different downstream processes, including power generation, conversion into liquid transportation fuels, chemical feedstock, enhanced oil recovery, reformed into synthetic natural gas.

Development of our proprietary technology

Chinchilla Demonstration Facility

We have a long history in UCG. We first operated our Chinchilla Demonstration Facility, which is located 300 km west of Brisbane, Australia, in July 1999 for the purposes of converting UCG syngas to liquid fuels. Since then, we made improvements to our gasifiers. Beginning with our first generation gasifiers which utilised linked vertical wells, our gasifiers progressed to be able to utilise a single horizontal well method. We commenced operations at our fifth generation gasifier in October 2011 and has in November 2013 announced plans to decommission after completing two continuous years of operations.

In September 2013, we also commenced work on decommissioning of our third generation gasifier ("**G3**") which operated for 12 months between August 2008 and August 2009. This is in-line with the recommendations of the Queensland Government's Independent Scientific Panel ("**ISP**") report issued in June 2013. Under the decommissioning plan, we will collect a variety of samples and direct measurements from within the gasifiers and around them. The data collected from the G3 works will be used to confirm the condition of the gasification cavity after the cool down and the shutdown process in order to finalise any further decommissioning activities which may be required. This will also assist in informing the ISP that the shutdown process of UCG is safe and reasonable. Prior to this, we have also previously successfully managed the shutdown of four of our UCG gasifiers.

Our Chinchilla Demonstration Facility has UCG trial generators and a GTL pilot plant, and is the only UCG to GTL demonstration facility operating in the world. This GTL demonstration facility was commissioned in 2008 to demonstrate the integration of liquid fuel production with the UCG technology. Our Chinchilla Demonstration Facility allowed us to conduct further research and development to optimise and facilitate the next phase of UCG and GTL technology commercialisation. In addition, being a demonstration facility means the facility had been designed to validate the operation of key technology blocks using UCG produced syngas, including primary gas cleaning, sulphur removal, hydrogen and carbon monoxide control of the syngas and Fisher Tropsch synthesis. Subsequent to the decommissioning of the Chinchilla Demonstration Facility, we intend to move our UCG operations elsewhere and to continue to focus on the commercialisation of our UCG technology. See "Business—Technology, Research and Development" for further information on the amount of research and development that has been carried out.

Yerostigaz Facility

We hold a 91.6% controlling interest in and operate the Yerostigaz facility in Angren, Uzbekistan, which we believe is the world's longest running commercial UCG operation, having been in operations for over 50 years, and which supplies energy to a nearby power station. The remaining minority interests are held by other unrelated third parties comprising the management of the Yerostigaz facility. The Angren Power Station commits to purchase all of the UCG syngas produced by us. Correspondingly, we are under a contractual obligation to supply a minimum volume of 350 million m^3 of gas annually.

Wyoming

On or about 30 August 2013, we received official notification from the Wyoming Department of Environmental Quality that our licence application for a UCG demonstration project was complete and ready for public notice of 30 days to be followed by a 30-day public comments period. An objection was filed by Powder River Basin Resource Council on 21 October 2013 and pursuant to this objection, the Wyoming Environmental Quality Council heard the matter on 14 November 2013 and 15 November 2013, whereby approval of the license was given. We expect to be awarded with the licence permitting us to have an UCG demonstration facility in Powder River Basin, Wyoming. As such licence will allow us the option to either commission or delay the commencement of the UCG demonstration facility, we can make the investment decision based on the commercial justification at the relevant point in time.

Other potential coal interests for UCG

We also hold the following interests which have been earmarked for UCG:

Assets' Location	Gross Area (sq km)/(acres)	Status
Poland	216.0 / 53,374	Exploration
Uzbekistan	4.1 / 1,000	Exploration
Alaska	679.5 / 167,917	Exploration
Wyoming	730.1 / 180,651	Exploration
Arckaringa, Eromanga, Cooper and Walloway Basins	84,477.0 / 21,121,826	Exploration

We intend to assess whether these coal assets are suitable for the application of our UCG technology. The main factors to consider for a UCG site are:

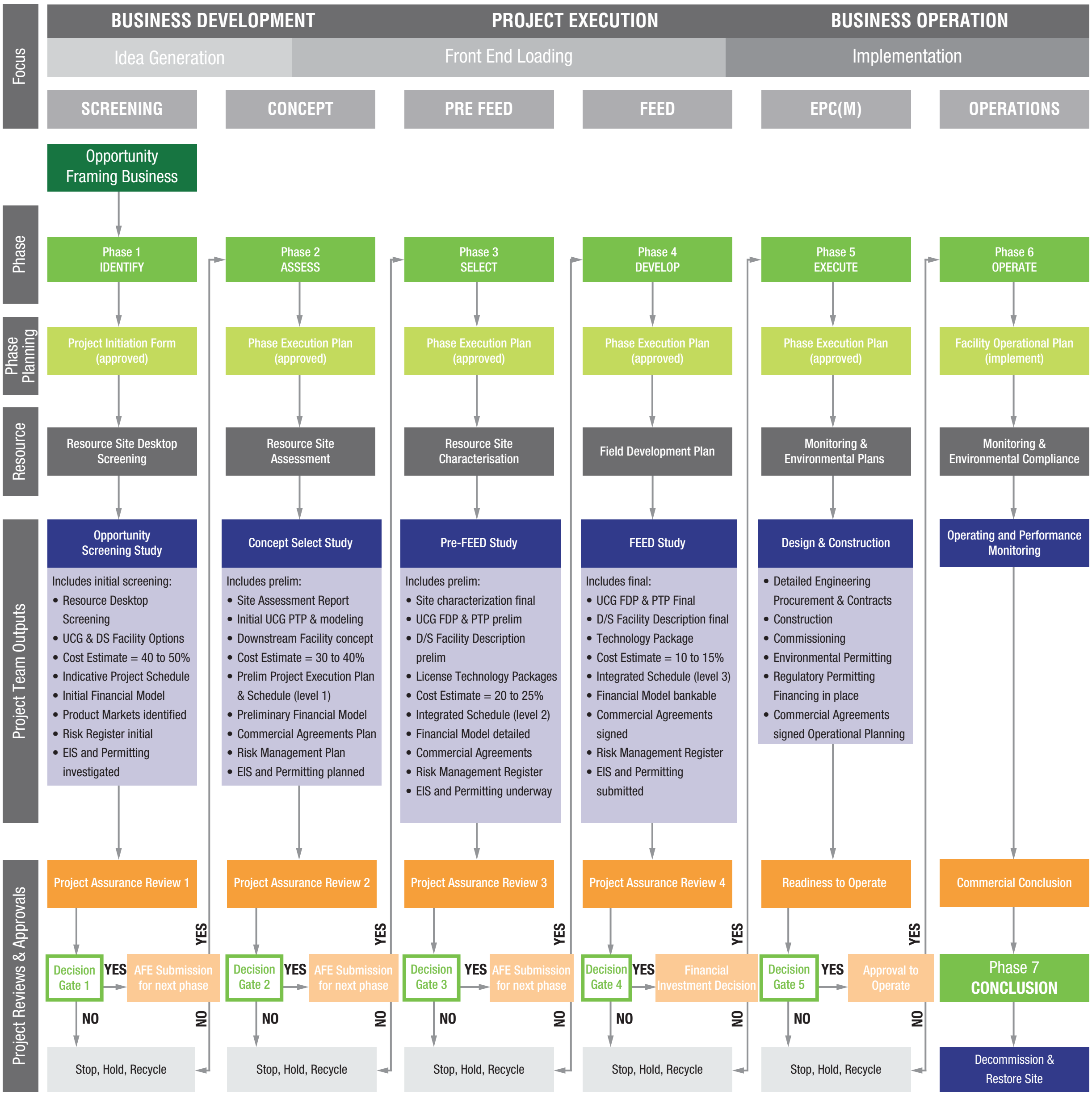
(a) the chemical nature, structure, depth and thickness of the coal seam;

(b) hydrogeology, in particular, the groundwater which supplies water for gasification reactions, and the amount of hydrostatic pressure needed to contain the UCG process; and

(c) geology, whereby good structure and low permeability of rock immediately overlying the coal is favourable to limit subsidence and provide a seal between the coal and overlying strata.

Our experienced UCG team allows us to, among others, understand the geology and coal chemistry to predict the suitability of particular locations and coals for UCG, understand the hydrogeological systems, including groundwater flow and balance around the UCG generator and develop and protect core UCG technologies and technical intellectual property. See “Business—Intellectual Property—Patents” on the list of patents we have to protect our proprietary UCG technology.

In order to make an initial assessment of the coal resource for UCG purposes, to identify and validate the Clean Energy business opportunity and identify key risks and opportunities we would begin with a desktop screening study of the coal geology, and undertake initial technical and economic analysis before commencing the development roadmap as set out below:



An example of a UCG site we are currently drilling at is in Spytkowice, Poland, where we hold our coal exploration lease and have completed Phase 1 of our exploration commitments. Our lease covers a land area of approximately 216 sq km (53,374 acres). We are also meeting with government officials from Poland with a view to commercialising UCG in Poland. Clarity of legislative and concession related matters are also under discussion with the relevant officials from the Ministries of Environment and Economy. Concurrent with these discussions, we have commenced discussion with a number of prospective partners with regard to an agreement to purchase UCG syngas from future commercial projects.

Commercialisation of our UCG technology

Apart from developing projects on our coal assets, we also intend to commercialise our UCG technology through strategic partnerships to acquire an equity participation in the relevant projects. We also plan to enter into licensing agreements with selected partners which will include either all or some of the following: (a) licensing fees, (b) royalty fees, (c) carried equity interests and (d) consulting and engineering fees.

In addition, to advance the commercialisation of our UCG technology, we intend to introduce modular UCG gasifiers. The modular UCG gasifiers will, among others, be designed to fit into a shipping container and the facilities will also be able to function appropriately despite a full range of anticipated site operating conditions. Accordingly, this would facilitate the mobilisation process and the facility can be assembled efficiently upon delivery to the site.

On 30 May 2013, we entered into formal agreements with Exxaro Resources to jointly pursue UCG as a commercial business to develop energy solutions in Sub-Saharan Africa.

The licence agreement with Exxaro Resources grants them a non-exclusive right to use our UCG technology in Sub-Saharan Africa. A total licence fee of A$30.0 million (US$28.0 million), of which A$3.0 million (US$2.8 million) has been paid on signing of the initial term sheet, is payable. The next payment of A$20.0 million (US$18.7 million) will be made once all the condition precedents contained with the agreement are satisfied. Currently, only one of such conditions, which relates to the extension of prospecting rights over the current area of interest for this project, remains outstanding. The balance of A$7.0 million (US$6.5 million) is payable on the completion of the performance testing of the first project, which is currently targeted for 2017. In addition to these licence fees, we will receive a royalty for the UCG syngas produced and sold. We will also provide engineering services in support of our licence agreement.

The bankable feasibility study to support the initial project will be completed by mid 2015 with commissioning of the first gasifier scheduled mid 2016. We will hold a minimum 15.0% equity interest in this project and have an option to participate up to a 49.0% equity interest in this, as well as all subsequent UCG projects which Exxaro Resources develops.

From time to time, we also enter into opportunity screening studies with resource owners and we are currently exploring opportunities in areas including Asia and North America to evaluate whether their resources are suitable for commercialisation with our UCG technology. We undertake these studies for a fee. Upon completion of such studies, if the resource is suitable to be commercialised with our technology, the studies will form the basis of our negotiation for joint ventures for the commercialisation of the resource. For example, we had entered into agreements with LLC YakutMinerals and DTEK Oil and Gas on 19 June 2013 and 30 November 2012, respectively.

We signed a letter of intent and services agreement with LLC YakutMinerals, an affiliate of Ervington Investments Ltd, to evaluate and progress the development and to assess the potential of deploying our UCG technology on the coal resources at Chukotka in north eastern Russia. The letter of intent between us and LLC YakutMinerals outlines a set of principles which will guide future discussions on the negotiation of final commercial terms regarding the commercialisation of our UCG technology and integrated downstream applications, including GTL, in partnership with LLC YakutMinerals. Under the services agreement, LLC YakutMinerals will accordingly fund the initial resources screening and opportunity assessment study.

We entered into an agreement with DTEK Oil and Gas for the collaboration and evaluation of the underground UCG potential in Ukraine in relation to their local coal resources. Pursuant to which, DTEK Oil and Gas has agreed to pay us for an initial resource assessment. If a coal resource suitable for UCG commercialisation is identified, we intend to co-operate to bring a UCG gas project to commercial fruition in Ukraine over the next few years.

SAPEX

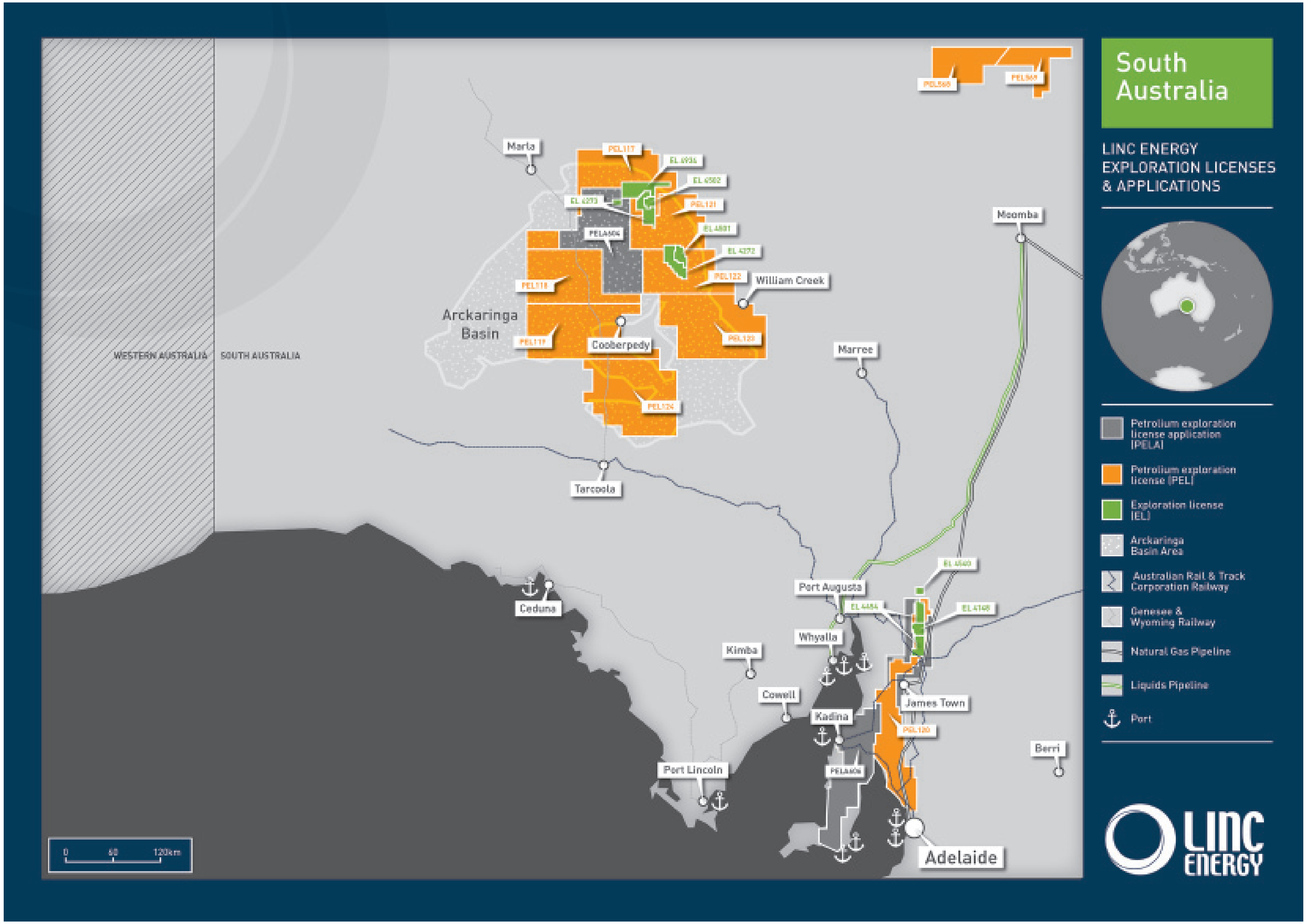
Description of the assets

Our shale oil and gas business consists primarily of our Arckaringa Basin assets held through our wholly-owned subsidiary, SAPEX Limited, that was acquired in October 2008. We have eight long-term petroleum exploration licences ("**PELs**") being PEL 117, PEL 118, PEL 119, PEL 121, PEL 122, PEL 123, PEL 124 and PEL 5319 in the Arckaringa Basin.

We hold 100% of the exploration rights in our PELs which cover a contiguous area of approximately 65,000 sq km (16 million acres). This is approximately 80% of the geographical area of the Arckaringa Basin of approximately 80,000 sq km (20 million acres). The Arckaringa Basin is largely unexplored. It is located in the state of South Australia, and is 500 miles to the north west of Adelaide and 1,300 miles south of Darwin.

It is flat terrain, with no surface restrictions for infrastructure development. There is existing road access to both Darwin and Adelaide and ready access to adequate water supply from natural and shallow aquifers, which is required for fracturing. There are numerous ports which could potentially be utilised in order to market the resource to international offtake markets. The Adelaide to Darwin railway line runs directly through our western tenements providing the potential for shale oil and gas to be transported to the ports via this railway. There is also an existing airport at Coober Pedy which could be utilised to support our operations.

The following map illustrates the location of our PELs and PELA in the Arckaringa Basin:



In addition to the various PELs in the Arckaringa Basin, we also hold PELs, PELA and exploration licenses (“**ELs**”) in the Stansbury and Walloway Basins in the coastal area north of Adelaide, South Australia and in the Eromanga Basin in the north-eastern part of South Australia.

Resources

The DeGolyer and MacNaughton Report and the Gustavson Report presents estimates of the potential hydrocarbon prospective resources of certain sections of the Arckaringa Basin. Specifically, the Stuart Range formation and the underlying Boorthanna and Pre-Permian formations have kerogen that may form the basis of a new liquids-rich shale operation. Shale oil and gas extraction utilises new technologies to drill vertically and then horizontally for distances of more than 1 kilometre through shale rocks that contain oil. The findings in these reports lends support to our view that the various formations within the Arckaringa Basin have excellent shale oil resource-play potential. Furthermore, in our view, the Stuart Range, Boorthanna and Pre-Permian formations, the total organic carbon levels, permeability, porosity and thickness compare favourably to other high-volume unconventional shale oil plays such as the Eagle Ford and Bakken in the United States.

The following table sets forth a summary of our prospective resources quantities in relation to our shale oil assets as at 15 September 2013 based on the statistical aggregation method, which has been extracted from the DeGolyer and MacNaughton Report.

	Gross attributable to Licence	Net attributable to Issuer	
			Change from previous update (%)
Unrisked Prospective Resources			
Oil	(MMBBL)	(MMBBL)	
Low estimate	14,358	14,358	N/A
Best estimate	20,915	20,915	N/A
High estimate	30,468	30,468	N/A
Mean	21,836	21,836	N/A
Gas	(TCF)	(BCF)	
Low estimate	166.8	166.8	N/A
Best estimate	244.8	244.8	N/A
High estimate	386.5	386.5	N/A
Mean	261.9	261.9	N/A
Condensate	(MMBBL)	(MMBBL)	
Low estimate	16,693	16,693	N/A
Best estimate	30,578	30,578	N/A
High estimate	56,018	56,018	N/A
Mean	34,187	34,187	N/A
Solution Gas	(TCF)	(BCF)	
Low estimate	9.1	9.1	N/A
Best estimate	16.8	16.8	N/A
High estimate	30.7	30.7	N/A
Mean	18.7	18.7	N/A
Risked Mean Prospective Resources(1)			
Oil **(MMBBL)**	516	516	N/A
Gas **(TCF)**	9.9	9.9	N/A
Condensate **(MMBBL)**	1,263	1,263	N/A
Solution Gas **(TCF)**	0.5	0.5	N/A

Note:

(1) The probability of discovering reservoirs that flow petroleum at a measurable rate, has been applied resulting in the risked mean quantities. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

DeGolyer and MacNaughton estimated gross prospective oil, gas, condensate and solution gas prospective resources for various licences as of 15 September 2013 in the Arckaringa Basin. We have utilised these quantities in our estimate of 102,800 MMBOE based on the unrisked mean.

The following table sets forth a summary of the prospective resources quantities in relation to our unconventional shale oil assets as at 15 August 2013 which has been extracted from the Gustavson Report.

	Gross attributable to Licence	Net attributable to Issuer	
	(MMBBL)	(MMBBL)	Change from previous update (%)
Unrisked Prospective Resources			
Oil(1)			
Low estimate	86,697	86,697	N/A
Best estimate	232,832	232,832	N/A
High estimate	515,217	515,217	N/A

Note:

(1) Figures in respect of unrisked prospective resources in unconventional reservoirs in the Arckaringa Basin.

In addition to the analysis on the shale oil potential of the Arckaringa Basin, Gustavson Associates also analysed the conventional hydrocarbon structures in the pre-Permian strata of parts of the Arckaringa Basin. The following table sets forth a summary of our resources profile in relation to this potential at 15 August 2013 which has been extracted from the Gustavson Report.

	Gross attributable to Licence	Net attributable to Issuer	
	(MMBBL)	(MMBBL)	Change from previous update (%)
Unrisked Prospective Resources			
Oil			
Low estimate	59,383	59,383	N/A
Best estimate	124,997	124,997	N/A
High estimate	258,356	258,356	N/A

Background

Prior to our acquisition in October 2008, the previous owners of Arckaringa Basin were focused on conventional oil and gas. In 2010, oil was discovered in Maglia-1 and in 2011, subsequent geotechnical analysis of organically rich cores recovered from the Arck-1 and Wirrangula Hill-1 wells signalled potential for commercially viable deposits of shale oil and gas. We believe that in January 2013, independent reports from DeGolyer and MacNaughton and Gustavson Associates confirm the potential for significant hydrocarbon prospective resources in certain sections of the Arckaringa Basin.

Drilling, Development and Production

We have been working on detailed plans for the next phase of field work, which will focus on identifying the most favourable parts of the Arckaringa Basin for commercial development of unconventional oil. Drilling, core sampling, and seismic work are planned for FY2014 field season. Production testing will also be carried out on all zones where moveable hydrocarbons are encountered. Specialised technical analysis and evaluation is required to access and produce the hydrocarbons contained within these organically rich marine shale deposits.

Strategy

We retained the services of Barclays Bank PLC to assist in the identification of potential investors who might be well suited for working with us in a joint venture or other commercial arrangement for the further delineation and commercial development of the Arckaringa Basin. The most important objective of this investigation is to define the course of action resulting in the maximum benefit for Shareholders. As of the Last Practicable Date, we continue to evaluate our options in this regard.

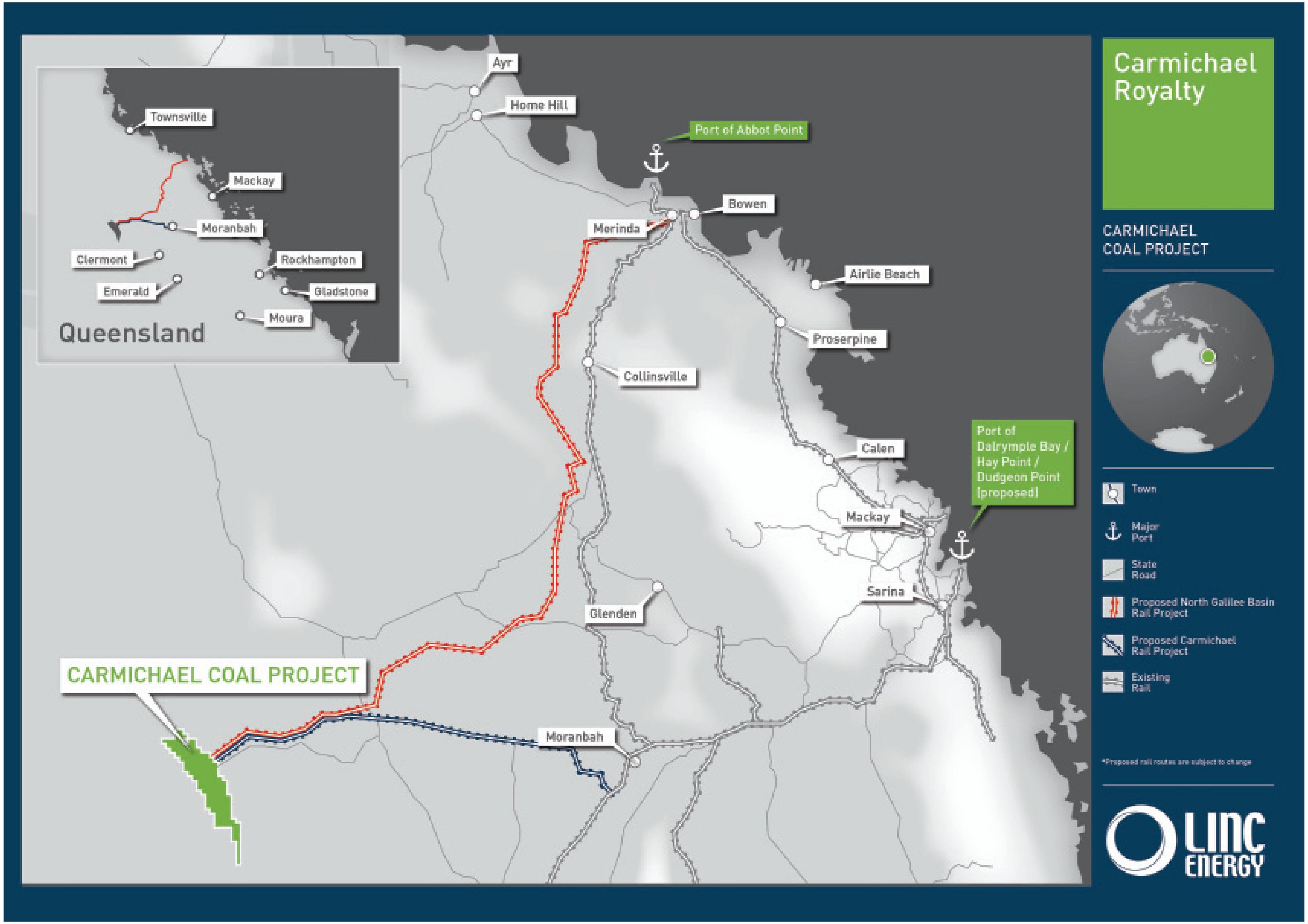
OUR COAL BUSINESS

Carmichael Royalty

The Carmichael coal tenement is one of the largest coal tenements in Australia, and is located in the Galilee Basin of Queensland, Australia. It is approximately 160 km north-west of Clermont. In August 2010, we sold our interests in the Carmichael coal tenement to Adani for A$500.0 million (US$466.8 million). Pursuant to the terms of the sale, we will also receive the Carmichael Royalty, being payments of A$2 per tonne (indexed to the Consumer Price Index (Brisbane) All Groups number) of coal for the first 20 years of production from the date of first production. Adani, the existing owner and developer of the asset has reported that it is expecting to commence production in the first quarter of 2017.

To date, Adani has invested over A$2.0 billion (US$1.9 billion) in their Australian operations, and achieved a number of important milestones such as the completion of a substantial portion of in-fill drilling and studies on the Carmichael tenements, the acquisition of Moray Down Cattle property in 2011, securing port access options, commencement and submission of the environmental impact statement for the mine, the acquisition of Terminal One at the Port of Abbot Point from the Queensland State Government for A$1.83 billion (US$1.7 billion) with rights to investigate feasibility of expansion, and the purchase of freehold surface land over a substantial portion of the mine site and along the proposed rail corridor. Adani was also awarded preferred developer status for the greenfield expansion of the Port of Hay Point at Mackay in Queensland. According to information available on the Queensland Government's Department of State Development, Infrastructure and Planning, as at the Latest Practicable Date, Adani has filed its Environmental Impact Statement report which states that Adani is proposing to develop a 60 Mtpa thermal coal mine. This is a key milestone in the awarding of a mining lease. Rail options include the coal being railed via a privately-owned narrow gauge rail line connecting to the existing QR National rail infrastructure near Moranbah or directly to the Port of Abbot Point via a privately-owned standard gauge rail line, and shipped through coal terminal facilities at the Port of Abbot Point and/or the Port of Hay Point (Dudgeon Point expansion). The mine would be a greenfield coal mine which includes both open cut and underground mining, on mine infrastructure and associated mine processing facilities and offsite infrastructure. It is expected that the mine would have an operating life of approximately 90 years.

The following map sets out the location of the Carmichael coal project:



Conventional Coal Mining

Our conventional coal mining business is principally focused on acquiring, operating and developing conventional coal mining assets in Australia. We intend to divest and/or demerge our conventional coal mining assets, and are considering several options such as an initial public offering, demerger, sale of assets or a combination with other assets, in 2014 or after.

In October 2013, we entered into a sale and purchase agreement to acquire the Blair Athol Mine from an unrelated third party joint venture consisting of Queensland Coal Pty Limited, Leichhardt Coal Pty Limited, J-Power Australia Pty Ltd and J.C.D Australia Pty Ltd. (collectively, the "**Blair Athol Joint Venture Party**"). We expect to recommence mining operations at the Blair Athol Mine by June 2014. We also have a number of mining projects at the development stage including the Teresa Project, the Pentland Project and the Dalby Project. In addition to these, we also hold interests in several exploration assets located in Queensland. Our conventional coal mining assets consists of (i) one mining lease ("**ML**"), (ii) one mineral development lease ("**MDL**") (iii) 27 exploration permits for coal ("**EPCs**") representing over 11,515 sq km (28,454,679 acres) of exploration and mining tenure in Queensland's known coal basins, (iv) two mining lease applications ("**MLas**"), (v) one mineral development Lease application ("**MDLa**") and (vi) one petroleum lease application ("**PLa**"). This PLa was necessary for the purpose of mine gas drainage purposes. This represents 756.0 Mt of JORC Resources (12.6 Mt measured, 266.6 Mt Indicated, 476.8 Mt Inferred) based on the Snowden Report, the Blair Athol Resource Report, the Teresa Resource Report, the Dalby Resource Report and the Pentland Resource Report.

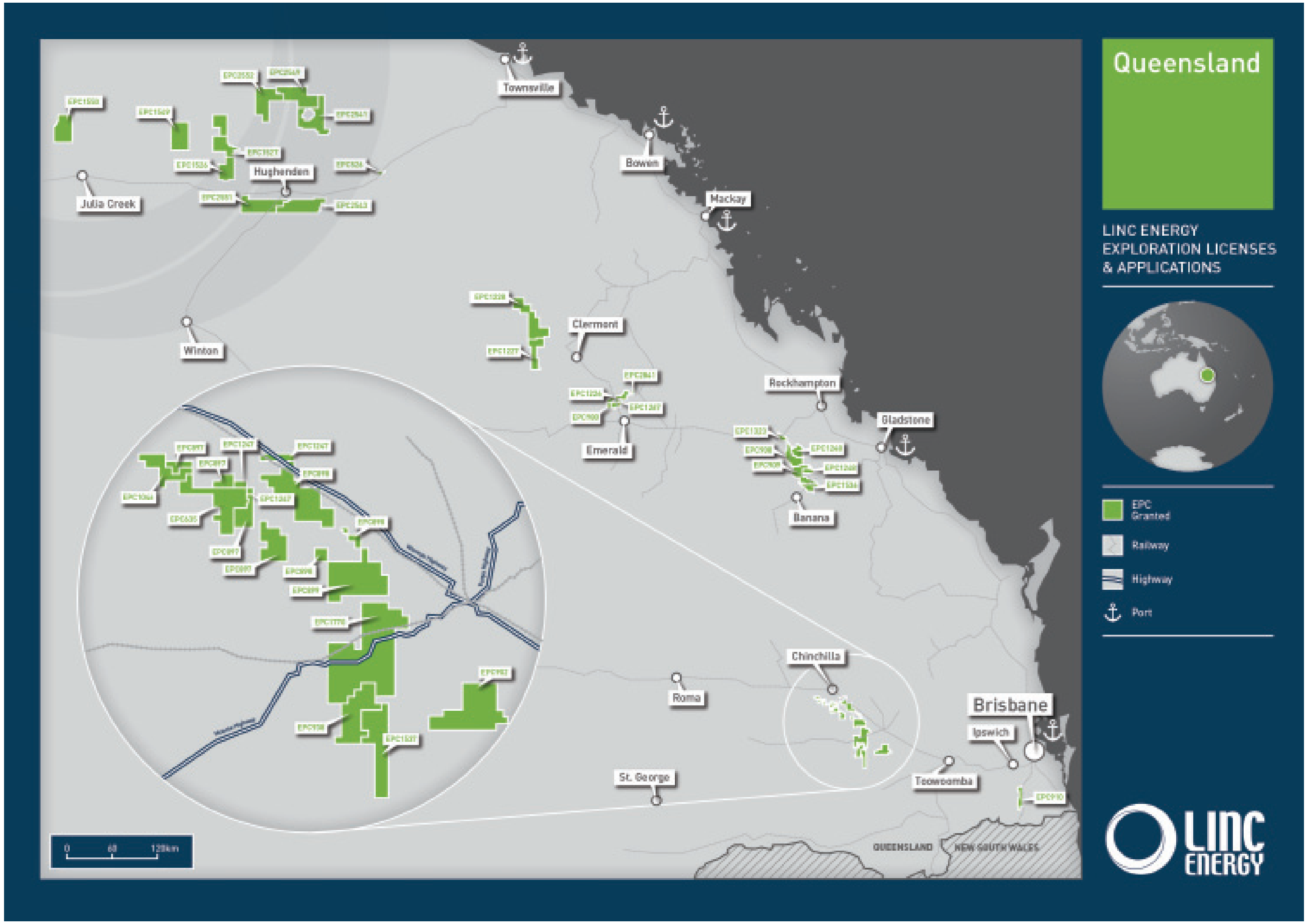
The following table sets out, among others, the stages of development of our various assets:

Locations	Gross Area (Sq km)	Equity Interest[1] (%)	Status	Coal Type
Blair Athol Mine	23.6	100.0	Mine	Thermal
Teresa Project	342.9	100.0	Prefeasibility	Thermal /Metallurgical
Pentland Project	38.5	100.0	Concept	Thermal
Dalby Project	700.2	100.0	Exploration	Thermal
Great Northern Leases	7,829.6	100.0	Exploration	Unknown
Drummond Project	1,284.5	100.0	Exploration	Unknown
Biloela Project	1,180.8	100.0	Exploration	Unknown
Rathdowney Project	114.9	100.0	Exploration	Unknown
Total / Average	**11,515**	**100.0**	-	-

Note:

(1) Our Equity Interest in respect of our coal assets refers to our share of profits after all costs have been deducted; it also refers to our share of any investment required during exploration, development, and production not fundable from cash flow from the asset.

The following map sets out the locations of our EPCs in Queensland:



The following table sets forth a summary of our reserves profile which has been prepared in accordance with the JORC Code 2004 or 2012, as the case may be, as extracted from the Snowden Report, the Blair Athol Reserve Report and the Teresa Reserve Report.

	Ore Reserves		
Location	**Proved Reserves Equity Interest[(1)] (Mt)**	**Probable Reserves Equity Interest[(1)] (Mt)**	**DCF-10[(2)] (A$'000)**
Blair Athol Mine	8.7	2.6	181,000
Teresa Project	-	49.6	259,000
Total	**8.7**	**52.2**	**440,000**

Notes:

(1) Our Equity Interest in respect of our coal assets refers to our share of profits after all costs have been deducted; it also refers to our share of any investment required during exploration, development, and production not fundable from cash flow from the asset.

(2) This figure is computed having taken into account the rehabilitation obligations, including the defrayment costs which the Blair Athol Joint Venture Party has committed to.

The following table sets forth a summary of our resources profile which has been prepared in accordance with the JORC Code 2004 or 2012, as the case may be, as extracted from the Snowden Report, the Blair Athol Resource Report, the Teresa Resource Report, the Dalby Resource Report and the Pentland Resource Report.

	Mineral Resources			
Location	**Measured Resource Equity Interest[(1)] (Mt)**	**Indicated Resource Equity Interest[(1)] (Mt)**	**Inferred Resource Equity Interest[(1)] (Mt)**	**Total Mineral Resources Equity Interest[(1)] (Mt)**
Blair Athol Mine	12.6	8.5	25.0	46.1
Teresa Project	-	82.3	215.8	298.1
Pentland Project	-	175.8	90.0	265.8
Dalby Project	-	-	146.0	146.0
Total	**12.6**	**266.6**	**476.8**	**756.0**

Note:

(1) Our Equity Interest in respect of our coal assets refers to our share of profits after all costs have been deducted; it also refers to our share of any investment required during exploration, development, and production not fundable from cash flow from the asset.

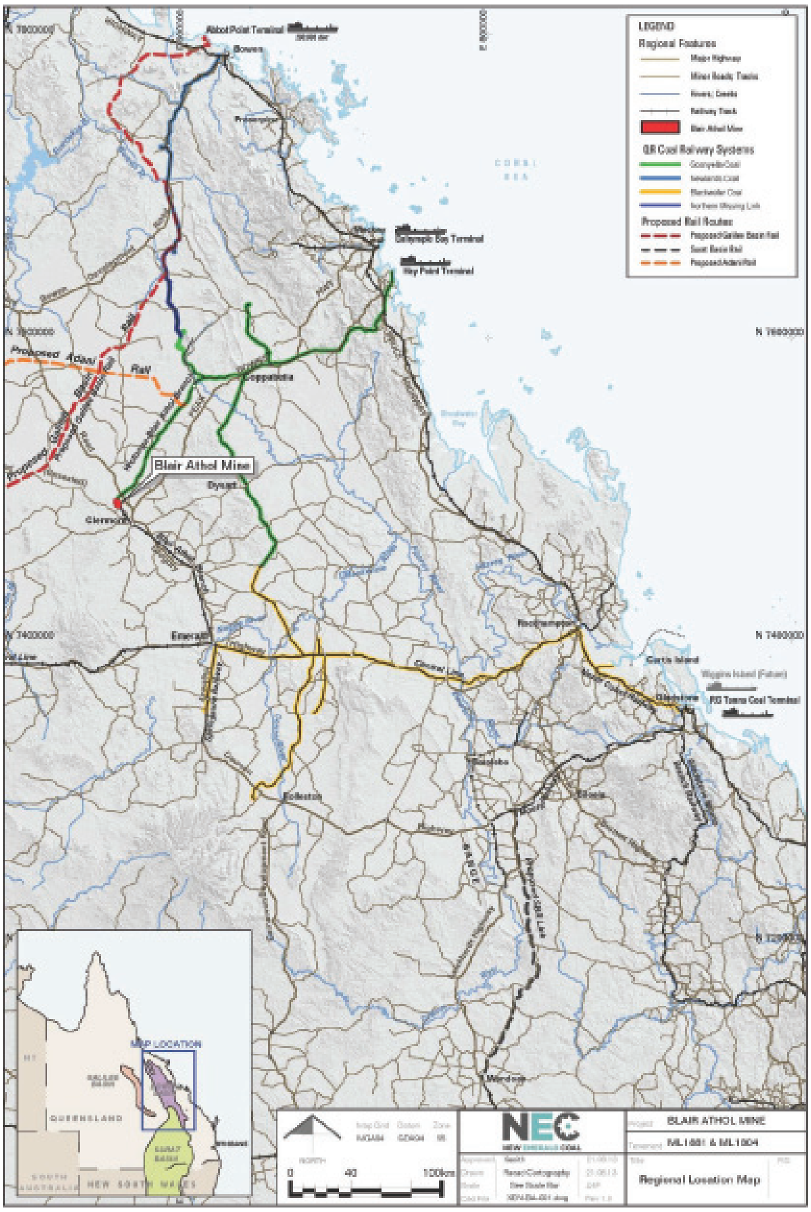
In respect of our conventional coal mining business process, exploration activities will typically be undertaken with respect to any potential resource and upon determination of potential for development, a toll-gated development process consisting of a number of stages including conceptual study, pre-feasibility study and feasibility study, will be undertaken, before making the final investment decision and commencing construction activities.

Blair Athol Mine

Description of asset

The Blair Athol Mine is an open-cut mine located approximately 220 km south-west of Mackay and approximately 24 km north-west of Clermont in the Bowen Basin region of Queensland, Australia. It has a well-defined geology with over 4,000 holes on-site.

The map below illustrates the location of the Blair Athol Mine:



The lease relating to the tenement for the Blair Athol Mine is represented by ML1804 which covers an aggregate land area of approximately 23.6 sq km (5,831.7 acres). This lease was granted on 1 December 1999 and is valid until 30 November 2014. We intend to make an application for renewal of the tenure at least six months prior to the expiration date.

The Blair Athol Mine has been granted the necessary consents, permits and licences for the purpose of conducting coal mining activities. It is located adjacent to existing coal handling facilities and coal chain infrastructure.

Coal product

The following table sets forth the typical marketing coal specifications for each brand of coal the Blair Athol Mine is expected to produce the following:

Coal Data

Proximate Analysis	
Total moisture (%) (gar)(1)	18.0
Inherent moisture (%) (ad)(2)	7.2
Calorific value (kcal/kg) (gar)(1)	5564
Calorific value (kcal/kg) (ad)(2)	6300
Ash content (%) (ad)	12.5
Total sulphur (%) (ad)	0.33
Volatile matter (%) (ad)	26.5
Fixed carbon (%) (ad)	53.9
Grindability (HGI)	70 est
Ash fusion temperature (reducing)	1600
Initial deformation (°C)	1600
Softening (°C)	1600
Hemispherical (°C)	1600
Fluid/flow (°C)	1600

Reserves and Resources

Based on the Snowden Report, the Blair Athol Reserve Report, and the Blair Athol Resource Report, our Blair Athol Mine has coal reserves of 11.3 Mt and coal resources of 46.1 Mt in accordance with the JORC Code. The following table sets out the amount and category of these reserves and resources in our tenements in the Blair Athol Mine:

	Working Interest		Equity Interest(1)		
Category	**Mt**	**Grade**	**Mt**	**Grade**	**Change from previous update (%)**
Reserves					
Proved	8.7	Thermal	8.7	Thermal	N/A
Probable	2.6	Thermal	2.6	Thermal	N/A
Total	**11.3**	**Thermal**	**11.3**	**Thermal**	**N/A**
Resources(2)					
Measured	12.6	Thermal	12.6	Thermal	N/A
Indicated	8.5	Thermal	8.5	Thermal	N/A
Inferred	25.0	Thermal	25.0	Thermal	N/A
Total	**46.1**	**Thermal**	**46.1**	**Thermal**	**N/A**

Notes:

(1) Our Equity Interest in respect of our coal assets refers to our share of profits after all costs have been deducted; it also refers to our share of any investment required during exploration, development, and production not fundable from cash flows from the asset.

(2) Mineral Resources are inclusive of, the Mineral Reserves.

Background

The Blair Athol Mine was previously operated by Rio Tinto as an open-cut mine. Coal had been mined from the Blair Athol Mine since 1985 but operations ceased in November 2012 as the previous owner had ceased operations for commercial reasons. The mine has been under care and maintenance since. In October 2013, our subsidiary, New Emerald Coal, entered into a sale and purchase agreement with the Blair Athol Joint Venture. We intend to recommence mining on site by the end of the June 2014.

Concurrent with our acquisition of the Blair Athol Mine, we will also enter into other ancillary agreements, namely (i) infrastructure access deed with Queensland Coal Pty Ltd ("**QCPL**") to use part of QCPL's below rail access rights for the rail network between the mine load out and the port, (ii) water deed to be entered into with the Clermont Joint Venture Party regarding the use of their water infrastructure and the water supply to the relevant mines (iii) electricity on supply agreement to be entered into with the Clermont Joint Venture Party for the purchase of energy and the on-supply of that energy, (iv) housing supply agreement between the Blair Athol Joint Venture Parties, Rio Tinto Coal Australia Pty Limited as manager and agent of the Blair Athol Joint Venture and us for the provision of certain housing quarters, and (v) coal tolling agreement entered into with the Clermont Joint Venture Party for the provision of tolling services such as taking delivery of our coal, stacking, stockpiling and managing our coal, reclaiming our stockpiled coal, and loading our coal onto trains. Only the housing supply agreement has been entered into.

Completion of this acquisition and title transfer is subject to (i) the provision of a performance bond to the Queensland Government to ensure that the rehabilitation works are carried out in accordance with the plan of operations, mining lease and Environmental Authority, and (ii) obtaining the transfer of the relevant regulatory permits and government approvals permitting recommencement of mining operations. The rehabilitation bond will be provided on our behalf by a commercial bank of appropriate standing. The rehabilitation bond amount is determined as part of establishing our plan of operations and is required to be in place when we become the registered holder of the mining lease.

Sales and marketing

The coal expected to be mined from the Blair Athol Mine could be sold into the rapidly growing Chinese and South East Asian import markets as well into the traditional North Asian markets of Japan, South Korea and Taiwan, either as a standalone product or a blend coal. New Emerald Coal is seeking to enter into long-term agreements to sell to a customer for the product coal prior to recommencement of operations.

Operation, Logistics and Infrastructure

The Blair Athol Mine is located in proximity to port, rail, roads, water, power and accommodation. The infrastructure that is used at the Blair Athol Mine is typical of most operations in the Bowen Basin. This infrastructure includes rail loop, water supply, dams, diversion channels, offices, coal plant, workshop and mine access road.

In addition to our senior operational coal mining staff, we are in the process of recruiting a workforce for the mine of approximately 120 personnel which we expect will be done after completion of the sale and purchase agreement.

Project Estimated Cost and Development Plan

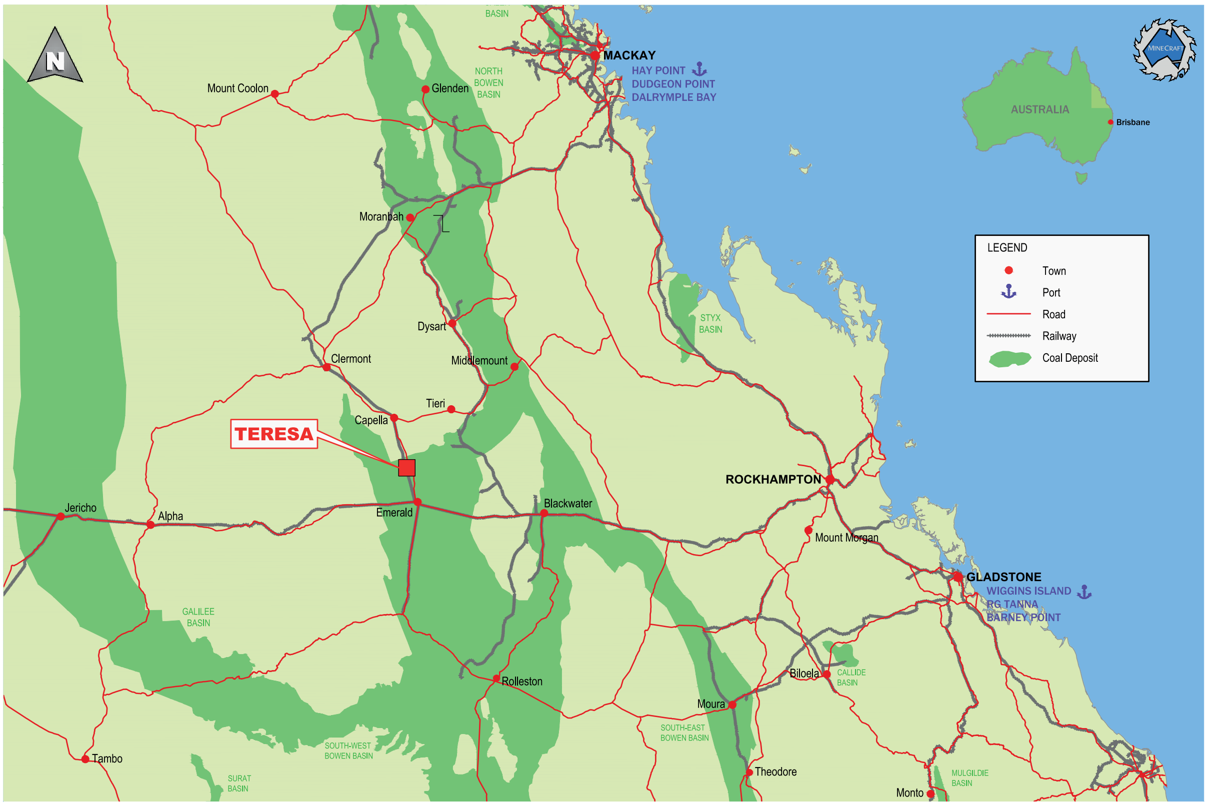
We expect to incur an aggregate sum of approximately A$10.9 million for FY2014 and A$9.8 million in FY 2015 in order to recommence production of the Blair Athol Mine. The scope of such capital expenditure includes site mobilisation and facilities re-commissioning, early site works such as upfront store purchases and critical spares, the proportional cash backing of an environmental rehabilitation bond as well as other ancillary items including the acquisition of a coal handling preparation plan. We intend fund such expenditure through internally-generated funds and/or debt financing.

Teresa Project

Description of asset

We hold all of the interest in the Teresa Project which consists of seven tenements, EPC 1226, EPC 1267, EPC980, EPC 2841, PLa286, MLa 70405 and MLa 70442. The identified deposit is located within the boundaries of our two MLas, namely MLa 70405 and MLa 70442. The project area is easily accessed via the Gregory Highway north from Emerald, with the highway cutting through the project area. The existing Emerald to Clermont rail line, the Blair Athol Branch Railway, also traverses the leases. The project area lies at a location approximately 17 km north of Emerald, the main regional centre with a population of over 11,000 residents.

The map below illustrates the location of the Teresa Project:



Coal product

The following table sets forth the typical marketing coal specifications for each brand of coal the Teresa Project is expected to produce:

	Average Coal Data – 10% Ash Washed Product	Average Coal Data – Raw ROM Coal
Proximate Analysis		
Total moisture (%) (gar)(1)	15.0	13.0
Inherent moisture (%) (ad)(2)	6.5	6.5
Calorific value (kcal/kg) (gar)(1)	6060	5280
Calorific value (kcal/kg) (ad)(2)	6663	5679
Ash content (%) (ad)	10.0	19.1
Total sulphur (%) (ad)	0.70	0.85
Volatile matter (%) (ad)	34.7	30.4
Fixed carbon (%) (ad)	48.8	42.6
Grindability (HGI)	~50 – 55	~50
Ash fusion temperature (reducing)	1560+	1560+
Initial deformation (°C)	1560+	1560+
Softening (°C)	1560+	1560+
Hemispherical (°C)	1560+	1560+
Fluid/flow (°C)	1560+	1560+

Reserves and Resources

Based on the Snowden Report, the Teresa Reserve Report and the Teresa Resource Report, our tenements in the Teresa Project have the following reserves and resources, in accordance with the JORC Code:

	Working Interest		Equity Interest[(1)]		
Category	**Mt**	**Grade**	**Mt**	**Grade**	**Change from previous update (%)**
Reserves					
Proved	-	-	-	-	-
Probable	49.6	Thermal	49.6	Thermal	N/A
Total	**49.6**	Thermal	**49.6**	Thermal	N/A
Resources[(2)]					
Measured	-	N/A	-	N/A	-
Indicated	82.3	Thermal	82.3	Thermal	N/A
Inferred	215.8	Thermal	215.8	Thermal	N/A
Total	**298.1**	Thermal	**298.1**	Thermal	N/A

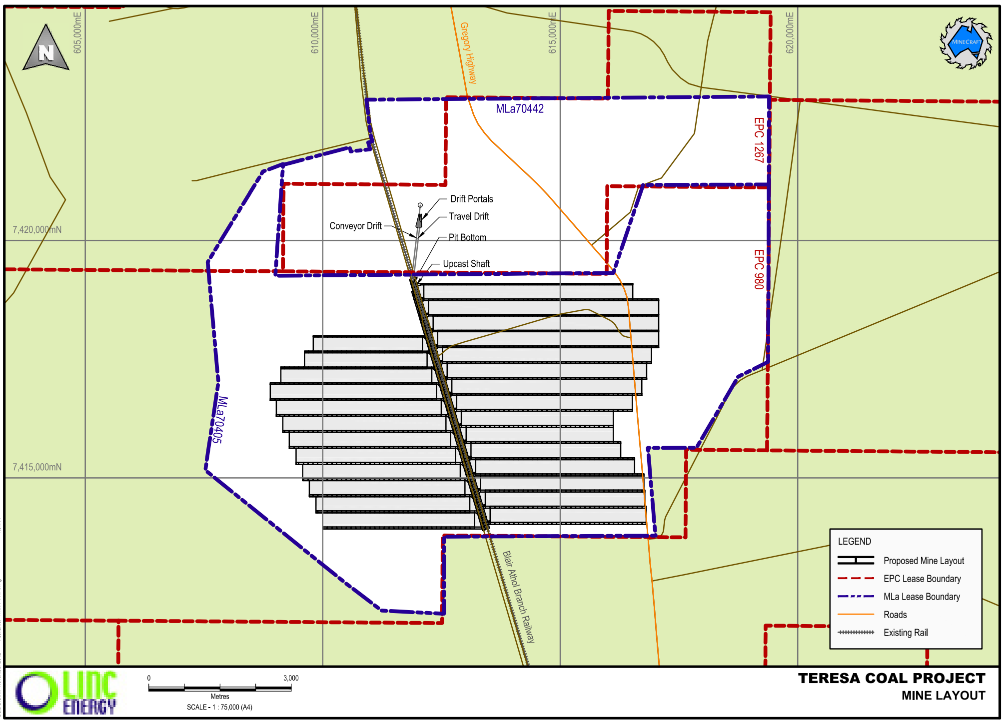
Notes:

(1) Our Equity Interest in respect of our coal assets refers to our share of profits after all costs have been deducted; it also refers to our share of any investment required during exploration, development, and production not fundable from cash flows from the asset.

(2) Mineral Resources are inclusive of, the Mineral Reserves.

Mining plans

We intend to develop a new underground coal mine and associated aboveground infrastructure that would produce up to 8 Mtpa of run-of-mine coal. The run-of-mine coal would be crushed and sized on site before being loaded onto trucks and hauled to the Burngrove-Gregory rail line for transportation to port. A new haul road would need to be constructed between the mine infrastructure and the Burngrove-Gregory rail line.



The principal method of mining would be retreat longwall extraction, supplemented by continuous mining methods for mine development. The life of the mine is expected to be between 20 to 30 years.

In June 2013, we submitted our Environmental Impact Study relating to the Teresa Project to the Queensland Government for assessment. On receipt of the relevant approvals enabling mining of the Teresa Project in line with our proposed development plans, we will be able to complete our mining lease application. The granting of the ML for the Teresa Project is expected in late 2014. Concurrent with the approvals process, a feasibility study will also be completed in order for a final investment decision to be made to proceed with the development on receipt of the mining lease.

We expect to raise financing to develop the Teresa Project through the feasibility study to the final investment decision. This is expected to be completed after the demerger / divestment of New Emerald Coal from our Company, subject to our Shareholders' approval at an extraordinary general meeting, in 2014 or after, and financing through a combination of debt and/or equity. We expect to commence construction in 2015 with a view to advancing to first commercial production in 2017.

Pentland Project

Our Pentland Project consists of two tenements, EPC 526 and MDL 361 (West Pentland). The Pentland deposit is a multi-seam deposit located within the northern Galilee Basin, which is approximately 220 km south-west of Townsville and seven km south-west of the township of Pentland in Brisbane, Australia. MDL 361 encompasses all of the EPC north of the Flinders Highway, with the portion of the EPC located on the south-eastern side of the Flinders Highway, overlapping with Xstrata Coal MDL 356. Based on initial coal quality testing, we expect the Pentland Project to produce, a thermal coal. According to the Pentland Resource Report, our tenements in the Pentland project have a JORC certified resource of 265.8 Mt resources, of which 175.8 Mt are Indicated and 90.0 Mt are Inferred. The coal would be extracted utilising opencut mining methods.

Dalby Project

Our Dalby Project consists of the tenements represented by MDLa 371, EPC 902, EPC 938, EPC 1537 and EPC 1770 which is located approximately 20 km south west of the Dalby township, on the Moonie highway in Queensland, Australia. The Dalby Project is located in the Surat Basin which extends from the Moreton Basin east of the Kumbarilla bridge, to Roma in the west and as far north as Taroom. Based on initial coal quality testing, we expect the Dalby Project to produce thermal coal. According to the Dalby Resource Report, our tenements in the Dalby project have a total of 146.0 Mt of JORC compliant coal resources, all of which are Inferred. The coal would be extracted utilising opencut mining methods.

Others

In addition to Teresa, Pentland and Dalby Projects, we hold interests in several exploration assets located in Queensland, Australia. These interests consist of granted greenfield EPCs across known coal basins and would comprise the Great Northern Leases, the Drummond Project, the Rathdowney Project and the Biloela Project.

Strategy

Going forward, we intend to further develop our coal assets and, establish a pure-play Australian coal company via a divestment and/or demerger of New Emerald Coal in 2014 or after. New Emerald Coal's strengths include possessing a management team with operational and turn-around experience in both underground and open-cut operations, and it plans to develop newly acquired and existing conventional coal assets, acquire further producing and development assets, and the focus on efficient mining operations.

OUR OIL AND GAS RESERVES AND RESOURCES

We have engaged the following Qualified Persons, namely:

(a) Haas Petroleum to issue the Haas Petroleum Report on our oil and gas reserves in the Gulf Coast Region;

(b) Ryder Scott to issue the Ryder Scott Reports on our oil and gas reserves in Wyoming and in Alaska; and

(c) DeGolyer and MacNaughton and Gustavson Associates to each issue the DeGolyer and MacNaughton Report and the Gustavson and Associates Report, respectively on our oil and gas prospective resources in South Australia.

Haas Petroleum, Ryder Scott, DeGolyer and MacNaughton, and Gustavson Associates have reviewed and incorporated only field studies and data that were available up to the date in relation to the assets covered in the reports. For a summary of information of certain assumptions used in each of Qualified Persons' Reports, see "Notice to Investors—Certain Reserves and Resources Information". Haas Petroleum, Ryder Scott, DeGolyer and MacNaughton, and Gustavson Associates have estimated oil and gas reserves and prospective resources under the Petroleum Resource Management System by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers ("**PRMS**") standards. You should note that such reports under the 2007 PRMS standards, may differ from the standards used by other companies in the industry.

Oil and Gas Reserves

Oil and gas 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 at the evaluation date) 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 characterised by development and production status.

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.

Probable reserves are those additional reserves which by 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.

Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of proved plus probable plus possible ("**3P**"), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

We derive our reserves from our conventional oil and gas business in the United States. The following table sets forth information regarding our oil and gas reserves extracted from the relevant Qualified Person's Reports:

	Total 1P Barrels of Oil Equivalent (MMBOE)	Total 2P Barrels of Oil Equivalent (MMBOE)	Total 3P Barrels of Oil Equivalent (MMBOE)	Oil (%)	1P PV-10(1) (US$' million)	2P PV-10(1) (US$' million)	3P PV-10(1) (US$' million)	Working Interest Area (acres)	Net Revenue Interest(2) %	Producing Fields
Gulf Coast	12.8	12.9	12.9	96.0	601.2	601.4	601.4	13,537	70.2	13
Alaska	-	154.6	194.1	100.0	-	2,465.3	2,845.5	19,348	80.0(3)	-
Wyoming	0.8	0.8	67.7	100.0	13.4	13.4	1,140.0	26,954	75.0	3
Total	**13.6**	**168.2**	**274.6**	**N/A**	**614.5**	**3,080.1**	**4,586.9**	**60,531**	**N/A**	**16**

Notes:

(1) Based on unweighted average benchmark West Texas Intermediate oil price and Henry Hub gas prices at the first of each month during the twelve-month period ended (i) 31 August 2013, for our assets in the Gulf Coast Region of US$95.40 per BBL and US$3.60 per MMCF and before future income taxes based on the Haas Petroleum Report, (ii) 31 August 2013, for our assets in Alaska of US$97.25 per BBL before future income taxes based on the Ryder Scott Report on Alaska; and (iii) 31 August 2013, for our assets in Wyoming, of US$89.86 per BBL before future income taxes based on the Ryder Scott Report on Wyoming.

(2) Our Net Revenue Interest in respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest on petroleum under the relevant licence, all royalty burdens and interests owned by others have been deducted.

(3) Our subsidiary Linc Alaska Resources LLC owns an 84.5% interest in Renaissance Umiat LLC. Renaissance Umiat LLC holds the entire Working Interest and a 80.0% Net Revenue Interest in our Umiat field in Alaska.

Oil and Gas Prospective Resources

Oil and gas prospective resources are those quantities of petroleum estimated, as at a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The estimation of resources quantities for a prospect is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities, which is dependent on the amount and quality of both technical and commercial data that are available and may change as more data becomes available. Estimates of petroleum are expressed using the terms low estimate, best estimate, high estimate and mean estimate to reflect the range of uncertainty. There should be at least a 90.0% probability that the quantities actually recovered will equal or exceed the low estimate of prospective resources, at least a 50.0% probability that the quantities actually recovered will equal or exceed the best estimate of prospective resources and at least a 10.0% probability that the quantities actually recovered will equal or exceed the high estimate of prospective resources. A possibility exists that the prospects will note result successful discoveries and developments, in which case there could be no future revenue. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The following table sets forth a summary of our oil and gas prospective resources quantities in relation to our assets in the Arckaringa Basin which has been extracted without material adjustment from the DeGolyer and MacNaughton Report and the Gustavson Report. The rationale for commissioning two Qualified Persons' Report in respect of the Arckaringa Basin was to provide a greater level of certainty to shareholders.

The estimated prospective resources quantities, on an unrisked and risked basis, as set out in the DeGolyer and MacNaughton Report are summarised as follows(1):

	Prospective Resources				
	Unrisked				Risked(1)
Resources	**Low**	**Best**	**High**	**Mean**	**Mean**
Oil (MMBBL)	14,358	20,915	30,468	21,836	516
Gas (TCF)	166.8	244.8	386.5	261.9	9.9
Condensate (MMBBL)	16,693	30,578	56,018	34,187	1,263
Solution Gas (TCF)	9.1	16.8	30.7	18.7	0.5
Total (MMBOE)	**60,370**	**95,081**	**156,015**	**102,800**	**3,510**

Note:

(1) The estimates for risked prospective resources are derived directly from the estimates for unrisked prospective resources while incorporating a geologic risk assessment for each prospect. Geologically risked prospective resources do not incorporate a development risk assessment. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum and this risk analysis is conducted independent of estimations of petroleum volumes. Geologic chance factors of the petroleum system include: (1) trap characteristics, (2) reservoir presence and quality, (3) source rock capacity, quality, and maturity, and (4) timing, migration and preservation of petroleum in relation to trap formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators, and is subject to revision with further data acquisition or interpretation. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The unrisked prospective resources in unconventional reservoirs in the Arckaringa Basin, as set out in the Gustavson Report:

	Prospective Resources		
Interval	**Low (MMBBL)**	**Best (MMBBL)**	**High (MMBBL)**
Stuart Range Formation	7,228	13,280	24,873
Boorthanna Formation	5,130	12,472	26,010
Pre-Permian Strata	74,340	207,080	464,334
Total	**86,697**	**232,832**	**515,217**

The unrisked prospective resources in conventional traps in the Arckaringa Basin, as set out in the Gustavson Report:

	Prospective Resources		
Interval	**Low (MMBBL)**	**Best (MMBBL)**	**High (MMBBL)**
Pre Permian Erosional Truncation	40,226	67,255	106,861
Pre Permian Low-Stand Valley Fill Traps	13,267	46,675	129,932
Pre-Permian Strata	5,861	11,068	21,563
Total	**59,383**	**124,997**	**258,356**

OUR COAL RESERVES AND RESOURCES

We have engaged Snowden, Xenith and Minecraft to prepare reports on our coal reserves and resources in Queensland, Australia. In particular, Xenith has prepared the report on coal reserves and resources for the Blair Athol Mine, the coal resources for the Teresa Project, the coal resources for the Pentland Project, and the coal resources for the Dalby Project, and Minecraft has prepared the report on coal reserves for the Teresa Project.

Each of Snowden, Xenith and Minecraft have reviewed and incorporated only field studies and data that were available up to the date in relation to the assets covered in the reports. For a summary of information of certain assumptions used in each of Qualified Persons' Reports, see "Notice to Investors—Certain Reserves and Resources Information". The Qualified Persons' Report with respect to our coal reserves and resources in Queensland, Australia have calculated estimated under the Australasian Code for Reporting of Exploration Results, Mineral Resources and Ore Reserves promulgated in 2004 and 2012, as the case may be, by the Joint Ore Reserves Committee of the Australasian Institute of Mining and Metallurgy, Australian Institute of Geoscientists and Minerals Council of Australia (the "**JORC Code**"). You should note that such report under the JORC Code, may differ from the standards used by other companies in the industry.

Coal Reserves

Ore reserves are the economically mineable part of a measured and/or indicated mineral resource. It includes diluting materials and allowances for losses which may occur when the material is mined. Appropriate assessments and studies have been carried out, and include consideration of and modification by realistically assumed mining, metallurgical, economic, marketing, legal, environmental, social and government factors. These assessments demonstrate at the time of reporting that extraction could reasonably be justified. Ore reserves are sub-divided in order of increasing confidence into probable ore reserves and proved ore reserves. Ore reserves are selected from measured and indicated mineral resources after a consideration of the relevant modifying factors, which include mining, metallurgical, economic, marketing, legal, environmental, social and governmental considerations. These assessments demonstrate at the time of reporting that extraction could reasonably be justified. The JORC Code deems inferred mineral resources to be too poorly delineated to be transferred into an ore reserve category. Ore reserve figures incorporate mining dilution, mining losses and are based on an appropriate level of mine planning, design and scheduling. Ore reserves are subdivided into the following categories: (i) probable ore reserves being the economically mineable part of an indicated mineral resource, and in some circumstances, a measured mineral resource which has a lower level of confidence than proved ore reserves, but is of sufficient quality to serve as the basis for a decision on the development of the deposit, and (ii) proved ore reserve being the economically mineable part of a measured mineral resource which has the highest confidence category of reserve estimates. The style of mineralisation or other factors could mean proved ore reserves are not achievable in some deposits.

Our coal reserves are located in Queensland, Australia. The following table sets forth a summary of our coal reserves which has been extracted from the Snowden Report, the Blair Athol Reserve Report and the Teresa Reserve Report.

	Ore Reserves		
Location	**Proved Reserves Equity Interest[(1)] (Mt)**	**Probable Reserves Equity Interest[(1)] (Mt)**	**DCF-10[(2)] (A$'000)**
Blair Athol Mine	8.7	2.6	181,000
Teresa Project	-	49.6	259,000
Total	**8.7**	**52.2**	**440,000**

Notes:

(1) Our Equity Interest in respect of our coal assets refers to our share of profits after all costs have been deducted; it also refers to our share of any investment required during exploration, development, and production not fundable from cash flow from the asset.

(2) This figure is computed having taken into account the rehabilitation obligations, including the defrayment costs which the Blair Athol Joint Venture Party has committed to.

Coal Resources

Mineral resources are a concentration or occurrence of material of intrinsic economic interest in or on the Earth's crust in such form, quality and quantity that there are reasonable prospects for eventual economic extraction. The location, quantity, grade, geological characteristics and continuity of a mineral resource are known, estimated or interpreted from specific geological evidence and knowledge. Mineral resources are sub-divided, in order of increasing geological confidence, into inferred, indicated and measured categories. Mineral resources are sub-divided in order of the increasing geological confidence of the estimate into the following categories being (i) inferred mineral resources being that part of a mineral resource for which tonnage, grade and mineral content can be estimated with a low level of confidence, (ii) indicated mineral resource being that part of a mineral resource for which tonnage, densities, shape, physical characteristics, grade and mineral content can be estimated with a reasonable level of confidence; and (iii) measured mineral resource being that part of a mineral resource for which tonnage, densities, shape, physical characteristics, grade and mineral content can be estimated with a high level of confidence.

Our coal resources are located in Queensland, Australia. The following table sets forth a summary of our coal resources which has been extracted from the Snowden Report, the Blair Athol Resource Report, the Teresa Resource Report, the Pentland Resource Report and the Dalby Resource Report.

	Mineral Resources			
Location	**Measured Resource Equity Interest(1) (Mt)**	**Indicated Resource Equity Interest(1) (Mt)**	**Inferred Resource Equity Interest(1) (Mt)**	**Total Mineral Resources Equity Interest(1) (Mt)**
Blair Athol Mine	12.6	8.5	25.0	46.1
Teresa Project	-	82.3	215.8	298.1
Pentland Project	-	175.8	90.0	265.8
Dalby Project	-	-	146.0	146.0
Total	**12.6**	**266.6**	**476.8**	**756.0**

Note:

(1) Our Equity Interest in respect of our coal assets refers to our share of profits after all costs have been deducted; it also refers to our share of any investment required during exploration, development, and production not fundable from cash flow from the asset.

TECHNOLOGY, RESEARCH AND DEVELOPMENT

We are a leader in UCG technology and we believe we are the only company in the world to have demonstrated the ability to produce diesel and jet fuel from UCG syngas, which provides us with a first mover advantage in the UCG front for the production of valuable and cleaner energy solutions. Prior to its decommissioning being completed, we have established, at our Chinchilla Demonstration Facility a specialised laboratory team to enable round the clock gas and liquid analysis to support our UCG and GTL operations. We believe that key to commercialising UCG has also been our commitment to environmental management. We have set out some aspects of our technological capabilities below.

UCG process

The following table sets out the amount spent on research and development carried out on the UCG process:

	FY2011	FY2012	FY2013
Amount spent (A$'000)	14,329	32,050	12,185
Percentage of revenue (%)	447.9	56.2	9.8

Our experienced UCG team allows us to, among others:

- understand the geology and coal chemistry to predict the suitability of particular locations and coals for UCG;
- understand the hydrogeological systems, including groundwater flow and balance around the UCG generator;

- understand UCG chemistry and reaction kinetics, including linkages with the physical aspects of UCG design, configuration, geometry, hydrogeological impacts, coal chemistry, and other parameters;

- predict gasification performance, resource utilisation and environmental impacts;

- develop and enhance methods to improve the control of synthesis gas quality and quantity; and

- drill and complete wells suitable for UCG purposes and then manage the ignition and cavity development through down well technology.

- develop and protect core UCG technologies and technical intellectual property.

See "Business—Intellectual Property—Patents" on the list of patents we have to protect our proprietary UCG technology

GTL process

The following table sets out the amount spent on research and development carried out on the GTL process:

	FY2011	FY2012	FY2013
Amount spent (A$'000)	7,873	8,179	5,473
Percentage of revenue (%)	246.1	14.3	4.4

Our experienced GTL technical team allows us to, among others:

- pursue a safe, efficient and viable GTL business within our strategy to value add to Clean Energy business opportunities;

- develop a sound GTL development process, including engineering scope, technology selection, project delivery, feasibility studies and scheduling;

- implement GTL technology, including opportunity identification and verification, economic optimisation, detailed engineering, procurement and construction of commercial facilities;

- integrate UCG and GTL together through customised gas clean-up solutions, catalysts and management of the syngas quality and volumes; and

- develop and grow core GTL technologies and technical intellectual property, including process refinement and further development and optimisation of our Chinchilla Demonstration Facility, prior to the decommissioning of our Chinchilla Demonstration Facility. See "Business—Intellectual Property—Patents" on the list of patents we have to protect our proprietary GTL technology.

Partial Block Extraction

Partial Block Extraction is a method of mining coal seams that differs from conventional mining practices. Though it relates to methods of mining underground and open cut coal seam, it seeks to eliminate the need for substantial roof support during the mining process, reduce the people working at the mining face, and provide an economic way to access additional resources in difficult geological conditions. Capital expenditure incurred on the research and development carried out on partial block extraction has been minimal.

See "Business—Intellectual Property—Patents" on the patent we have to protect our partial block extraction technology.

INTELLECTUAL PROPERTY

We undertake the identification, development, assessment, and registration of valuable intellectual property in accordance with our Intellectual Property Management Plan and Intellectual Property Management Policy and in consultation with our relevant technical and business sections. All of our intellectual property are registered internally in a database and managed by our Knowledge Manager. Categories of intellectual property developed and maintained by us include knowledge and know-how, trade secrets, patentable inventions and trademarks.

Patentable inventions identified and captured in the course of research and development, engineering and operational activities undergo an extensive review process by a committee comprising the managers from various departments, including Technical, Project, Commercial and Legal. Assessment criteria employed by the committee include technical strength, novelty/non-obviousness, project fit and business fit. Following approval by the committee, patent applications are prepared and filed for qualified inventions.

Inventions differ in their patentability and commercial significance and our strategy for the development of patentable inventions takes this into account. Various options for patent application filing are available, including Australia only (for inventions with low patentability and lesser commercial significance) and international filings (for inventions with high patentability and significant commercial significance) to ensure our intellectual property is protected in a rational and cost-effective manner.

Our Intellectual Property Management Policy supports our business objectives by providing guidance and expectations in relation to the use and management of our intellectual property and sets out the policies and procedures to be followed by any party that enters into an agreement to use our intellectual property to ensure that it is properly used and managed by that party.

As at the Latest Practicable Date, we have applied for and published patents in Australia and certain designated states under the Patent Cooperation Treaty (the "**PCT**") as well as registered trademarks in countries such as Australia, South Africa and the United States. Except as disclosed below, there are no other trademarks, patents, other intellectual or industrial property rights which are material in relation to our business:

Patents

The following table sets out the list of our published / sealed patents:

Patent	Territory	International Application Number	Validity Period
Injected air/oxygen method	Australia	AU 2012100863 A4	22 December 2011 to 12 June 2020
Apparatus and method for syngas processing	Australia	AU 2012101312 A4	23 December 2011 to 29 August 2020
Injection method for controlling the composition of product gas	Australia	AU 2012101287 A4	25 October 2011 to 23 August 2020
Underground coal gasification in thick coal seams	Australia	AU 2012101716 A4	23 December 2011 to 26 November 2020
In situ reforming of synthesis gas	Australia	AU 2012101824 A4	23 December 2011 to 12 December 2020
System and method for syngas processing	Australia	AU 2012101392 A4	23 December 2011 to 7 September 2020
Intersecting air/oxygen injection for underground coal gasification	Australia	AU 2012100988 A4	23 December 2012 to 29 June 2020

The following table sets out the list of our published applications:

Patent	Territory	International Application Number	International Publication Date
Method and apparatus for treating a raw UCG product stream	PCT	PCT/AU2011/001692	13 September 2012
Igniting an underground coal seam in an UCG process	PCT	PCT/AU2012/000157	23 August 2012
UCG product gas quenching method and apparatus	PCT	PCT/AU2012/001350	27 June 2013
UCG well liner	PCT	PCT/AU2012/001185	27 June 2013
In situ treatment of synthesis gas	PCT	PCT/AU2012/000768	28 March 2013
System and method for integrated enhanced oil recovery	PCT	PCT/AU2012/001243	15 November 2012
UCG method	PCT	PCT/AU2012/001517	18 April 2013
Method and system for treating a waste stream derived from UCG product gas	PCT	PCT/AU2012/001111	27 June 2013
UCG channel	PCT	PCT/AU2012/000117	20 June 2013
Conditioning of syngas from UCG	PCT	PCT/AU2011/001693	15 November 2012
Partial Block Extraction—continuous mining method(1)	Australia	2013901178	5 April 2013
Improved Underground Coal Gasification Method and Apparatus	PCT	PCT/AU2013/000397	24 October 2013

Note:

(1) This is provisional application. A full application for an innovation or a standard patent can only be made 12 months following the date of the provisional application.

Trademarks

The following table sets out the list of our trademarks:

Trademark	Class	Territory	Registration Number
LINC ENERGY	07, 11, 35, 40, 42	Australia	1210599[(1)]
LINC ENERGY	04, 37, 39	Australia	1234819[(2)]
LINC ENERGY	07, 11, 35, 40, 42	Australia	1234049[(3)]
LINC ENERGY	04, 37, 39	Australia	1259560[(3)]
LINC ENERGY	11	South Africa	2008/23489
LINC ENERGY	37	South Africa	2008/23490
LINC ENERGY	39	South Africa	2008/23491
LINC ENERGY	40	South Africa	2008/23492
LINC ENERGY	42	South Africa	2008/23493
LINC ENERGY	04	South Africa	2008/23487
LINC ENERGY	07	South Africa	2008/23488
LINC ENERGY	04, 07, 11, 37, 39, 40, 42	India	1742961
LINC ENERGY	04, 07, 11, 35, 37, 39, 40, 42	Madrid Protocol (Designating China, UK, Japan, USA & Vietnam)	987600[(4)]
LINC	04, 07, 09, 11, 37, 40	Australia	1265615[(4)]
LINC	37, 39, 42	Australia	1283970[(4)]
LINC	04, 07, 09, 11, 37, 39, 40, 42	Madrid Protocol (Designating China, UK, Japan, USA & Vietnam)	1010773

Notes:

(1) Expires on 16 November 2017.
(2) Expires on 14 April 2018.
(3) Expires on 9 April 2018.
(4) Expires on 3 October 2018.

Except as disclosed above, we do not own or use any other patents, trademarks or intellectual property on which our business or profitability is materially dependent.

MAJOR CUSTOMERS

We sell all our oil and gas produced in the United States to third parties such as Shell Trading (US) Company and Enterprise Products Operating LLC presently as they offer us the best commercial terms. We do not have any minimum take or pay arrangements although we have entered into purchase agreements with each of them. Our oil and gas production is sold under contracts with prices based on market indices, adjusted for location, quality and transportation. Oil and gas produced in the United States can be sold to other parties relatively easily. We have minimal gas sales. The contracts entered into with Shell Trading (US) Company are on a fixed term basis of one year and continue thereafter on a monthly evergreen basis. While our Company has a month-to-month contract with Enterprise Products Operating LLC which is terminable by either party upon thirty days' notice.

Due to the nature of oil and gas markets, and because oil and gas are freely traded commodities, and there are numerous purchasers in the Gulf Coast Region and Wyoming, we do not believe that the loss of any purchasers would materially affect our ability to sell our production. As such, we are not materially dependent on any contract with any customer and none of our Directors, Substantial Shareholders or their respective associates has any interest, direct or indirect in the customers set out above.

MAJOR SUPPLIERS

As is typical for oil, gas and coal mining companies, we currently use and intend to use suppliers for various services associated with operations. One of the key benefits of using such sub-contracting arrangements is that it reduces our need for capital investment in equipment and human resources. We maintain strict supervisory control over our suppliers and require high levels of safety and environmental management and regulatory compliance.

Except as disclosed below, none of our suppliers account for more than 5.0% of our total lease operating costs for the relevant financial year. Our business and profitability are not dependent on any single supplier. Our Directors, Substantial Shareholders or their respective associates do not have any interest in our major suppliers set out below. Our suppliers are generally chosen on a tender basis and factors considered in selecting our suppliers include quality, reputation, experience and cost. As such, we may not necessarily continually contract with any single supplier.

		Percentage of total lease operating cost for FY (%)		
Supplier	**Item supplied**	**2011**	**2012**	**2013**
C&L Vacuum Services[1]	Disposal services	n.m.	7.63	n.m.
KDR Supply Inc[2]	Supplies such as the provision of gauges	n.m.	5.97	n.m.
Rocky Mountain Power	Electrical services such as preliminary engineering and delivery of voltage to wells	8.19	4.97	n.m.
M&M Oilfield Services Inc[3]	Maintenance services such as repairing, improving, installing, of wells drilled for the purposes of UCG	16.50	n.m.	n.m.
Northern Production Co.,Inc[3]	Oil and gas well services	9.78	n.m.	n.m.
Borets-Weatherford US Inc[3]	Tools / Supplies such as the provision of field services	9.37	n.m.	n.m.

Notes:

(1) As C&L Vacuum Services is a Texas vendor, we had not engaged their services prior to the acquisition of our Gulf Coast assets in FY2011. Accordingly, total lease operating cost from C&L Vacuum Services increased in FY2012 from FY2011 after the engagement of their services in FY2012. In respect of FY2013, although on a dollar basis, we had paid more to C&L Vacuum Services, on a percentage basis, more money was also paid to the other vendors proportionately which resulted in the corresponding decrease in percentage.

(2) As KDR Supply Inc is a Texas vendor, we had not engaged their services prior to the acquisition of our Gulf Coast assets in FY2011. Accordingly, total lease operating cost from KDR Supply Inc increased from in FY2012 from FY2011 after the engagement of their services in FY2012. In FY2013, we bought supplies from a different vendor with more competitive pricing which accordingly resulted in the decreased in percentage.

(3) Although on a dollar basis, we had paid more to each of M&M Oilfield Services Inc, Northern Production Co. Inc and Borets-Weatherford US Inc in FY2012 compared to FY2011, there was a corresponding decrease on a percentage basis in respect of the same period due to the general higher aggregate lease operating expenses which we had incurred in FY2012 compared to FY2011 coupled with an increasing mix of vendors.

COMPETITION

The oil, gas and coal industries are highly competitive. We encounter strong competition from other independent operators and from major oil, gas and coal companies, respectively, in acquiring assets and securing trained personnel. Many of these competitors have financial and technical resources and staff substantially larger than ours. As a result, our competitors may be able to pay more for desirable oil and gas assets, or to evaluate, bid for and purchase a greater number of assets than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drill attempts, mining exploration, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position.

Particularly in respect of our oil and gas business, we are affected by competition for drilling rigs and the availability of related equipment. To the extent that in the future we acquire and develop undeveloped assets, higher commodity prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Over the past three years, oil and gas companies have experienced higher drilling and operating costs. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill wells and conduct our operations.

Competition is also strong for attractive oil and gas producing assets, undeveloped leases and drilling rights, and we cannot assure you that we will be able to compete satisfactorily when attempting to make further acquisitions.

In relation to our Clean Energy business, due to the fact that the industry is in its development phase, there are no established competitors with commercial operations in direct competition with us.

LICENCES, PERMITS, AND APPROVALS

We have obtained all the relevant material licences, permits and certificates necessary to conduct our operations as currently conducted from the relevant governmental bodies in the jurisdictions where we operate. We have complied with all material conditions imposed thereunder, if any. We also have the relevant rights to carry out our operations, subject to compliance with conditions as may be imposed under those licences or concession rights.

In connection with our conventional oil and gas assets in the Gulf Coast Region, in order to drill and operate wells, we would require, numerous permits and licences for each well, including among others, a drilling permit, a water board letter and an air permit or other authorisation, in some cases, we would also need to receive a U.S. Army Corps of Engineers permit.

In connection with our oil and gas assets in Wyoming, in order to continue to control and regulate all aspects regarding the exploration for and production of oil and gas, including drilling approvals, and certain other aspects concerning production, we would require permits and licenses from the Wyoming Oil and Gas Commission.

For the future wells in the Gulf Coast and Wyoming which we intend to drill, we will apply for all relevant permits and licenses at the appropriate time. We do not foresee any difficulties in obtaining these approvals which they will obtain in the ordinary course.

In connection with our oil and gas assets in Alaska, in order to continue our exploration for and development of our oil and gas leases, we would require permits and licences from the Bureau of Land Management and permits from other authorities for, but not limited to, waste, water and air discharges.

In connection with unconventional oil and gas assets in South Australia, we have obtained the necessary petroleum and exploration (minerals) licences to undertake our proposed activities in the area. Each licence contains specific provisions about the exploration and associated activities permitted to be carried out. We have also, where necessary entered into access agreements with Native Title Holders.

In respect of our conventional coal mining assets in Queensland, Australia, that are either in exploration or development, all requisite approvals are in place for their current stage of development. In particular of the Blair Athol mine, there are two material approvals required prior to recommencement of operations, namely, the mining lease and the associated Environmental Authority. The sale and purchase agreement to acquire the Blair Athol Mine provides for the transfer of these approvals as part of completion. The indicative approval for the transfer of the mining lease will be applied for as part of the conditions precedent for completion of the sale and purchase agreement. The Blair Athol Joint Venture Party has the documents required to make this application but is waiting for further information from the government before lodging this application. We expect the application for the transfer to be submitted by the end of December 2013. The granting of an Environmental Authority is a matter of procedure after the mining lease has been transferred. We are also in the process of seeking production licences in relation a number of our other coal mining assets.

See "Appendix A—Regulations" for a summary of laws and regulations which govern our material operations and "Appendix H—Our Oil, Gas and Coal Tenements and Leases" which sets out the list of our material tenements and leases held by our Group.

CORPORATE SOCIAL RESPONSIBILITY INITIATIVE

We recognise that our oil, gas and coal exploration and production activities could have social, cultural and economic impacts on key stakeholders including local citizens, governments, industry groups, service providers, non-governmental organisation and landowners. We embrace this responsibility and have devised and implemented plans to minimise potential impacts and to support local communities in sustainable ways including but not limited to the following:

(a) conducting private meetings and public community information sharing sessions to initiate stakeholder dialogue and feedback on potential social, economic and environmental impacts our projects may have and to collaboratively identify and implement appropriate tactics to manage outcomes;

(b) ensuring continual, transparent engagement with stakeholders, including identifying dedicated company stakeholder representatives to support operations and to collaborate with local landholders and stakeholders to manage and mitigate potential impacts;

(c) conducting meetings with landholders and stakeholders in relation to the surface layout of drilling or mining infrastructure to ensure long term, positive relationships are developed and managed to mitigate potential impacts;

(d) negotiating long term cultural heritage stakeholder management plans with native and aborigine communities to mitigate impacts; and

(e) investing in the communities where we live and operate through employee volunteer initiatives and strategic corporate resource contributions.

For example, in respect of our operations at Umiat, we have managed such relations through personal meetings, presentations and updates with the Nuisquit Village and the Anaktuvuk Pass Village in June 2013 to inform the communities on the winter drilling programme, spring and summer programmes as well as employment opportunities in our operations.

In addition, we are committed to contributing to the communities where we operate. To achieve strong community relationships, we offer sponsorship to community activities and events that meet our sponsorship criteria. Our sponsorship criteria includes (a) synergies between our Group and the location of the community, organisation, event or project to be sponsored, (b) level of engagement with the sponsorship recipient, (c) size of the target audience reached, and (d) general benefits of the sponsorship to our Group, our shareholders and the local community. Examples of previous sponsorships and community engagement include involvement with the Science, Technology, Engineering and Mathematics education initiatives in the United States, the University of Fairbanks Arctic Development Study, and other local community events.

We are also committed to addressing environmental, health and safety issues which are related to our operations. See "Business—Health, Safety and Environmental Considerations" of the offering document for further information.

HEALTH, SAFETY AND ENVIRONMENTAL CONSIDERATIONS

Our operational divisions have a dedicated Health, Safety and Environment (“**HSE**”) Team or specific employees who, directly or indirectly, report to the relevant divisional President. Where necessary, support is provided between divisions. These teams comprise environmental engineers, environmental scientists and qualified health and safety specialists. Within our conventional oil and gas business in the United States, the chief operating officer and the general manager of oil and gas, Alaska, bear the responsibility of reporting environmental, health and safety issues to the President, Oil and Gas. In respect of our Clean Business, we have a general manager for Chinchilla Operations and a General Manager, Health, Safety, Environment and Quality, as well as a US Vice President reporting to the President, Clean Energy. The President, SAPEX is updated by the senior petroleum geologist, exploration geologist and is also supported by the UCG HSE team as well. Finally HSE matters in respect of our coal business are reported by the HSE and Community Manager to the President, Coal.

In respect of our Australian operations, audit and assurance requirements are met by tenure specific environmental authorities and legislation such as the Environmental Protection Act, most of which contain standardised external auditing requirements or standardised compliance programmes. As such, we have in place an Environmental Management System (“**EMS**”). Due to our relatively small size, components of an ISO14001 compliant system that are relevant to large and complex operations are not necessarily incorporated into our Australian EMS procedures. In addition, our Chinchilla Demonstration Facility, prior to its decommissioning being completed, will also be managed pursuant to a formal EHS Management Plan which is based on standardised industry practices for management of EHS issues. It is also a legislative requirement that this document exists and addresses certain health and safety matters.

The contractors which we engage have to comply with our EMS, which is usually provided for in our standard form contracts. Contractors not willing to comply with such obligations are not selected. For example, our Chinchilla Demonstration Facility, prior to its decommissioning being completed, has a comprehensive contractor management system (which covers EHS requirements for the site and involves a formal site specific induction training session) that all contractors must participate in prior to entry to site and while at site.

In early 2011, the Department of Environment and Resource Management, presently known as DEHP, the entity which administers the EPA, received complaints from landholders in the vicinity of odours from the Chinchilla demonstration facility. We subsequently submitted an odour monitoring report and carried out our own investigations in respect of the complaints. Subsequent to further complaints, DEHP issued a notice requesting that environmental evaluation be carried out by an independent, suitably qualified person, and we hired PAEholmes, a specialist environmental group focusing on air quality. On 14 May 2012, PAEholmes issued their environmental evaluation report and proposed mitigation methods including a dam remediation work, implementation of further training structured around an odour management plan, and re-evaluation regarding the modelling of the gas phase controlled emissions. Subsequent to further queries from DEHP, DEHP advised that the mitigation methods did not abate the odour emissions, and issued an environmental protection order (“**EPO**”) on 24 August 2012. We have since lodged an application for internal review within DEHP for the decision to issue the EPO as at 10 September 2012, and DEHP issued an amended EPO as a result of our request for internal review as at 9 October 2012. On 23 October 2012, we requested that DEHP amend the EPO, and following further assessment and investigation on the grounds that some of the odour mitigation methods were not feasible or safe to implement. The EPO was further amended on 8 November 2012. Pursuant to the EPO re-issued on 8 November 2012, we had to provide information to the DEHP such as the provision of sample water or gas analysis, air emissions, commence radiation of certain sites, submit process waste management strategy plans and to submit a report that provides an evaluation of the efficacy and suitability of odour mitigation measures adopted as a consequence of the EPO. The EPO did not affect our daily operations. We have submitted an interim report on the monitoring undertaken as part of the EPO and will conduct further monitoring as and when required under the EPO.

In early 2013, DEHP issued a notice under the EPA requesting for further information in relation to the operation of our Chinchilla Demonstration Facility, which we have since sought an internal review within DEHP in respect of the 2013 notice. DEHP later reissued the notice, and we have sought an appeal in the Planning and Environment Court at Brisbane against the review decision made by DEHP as at 22 May 2013. The appeal is presently on-going. On 19 September 2013, we entered into mediations with DEHP. In the event that an unfavourable decision is made against us, the potential implications are that we will have to provide information requested by DEHP.

In October 2013, we received a notice from the DEHP in Queensland requiring us to make available certain information so as to enable the DEHP to conduct an investigation into allegations regarding the unlawful release of contaminants at our Chinchilla Demonstration Facility in contravention of the EPA and the conditions of our Environmental Authorities. We intend to and have been cooperating with all proper and reasonable requests from the DEHP in connection with the subject matter of their investigation. Although we believe that these allegations are without merit, there can be no assurance that we will not be found to be in breach of the requirements of the EPA or in contravention of the conditions of our Environmental Authorities. In the event that we are found to be in such breach of the requirements of the EPA or in contravention of the conditions of our Environmental Authorities, the maximum aggregate financial penalty under the EPA for the potential offences is approximately A$3.4 million (US$3.2 million). In the event that an unfavourable decision is made against us, we believe that the more likely potential implications are that we may have to pay a nominal fine, undertake some form of rehabilitation and engage in regular compliance monitoring and reporting to DEHP, which should not have a material impact on our operations.

In respect of our operations in the United States, while we do not have an overarching EMS, each of our facilities in the United States operates pursuant to varying environmental regulations, including comprehensive permitting and on-going compliance requirements. For example, each of the facilities that have storage tanks must have a spill prevention control and containment plan. There are also individuals responsible for coordinating EHS matters such as an Environmental Permitting Manager or Compliance Manager. It is the responsibility of the EHS team to assess each facility and determine what actions are necessary to ensure that the facility complies with all relevant environmental regulations. We conducted a comprehensive assessment of environmental regulations required when we acquired the business and further assessment is done on an on-going basis.

In addition, we have a General Manager of Stakeholder Relations, who is responsible for social and community outreach. In this regard, our stakeholder relations management plan supports all US operations. In relation to our Umiat field, we enjoy an ongoing relationship and dialogue with key stakeholders on the North Slope including the North Slope Borough and Native Alaskan communities near Umiat including Nuiqsut and Anaktuvuk Pass. Our representatives meet regularly in person with stakeholders in the Umiat region and maintain open dialogue with communities.

We also require that prospective contractor's service agreements contain requirements for legal EHS compliance and safety management. We would review the adequacy of each contractor's EHS compliance and safety management systems before mobilisation onto our work sites is carried out.

In respect of our operations in the United States, the only major incident in the last three years was an oil spill at Black Bayou, Louisiana which occurred in July 2012. The spill was of approximately 50 barrels of oil and was caused by vandalism. Response and clean-up was handled by ES&H Inc. our emergency response contractor and complied in all respects with all applicable regulations. The spill was contained and remediated. In this regard, most of the compliance actions relate to *de minimis* spills of crude oil, which has resulted in citations in the US$1,000 to US$5,000 range.

In addition, we may in future implement a global Health and Safety Management System ("**HSMS**"), which is based on OHSAS 18000:1. This would supplement our existing health and safety policies, which has as its primary objective the maintenance of the employee's health and safety at the workplace. The intention for a HSMS manual and associated health and safety principles is to create a framework of performance standards, provide an auditable trail within the HSMS that define performance requirements, especially for our clean energy business, and ensure compliance with applicable laws and regulations. Our Environment Policy requires that all employees conduct our business with high regard for environmental management and corresponding levels of environmental performance. In accordance with our Environment Policy, we strive to minimise the impact of operational activities on the environment while maximising social and economic benefits.

In addition to our Environment Policy, our Australian activities are guided by Federal environmental legislation, legislation in each State in which we operate and our specific environmental licences. We have a dedicated team of environmental professionals (including environmental engineers and scientists) whose roles include ensuring we comply with our internal and external environment obligations such as regular compliance monitoring and reporting to government.

In addition to our Environment Policy, our activities in the United States are guided by licence specific permitting and ongoing compliance requirements and state specific regulations.

In the last three years, we had no fatality across our operations including Australia and the United States. Apart from the one lost time injury in Australia in FY2013, we have not had any lost time injuries in our operations.

EMPLOYEES

As at the Latest Practicable Date, we had 447 employees. Our employees are not unionised. There has not been any incidence of work stoppages or labour disputes which affected our operations. In addition, we do not employ a significant number of employees on a temporary basis.

A breakdown of our employees by function and geography as at the end of each of the three most recent completed financial years is as follows:

	As at 30 June		
	2011	2012	2013
Function			
Executive Management	6	10	11
Corporate Professionals	104	121	113
Geological and geophysical and drilling	34	23	28
Technology	239	186	184
Operations	52	73	64
Administration	31	28	22
Total	**466**	**441**	**422**

	As at 30 June		
	2011	2012	2013
Area			
United States	71	99	93
Australia	166	146	131
United Kingdom	3	2	2
South Africa	-	-	2
Uzbekistan	226	194	194
Total	**466**	**441**	**422**

STAFF TRAINING

We believe that the technical competence and execution skills of our employees are instrumental in maintaining our competitive position. The objective of our employee training is to equip all of our employees with the necessary skills and knowledge to ensure that they are able to safely fulfil their job requirements and to enhance their work performance.

All of our employees are required to complete both corporate and safety inductions. Further job specific training is divided into three categories—Compliance Training, Mandatory Training and Professional Learning and Development. Whilst most training is typically planned, ad-hoc training may be organised as required. Training is conducted by external parties as well as internally by our senior employees.

During the last three financial years, our staff training costs were not material.

PROPERTIES

We own various properties on which our operations are located. However, we do not consider that any of these properties constitute material assets. The following table sets forth information relating to the location, area, tenure and encumbrances of the material property which we own as at 30 June 2013. These properties are either our demonstration facilities or for our mining operations. As at the Latest Practicable Date, there is no production at the Blair Athol Mine.

Property	Real Property Details	Area (hectares)	Tenure	Encumbrances
Chinchilla Demonstration Facility	Lot 40 Plan CPDY 85	517.67	Freehold	Nil
Chinchilla (surrounding Demonstration Facility)	Lot 67 Plan CPDY 78	517.78	Freehold	Nil
Chinchilla (surrounding Demonstration Facility)	Lot 2 Plan RP 117442	497.21	Freehold	Nil

Property	Real Property Details	Area (hectares)	Tenure	Encumbrances
Chinchilla (surrounding Demonstration Facility)	Lot 1 Plan RP 169961	680.04	Freehold	Nil
Chinchilla (surrounding Demonstration Facility)	Lot 1 Plan RP 98550	246.4	Freehold	Nil
Orroro, South Australia	Orroro Volume 5988 Folio 743	257.27	Freehold	Nil
Orroro, South Australia	Orroro Volume 5497 Folio 631	Not available	Freehold	Nil
Blair Athol Mine(1)				
Blair Athol Closed Road, Clermont, Queensland	Lot 1 Plan RP 607100	3.719	Freehold	Nil
Blair Athol Hetherington Street, Clermont, Queensland	Lot 2 Plan RP 607100	35.896	Freehold	Nil
Blair Athol Closed Road, Clermont, Queensland	Lot 2 Plan RP 600709	0.9495	Freehold	Nil
Blair Athol Closed Road, Clermont, Queensland	Lot 2 Plan RP 600710	0.7133	Freehold	Nil
Blair Athol Closed Road, Clermont, Queensland	Lot 1 Plan CP CLM149	1.55	Freehold	Nil
Blair Athol Closed Road, Clermont, Queensland	Lot 2 Plan CP CLM150	5.941	Freehold	Nil
Blair Athol Hetherington Street, Clermont, Queensland	Lot 504 Plan CP B9061	0.1012	Freehold	Nil
Blair Athol Hetherington Street, Clermont, Queensland	Lot 505 Plan CP B9061	0.1012	Freehold	Nil

Note:

(1) This is in respect of a number of small parcels of land held pursuant to the Blair Athol Mine.

We lease various properties on which certain of our offices are located. We do not consider any of our leases to be a material fixed asset.

See "Appendix H—Our Oil, Gas and Coal Tenements and Leases" of this offering document for a list of our material tenements and leases entered into by us in respect of our oil, gas and coal tenements. Our Group's interests in our tenements do not imply that we have any form of leasehold interest in the land covered by our tenements.

LEGAL PROCEEDINGS

From time to time, we are involved in legal proceedings concerning matters arising in connection with the conduct of our business. We do not believe that there are any legal or arbitration proceedings that are pending or known to be contemplated that may have, or that have had in the 12 months immediately preceding the date of lodgement of this offering document, individually or taken as a whole a material effect on our financial position or the profitability of our Group.

In 2012, Ruby Mae Simon Constance, Georgia Authement Constance and others filed a claim against our subsidiary, Diasu Oil & Gas Company, Inc, seeking unspecified damages as a result of our oil and gas activities which had damage various tracts of land in the 38th Judicial District Court, Cameron Parish, Louisiana. The cases have been removed to the United States District Court for the Western District of Louisiana. We had filed a defence and intend to contest the claims.

Also, in 2012, ERG Resources, L.L.C. ("**ERG**") filed a claim against our subsidiary, Linc Gulf Coast Petroleum, Inc. for an unspecified sum in the 11th Judicial District Court of Harris County, Texas, alleging a breach of contract by us in relation to our acquisition of our oil and gas assets in the Gulf Coast Region in 2011. ERG also asserted that we had damaged certain property that it claimed to own in connection with our operations. We responded and filed a counter-claim for a breach of contract by ERG. This matter was settled and the settlement agreement was effective from 4 October 2013.

On 3 October 2012, we filed a claim against Arctic Falcon Exploration, LLC for Declaratory Judgement in the Superior Court of the State of Alaska, Third Judicial District at Anchorage regarding an interpretation of the operating agreement applicable to our subsidiary Renaissance Umiat. We asserted that the interests of Arctic Falcon in Renaissance Umiat have been diluted as a result of Arctic Falcon's failure to make capital contributions. The parties have been discussing a settlement. If the parties cannot come to agreement, the matter will be heard by the court. In the event our position is upheld, our interest in Renaissance Umiat, LLC would increase. Further, our interest in Renaissance Umiat, LLC will not change if the Arctic Falcon's position is upheld.

On 22 November 2012, Ancon Drilling Pty Ltd ("**Ancon**") filed a Claim and Statement of Claim against us in the Supreme Court of Queensland. Ancon's claim seeks the payment of a sum of A$1.1 million as damages for breach of a drilling services contract entered into between us and Ancon dated on or about 26 October 2011. The contract governed the drilling of exploration wells in certain of our coal exploration tenements in Queensland. We have defended the claim and filed a counterclaim against Ancon, and seek damages for breach of contract and other remedies amounting to a sum of A$0.8 million. We expect that the Supreme Court of Queensland will request that parties to the case negotiate timing in respect of the proceedings and in particular, the timetable setting down the future conduct of this matter.

On 18 October 2013, we received a notice from the DEHP in Queensland requiring us to make available certain information so as to enable the DEHP to conduct an investigation into allegations regarding the unlawful release of contaminants at our Chinchilla Demonstration Facility in contravention of the EPA and the conditions of our Environmental Authorities. See "Business—Health, Safety and Environmental Considerations" for further details.

INSURANCE

We maintain public and products liability insurance across our operations. In particular, we have industrial special risks and professional indemnity insurance for our operations in Australia and insurance coverage relating to control of well, hull and machinery and pollution for our operations in the United States. In addition, our insurance also provides coverage for personal accident and medical health in respect of our employees. Further, we believe that our existing insurance coverage is generally in line with industry standards in the countries where we operate.

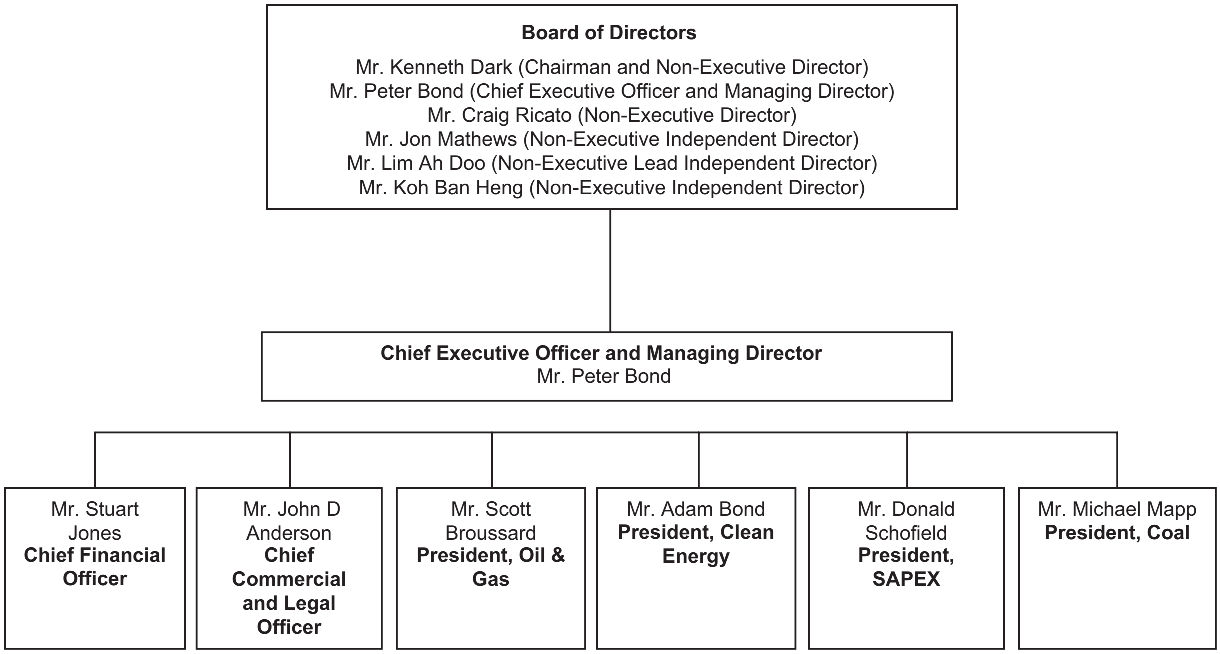
However, our insurance coverage does not provide 100% reimbursement of potential losses resulting from operational hazards, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

Our Directors regularly review the extent of our insurance coverage and believe that our existing insurance coverage is adequate as of the Latest Practicable Date. Further, we believe that our existing insurance coverage is generally in line with industry standards in the countries where we operate. For further discussion on the risks relating to insurance, see "Risk Factors—Risks Relating to our Business—We may not have sufficient insurance coverage against potential operational risks".

MANAGEMENT AND CORPORATE GOVERNANCE

MANAGEMENT STRUCTURE

The following chart shows our management reporting structure:



OUR DIRECTORS

Our board of directors has ultimate responsibility for the administration of the affairs of our Company. Our directors are as follows:

Name	Age	Address	Position
Mr. Kenneth Dark	70	Smellie & Co Building 32 Edward Street Brisbane, Queensland 4000, Australia	Chairman and Non-Executive Director
Mr. Peter Bond	51	Smellie & Co Building 32 Edward Street Brisbane, Queensland 4000, Australia	Chief Executive Officer and Managing Director
Mr. Craig Ricato	43	Smellie & Co Building 32 Edward Street Brisbane, Queensland 4000, Australia	Non-Executive Director
Mr. Lim Ah Doo........	64	10 Anson Road #23-13 International Plaza Singapore 079903	Non-Executive Lead Independent Director
Mr. Jon Mathews	62	Smellie & Co Building 32 Edward Street Brisbane, Queensland 4000, Australia	Non-Executive Independent Director
Mr. Koh Ban Heng	65	One Temasek Avenue #27-00 Millenia Tower Singapore 039192	Non-Executive Independent Director

Experience of our Directors

Information on the areas of responsibility, the business and working experience of our directors is set out below:

Mr. Kenneth Dark is our Chairman and Non-Executive Director. Mr. Dark was appointed to our Board of Directors in October 2004 and has been Chairman since September 2011. Mr. Dark began his early working life as an electrician before gaining tertiary engineering qualifications in the field of electronics and communications at NSW TAFE. Further study saw Mr. Dark promoted to a management role at Alcan Aluminium Limited's Australian smelter. Mr. Dark's final role at Alcan Aluminium Limited saw him managing the in-plant multi-disciplined project engineering team. At that time, projects included world-leading innovations in industrial process control. Concepts Mr. Dark pioneered then are still the mainstay of process control for the international aluminium smelting industry.

In 1986, Mr. Dark left the corporate world and established a highly successful business in the fuel distribution and retail industry through his own Darton group of companies. He has represented fuel distributors and retailers, chairing the national marketing committees for two major fuel companies and leading the national franchise negotiation committee to the successful renewal of contracts with one of the oil majors. He then went on to built a small chain of independent fuel and grocery outlets, a business in which he continues to maintain an interest. Mr. Dark's other business pursuits include time spent providing freelance management consulting. Mr. Dark has completed the Australian Institute of Company Directors course and is admitted as a Graduate member.

Mr. Peter Bond is our Chief Executive Officer and Managing Director. Mr. Bond has a successful track record in the coal and mining industries, both in Australia and overseas. His business interests include mineral, mining and associated operations in Australia and South East Asia. Mr. Bond was appointed to our Board in October 2004 and has been pivotal to our success since we listed on the ASX in May 2006. He has personally seen our Company evolve from a small-capitalisation business into an ASX 200 company, and seen our Company grow in talent from a small team to over 400 employees around the world. Over the years he has also owned and managed other of his own companies such as Bond Bros Contracting Pty Ltd and P.A. Bond & Co Pty Limited.

Building on his early engineering background as a metallurgist trainee in the early 80s, Mr. Bond has gained a unique knowledge and understanding of the industry over the course of a diversified career spanning more than 20 years. Mr. Bond has experience in the design, installation, commissioning and operation of complex processing plants and projects, and his various companies such as Auminco Mineral Processing Pty Ltd, Ore Pro Pty Ltd.

Mr. Craig Ricato is our Non-Executive Director. He brings a broad range of international experience to our Company across the regulatory, accounting and legal industries. Mr. Ricato joined our Company in March 2008 as General Counsel and Company Secretary, and was appointed to our Board in late 2010. He was previously our Executive Director of Legal and Corporate Affairs, where he was responsible for all transactional and corporate legal matters, including the management of an engagement and negotiation of all key commercial and regulatory matters. Prior to joining us, Mr. Ricato was a partner at Hemming + Hart Lawyers from February 2006 to March 2008, and a senior associate at Mallesons Stephen Jacques from January 2001 to February 2006, both in the area of dispute resolution and construction law. He was an assistant manager in the forensic accounting practice at KPMG from early 2000 to January 2001. Mr. Ricato also served as a police officer of the Queensland Police Service for eight years from 1992.

Mr. Ricato is currently a professional member of the Queensland Law Society. He was admitted as a Legal Practitioner of the Supreme Court of New South Wales and the Supreme

Court of Queensland in 2001 after graduating with a Bachelor of Laws with First Class Honours from the Queensland University of Technology. Mr. Ricato had also obtained a Bachelor of Commerce degree in 1991 from University of Queensland.

Mr. Lim Ah Doo was appointed Non-Executive Lead Independent Director of our Company on 22 November 2013. Mr. Lim is an independent director and chairman of the audit committees of Sembcorp Marine Ltd, GP Industries Limited and ARA-CWT Trust Management (Cache) Limited, (all of which are listed on the SGX-ST). He is also an independent director of SM Investments Corporation (a company listed on the Philippine Stock Exchange), an independent director, member of the audit committee and chairman of the nominating committee of Sateri Holdings Limited (a company listed on the Hong Kong Stock Exchange), and an independent director, chairman of the audit committee and member of the remuneration committee of U Mobile Sdn Berhad.

Mr. Lim brings with him vast experience and wide knowledge as a former senior banker and corporate executive. He held several key positions in Morgan Grenfell during his 18-year banking career with Morgan Grenfell (Asia) Limited ("**MGAL**") from 1977 to 1995 including his appointment as its Chairman and Managing Director in 1993, a position which he held until he left MGAL in 1995. From 2003 to 2008, he was the president and subsequently non-executive vice chairman of RGE Pte. Ltd., formerly known as RGM International Pte. Ltd., a leading global resource-based group. Mr. Lim was formerly an independent commissioner and chairman of the audit committee of PT Indosat Tbk, a leading listed Indonesian telecommunications group. Mr. Lim previously held directorships in EDB Investments Pte. Ltd., PST Management Pte. Ltd. and Chemoil Energy Limited. He also represented RGE Pte. Ltd. as a council member of the Singapore-Shandong Business Council and Singapore-Jiangsu Co-operation Council, and served as chairman of EDBV Management Pte. Ltd. from 2005 to 2006 and the Singapore Investment Banking Association in 1994 (as representative of Morgan Grenfell (Asia) Limited).

Mr. Lim holds an honours degree in engineering from the Queen Mary College, University of London and a Master in Business Administration degree from the Cranfield Institute of Technology.

Mr. Jon Mathews is our Non-Executive Independent Director. Mr. Jon Mathews joined our Company in December 2009. He brings to our Company over 30 years of experience in the coal mining industry prior to joining us. Between 1971 and 1973 he was employed by the Queensland Coal Association as a Cadet Mine Manager. From 1976 to 1996 he was employed at Rhondda Collieries, Ipswich, holding positions through all facets of mining. He became the Mine Manager of MW Haenke Mines in 1980, which at the time was the largest underground producing operation in Queensland and from 1986 to 1996 progressed to the position of Company Manager Qld.

During his period at Rhondda Collieries he worked for various companies who owned the mining operation including Bond Coal Division, FAI mining Limited and Oceanic Coal Pty Ltd. He was also responsible during this period for ensuring the success of a joint venture partnership with a Japanese company, Showa Coal Australia, between 1986 and 1996. Between 2001 and 2009, he was a self-employed consultant to the coal mining, transport and waste industries.

Mr. Mathews was a member of the Executive Committee of the Queensland Coal Association between 1987 and 1996, he also served as Chairman of the Underground Mine Managers Committee for three years and was also a member of the selection panel for Cadet Mine Manager for Queensland.

Between 1987 and 1996, Mr. Dark served as a director of West Moreton Coal Exporters between 1987 and 1996, and a Director of Parkhead Rail Terminal for the same period. Mr. Mathews obtained his unlimited first-class mine manager's certificate of competency (coal) (opencut and underground) in 1975.

Mr. Koh Ban Heng was appointed Non-Executive Independent Director of our Company on 22 November 2013. Mr. Koh started his career in the oil industry in 1972 with the then Mobil Oil Singapore as an operations engineer. In 1974, he joined Singapore Petroleum Company Limited where he held various positions throughout the years. Mr. Koh was appointed as the Chief Executive Officer and Executive Director of Singapore Petroleum Company Limited in 2003, and subsequently appointed Chief Executive Officer and Managing Director in March 2009. He retired as Chief Executive Officer and Managing Director on 30 June 2011 and was then appointed as Senior Advisor from 1 July 2011. Mr. Koh's experience spans aspects such as refining operations and planning, marketing, distribution and terminalling, supply and trading, oil and gas exploration and production, including the development and establishment of new businesses. Mr. Koh currently holds directorships in Singapore Petroleum Venture Private Limited and Singapore Refining Company Private Limited. Mr. Koh is also an independent director of Keppel Infrastructure Holding Pte. Ltd., a fully owned subsidiary of Keppel Corporation Limited which is listed on the SGX-ST, and an independent director of Tipco Asphalt PLC, a listed company in Thailand. Mr. Koh is a director on the school boards of Chung Cheng High School Main, Chung Cheng High School Yishun and Nanyang Junior College. He also serves as the Chairman of the Asean Council on Petroleum for Singapore, as appointed by Keppel Corporation Limited which is a member of the Asean Council on Petroleum.

Mr. Koh graduated from the then University of Singapore with a Bachelor of Sciences degree in 1972 and obtained a post-graduate diploma in Business Administration from the then University of Singapore in 1978.

As evidenced by their respective business and working experience set out above, our directors possess the appropriate expertise to act as directors of our Company. In accordance with the requirements under the SGX-ST listing rules, we have made arrangements for our directors to be briefed on the roles and responsibilities of a director of a public listed company in Singapore.

Other Principal Directorships of our Directors

The list of present and past directorships held by our directors in the last five years preceding the date of this offering document, excluding those held in our Company, is set out in "Appendix E—List of Present and Past Directorships—Directors".

Interest in Shares

As at the date of this offering document, Mr. Peter Bond, Mr. Kenneth Dark, Mr. Craig Ricato and Mr. Jon Mathews each holds interests in our Shares. For further details as to our Directors' interests in our Shares, see "Share Ownership—Ownership Structure".

Service Agreements

Our Group has entered into the following service agreements with our Directors:

- in relation to Mr. Peter Bond, with a company that Mr. Peter Bond is the sole shareholder and director, Newtron for the period 1 January 2010 to 31 December 2013, subject to renewal. He will be eligible to participate in our Company's Performance Rights Plan. If the agreement is terminated for our convenience or by Newtron if there is a change of control of our Company (which is defined under Section 50AA of the Corporations Act as a change to the person or entity that has the capacity to determine the outcome of decision of our financial and operating policies), Mr. Bond will be entitled to a management fee for the unexpired period of the entire term upon termination; and
- in relation to Mr. Craig Ricato with a professional contracting entity, the Executive Management Services Discretionary Trust for the provision of executive services effective 1 July 2013 on an as-needed basis. There is no fixed term in the agreement. Mr. Ricato, with 14 days notice period in writing, will be entitled to any outstanding service fees and/or expenses as at the date of termination, and if the agreement is

terminated before 31 December 2013, a pro-rated amount of a retainer fee due to him under the agreement. This agreement was entered into when Mr. Craig Ricato stepped down from his full time role as executive director to non-executive director to pursue other opportunities. See "Interested Person Transactions and Conflicts of Interest—Interested Person Transactions—Present and Ongoing Interested Person Transactions—Transactions with Directors—Mr. Craig Ricato" for further details on this agreement.

Except as disclosed above, there are no existing or proposed service agreements entered into or to be entered into by our Directors with our Company or any of our subsidiaries.

Terms of Office

Our Directors do not currently have a fixed term of office. A director must not hold office (without re-election) past the third annual general meeting following that Director's appointment or three years. A retiring director shall be eligible for re-election. We must hold an election of Directors each year and if no election of Directors is otherwise scheduled to occur at an annual general meeting, then one Director must retire from office in that annual general meeting. The Director (other than a Director who is a Managing Director) to retire pursuant to which shall be the one who has been longest in office since his last re-election or appointment.

OUR EXECUTIVE OFFICERS

In addition to our directors, our Executive Officers are responsible for our day-to-day management and operations. Certain information regarding our Executive Officers are as follows:

Name	Age	Address	Position
Mr. Peter Bond	51	Smellie & Co Building 32 Edward Street Brisbane, Queensland, 4000, Australia	Managing Director and Chief Executive Officer
Mr. Stuart Jones	48	Smellie & Co Building 32 Edward Street Brisbane, Queensland, 4000, Australia	Chief Financial Officer
Mr. John D. Anderson	51	Smellie & Co Building 32 Edward Street Brisbane, Queensland, 4000, Australia	Chief Commercial and Legal Officer
Mr. Scott Broussard	56	1000 Louisiana Street Suite 1500 Houston, Texas USA 77002	President, Oil and gas
Mr. Adam Bond	37	Smellie & Co Building 32 Edward Street Brisbane, Queensland, 4000, Australia	President, Clean Energy
Mr. Donald Schofield	62	Smellie & Co Building 32 Edward Street Brisbane, Queensland, 4000, Australia	President, SAPEX
Mr. Michael Mapp	49	Smellie & Co Building 32 Edward Street Brisbane, Queensland, 4000, Australia	President, Coal

Experience of our Executive Officers

Information on the areas of responsibility, the business and working experience of our Executive Officers is set out below:

Mr. Peter Bond is our Chief Executive Officer and Managing Director. Please see the description above.

Mr. Stuart Jones is our Chief Financial Officer. He joined our Company in February 2013 and has over 20 years of accounting and finance experience and has held senior corporate positions in both the oil and gas and banking industries. Prior to joining us, Mr. Jones was an independent consultant focused on the energy and resources sector. He was General Manager Finance and Investor Relations at Nexus Energy Ltd, an ASX-listed company, from September 2009 to July 2012 where he was in charge of the funding and investor relations. From May 2008 to July 2009 Mr. Jones served as the Chief Financial Officer of Viking Oil & Gas International Ltd, a privately held start-up entity, and between May 1998 and May 2008, was Director, oil and gas at HBOS Plc, where he was in charge of the execution of funding to the energy sector. From 1990 to May 1998, Mr. Jones was also the Chief Accountant at Sanctuary Group where he was responsible for overall finance, funding and treasury matters. Mr. Jones obtained a Bachelor of Science (Mathematics) (with Honours) from the University of Liverpool in 1987 and obtained his ACCA Certificate, UK for July 1998 to February 2011.

Mr. John D. Anderson is our Chief Commercial and Legal Officer. Mr. Anderson was appointed to his position in our Company effective from July 2013, and is responsible for all global commercial and legal functions including intellectual property management. Prior to joining our Company, he founded BKK Partners, an Australian based investment bank and corporate advisory firm focusing on resource, oil and gas in 2009. From 2003 to 2009 he worked with Goldman Sachs JBWere, Sydney, holding various positions including, Executive Director, Managing Director, Head of Financial Institutions Group, an Advisor, and from 1999 to 2003 he was an Executive Director for Goldman Sachs Hong Kong. Prior to joining Goldman Sachs, Mr. Anderson served as an associate foreign counsel with Davis Polk & Wardwell in Hong Kong from 1994 to 1999 where he focused on international capital markets and mergers and acquisitions. Mr. Anderson obtained his Juris Doctor from the University of Michigan Law School in 1986 where he graduated with a Magna Cum Laude, and a Bachelor of Arts from Albion College in 1983.

Mr. Scott Broussard is our President, Oil and gas. Mr. Broussard has over 30 years of executive and operations experience in the Gulf Coast oil and gas business. He joined our Company in October 2011 where he served as General Manager of the Gulf Coast Region. From 2008 to late 2010, Mr. Broussard acted as chief executive officer and chairman of Probe Resources Ltd., an exploration and production company with assets in the Gulf of Mexico, United States listed on the Toronto Stock Exchange. Mr. Broussard was the vice president of operations at Norsk Hydro between January 2005 and December 2006, and from March 1998 to December 2005, he was also vice president operations of Hydro Gulf of Mexico, formerly Spinnaker Exploration, where he supervised all phases of the oil and gas operations in the U.S. Gulf of Mexico region. He was also previously a partner from 1995 to 1998 in an engineering consulting firm, HTK Consultants, which that provided engineering and operations expertise, both offshore and onshore, on the Gulf Coast. Mr. Broussard obtained his Bachelor of Science degree in petroleum engineering from Louisiana State University in 1982.

Mr. Adam Bond is our President, Clean Energy. Mr. Bond joined our Company as President, European Operations in 2011. He is now President of the Clean Energy department, where he is responsible for the execution and deployment of our Clean Energy strategy globally, including UCG to GTL projects. Mr. Bond has a commercial background in leading and executing large, complex infrastructure projects. Prior to joining us, Mr. Bond held key positions with the British Government as Project Director on the United Kingdom’s first carbon capture and storage programme from October 2009 to July 2011. From May 2002 to October 2009, Mr. Bond was an Associate Director in charge of project finance and corporate advisory services with Ernst & Young LLP, and was also previously a manager at Arthur Andersen—Brisbane from February 1999 to May 2002. Mr. Bond is presently a Non-Executive Director of AFC Energy PLC. He obtained his Bachelor of Commerce in 1997 and his Bachelor of Laws in 1998, both from the University of Queensland, and his Masters of Taxation from the University of New South Wales in 2002.

Mr. Donald Schofield is our President, SAPEX. Mr. Schofield joined our Company in 2007 as General Manager of our UCG business. Mr. Schofield was based in the United States as President of Linc Energy Operations Inc in 2010 and assumed the role of President of SAPEX in 2012. Between January 2004 and May 2007, Mr. Schofield was the Managing Director of White Sands Petroleum Limited a petroleum exploration company. Between April 2002 and February 2004, he was the Managing Director of OME Group Ltd which is involved in drilling operations and petroleum exploration, and General Manager of A.J. Lucas Ltd from 2001 to 2002 which was involved in directional drilling in large construction products and underground mine. Between 1994 and 2011, he was also an independent consultant on drilling, oil and gas and mining projects. Mr. Schofield was also appointed the director of Australian Oceanographics Pty. Ltd. in May 2009. Mr. Schofield obtained a Bachelor of Science (Geology) in 1973 and a Masters of Arts (Marine Geology) in May 1980.

Mr. Michael Mapp is our President, Coal. Mr. Mapp joined our Company in February 2012 as the President of our conventional coal mining business. Mr. Mapp joined our Company from Intra Energy Corporation Ltd where he held the position of Chief Operating Officer from May 2011 to February 2012. Prior to Intra Energy Corporation Ltd, he worked at Xstrata Coal as Operations Manager of Ulan underground until May 2011. Between 2007 and 2010 he worked in various positions in Vale Australia including General Manager of the Integra Coal Operations and Executive General Manager of the NSW Operations before being promoted to Director of the coal operations in Australia. Mr. Mapp was responsible for operations including Carborough Downs, Isaac Plains, Broadlea and the Integra Coal underground and open-cut mines at Vale Australia. Between December 2005 and May 2007, he was General Manager of Integra Coal Operations with AMCI Holdings. Between 2009 and 2010, Mr. Mapp was an executive committee member of the New South Wales Minerals Council.

Other Principal Directorships of our Executive Officers

The list of present and past directorships held by our Directors in the last five years preceding the date of this offering document, excluding those held in our Company, is set out in "Appendix E—List of Present and Past Directorships—Executive Officers".

FAMILY RELATIONSHIPS

There are no family relationships between any of our Directors and Executive Officers and between our Directors and Executive Officers and our Substantial Shareholders.

INDEPENDENT DIRECTORS

None of our Non-Executive Independent Directors sits on the boards of our principal subsidiaries that are based in jurisdictions other than Singapore.

ARRANGEMENTS OR UNDERSTANDING

None of our Directors or Executive Officers has any arrangement or understanding with any of our Substantial Shareholders, customers or suppliers or other persons, pursuant to which he or she was appointed as our Director or Executive Officer, as the case may be.

COMPENSATION

The compensation paid by our Company and our subsidiaries to each of our Directors and each of our Executive Officers for services rendered by them in all capacities to our Company and our related corporations for FY2012 and FY2013 and expected to be payable by our Company and our subsidiaries to each of these Directors and Executive Officers for services rendered by them in all capacities to our Company and our related corporations for the year FY2014, in remuneration bands[(1)], are as follows:

Name	Year ended or ending 30 June 2012	2013	2014 (estimated)[(2)]
Directors			
Mr. Kenneth Dark	Band A	Band A	Band A
Mr. Peter Bond	Band D	Band E	Band E
Mr. Craig Ricato	Band H	Band F	Band C
Mr. Lim Ah Doo	-[(3)]	-[(3)]	Band A
Mr. Jon Mathews	Band C	Band B	Band A
Mr. Koh Ban Heng	-[(3)]	-[(3)]	Band A
Executive Officers (who are not Directors)			
Mr. Stuart Jones	-[(3)]	Band B	Band B
Mr. John D. Anderson	-[(3)]	-[(3)]	Band B
Mr. Scott Broussard	Band C	Band F	Band C
Mr. Adam Bond	Band C	Band C	Band B
Mr. Donald Schofield	Band G	Band B	Band B
Mr. Michael Mapp	Band A	Band E	Band B

Notes:

(1) Remuneration bands:
Band A means between S$1 and S$250,000.
Band B means between S$250,001 and S$500,000.
Band C means between S$500,001 and S$750,000.
Band D means between S$750,001 and S$1,000,000.
Band E means between S$1,000,001 and S$1,250,000.
Band F means between S$1,250,001 and S$1,500,000.
Band G means between S$1,500,001 and S$1,750,000.
Band H means between S$1,750,001 and S$2,000,000.

(2) The estimated amount of remuneration excludes any bonus or profit-sharing plan or any other profit-linked agreement or arrangement payable for FY2014.

(3) Not yet employed or appointed by our Group.

Except as required under any laws or regulations, we do not set aside or accrue any amounts for pension, retirement or similar benefits.

Compensation includes benefit-in-kinds and compensation that has already been paid and includes any deferred compensation accrued for the financial year in question and payable at a later date.

Certain of our Directors and Executive Officers also received Options and Rights granted to them under the Employee Option Plan and the Performance Rights Plan, respectively, as part of their compensation. See "Share-based Incentive Plans" of this offering document.

No Options were granted to the Directors and Executive Officers in the financial years ended 30 June 2012 and 2013, and none will be granted going forward under the Employee Option Scheme, as this was replaced by the Performance Share Plan. See "Share-Based Incentive Plans" for further details.

In respect of FY2012, Mr. Kenneth Dark, our Chairman and Non-Executive Director, exercised his remaining 1,000,000 Options at A$0.25 per Option, and Mr. Craig Ricato, our Non-Executive Director, continued to hold 500,000 Options exercisable at A$0.70 per Option expiring 31 December 2012 at the end of FY2012. Mr. Donald Schofield, our Executive

Officer, exercised 483,334 Options at an exercise price of A$0.76 per Option within FY2012, and held 666,666 Options at the end of FY2012.

In respect of FY2013, Mr. Ricato exercised his remaining 500,000 Options, while Donald Schofield, our executive officer, exercised his remaining 666,666 Options.

The number of Shares in respect of which outstanding Rights have been granted to our Directors and Executive Officers are:

Name	No. of Shares in respect of which outstanding Rights have been granted	Vesting Date
Our Director		
Mr. Jon Mathews	125,000	25 November 2013
	125,000	25 November 2014
Our Executive Officers		
Mr. Stuart Jones	200,000	17 August 2014
	200,000	17 August 2015
	200,000	17 August 2016
	200,000	17 August 2017
Mr. Scott Broussard	100,000	24 April 2014
	100,000	24 April 2015
	100,000	24 April 2016
Mr. Adam Bond	150,000	1 September 2014
	150,000	1 September 2015
	150,000	1 September 2016
	100,000	7 February 2014
	100,000	7 February 2015
	100,000	7 August 2015

Performance related bonuses were also implemented for Mr. Scott Broussard for FY2013. Mr. Scott Broussard is eligible for two performance bonuses equivalent to one tranche of 200,000 Rights and one tranche of 400,000 Rights linked to performance outcomes. Mr. Stuart Jones is eligible for approximately 800,000 Rights subject to his fulfillment of a minimum of 18 months continuous employment with us, which would thereafter vest over four consecutive years with one-quarter of the Rights awarded vested each year. In addition, Mr. Stuart Jones is also entitled to either 200,000 Shares, or the maximum amount of his base salary permitted under the Corporations Act, if his employment is terminated within 18 months upon the occurrence of certain events resulting in a change of control of our Company. Mr. Michael Mapp will be paid A$500,000 for the first performance bonus payable on the date that is 18 months from the date of his commencement, and A$500,000 for the second performance bonus payable on the date that is 30 months from the date of his commencement, subject to certain conditions such as the divestment of the Teresa Project coal asset or our subsidiary, New Emerald Coal. If such divestments have not taken place, the relevant performance bonus shall be paid in our Shares having a value equal to the performance bonus in accordance with the Performance Rights Plan.

Pensions, Retirement or other Benefits

Most of our employees in Australia are members of a superannuation fund, some of our employees are members of their own self-managed superannuation fund.

The purpose of superannuation funds under Australian law is to provide retirement and death benefits for employees which can take the form of either a lump sum or pension entitlement. All superannuation funds we contribute to on behalf of our employees comply with the relevant Australian legislation, Superannuation Guarantee (Administration) Act 1992 (Cth).

Our United States subsidiaries offer their employees the option to contribute to a "401(k) plan" which is the common name in the United States for the tax-qualified, defined-contribution pension account defined in subsection 401(k) of the U.S. Internal Revenue Taxation Code. Under this plan, our employees employed in the United States may, but are not required, to contribute a portion of their salary to the plan, subject to certain internal revenue service limitations. We will match such contributions up to 5.0% per annum of the employee's annual base salary.

We have no other liabilities with respect to retirement benefits or pensions for our employees. We have not set aside and have not accrued any amounts to provide pension, retirement or similar benefits for our Directors or our Executive Officers.

CORPORATE GOVERNANCE

We recognise the importance of corporate governance and the maintenance of high standards of accountability to our Shareholders.

The Code of Corporate Governance recommends that the roles of chairman and chief executive officer be separated, to ensure an appropriate balance of power and increased accountability to shareholders. The roles of Chief Executive Officer and Non-Executive Chairman are currently held by Mr. Peter Bond and Mr. Kenneth Dark, respectively.

In addition, Mr. Lim Ah Doo has been appointed the Non-Executive Lead Independent Director of our Company and is available to our Shareholders where they have concerns for which contact through the normal channels of Chief Executive Officer or Chief Financial Officer has failed to resolve or for which such contact is inappropriate.

We have three board committees, (i) the Audit and Risk Management Committee, (ii) the Nominating Committee, and (iii) the Remuneration Committee.

Audit and Risk Management Committee

Our internal policy requires our Audit and Risk Management Committee to have at least three members, all of whom have to be non-executive and the majority of whom, including the Chairman, have to be independent. Under our Audit and Risk Management Committee's terms of reference, our Audit and Risk Management Committee should include members who are financially literate and have at least two members, including the Chairman having recent and relevant accounting or related financial management expertise or experience and some members who have an understanding of the industries in which we operate. Our Audit and Risk Management Committee will have explicit authority to investigate any matter within its terms of reference, full access to and co-operation by our management and full discretion to invite any Director or Executive Officer to attend its meetings, and reasonable resources to enable it to discharge its functions properly.

The Audit and Risk Management Committee comprises three members, namely Mr. Lim Ah Doo, Mr. Craig Ricato and Mr. Jon Mathews. The Chairman of the Audit and Risk Management Committee is Mr. Lim Ah Doo. The Audit and Risk Management Committee is required to meet at least four times a year to perform functions such as:

(a) overseeing the adequacy of the controls established by executive management to identify and manage areas of potential risk and to safeguard our assets;

(b) evaluating the processes in place to ensure that accounting records are properly maintained in accordance with statutory requirements and financial information provided to Shareholders and our Directors is accurate and reliable;

(c) review the significant financial reporting issues and judgments so as to ensure the integrity of the financial statements of our Company and any announcements relating to our Company's financial performance;

(d) review with external and internal auditors and reporting to our Board at least annually on the adequacy and effectiveness of our internal control system, including financial, operational, compliance and information technology controls (such review can be carried out internally or with the assistance of any competent third parties);

(e) review with internal auditors, the programme, scope and results of the internal audit and our management's response to their findings to ensure that appropriate follow-up measures are taken;

(f) review the effectiveness of our internal audit function;

(g) review the scope and results of the external audit, and the independence and objectivity of the external auditors;

(h) review with external auditors the impact of any new or proposed changes in accounting principles or regulatory requirements on our financial information;

(i) making recommendations to our Directors on the proposals to the shareholders on the appointment, re-appointment and removal of the external auditors, and approving the remuneration and terms of engagement of the external auditors;

(j) to review the interested person transactions (including the interested person transactions disclosed in this offering document except for those insofar as they relate to remuneration matters) or the transactions that may lead to conflicts of interests, to ensure that they are in compliance with the laws and the regulations of the SGX-ST, and are reasonable and in the best interests of our Company;

(k) monitor the investments in our customers, suppliers and competitors made by our Directors, controlling shareholders and their respective associates who are involved in the management of or have shareholding interests in similar or related business of our Company and make assessments on whether there are any potential conflicts of interests;

(l) review filings with the SGX-ST or other regulatory bodies which contain our financial information and ensure proper disclosure;

(m) commission and review the findings of internal investigations into matters where there is any suspected fraud or irregularity or failure of internal controls or infringement of any law, rule and regulation which has or is likely to have a material impact on our operating results and/or financial position;

(n) review policy and arrangements by which our staff and any other persons may, in confidence, raise concerns about possible improprieties in matters of financial reporting or other matters and ensure that arrangements are in place for such concerns to be raised and independently investigated, and for appropriate follow-up action to be taken;

(o) reviewing our risk management structure (including all hedging policies) and any oversight of our risk management processes and activities to mitigate and manage risk at acceptable levels determined by our directors;

(p) report to our Board the work performed by our Audit and Risk Management Committee in carrying out its functions;

(q) reviewing the co-operation given by our officers to the external auditors; and

(r) to perform any other act as delegated by our Board and approved by our Audit and Risk Management Committee.

All decisions at any meeting of our Audit and Risk Management Committee shall be decided by a majority of votes of the members present and voting and such decision shall at all times exclude the vote, approval or recommendation of any member who is interested in the subject matter under consideration.

Apart from the duties listed above, our Audit and Risk Management Committee is required to commission and review the findings of internal investigations into matters where there is any suspected fraud or irregularity, or failure of internal controls or infringement of any law, rule or regulation which has or is likely to have a material impact on our results of operations and/or financial position. Each member of our Audit and Risk Management Committee must abstain from voting on any resolution in respect of matters in which he is interested.

Adequacy of Internal Controls

Our Board, after making all reasonable enquiries and to the best of its knowledge and belief, with the concurrence of our Audit and Risk Management Committee, is of the opinion that the internal controls of our Group are adequate to address the financial, operational and compliance risks of our Group.

Suitability of our Chief Financial Officer

Our Audit and Risk Management Committee has reviewed Mr. Stuart Jones' curriculum vitae and has also interviewed Mr. Jones. Our Audit and Risk Management Committee noted that Mr. Jones has over 20 years of accounting and finance experience and has held senior corporate positions in both the oil and gas and banking industries. He was previously General Manager Finance and Investor Relations at Nexus Energy Ltd, an ASX-listed company from September 2009 to July 2012, and Director, oil and gas at HBOS Plc and Chief Accountant at Sanctuary Group from 1990 to May 1998. Mr. Jones obtained a Bachelor of Mathematics (with Honours) from the University of Liverpool in 1987.

In the course of preparing for the listing of our Company on the Main Board of the SGX-ST, our Audit and Risk Management Committee has observed and noted Mr. Jones' contributions at various occasions, discussions and meetings. In the course of such interactions, our Audit and Risk Management Committee is of the view that Mr. Jones has demonstrated a strong and clear understanding of our businesses and familiarity with the finance and accounting functions of our Group, and our Audit and Risk Management Committee has not been made aware of any other matter that would question Mr. Jones' suitability for the position of Chief Financial Officer.

Having considered the above, and the qualifications and past working experience of Mr. Jones, our Audit and Risk Management Committee is of the view that Mr. Jones is suitable for the position of Chief Financial Officer of our Group.

After making all reasonable enquiries, and to the best of the knowledge and belief of our Audit and Risk Management Committee, nothing has come to the attention of the members of our Audit and Risk Management Committee to cause them to believe that Mr. Jones, who is appointed Chief Financial Officer, does not have the competence, character and integrity expected of a Chief Financial Officer (or its equivalent rank) of a listed issuer.

Nominating Committee

Our internal policy requires the Nominating Committee to have at least three members, of whom the majority has to be independent, including the Chairman. Our Nominating Committee comprises Mr. Koh Ban Heng, Mr. Kenneth Dark and Mr. Lim Ah Doo. The Chairman of the Nominating Committee is Mr. Koh Ban Heng. Our Nominating Committee is responsible for matters such as:

(a) review and recommend candidates for appointments to our Board and Board committees (excluding the appointment of existing members of our Board to each of our Audit and Risk Management Committee, our Nominating Committee and our Remuneration Committee for the purposes of the initial establishment of such Board committees), as well as candidates for senior management staff, who are not also candidates for appointment to our Board;

(b) review of board succession plans for our Directors, in particular, our Chairman and our Chief Executive Officer;

(c) develop of a process for evaluation of the performance of our Board, our board committees and our Directors;

(d) review of training and professional development programmes for our Board;

(e) review and recommend nomination for re-appointment or re-election or renewal of appointment of our Directors;

(f) review and recommend candidates to be our nominees on the boards and board committees of the listed companies and entities within our Group;

(g) determine independence of our Directors (except where the relevant Directors are conflicted);

(h) review the participation (whether by way of obtaining an interest in or taking a board seat or otherwise) by each Non-Executive Independent Director in any competing businesses and take into account such matters in the re-appointment or re-election or renewal of appointment of such Non-Executive Independent Director; and

(i) undertake generally such other functions and duties as may be required by law or the Listing Manual, and by amendments made thereto from time to time.

In the event that any member of our Nominating Committee has an interest in a matter being deliberated upon by our Nominating Committee, he will abstain from participating in the review and approval process relating to that matter as well as from voting on any resolutions relating to such matters.

Remuneration Committee

Our internal policy requires the Remuneration Committee to have at least three members, all of whom have to be non-executive and a majority of whom have to be independent, including the Chairman. Our Remuneration Committee comprises, Mr. Jon Mathews, Mr. Kenneth Dark and Mr. Koh Ban Heng. The Chairman of the Remuneration Committee is Mr. Jon Mathews. Our Remuneration Committee is responsible for, among others, recommending to our Board a framework and criteria of remuneration for the directors and key executives, including the review of interested person transactions that relate to remuneration matters, and for recommending specific remuneration packages for each director and the chief executive officer. The recommendations of our Remuneration Committee are submitted for endorsement by the entire Board, subject to the requirement that no individual is directly involved in deciding their own remuneration. All aspects of remuneration, including but not limited to directors' fees, salaries, allowances, bonuses, options and benefits in kind shall be covered by our Remuneration Committee.

All decisions at any meeting of our Remuneration Committee shall be decided by a majority of votes of the members present and voting and such decision shall at all times exclude the vote, approval or recommendation of any member who in interested in the subject matter under consideration.

SHARE-BASED INCENTIVE PLANS

Our Shareholders had approved the employee option plan (the "**Employee Option Plan**") at our annual general meeting in 2005. Following changes to the taxation of employee share schemes announced in the Australia 2009 Federal Budget, the Employee Option Plan was replaced with the performance rights plan (the "**Performance Rights Plan**", together with the Employee Option Plan, the "**Share-Based Incentive Plans**"), which was approved by our Shareholders at our annual general meeting in 2009. The rules of the Share-Based Incentive Plans may be inspected by Shareholders at the registered office of our Company for a period of six months from the date of registration of this offering document. See Appendix C of this offering document for a summary of the rules of the Performance Rights Plans.

Employee Option Plan

The Employee Option Plan was established as an effective retention tool which provided alignment between the interests of the management and the shareholders. Under the Employee Option Plan, the options under the Employee Option Plan (the "**Options**") were granted at the discretion of our Board in accordance with the rules of the Employee Option Plan and all directors and employees employed by our Group are eligible participants. As determined by our Board, a minimum continuous period of employment (usually twelve months) with our Company or any of our subsidiaries is required prior to the first exercise date, which falls on 31 December annually. Subject to ongoing employment with our Company or any of our subsidiaries, the Options are exercisable at the earlier of (i) the date falling two years after the grant date, and (ii) the date of which special circumstances (including total and permanent disablement, death, retirement or retrenchment) arise in respect of the participant. The Options will lapse one the earliest of, the last exercise date, being five years from the date of grant of Options, termination of the participant's employment where termination arose from circumstances where our Board considers to involve fraud, dishonesty or other serious misconduct, the expiration of 30 days after termination, where such termination arose from other circumstances not involving fraud, dishonesty or other serious misconduct and the receipt by us of notice from the participant that the participant has elected to surrender the Options. The Options do not carry dividend or voting rights. Apart from a time-based service condition, there are no other conditions. When exercisable, each Option is convertible into one Share.

Prior to being replaced by the Performance Rights Plan, we had granted to 121 participants (including our Directors, our Executive Officers and our employees) an aggregate of 48,350,000 Options. As at the Latest Practicable Date, 1,944,992 Options remain outstanding. All of these Options are held by our employees and none of which are held by our Directors. Subject to our Board's discretion to charge a nominal consideration for the grant of Option, no consideration was required to be paid by each participant on acceptance of the grant of Options. Details of the outstanding Options, including those held by our employees are set out below:

No. of Shares in respect of which outstanding Options have been granted	Expiration Date	Exercise Price
1,553,661	31 December 2013	A$0.59 to A$3.16
391,331	31 December 2014	A$1.34 to A$3.16

Under the Employee Option Plan, in the event of a variation in our issued share capital (whether by way of a bonus issue, *pro rata* issue of Shares, reorganisation of capital), the exercise price, which is to be determined at the discretion of our Board at the time of the grant of Options, and/or number of Shares comprised in an Option to the extent unexercised shall be adjusted in such manner as the committee administrating the Employee Option Plan may in its absolute discretion determine to be appropriate.

Subsequent to the adoption of the Performance Rights Plan, no further Options were granted pursuant to the Employee Option Plan. Accordingly, no further Options will be granted upon our admission to the Official List of the SGX-ST and our admission will not affect the validity of the Options that have been granted under the Employee Option Plan. However, Options may lapse on certain events such as the participant ceasing to be an employee.

Performance Rights Plan

Similar to the Employee Option Plan which it replaced, the Performance Rights Plan seeks to align the interest of the eligible employees with the future and current Shareholders through the sharing of a personal interest in the future growth and development of our Company. The provision for the Performance Rights Plan to vest in multiple tranches over multiple years provides the balance between the objectives of attracting and retaining high performing employees and aligning the interests of these employees with the shareholders in the long term. The rights issued under the Performance Rights Plan (the "**Rights**") will be determined at the discretion of our Board. To this end, our Board may from time to time, in its absolute discretion, grant to a full time employee or director of our Company or subsidiaries, Rights. The Rights will vest in four equal tranches over 48 months, with the first tranche vesting 18 months following commencement of employment. In determining the number of Rights granted to an employee, our Board takes into consideration an employee's base salary, level within our Company and our Share price at the time of grant. Rights under the Performance Rights Plan do not carry dividend or voting rights until they convert into ordinary Shares. Rights automatically convert to Shares on the vesting dates provided all vesting conditions, imposed at the discretion of our Board, have been met. Each Right is convertible to one Share.

Should employment of the eligible participant lapse due to death or total permanent disability, the unvested Rights will continue to vest but there will be no further entitlements to future Rights awards. In the case where employment of the eligible participant ceases due to redundancy, our Board, in its sole and absolute discretion and on a case-by-case basis, may consider whether the unvested Rights will vest and if so, how many.

Rights have previously been granted under our Performance Rights Plan. As at the Latest Practicable Date, 9,082,676 Rights which were granted remain outstanding. All of these Rights are held by our employees (including our Directors and our Executive Officers). No consideration was required to be paid on acceptance of the grant of the Rights. Details of the outstanding Rights held by such Director or employee, including the vesting period, are set out below[(1)]:

Vesting Period	No. of Shares in respect of which outstanding Rights have been granted
2013	543,485
2014	3,699,918
2015	2,380,065
2016	1,714,819
2017	667,555
2018	76,834
Total	9,082,676

Note:

(1) Excludes our Directors and Executive Officers, who hold, in aggregate, 2,100,000 Rights as at the Latest Practicable Date.

The Performance Rights Plan is not in full compliance with Chapter 8 of the SGX-ST Listing Rules (the "**Relevant Provisions**"). However, as it is a pre-existing plan and has already been previously approved by shareholders when the Company was previously listed on the ASX, the Company will amend the rules to comply with the Relevant Provisions. Prior to such amendment, we have undertaken not to grant any further Rights under the Performance Rights Plan.

Administration of our Performance Rights Plan

Our Remuneration Committee will be designated as the committee responsible for the administration of our Performance Rights Plan. Our Remuneration Committee will determine, among others, the following:

(i) the persons to be granted Rights; and

(ii) recommendations for modifications to the Performance Rights Plan.

In compliance with the requirements of the Listing Manual, a participant of the Performance Rights Plan who is a member of the Remuneration Committee shall not be involved in its deliberations in respect of the Rights to be granted to or held by that member of the Remuneration Committee.

Size of the Performance Rights Plan

The aggregate number of new Shares which may be issued pursuant to the exercise of Rights granted under the Performance Rights Plan, when added to the number of Shares issued in respect of the Employee Option Plan, at any point in time, shall not exceed 5.0% of the total issue share capital of our Company on the day immediately preceding the date of the relevant grant.

Participation of controlling shareholders

The Performance Rights Plan will also include the participation of the controlling shareholders as defined by the Listing Manual, who have actively contributed to the progress and success of our Group. This will enable us to have a fair and equitable system to reward employees who have made and continue to make important contributions to the long-term growth of our Group notwithstanding that they are controlling shareholders. It will serve as a way of rewarding them for their dedicated services to our Group and also as a motivation for them to take a long-term view of our Group.

Although the controlling shareholders already have shareholding interests in us, their participation in the Performance Rights Plan ensures that they are equally entitled with our employees who are not controlling shareholders, to take part and benefit from these systems of remuneration.

There will be safeguards in place to prevent abuses of the Performance Rights Plan resulting from the participation of controlling shareholders such as the following:

(i) the participation of the controlling shareholders must be specifically approved by independent Shareholders in separate resolutions for each such person; and

(ii) in seeking such approval, clear justification as to their participation, the number of Shares comprised in the Rights and the terms of the Rights to be granted to the controlling shareholders must be provided.

The controlling shareholder who is entitled to participate in the Performance Rights Plan and the rationale for his participation is described below.

Proposed participation of Mr. Peter Bond

We are proposing that Mr. Bond be given the opportunity to participate in the Performance Rights Plan. Mr. Bond is our Chief Executive Officer and Managing Director and has been instrumental to our growth since he acquired a controlling interest in us and appointed as a Director in 2004. Mr. Bond oversees all aspect of our Company and has been pivotal to our success since we listed on the ASX in May 2006.

Mr. Bond's aggregate annual remuneration (including salary, bonus and other incentives (both monetary or otherwise)) in the last two financial years ended 30 June 2012 and 2013 from our Group in respect of the executive capacities held by him in our Group was in the range S$750,001 and S$1,000,000. As at the Latest Practicable Date, Mr. Bond does not hold any Rights.

Financial Effects of the Share-based Incentive Plans

Share capital

The Share-based Incentive Plans may result in an increase in our Company's issued share capital when new Shares are issued to participants pursuant to the exercise of Options or the grant of the Rights, as the case may be. However, if existing Shares are purchased for delivery to participants in lieu of issuing new Shares to them, there will be no impact on our Company's issued share capital.

Net tangible assets

As described below, the Share-based Incentive Plans will result in a charge to our statement of profit or loss and other comprehensive income equal to the fair value at which the new Shares are issued or liability recognised. For cash-settled Share-based Incentive Plans, our net tangible assets will decrease by the amount of expenses charged to the statement of profit or loss and other comprehensive income. For equity-settled Share-based Incentive Plans, there will be no effect on our net tangible due to the offsetting effect of expenses recognised and increased share capital or reserves.

It should be noted that the delivery of Shares to the participants is contingent upon the participants meeting prescribed performance targets and conditions. Accordingly, it will result in significant added value to our net tangible assets before our Shares are delivered.

Costs to our Group

Equity-settled share-based payments are measured at fair value at the date of grant, whereas cash-settled share-based payments are measured at current fair value at each statement of financial position date. In estimating the fair value of the compensation costs, market-based performance conditions are taken into account. The cost is charged to the statement of profit or loss and other comprehensive income on a basis that fairly reflects the manner in which the benefits will accrue to the employees under the respective plans over the vesting period.

We have made an application to the SGX-ST for permission to deal in and for quotation of the Employee Option Plan Shares and Performance Rights Plan Shares which may be issued pursuant to the grant of Options and/or Rights under the Share-based Incentive Plans.

SHARE OWNERSHIP

SHARE CAPITAL OF OUR COMPANY

Our company was incorporated as a no liability public company under the name "Linc Energy N.L.". In November 2000, we were converted to a public company limited by shares and we were renamed "Linc Energy Ltd". Our principal places of businesses are in the United States and Australia. As at the Latest Practicable Date, our issued and paid-up ordinary share capital was A$325,622,000 (US$300,358,063) comprising 522,996,195 shares.

At an extraordinary general meeting held on 6 November 2013, our Shareholders approved, among others:

(a) that our Company be removed from the Official List of ASX subject to our listing on the Main Board of the SGX-ST;

(b) that our Constitution be amended subject to our listing on the Main Board of the SGX-ST; and

(c) the issue of the 2018 Convertible Notes and the future issue of Shares to the holders of the 2018 Convertible Notes (the "**CN Shares**") in accordance with the terms and conditions of the 2018 Convertible Notes. The CN Shares when issued and fully paid-up, will rank *pari passu* in all respects with the existing issued and fully paid-up Shares.

At the annual general meeting to be held on 28 November 2013, our Shareholders are asked to approve, among others, that authority be given to our Directors to (i) issue Shares whether by way of rights, bonus or otherwise; and (ii) make or grant any offer, agreement or option (collectively, "**Instruments**") that might or would require shares to be issued, including but not limited to the creation and issue of (as well as adjustments to) warrants, debentures or other instrument convertible into Shares, at any time and upon such terms and conditions and for such purposes and to such persons as our Directors shall in their absolute discretion deem fit, (notwithstanding the authority conferred by such authority may have ceased to be in force) issue Shares in pursuance of any Instrument made or granted by our Directors while such authority was in force, provided that:

(A) the aggregate number of Shares to be issued pursuant to such authority (including Shares to be issued to in pursuance of Instruments made or granted pursuant to such authority) shall not exceed 50.0% of the total number of Shares in the post-Offering issued share capital of our Company (excluding treasury shares), of which the aggregate number of Shares to be issued other than on a *pro rata* basis to the then existing Shareholders of our Company shall not exceed 20.0% of the number of Shares in the post-Offering issued share capital of our Company (excluding treasury shares);

(B) (subject to such manner of calculation as may be prescribed by the SGX-ST) for the purpose of determining the aggregate number of shares that may be issued under the paragraph above, the percentage of issued Shares shall be based on the total number of issued Shares excluding treasury shares immediately following the close of the Offering, after adjusting for:

    (i) new Shares arising from the conversion or exercise of any convertible securities or share options or vesting of share awards which are outstanding or subsisting at the time such authority is passed;

    (ii) new Shares arising from exercising share options or vesting of share awards outstanding or subsisting at the time of the passing of this resolution; and

    (iii) any subsequent bonus issue, consolidation or subdivision of Shares;

(C) in exercising the authority conferred by such authority, we shall comply with the provisions of the Listing Manual for the time being in force (unless such compliance has been waived by the SGX-ST) and the Constitution; and

(D) unless revoked or varied by our Company in general meeting, such authority shall continue in full force until the conclusion of our next annual general meeting of our Company or the date by which the next annual general meeting is required by law or by our Constitution to be held, whichever is earlier, except that our Directors shall be authorised to allot and issue new Shares pursuant to convertible securities notwithstanding that such authority has ceased.

Details of changes in our issued share capital since 1 July 2012 and immediately after the Offering are as follows:

	Number of shares	**Resultant issued share capital (A$'000)**
Shares as at 1 July 2012	509,952,685	310,606
Shares issued pursuant to the exercise of Options[1]	3,266,797	315,832
Shares issued on vesting of Rights[2]	6,248,934	325,388
Shares as at 30 June 2013	519,468,416	325,388
Pre-Offering share capital as at the Latest Practicable Date	522,996,195	325,622
Offering Shares to be issued pursuant to the Offering	[●]	[●]
Share capital immediately after the Offering	[●]	[●]

Notes:

(1) The total cash received by our Group from the exercise of the Options was A$3.2 million. Since 1 July 2013, no Shares have been issued as a result of the exercise of Options.

(2) No consideration was received for the vesting of the Rights. Since 1 July 2013, no Shares have been issued as a result of the vesting of Rights.

DELISTING FROM ASX

At our extraordinary general meeting dated 6 November 2013, our Shareholders approved, among others, the delisting of our Company from the ASX. We received a no-objection letter from the ASX on 30 September 2013 to the notice of meeting to our Shareholders containing the resolution for the approval of our delisting from the ASX. As at the date of this offering document, our Shares have been voluntarily suspended, pending our delisting which is expected to take place on or about the Listing Date.

See "Share Ownership—Share Capital of our Company" for further details on the resolutions passed at the extraordinary general meeting held on 6 November 2013 and the annual general meeting to be held on 28 November 2013.

CONVERTIBLE NOTES

We had on 10 April 2013 issued the 2018 Convertible Notes, listed on the SGX-ST, being an aggregate principal amount of US$200.0 million 7.0% convertible, unsubordinated and unsecured notes, due 10 April 2018. The registered holder of the Convertible Notes is a common depositary for Euroclear Bank S.A./N.V. and Clearstream Banking, *société anonyme*. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Borrowing and other indebtedness—2018 Convertible Notes" of this offering document for further information on the summary terms of the 2018 Convertible Notes.

Following the resolutions passed at the CB Noteholder Meeting held on 16 October 2013, unless previously redeemed or purchased and cancelled, noteholders will have the right commencing 21 May 2013 until their redemption or maturity, to convert the 2018 Convertible Notes into CN Shares at the conversion price of S$[●], being the lower of (ii) A$3.40 per Share or (ii) the arithmetic average of the volume weighted average price of Shares traded on the ASX for each day during the 20 consecutive trading days ended on 15 November 2013 multiplied by 1.35 or the Offering Price multipled by 1.35, depending on the amount of the gross proceeds of the Offering, translated into Singapore dollar at the prevailing rate. Pursuant to the CB Noteholder Meeting, the conditions of the 2018 Convertible Notes were amended to, among others, facilitate our plans in reviewing optimal stock exchange venues and jurisdictions, and our consideration in listing our shares in an alternative or additional stock exchange from the ASX.

As at the Latest Practicable Date, none of the Convertible Notes has been converted to CN Shares.

OWNERSHIP STRUCTURE

The table below sets out the shareholdings interests, whether direct or deemed under Section 4 of the Securities and Futures Act, of each Substantial Shareholder, being a shareholder who is known by us to own 5.0% or more of our issued Shares, and our Directors, as at the Latest Practicable Date and immediately after completion of the Offering. All Shares held by our Substantial Shareholders, our Directors and the new Shares to be issued pursuant to the grant of rights under our Performance Rights Plan will carry the same voting rights as the Offering Shares.

Percentage ownership is based on 522,996,195 Shares outstanding as at the Latest Practicable Date and [●] Shares outstanding immediately after completion of the Offering.

	Shares owned as at the Latest Practicable Date(1)				Shares owned immediately after completion of the Offering (assuming the Over-allotment Option is not exercised)(1)				Shares owned immediately after completion of the Offering (assuming the Over-allotment Option is exercised in full)(1)			
	Direct Interest		Deemed Interest		Direct Interest		Deemed Interest		Direct Interest		Deemed Interest	
Name	**No. of Shares**	**%**	**No. of Shares**	**%**	**No. of Shares**	**%**	**No. of Shares**	**%**	**No. of Shares**	**%**	**No. of Shares**	**%**
Directors(2)												
Mr. Kenneth Dark	-	-	2,037,000(3)	0.39	[●]	[●]	[●]	[●]	[●]	[●]	[●]	[●]
Mr. Peter Bond	-	-	202,621,028(4)	38.7	[●]	[●]	[●]	[●]	[●]	[●]	[●]	[●]
Mr. Craig Ricato	2,501,561	0.48	-	-	[●]	[●]	[●]	[●]	[●]	[●]	[●]	[●]
Mr. Lim Ah Doo	-	-	-	-	[-]	[-]	[-]	[-]	[-]	[-]	[-]	[-]
Mr. Jon Mathews	250,000	0.05	3,000	n.m.	[●]	[●]	[●]	[●]	[●]	[●]	[●]	[●]
Mr. Koh Ban Heng	-	-	-	-	[-]	[-]	[-]	[-]	[-]	[-]	[-]	[-]
Substantial Shareholders												
Newtron Pty Ltd(4)	130,765,166	25.0	71,000,000(5)	13.6	[●]	[●]	[●]	[●]	[●]	[●]	[●]	[●]
Credit Suisse Group AG(6)	-	-	49,768,726	9.5	[●]	[●]	[●]	[●]	[●]	[●]	[●]	[●]
Public Shareholders												
Existing ASX Shareholders	389,479,468	74.5	-	-	[●]	[●]	-	-	[●]	[●]	-	-
Total	**522,996,195**	**100.0(7)**	**-**	**-**	**[●]**	**100.0(7)**	**-**	**-**	**[●]**	**100.0(7)**	**-**	**-**

Notes:

(1) Assuming none of the 2018 Convertible Notes have been converted into Shares. Ownership of shares disclosed does not include the Options or Rights granted to the Directors under the Share-Based Incentive Plans.

(2) The table assumes that none of our Directors subscribes for any Shares in the Offering. In the event that any Shares are subscribed by our Directors, such subscriptions will be disclosed in an announcement in accordance with Rule 240 of the Listing Manual.

(3) 2,017,000 shares are held by Ken & Sandy Dark Pty Ltd, a company wholly owned by Mr. Kenneth Dark.

(4) Mr. Peter Bond is deemed interested in 202,621,028 Shares, with 201,765,166 Shares held through Newtron Pty Ltd ("**Newtron**") and 855,862 Shares held through ISNY Pty Ltd ("**ISNY**").
Newtron is an Australian incorporated investment holding company which is the corporate trustee of The Peter Bond Family Trust, a discretionary trust whose sole beneficiary is Mr. Peter Bond, who is also the sole shareholder of Newtron. ISNY is an Australian incorporated investment holding company which is the corporate trustee of The Bond Family Trust, a discretionary trust whose beneficiaries are Mr. Peter Bond, who is also the sole shareholder of ISNY, and his immediate

family members. Accordingly, Mr. Peter Bond is deemed interested in Shares held by Newtron and ISNY by virtue of Section 4(3) of the Securities and Futures Act.

(5) Newtron entered into a master loan agreement with Equities First Holdings, LLC (the "**Lender**") dated 12 September 2012 (the "**Master Loan Agreement**"). As at the Latest Practicable Date, Mr. Peter Bond has, through his wholly-owned company, Newtron, pledged 71,000,000 Shares to the Lender pursuant to the Master Loan Agreement (the "**Pledged Collateral**").

Pursuant to the Master Loan Agreement, Mr. Peter Bond, through his wholly-owned company, Newtron, had pledged 20,000,000 Shares to the Lender in consideration for a loan from the Lender to Borrower of funds equal to 65.0% of the current fair market value of 20,000,000 Shares. Newtron and Lender had discussed that they each may elect to enter into additional loan transactions collateralised by additional tranches of the same security, whereby the Lender would make its best efforts to fund additional loans in additional tranches contingent on market conditions such as Share price. Newtron shall pay the Lender a simple interest on the loan principal amount at a fixed interest rate of 3.85% per annum. Newtron acknowledges that the Lender has the absolute right to sell and buy any or all of the Pledged Collateral during the term of the Master Loan Agreement and the loan documents. Newtron further acknowledges and agrees that as long as the loan principal amount or the obligations remain outstanding, the Lender may take any and all actions with respect to the Pledged Collateral as the Lender, in its sole and absolute discretion, may deem to be advisable, including without limitation, selling and buying some or all of the Pledged Collateral during the term of the agreement and the loan documents. It is noted that an event of default arises if the Pledge Collateral is removed from a national or international securities exchange, or trading is halted for more than three exchange business days by a regulatory authority. Upon the occurrence of an event of default which remains uncured, the loan, together with any accrued and unpaid interest thereon, shall be immediately due and payable without notice or demand.

Pursuant to the master pledge agreement dated 12 September 2012 (the "**Master Pledge Agreement**"), Newtron as transferor of the Shares, shall receive from the Lender a payment of credit against interest due of an amount equivalent to all interest, dividends and other distributions which the beneficial owner of those Shares is entitled to receive during the period of the loan. All voting or other such consensual rights and powers are transferred to the Lender. The Lender will not exercise any voting or other consensual rights or powers under the terms of the agreements.

(6) Four affiliates of Credit Suisse Group AG hold an aggregate of approximately 9.5% of the issued share capital of our Company, pursuant to the provision of services related to securities activities. Of these affiliates, Credit Suisse Equities (Australia) Limited directly holds 49,019,688 Shares, representing 9.4% of the issued share capital of our Company. None of these holdings were acquired pursuant to transactions that were entered into on the instruction of or for the benefit of our Directors, Controlling Shareholders and any of their respective associates. These holdings were purchased pursuant to open market transactions.

37,453,184 Shares indirectly held by Mr. Peter Bond are the subject matter of a securities lending agreement ("**SLA**") entered into between Newtron as lender, and Credit Suisse Equities (Australia) Limited ("**CS Equities**") as borrower. As at the date of this offering document, no Shares have been borrowed under the SLA.

See "Plan of Distribution—Other Relationships".

(7) Shareholding does not add up to 100.0% due to rounding differences.

Except as disclosed above, there are no other relationships between our Directors and Substantial Shareholders.

The Shares held by our Directors and Substantial Shareholders described above do not carry any different voting rights from the Offering Shares.

CONTROL OF OUR COMPANY

To our knowledge, our Company will not be owned or controlled by any corporation (other than as disclosed above) immediately after the completion of the Offering. Other than as described above, our Company is not indirectly or directly owned or controlled by another corporation, whether severally or jointly, or by any government or other natural or legal person.

We are not aware of any arrangements that may, at a subsequent date, result in a change of control of our Company.

SIGNIFICANT CHANGES IN PERCENTAGE OF OWNERSHIP

Except as disclosed in this offering document, there were no significant changes in the percentage of ownership in our Company in the period from the beginning of the last three financial years up to the Latest Practicable Date.

INTERESTED PERSON TRANSACTIONS AND CONFLICTS OF INTERESTS

INTERESTED PERSON TRANSACTIONS

In general, transactions between our Group and any of our interested persons (namely, the directors or controlling shareholder or the associates of such directors or controlling shareholder holding directly or indirectly 15.0% of the nominal amount of all voting shares in our Company) are "**Interested Person Transactions**" for the purposes of Chapter 9 of the Listing Manual.

Except as disclosed below, there are no interested person transactions that are material in the context of the Offering for the last three financial years ended 30 June 2011, 2012 and 2013 and for the period from 1 July 2013 to the Latest Practicable Date. Except as otherwise provided in this section, investors, upon purchase of the Offering Shares, are deemed to have specifically approved these transactions with our interested persons and as such these transactions are not subject to Rules 905 and 906 of the Listing Manual to the extent that there are no subsequent changes to the terms of the agreements in relation to each of these transactions.

In line with the rules set out in Chapter 9 of the Listing Manual, a transaction with a value of less that S$100,000 is not considered material in the context of the Offering and is not taken into account for the purposes of aggregation in this section.

In respect of all transactions described below which is stated to be entered into on arms' length as the terms and conditions of such transactions were no more favourable than those available, or which may be available on similar transactions with non-interested persons, such conclusions were arrived at by our Board after taking into consideration factors including the pricing and market availability, the type of services being provided as well as the terms in respect of comparable transactions with external parties.

Past Interested Person Transactions

Past transactions between our Group and interested persons which are material in the context of the Offering for the last three financial years ended 30 June 2011, 2012 and 2013 and for the period from 1 July 2013 to the Latest Practicable Date.

Loans to Director / Entity controlled by Director

On 16 December 2011, our Company provided a loan of A$250,000 (US$233,375) to Mr. Kenneth Dark, our Chairman and Non-Executive Director, for the purposes of exercising options granted to him pursuant to the Employee Option Plan. The loan was provided on normal commercial terms with interest calculated monthly at a rate of 10.08% per a per annum basis, secured by his Shares, and was accordingly entered into at arm's length. The largest amount outstanding during the period under review was A$264,003 (US$246,447) and as at the Latest Practicable Date, A$241,104 (US$225,071) remained outstanding. The loan was fully repaid on 23 November 2013. We have ceased such arrangements with Mr. Kenneth Dark and do not intend to enter into similar transactions in the future.

On 22 August 2012, our Company entered into a loan agreement for approximately A$249,917 (US$233,298) denominated in pounds sterling, with Hillgrove Investments Pty Ltd, a company wholly-owned by Mr. Peter Bond, for the purposes of providing funding convertible loan to Powerhouse Energy plc. On 5 November 2012, the loan was amended, extending the quantum by an additional A$16,661 (US$15,553). The loan was provided on normal commercial terms with interest monthly at a rate of 10.08% and was accordingly entered into at arm's length. The largest amount outstanding during the period under review and as at the Latest Practicable Date was A$293,213 (US$273,714). The loan was fully repaid on 23 November 2013. We have ceased such arrangements with Hillgrove Investments Pty Ltd and do not intend to enter into similar transactions in the future.

Reimbursements from Entities controlled by Directors

Mr. Peter Bond

Mr. Peter Bond and Bond Bros Contracting Pty Ltd, a company which Mr. Peter Bond is the sole shareholder of, had from time to time, been required to reimburse our Group for personal expenses (the "**Reimbursement Expenses**") which had been incurred by our Group for their respective benefit. The Reimbursement Expenses included, among others, Mr. Bond's Newcastle office premises and associated costs. The aggregate amount paid by Mr. Peter Bond and Bond Bros Contracting Pty Ltd for the period under review is as follows:

	FY2011	FY2012	FY2013	1 July 2013 to the Latest Practicable Date	
	(A$)	*(A$)*	*(A$)*	*(A$)*	*(US$)*
Reimbursement Expenses paid	**33,447**	**32,408**	**61,931**	**-**	**-**

The largest amount outstanding during the period under review was A$136,053 (US$127,006). As we charge no interest in respect of the Reimbursement Expenses, the transaction would not ordinarily be considered to have been entered into at arm's length. The Reimbursement Expenses was fully repaid on 31 May 2013. We have ceased such arrangements with Mr. Peter Bond and Bond Bros Contracting Pty Ltd and do not intend to enter into similar transactions in the future.

Reimbursements to Entities controlled by Directors

Mr. Kenneth Dark

In FY2012, we reimbursed KE & SL Dark, a family partnership established by Mr. Kenneth Dark, for expenses incurred by KE & SL Dark on behalf of our Company in the course of Mr. Kenneth Dark's chairmanship and directorship for an amount of A$12,369 (US$11,546). The reimbursement expenses incurred by KE & SL Dark included, among others, expenses incurred on Mr. Kenneth Dark's accommodation and transportation. As no interest was charged by KE & SL Dark in respect of the reimbursement expenses, the transaction would not ordinarily be considered to have been entered into at arm's length. There is A$0 outstanding as at the Latest Practicable Date. We have ceased such arrangements with Mr. Kenneth Dark and KE & SL Dark and do not intend to enter into similar transactions in the future.

Transactions with Directors

Mr. Craig Ricato

We had on 1 October 2010 entered into an agreement with Executive Management Services Discretionary Trust for the provision of executive services. The agreement expired on 30 June 2013 and a new arrangement was entered into on 1 July 2013 between our Company and Executive Management Services Discretionary Trust. Please refer to the section titled "Interested Person Transactions and Conflicts of Interests—Present and Ongoing Interested Person Transaction—Transactions with Directors—Mr. Craig Ricato" for further details. Mr. Craig Ricato is the sole shareholder of EMS (QLD) Pty Ltd., the corporate trustee of Executive Management Services Discretionary Trust. The key beneficiaries of the Executive Management Services Discretionary Trust are Craig Ricato and his immediate family. The executive services included, among others, executive services as a director of our Company and those associated with his previous position as "Company Secretary and General Counsel". The amount paid to Executive Management Services Discretionary Trust, which was determined by our Board and Remuneration Committee after taking into consideration his experience and his duties and responsibilities in our Company, for the period under review is as follows:

	FY2011	FY2012	FY2013	1 July 2013 to the Latest Practicable Date	
	(A$)	*(A$)*	*(A$)*	*(A$)*	*(US$)*
Executive Management Services Discretionary Trust	297,713	555,940	633,072	-	-

The terms and conditions of the transaction with Executive Management Services Discretionary Trust were no more favourable than those available, or which may be available, on similar transactions to non-interested persons. Accordingly, the transaction was entered into at arm's length.

Mr. Peter Bond

We entered into an agreement with Rough Diamond Media Pty Ltd in November 2011 to provide documentary film services. Mr. Peter Bond is the sole shareholder and director of Rough Diamond Media Pty Ltd. The amount paid to Rough Diamond Media Pty Ltd is as follows:

	FY2011	FY2012	FY2013	1 July 2013 to the Latest Practicable Date	
	(A$)	*(A$)*	*(A$)*	*(A$)*	*(US$)*
Rough Diamond Media Pty Ltd	50,000	67,897	2,913	5,005	4,616

The terms and conditions of the transaction with Rough Diamond Media Pty Ltd was no more favourable than those available, or which may be available, on similar transactions to non-interested persons on an arm's length basis.

Present and Ongoing Interested Person Transactions

Details of present and ongoing transactions between our Group and interested persons which are material in the context of the Offering are set out below. These transactions and future transactions with any of the relevant interested persons will be subject to the review procedures under "—Guidelines and Review Procedures for Present and Ongoing and Future Interested Person Transactions" to the extent required by the Listing Manual.

Transactions with Directors

Mr. Peter Bond

We had on 10 September 2010 entered into an agreement with Newtron Pty Ltd for the provision of executive services, effective 1 January 2010, by Mr. Peter Bond to our Group, with payment for such services being made to Bond Bros Contracting Pty Ltd which provides the invoices on behalf of Newtron. Mr. Peter Bond is the sole shareholder of Bond Bros Contracting Pty Ltd. The executive services included, among others, the provision of Mr. Bond's services as Chief Executive Officer. The amount paid to Bond Bros Contracting Pty Ltd for the provision of such executive services, which was determined by our Board and Remuneration Committee after taking into consideration his experience and his duties and responsibilities to our Company, for the period under review is as follows:

	FY2011	FY2012	FY2013	1 July 2013 to the Latest Practicable Date	
	(A$)	*(A$)*	*(A$)*	*(A$)*	*(US$)*
Bond Bros Contracting Pty Ltd	583,000	824,633	1,008,333	458,333	422,720

The terms and conditions of the transaction with Newtron Pty Ltd were no more favourable than those available, or which may be available, on similar transactions to non-interested persons. Accordingly, the transaction was entered into at arm's length.

We had on 25 March 2011 entered into an agreement with Bond Air Charters Pty Ltd for the provision of chartered flight services. This arrangement was adopted as it provides greater flexibility in terms of timing of use as opposed to relying on commercial flights. Mr. Peter Bond is a shareholder of Bond Air Charters Pty Ltd. The amount paid to Bond Air Charters for the period under review is as follows:

	FY2011	FY2012	FY2013	1 July 2013 to the Latest Practicable Date	
	(A$)	*(A$)*	*(A$)*	*(A$)*	*(US$)*
Bond Air Charters Pty Ltd	259,140	480,188	173,201	7,089	6,538

The terms and conditions of the transaction with Bond Air Charters Pty Ltd were no more favourable than those available, or which may be available, on similar transactions to non-interested persons. Accordingly, the transaction was entered into at arm's length.

Mr. Craig Ricato

We had on 1 July 2013 entered into an agreement with Mr. Craig Ricato's professional contracting entity, Executive Management Services Discretionary Trust, for the provision consultancy and project management services to us on an as-needed basis. When Mr. Ricato stepped down from an executive director to a non-executive director role in June 2013, our Board requested that he continue to assist us in respect of the management of our Company's major corporate transactions given his experience and familiarity with our Group. Mr. Ricato holds EMS (QLD) Pty Ltd, the corporate trustee of Executive Management Services Discretionary Trust. The compensation for services provided to us comprises (i) a time-costed rate of A$550 per hour (inclusive of GST) based on the prevailing market rates of a law firm partner, and (ii) a retainer fee payable in two tranches on 2 July 2013 and 2 January 2014, being the respective dates of the beginning of the retainer and the end of the retainer, and calculated by reference to our closing share price on the relevant dates multiplied by 250,000 per tranche. This was determined by reference to the 500,000 Shares which Mr. Ricato would have been eligible to receive at the end of 2013 if he had continued as a full time employee of our Company. The payment of the retainer was to secure Mr. Ricato's availability in the event that our Company would require his services. The amount paid to Executive Management Services Discretionary Trust for the period under review is as follows:

	FY2011	FY2012	FY2013	1 July 2013 to the Latest Practicable Date	
	(A$)	*(A$)*	*(A$)*	*(A$)*	*(US$)*
Executive Management Services Discretionary Trust	-	-	-	687,015	633,633

The terms and conditions of the transaction with Executive Management Services Discretionary Trust were no more favourable than those available, or which may be available, on similar transactions to non-interested persons. Accordingly, the transaction was entered into at arm's length.

Mr. Kenneth Dark

We have entered an agreement with KE & SL Dark, a family partnership established by Mr. Kenneth Dark, for the provision of executive services. Mr. Ken Dark is presently the sole partner of KE & SL Dark. The executive services relates to his duties provided to our Company which were customary of a non-executive director and chairman. The amount paid to KE & SL Dark for executive services and the reimbursement of expenses for the period under review is as follows:

	FY2011	FY2012	FY2013	1 July 2013 to the Latest Practicable Date	
	(A$)	*(A$)*	*(A$)*	*(A$)*	*(US$)*
KE & SL Dark	65,945	129,809	166,440	46,638	43,014

The terms and conditions of the transaction with KE & SL Dark in respect of payment for executive services were no more favourable than those available, or which may be available, on similar transactions to non-interested persons on an arm's length basis. Accordingly, the transaction was entered into at arm's length.

Upon our listing on the Main Board of the SGX-ST, two other quotations from non-interested persons will be obtained (where available) when engaging the services of an interested person, for comparison to ensure that the interest of minority shareholders are not disadvantaged. The fee for services shall not be higher than the most competitive price or fee of the two other quotations from non-interested persons. In determining the most competitive price or fee, all pertinent factors, including but not limited to quality, delivery time and track record will be taken into consideration.

GUIDELINES AND REVIEW PROCEDURE FOR PRESENT AND ONGOING AND FUTURE INTERESTED PERSON TRANSACTIONS

All future interested person transactions will be reviewed and approved in accordance with the threshold limits set out under Chapter 9 of the Listing Manual, to ensure that they are carried out on normal commercial terms and are not prejudicial to our interests and the interests of our minority shareholders. In the event that such interested person transactions require the approval of our Board and our Audit and Risk Management Committee, relevant information will be submitted to our Board or the Audit and Risk Management Committee for review. In the event that such interested person transactions require the approval of shareholders, additional information may be required to be presented to shareholders and an independent financial adviser may be appointed for an opinion.

In the review of all future interested person transactions the following procedures will be applied:

(a) transactions (either individually or as part of a series or if aggregated with other transactions involving the same related party during the same financial year) equal to or exceeding S$100,000 in value but below 3.0% of the value of our net tangible assets will be subject to review by our Audit and Risk Management Committee at regular intervals;

(b) transactions (either individually or as part of a series or if aggregated with other transactions involving the same related party during the same financial year) equal to or exceeding 3.0% but below 5.0% of the value of our net tangible assets will be subject to the review and prior approval of our Audit and Risk Management Committee. Such approval shall only be given if the transactions are on arm's length commercial terms and are consistent with similar types of transactions made with non-interested parties; and

(c) transactions (either individually or as part of a series or if aggregated with other transactions involving the same related party during the same financial year) equal to or exceeding 5.0% of the value of our net tangible assets will be reviewed and approved by our Audit and Risk Management Committee, prior to such transactions being entered into, which may, as it deems fit, request advice on the transaction from independent sources or advisers, including the obtaining of valuations from independent professional valuers.

Any interested person transaction will be properly documented in a register (incorporating the basis, amount and nature, on which they are entered into). Our Audit and Risk Management Committee will review all interested person transactions to ensure that the prevailing rules and regulations of the SGX-ST (in particular, Chapter 9 of the Listing Manual) are complied with. We will also endeavour to comply with the recommendations set out in the Code of Corporate Governance 2012.

The annual internal audit plan will incorporate a review of all interested person transactions entered into. Our Audit and Risk Management Committee will review internal audit reports to ascertain that the guidelines and procedures established to monitor interested person transactions have been complied with. In addition, our Audit and Risk Management Committee will also review from time to time such guidelines and procedures to determine if they are adequate and/or commercially practicable in ensuring that transactions between us and our interested persons are conducted on arm's length commercial terms.

Transactions falling within the above categories, if any, will be reviewed quarterly by our Audit and Risk Management Committee to ensure that they are carried out on normal commercial terms and in accordance with the procedures outlined above. All relevant non-quantitative factors will also be taken into account. Such review includes the examination of the transaction and its supporting documents or such other data deemed necessary by our Audit and Risk Management Committee. Our Audit and Risk Management Committee will also ensure that all disclosure, approval and other requirements on interested person transaction, including those required by prevailing legislation, the Listing Manual and relevant accounting standards, are complied with.

In the event that a member of our Audit and Risk Management Committee is interested in any interested person transaction, he will abstain from reviewing that particular transaction. We will also disclose the aggregate value of interested person transactions conducted during the current financial year in our annual report.

POTENTIAL CONFLICTS OF INTERESTS

In order to manage any potential competition and potential conflicts of interest that may arise between Mr. Peter Bond and our Company, on [●] 2013, Mr. Peter Bond entered into a non-compete agreement with our Company (the "**Non-Compete Undertaking**"), whereby he has agreed not to, and will procure that his associates will not, do or permit to be done any of the following, without the prior written consent of the Audit and Risk Management Committee:

(a) have a direct interest in 5% or more of the total votes attached to all the voting shares of a corporation or voting rights of a partnership, as the case may be ("**Interest**") in any other business which competes with the Business of our Group; or

(b) cause or permit any person or company directly or indirectly under his Control (whereby "**Control**" means the capacity to dominate the decision-making, directly or indirectly, in relation to the financial and operating policies of a company) to do the foregoing (which, for the avoidance of doubt, does not include any fund in which he does not exercise investment decisions).

Notwithstanding the above, Mr. Peter Bond, either directly or indirectly through any entity that he Controls (the "**Bond Controlled Entities**" and each a "**Bond Controlled Entity**"), shall be able to have an Interest in any other business that competes with the Business of our Group provided that prior to doing so, upon him or any of the Bond Controlled Entities being offered an opportunity to have an Interest in any other business that competes with the Business of the Group (a "**Business Opportunity**"), he or such Bond Controlled Entity, as the case may be, shall, provide written notice of such offer to our Company of all relevant details pertaining to the Business Opportunity (the "**Business Opportunity Offer**") which our Company may accept during the Business Opportunity Offer period (the "**Business Opportunity**

Acceptance Notice"). The Business Opportunity Offer period begins from the date of the service of the Business Opportunity Offer and ends the earlier of (i) the serving of the written notice to Mr. Peter Bond or the relevant Bond Controlled Entity rejecting the right to pursue the Business Opportunity (the "**Business Opportunity Rejection Notice**") or (ii) 40 calendar days after the Business Opportunity Offer is provided and no acceptance or rejection is received by Mr. Peter Bond or the relevant Bond Controlled Entity (a "**Business Opportunity Lapse**").

For the avoidance of doubt,

(a) upon service by our Company of a Business Opportunity Acceptance Notice, we shall have the right to pursue, and Mr. Peter Bond and the Bond Controlled Entities may not pursue, the Business Opportunity, unless no definitive binding agreement is entered into by our Company within 120 days from the date of the Business Opportunity Acceptance Notice, whereupon Mr. Peter Bond or the Bond Controlled Entities may pursue the Business Opportunity;

(b) upon service by us of a Business Opportunity Rejection Notice, Mr. Peter Bond or such Bond Controlled Entity shall have the right to pursue the Business Opportunity; and

(c) in the event of a Business Opportunity Lapse, the Director or such Bond Controlled Entity shall have the right to pursue the Business Opportunity.

Further, where Mr. Peter Bond or such Bond Controlled Entity has subsequently acquired the Business Opportunity and thereafter proposes to dispose of a portion or the whole of such Business Opportunity, Mr. Peter Bond or such Bond Controlled Entity shall provide written notice of such proposed offer of sale (the "**Proposed Disposal Offer**") by Mr. Peter Bond or such Bond Controlled Entity of its interest in the Business Opportunity (the "**Proposed Disposal**") which our Company may accept during the Proposed Disposal Offer period. Such Proposed Disposal Offer shall include sufficient details of the Proposed Disposal for the Company to evaluate the Proposed Disposal. The Proposed Disposal Offer period begins from the date of the service of the Proposed Disposal Offer and ends the earlier of (i) the serving of written notice to Mr. Peter Bond or the relevant Bond Controlled Entity rejecting the right to pursue the Proposed Disposal (a "**Proposed Disposal Rejection Notice**") or (ii) 40 calendar days after the Proposed Disposal Offer is provided and no offer or indication of interest (in the form of an offer letter with a clear price and conditions for acceptance being proposed) (the "**Proposed Disposal Indication of Interest**") is received by Mr. Peter Bond or the relevant Bond Controlled Entity (a "**Proposed Disposal Lapse**").

For the avoidance of doubt,

(a) upon service by our Company of the Proposed Disposal Indication of Interest, Mr. Peter Bond or such Bond Controlled Entity shall not offer the Business Opportunity to third parties unless no definitive binding agreement is entered into by our Company within 120 days from the date of the Proposed Disposal Indication of Interest or where our Company has served written notice to Mr. Peter Bond or the relevant Bond Controlled Entity rejecting the right to continue to pursue the Proposed Disposal, whereupon Mr. Peter Bond or such Bond Controlled Entity may pursue offering the Business Opportunity to third parties;

(b) upon service by us of a Proposed Disposal Rejection Notice, Mr. Peter Bond or such Bond Controlled Entity shall have the right to pursue offering the Business Opportunity to third parties; and

(c) in the event of a Proposed Disposal Lapse, Mr. Peter Bond or such Bond Controlled Entity shall have the right to pursue offering the Business Opportunity to third parties, provided in each case that Mr. Peter Bond or such Bond Controlled Entities may not divest the Business Opportunity on price, terms and conditions which are less favourable to our Company than those offered by our Company under the Proposed Disposal Indication of Interest.

"**Business**" as defined in the Non-Compete Agreement means:

(i) the business of our Company which, as of the date of the Non-Compete Agreement, comprises (a) the conventional oil and gas business division, which consists of the exploration and production of oil and gas in the United States, (b) the unconventional oil and gas business division, being the clean energy business, which focuses on the commercialisation of our proprietary technology in underground coal gasification, the process of converting coal into underground coal gasification synthetic gas in situ as well as its shale oil and gas business, which focuses on the exploration for shale oil and gas in Australia, and (c) the coal business division, which consists of a financial asset in the form of a contractual right to receive royalties from coal production over the Carmichael project in Queensland, Australia as well as our Company's conventional coal mining business in Australia; and

(ii) such other additional business as our Company may notify to Mr. Peter Bond in writing.

For the avoidance of doubt, to the extent our Company disposes of or divests any of the businesses referred to in (i) and (ii) above, such business will not be included in the definition of "Business" from the date of disposal or divestment;

The Non-Compete Agreement shall commence on the Listing Date and shall be valid for so long as our Company maintains our primary listing on the Official List of the SGX-ST and Mr. Peter Bond (i) remains a Director, executive officer of our Company or if he has appointed or nominated a director to the board of directors of our Company and (ii) remains a Controlling Shareholder of our Company.

As at the Latest Practicable Date, none of our Directors or Controlling Shareholders (including Mr. Peter Bond) or any of their associates:

(a) has had any interest, direct or indirect, in any material transactions to which our Group was or is a party;

(b) has any interest, direct or indirect, in any entity carrying on the same business or carrying on a similar trade as our Group, or dealing in similar products which competes materially and directly with the existing business of our Group; and

(c) has any interest, direct or indirect, in any enterprise or company that is a customer or supplier of goods and services of our Group.

TAXATION

The comments below are intended to provide a general summary (only) of the Australian and Singaporean income tax, GST, stamp duty and estate duty implications (to the extent it is relevant) for Shareholders who hold their Offering Shares on capital account, upon subscribing for Offering Shares under the Public Offer.

Shareholders who will:

(a) hold Offering Shares as trading stock or otherwise on revenue account; or

(b) are subject to the Taxation of Financial Arrangement ("**TOFA**") rules in Australia contained in Division 230 of the Income Tax Assessment Act 1997 (Cth);

should seek their own professional advice in relation to the tax consequences of investing in Offering Shares.

Shareholders who are resident in jurisdictions other than Australia or Singapore should seek their own professional advice in relation to their relevant jurisdictions.

These tax comments are provided on the basis that we will (at all applicable times) be a resident of Australia (solely) under the relevant tax laws of Australia and Singapore.

The comments in relation to Australian and Singaporean tax matters below are based on the relevant Australian and Singaporean taxation and stamp duty law, regulations and guidelines issued by the relevant authorities as at the offering document date. The comments do not take into account or anticipate changes in Australian or Singaporean taxation law or future judicial interpretations of law after this time, nor do they take into account taxation legislation of any countries other than Australia and Singapore.

The discussion is general in nature only and should not be regarded as tax advice as to a particular Shareholder's position. Accordingly, all Shareholders should seek their own professional advice from a qualified taxation advisor specific to their own circumstances. It is emphasised that neither us, our Directors nor any other persons involved in this offering document accepts responsibility for any tax effects or liabilities resulting from the subscription for, purchase, holding or disposal of Offering Shares.

This summary does not constitute financial product advice as defined in the (Australian) Corporations Act 2001. This summary is confined to taxation issues and is only one of the matters you need to consider when making a decision about your investments. You should consider taking advice from a licensed adviser, before making a decision about your investments.

Australian Tax Implications

Australian income tax treatment of dividends received by Australian tax resident Shareholders

Any dividends paid by us to our Australian tax resident Shareholders may be subject to withholding tax in Australia as noted below, but otherwise should not be subject to income tax in Australia.

Where a franking credit is included in a shareholders assessable income, the Shareholder will generally be entitled to a corresponding tax offset against tax payable.

To be eligible for the franking credit and tax offset, a Shareholder must satisfy the 'holding period' rules, which require that a shareholder holds the shares 'at risk' for a specified period of not less than 45 days (not including the date of acquisition and the date of disposal).

The holding period rule will not apply to a Shareholder who is an individual and whose tax offset entitlement (for all franked distributions received by the shareholder in the income year) does not exceed $5,000 for the income year in which the franked dividend is received.

Generally Shareholders who are Australian tax resident individuals or complying superannuation entities should be entitled to a refund to the extent the franking credits attached to a dividend exceeds the Shareholder's income tax liability for the relevant income year.

Shareholders who are Australian tax resident companies may be entitled to convert the excess of franking credits which cannot be offset against their income tax liability for the relevant year, to a carry forward tax loss. Additionally, for Shareholders who are companies and who receive franked dividends, a franking credit may arise in the Shareholders franking account (subject to satisfaction of the holding period rules).

Special rules apply to Shareholders that are trustees of trusts, and for partnerships.

Shareholders are advised to seek their own professional advice in assessing the consequences of receiving franking credits in their specific circumstances.

Australian income tax treatment of dividends received by non-Australian tax resident shareholders

Any dividends paid by us to our non-Australian tax resident Shareholders may be subject to withholding tax in Australia as noted below, but otherwise should not be subject to income tax in Australia income and therefore, should not be taxable in Australia, except as noted below in relation to withholding tax.

Fully franked dividends are not subject to Australian dividend withholding tax.

To the extent dividends are unfranked, Australian dividend withholding tax is imposed at a rate of 30% unless the Shareholder is a tax resident of a country which has entered into a Double Taxation Agreement ("**DTA**") with Australia. In these circumstances, the rate of Australian dividend withholding tax is generally reduced. For example, the withholding tax rate on unfranked dividends paid to tax residents of Singapore by an Australian tax resident company (e.g. our Company) may be reduced to 15% under the DTA between Australia and Singapore. Shareholders should seek their own tax advice in relation to the application of these rules to their particular circumstances.

Australian implications for Australian tax resident Shareholders disposing of Offering Shares

Where a Shareholder holds Offering Shares on capital account, the Capital Gains Tax ("**CGT**") rules should be applicable in determining the tax consequences of acquiring and disposing of Offering Shares.

If Shareholders choose to dispose of their Offering Shares in the future, a capital gain should arise to the extent the capital proceeds received in respect of the disposal exceeds the cost base of the Shares.

A capital loss will arise to the extent the capital proceeds received are less than the reduced cost base of the Shares. Capital losses can be carried forward and offset against any future capital gains, subject to the satisfaction of various carry forward loss and integrity rules.

The cost base of Offering Shares subscribed for under the Public Offer should broadly be equal to the money paid or required to be paid in respect of acquiring the Shares plus any incidental costs incurred by the Shareholder in respect of acquiring (or disposing) of the Shares.

As the Offering Shares are denominated in Singaporean dollars, the cost base of the Offering Shares and capital proceeds from disposal of the Offering Shares must be converted to an Australian dollar equivalent. Generally, the cost base should be converted at the relevant foreign exchange rate applicable at the date of purchase and the capital proceeds should be converted at the relevant foreign exchange rate applicable at the date of disposal. The capital gain or loss from disposal of the Offering Shares is then calculated using the Australian dollar amounts. However, this may differ for particular shareholders depending on their circumstances. Shareholders should seek their own professional tax advice in relation to the application of these rules to their particular circumstances.

If the Shareholder is an Australian tax resident individual, complying superannuation entity, or trust, they may be eligible to reduce their capital gain (net of any available capital losses) by a CGT discount if they have held their Offering Shares for at least 12 months prior to the disposal. For individuals and trusts the discount is one half and for complying superannuation entities one third. Shareholders that are companies (or trusts that are taxed under a corporate model in Australia) are not entitled to a CGT discount.

Shares held by trustees of trusts that have held the Offering Shares for at least 12 months may be eligible to flow through the CGT discount to non-company beneficiaries of the trust. Shareholders should seek their own professional advice in this regard.

Our Shareholders should not be treated as resident in Australia or carrying on business in Australia through a permanent establishment solely by reason of the issue, allotment or holding of our Shares. However, each individual Shareholder should obtain their own independent tax advice relevant to their particular circumstances as those other circumstances that may be particular to a Shareholder may influence whether they have residency in Australia for tax purposes and/or a permanent establishment presence in Australia.

Australian income tax implications for non-Australian tax resident shareholders disposing of Offering Shares

Where a non-Australian tax resident Shareholder holds Offering Shares on capital account, any capital gain or loss arising from the disposal of Offering Shares should be disregarded provided the Offering Shares are not taxable Australian property ("**TAP**").

If the Offering Shares held by a non-Australian tax resident Shareholder are TAP, then any capital gain or loss will be taxed in accordance with the CGT rules as outlined above in relation to Australian tax resident Shareholders disposing of Offering Shares.

Offering Shares may be TAP where:

The non-Australian tax resident Shareholder (together with its associates) owns 10% or more of the issued Share capital of our Company (including voting, capital and dividend rights) at the time of the disposal (or has done so for a 12-month period within the 24 months prior to disposal); and

Greater than 50% of our market value of the underlying assets (including interests in subsidiaries) is related to real property interests located in Australia (including mining and exploration rights).

Otherwise, Offering Shares should generally not be TAP for a non-Australian tax resident Shareholder.

Shareholders are advised to seek their own professional advice in relation to the application of these rules in their specific circumstances.

Tax File Numbers ("TFNs")

An Australian tax resident Shareholder is not required to quote a TFN to our Company. However, if an Australian tax resident Shareholder's TFN or relevant exemption details are not provided, Australian tax may be required to be deducted by our Company from certain distributions (other than fully franked dividends) at the maximum marginal tax rate plus medicare levy.

A shareholder that holds Offering Shares as part of an enterprise may quote their Australian Business Number instead of their TFN.

For non-Australian tax resident Shareholders, a TFN will be deemed to have been quoted at the time a dividend is paid by us, provided Australian dividend withholding tax applies or would have applied, but for certain dividend withholding tax exclusions (such as the dividend being franked).

Australian GST implications

There should be no Australian GST payable by Shareholders in respect of the acquisition or disposal of Offering Shares.

The extent to which a Shareholder may be entitled to recover Australian GST included in costs relating to the acquisition or disposal of Offering Shares will depend on the particular circumstances of the Shareholder and whether the acquisition/disposal may be classified as being 'GST-free' for Australian GST purposes. Shareholders should seek separate advice from their financial advisors to confirm their position.

No Australian GST should be payable by Shareholders as a result of dividends distributed by us.

The listing and trading on the SGX-ST should have no direct Australian GST implications for existing or future Shareholders.

Australian Stamp Duty implications

Shareholders acquiring Offering Shares should not bear any stamp duty liability on the acquisition.

Singapore Tax Implications

Corporate income tax

Corporate taxpayers, whether Singapore tax residents or non-residents, are subject to Singapore income tax on all income accrued in or derived from Singapore and on foreign-sourced income received or deemed received in Singapore from outside Singapore, subject to certain exceptions.

A company is regarded as a tax resident in Singapore if the control and management of its business is exercised in Singapore. Normally, control and management of a company is vested in its board of directors and in practice, the place of residence of the company is where its board of directors meets to make strategic business and management decisions. For companies which are investment holding companies deriving only passive sources of income, more factors will need to be considered to determine where its control and management is exercised and the company's tax residency status.

Foreign-sourced income in the form of dividends, branch profits and services income received or deemed received in Singapore by Singapore tax resident companies are exempt from Singapore income tax if the following conditions are met:

(i) the income is subject to tax of a similar character to income tax under the law of the jurisdiction from which such income is received;

(ii) at the time the income is received in Singapore, the highest rate of tax of a similar character to income tax in the jurisdiction from which the income is received is at least 15%; and

(iii) the Comptroller of Income Tax is satisfied that the tax exemption would be beneficial to the recipient of the foreign-sourced income.

The prevailing corporate tax rate (for both resident and non-resident corporate tax payers) in Singapore is 17%. In addition, partial tax exemption is granted on the first S$300,000 of a company's chargeable income arrived as follows:

(i) 75% of up to the first S$10,000 of the company's chargeable income, and

(ii) 50% of up to the next S$290,000 of a company's chargeable income.

Non-Singapore Shareholders are advised to consult their own tax advisors to take into account the tax laws of their respective countries of residence and the existence of any double taxation agreement which their country of residence may have with Singapore or Australia (as the case may be).

Individual income tax

In general, for individuals, only income which is sourced in Singapore will be subject to income tax in Singapore.

Most investment income sourced in Singapore is exempt from income tax in the hands of individuals. For individuals, any income arising from sources outside Singapore and received in Singapore is generally exempt from income tax unless it is received through a partnership in Singapore.

For Singapore individual tax purposes, a resident means a person who, in the year preceding the year of assessment, resides in Singapore except for such temporary absences there-from as may be reasonable and not inconsistent with a claim by such person to be resident in Singapore, and includes a person who is physically present in Singapore or who exercises employment (other than as director of a company) in Singapore for at least 183 days in the calendar year preceding the year of assessment.

In addition, there is an administrative concession, whereby an individual would be regarded as a tax resident if he is physically present or exercises employment in Singapore for at least 183 days, even if it straddles 2 calendar years.

The rate(s) at which tax is then applied to the Singapore sourced income will depend on the individuals' residency status.

As a tax resident, the individual will be taxed at progressive tax rates ranging from 0% to 20% and also enjoy the entitlement to claim deductions for personal reliefs.

Where an individual does not meet the conditions for tax residency outlined above, he will be regarded as a non-resident and subject to tax on Singapore sourced taxable investment income at a flat rate of 20% except for certain specified income that may be taxed at lower rates.

Non-Singapore Shareholders are advised to consult their own tax advisors to take into account the tax laws of their respective countries of residence and the existence of any double taxation agreement which their country of residence may have with Singapore or Australia (as the case may be).

Dividend distributions

Dividends paid by our Company to our Shareholders would be considered as sourced in Australia, i.e. foreign sourced for Singapore income tax purposes.

Foreign sourced dividends received in Singapore by individuals, whether Singapore tax resident or non-Singapore tax resident, are not subject to Singapore income tax.

Foreign sourced dividends received in Singapore by corporate Shareholders which are Singapore income tax residents, are exempt from Singapore income tax if the following conditions are met:

(i) the income is subject to tax of a similar character to income tax under the law of the jurisdiction from which such income is received; and

(ii) at the time the income is received in Singapore, the highest rate of tax of a similar character to income tax in the jurisdiction from which the income is received is at least 15%; and the Comptroller of Income Tax is satisfied that the tax exemption would be beneficial to the recipient of the foreign-sourced income.

For non-Singapore tax resident corporate Shareholders that do not operate in or from Singapore (including having no trade or business carried on in Singapore), such dividends would not be subject to Singapore corporate income tax.

Gains on disposals of ordinary Shares

Singapore does not impose tax on capital gains. Generally, if Offering Shares are held as investment assets on capital account, any gains arising from subsequent sales of Offering Shares should generally be considered capital gains not subject to Singapore income tax. However, if Offering Shares have been held on trading account, the gains arising from a subsequent sale may be taxed as income at the prevailing tax rate. Additionally, gains of an income nature may be taxed as income at the prevailing tax rate.

Gains may be construed to be of an income nature and subject to Singapore income tax if they arise from or are otherwise connected with the activities of a trade or business carried on in Singapore. The gains may also be liable to tax in the hands of the Shareholders if Shares were acquired with the intention or purpose of making a profit by sale and not with the intention to be held for long-term investment purposes.

Under Section 13Z of the Income Tax Act (Chapter 134 of Singapore), the gains derived from the disposal of ordinary Shares in an investee company during the period 1 June 2012 to 31 May 2017 (both dates inclusive) is exempt from income tax if immediately prior to the date of the Share disposal, the divesting company had legally and beneficially held at least 20% of the ordinary Shares in the investee company for a continuous period of at least 24 months. This rule does not apply to a divesting company whose gains or profits from the disposal of shares are included as part of its income based on the provisions of Section 26 of the Income Tax Act, or disposal of Shares in an unlisted investee company that is in the business of trading or holding Singapore immovable properties (other than the business of property development).

In addition, corporate Shareholders who adopt the tax treatment to be aligned with the Singapore Financial Reporting Standard 39 Financial Instruments—Recognition and Measurement ("**SFRS 39**") for the purposes of Singapore income tax may be taxed on gains or losses (not being gains or losses in the nature of capital) even though no sale or disposal of Offering Shares is made.

Because the precise tax status will vary from Shareholder to Shareholder, Shareholders should consult their own accounting and tax advisers regarding the Singapore income tax consequences of their acquisition, holding and disposal of Offering Shares.

Singapore stamp duty

No stamp duty is payable on the subscription and issuance of new Shares.

Where existing Shares evidenced in certificated form are acquired in Singapore, stamp duty is payable on the instrument of transfer of the Shares at the rate of $0.20 for every $100 or any part thereof of the consideration for or market value of, the Shares, whichever is higher. The purchaser is liable for the stamp duty charge, unless otherwise agreed by the parties to the transaction.

No stamp duty is payable if no instrument of transfer is executed (such as in the case of scripless Shares, the transfer of which does not require an instrument of transfer to be executed) or if the instrument of transfer is executed outside of Singapore. However, stamp duty may be payable if the instrument of transfer which is executed outside Singapore is subsequently brought into Singapore.

Singapore estate duty

Singapore estate duty was abolished with effect from 15 February 2008.

Singapore GST

The sale of Offering Shares by a GST-registered investor belonging in Singapore through a SGX-ST member or to another person belonging in Singapore is an exempt supply not subject to GST.

Any GST (for example, GST on brokerage) incurred by the GST-registered investor in connection with the making of this exempt supply will generally become an additional cost to the investor unless the investor satisfies certain conditions prescribed under the GST legislation or certain GST concessions.

Where Offering Shares are sold by a GST-registered investor to a person belonging outside Singapore (and who is outside Singapore at the time of supply), the sale is a taxable supply subject to GST at zero rate. Consequently, any GST (for example, GST on brokerage) incurred by him in the making of this zero-rated supply for the purpose of his business will, subject to the provisions of the GST legislation, be recoverable as an input tax credit in his GST returns.

Investors should seek their own tax advice on the recoverability of GST incurred on expenses in connection with the purchase and sale of Offering Shares.

Services such as brokerage and handling services rendered by a GST-registered person to an investor belonging in Singapore in connection with the investor's purchase or sale of Offering Shares will be subject to GST at the prevailing rate (currently 7.0%). Similar services rendered contractually to an investor belonging outside Singapore are subject to GST at zero-rate provided that the investor is not physically present in Singapore at the time the services are performed and the services do not directly benefit a person who belongs in Singapore.

Certain U.S. Federal Income Tax Considerations

ANY DISCUSSION OF TAX ISSUES SET FORTH IN THIS PROSPECTUS WAS WRITTEN IN CONNECTION WITH THE PROMOTION AND MARKETING OF THE TRANSACTIONS DESCRIBED IN THIS PROSPECTUS. SUCH DISCUSSION WAS NOT INTENDED TO BE USED, AND IT CANNOT BE USED, BY ANY PERSON FOR THE PURPOSE OF AVOIDING ANY TAX PENALTIES THAT MAY BE IMPOSED ON SUCH PERSON. EACH INVESTOR SHOULD SEEK ADVICE BASED ON ITS PARTICULAR CIRCUMSTANCES FROM AN INDEPENDENT TAX ADVISOR.

The following discussion describes the material U.S. federal tax consequences of the purchase, ownership and disposition of the Shares to U.S. Holders (as defined below). This summary applies only to U.S. Holders that hold the Shares as capital assets (generally, property held for investment). This summary is based upon the U.S. Internal Revenue Code of 1986, as amended (the "Code"), proposed, temporary and final U.S. Treasury Regulations promulgated thereunder, administrative rulings and judicial decisions, all as in effect as at the date of this Prospectus and all of which are subject to change (possibly with retroactive effect) or to differing interpretations. The following discussion does not address any U.S. state or local or non-U.S. tax considerations or any U.S. federal estate, gift or alternative minimum tax considerations. The following discussion does not address all of the tax consequences that may be relevant to a particular investor or to persons subject to special tax treatment under U.S. federal income tax law such as:

- banks, insurance companies, and financial institutions;
- dealers in securities;
- U.S. expatriates;
- traders in securities that have elected the mark-to-market method of accounting for their securities;
- tax-exempt entities;
- persons whose functional currency is not the U.S. dollar;
- persons holding Shares as part of a straddle, hedging, conversion or integrated transaction; or
- persons that actually or constructively own 10% or more of the voting stock of our Company.

For purposes of this summary, a "U.S. Holder" is a beneficial owner of Shares that is:

- an individual who is a U.S. citizen or resident of the United States as determined for U.S. federal income tax purposes;
- a corporation, or other entity treated as a corporation for U.S. federal income tax purposes, created or organised in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate that is subject to U.S. federal income tax on its worldwide income; or
- a trust if either (i) a U.S. court is able to exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust or (ii) the trust has a valid election in effect to be treated as a U.S. person for U.S. federal income tax purposes.

The tax treatment of a partner in a partnership, including any entity treated as a partnership for U.S. federal income tax purposes, that holds Shares generally will depend on the status of the partner and the activities of the partnership. A partner in a partnership that holds Shares should consult its own tax advisors.

PROSPECTIVE PURCHASERS OF THE OFFER SHARES SHOULD CONSULT THEIR OWN TAX ADVISORS CONCERNING THE PARTICULAR U.S. FEDERAL INCOME TAX CONSEQUENCES APPLICABLE TO THEM OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF THE SHARES, AS WELL AS THE CONSEQUENCES ARISING UNDER THE LAWS OF ANY OTHER TAXING JURISDICTION.

Taxation of Distributions on Shares

Subject to the discussion under "PFIC Status" below, distributions made on the Shares, including the amount of any Australian taxes withheld on such distributions, generally will be included in the income of a U.S. Holder as dividend income to the extent of the current and accumulated earnings and profits of our Company, as determined under U.S. federal income tax principles. For U.S. federal income tax purposes, distributions in excess of a corporation's current and accumulated earnings and profits generally are treated first as a return of capital that reduces a shareholder's tax basis in its shares, and then as capital gain from the sale or exchange of such shares. However, we do not expect to calculate our Company's earnings and profits under U.S. federal income tax principles, and, accordingly, a U.S. Holder should expect that a distribution will generally be reported as a dividend (as discussed above) even if that distribution (or a portion thereof) would otherwise be treated as a tax-free return of capital or as capital gain. A corporate U.S. Holder will not be entitled to the dividends received deduction that is generally available upon the receipt by a U.S. corporation of dividends from U.S. corporations. Generally, dividends paid to non-corporate U.S. persons, including individuals, by a "qualified foreign corporation" may be eligible for reduced rates of taxation if certain holding period requirements are satisfied. A qualified foreign corporation includes a non-U.S. corporation that is eligible for the benefits of an income tax treaty with the United States that includes an exchange of information programme and that the U.S. Department of the Treasury has determined is satisfactory for this purpose. The U.S. Department of the Treasury has determined that the income tax treaty between the United States and Australia is satisfactory for this purpose. In addition, in order to be treated as a qualified foreign corporation, a non-U.S. corporation must not be a passive foreign investment company (a "PFIC") in the year the dividend is paid or have been a PFIC in the preceding taxable year. Potential purchasers of Shares are urged to consult their tax advisors regarding the application of these rules in their particular circumstances.

Dividends generally will be treated as foreign source "passive category income" or, in certain circumstances, "general category income" for U.S. foreign tax credit purposes. A U.S. Holder may be entitled to a U.S. foreign tax credit or deduction for any Australian tax withheld. Because of the complexity of the foreign tax credit rules, U.S. Holders should consult their own tax advisors with respect to the amount of foreign taxes that can be claimed as a credit. If any dividends are paid in Australian dollars, the amount includible in gross income will be the U.S. dollar value of such a dividend, calculated by reference to the exchange rate in effect on the date of receipt of the payment, regardless of whether the payment is actually converted into U.S. dollars on that date. If any Australian dollars received are later converted into U.S. dollars, U.S. Holders may realise gain or loss on the conversion. Gain or loss, if any, realised as a result of currency exchange fluctuations during the period from the date of inclusion of the payment in income to the date of conversion of the payment into U.S. dollars will be treated as ordinary income or loss. This gain or loss generally will be from sources within the United States for U.S. foreign tax credit purposes. U.S. Holders should consult their own tax advisors concerning the possibility of foreign currency gain or loss if any such currency is not converted into U.S. dollars on the date of receipt.

Sale, Exchange, Redemption or Other Disposition of Shares

Subject to the discussion under "PFIC Status" below, upon the sale, exchange, redemption or other disposition of a Share, a U.S. Holder generally will recognise capital gain or loss equal to the difference between (i) the amount of cash proceeds plus the fair market value of any property received upon the sale, exchange, redemption or other disposition and (ii) such U.S. Holder's adjusted tax basis in the Share. The capital gain or loss will be long-term capital gain or loss if the U.S. Holder's holding period for the Share is more than one year at the time of the sale, exchange, redemption or other disposition. Non-corporate U.S. Holders, including individual, are generally eligible for reduced rates of taxation with respect to long-term capital gains. The deductibility of capital losses is subject to limitations. Gain or loss generally will be treated as income or loss from within the United States for U.S. foreign tax credit purposes.

PFIC Status

Based upon the composition of our assets and income, we do not believe that we were a PFIC for our taxable year ended 30 June 2013 and do not anticipate becoming a PFIC for our current taxable year ending 30 June 2014. The determination of whether or not we are a PFIC is made on an annual basis and will depend upon the composition of our income and assets from time to time. Specifically, a non-U.S. corporation is considered to be a PFIC for any taxable year if either:

- 75% or more of its gross income for such year consists of certain types of "passive income"; or
- 50% or more of the value of its assets (based on an average of the quarterly values of the assets during the taxable year) is attributable to assets that produce or are held for the production of "passive income".

"Passive income" includes dividends, interest, certain rents and royalties and certain gains from the sale of commodities and securities. In determining whether we are a PFIC, we will be treated as owning our proportionate share of the assets and directly receiving our proportionate share of the income of any corporation in which we own, directly or indirectly, more than 25% (by value) of the stock. In addition, if any of our subsidiaries are also PFICs, a U.S. Holder will be deemed to own its proportionate share of such subsidiary PFICs, and may be subject to adverse tax consequences with respect to the shares of such subsidiary PFICs that the U.S. Holder would be deemed to own.

If we were a PFIC, special tax rules would generally apply with respect to any "excess distribution" received by such a U.S. Holder with respect to the Shares and to any gain realised by the U.S. Holder from a sale, exchange, redemption or other disposition of the Shares. Distributions received by a U.S. Holder in a taxable year that are greater than 125% of the average annual distributions received by the U.S. Holder during the three preceding taxable years (or, if shorter, the U.S. Holder's holding period for the Shares) would be treated as an excess distribution. Under these special tax rules:

- the excess distribution or gain will would allocated rateably over the U.S. Holder's holding period for the Shares;
- the amount allocated to the current taxable year, and to any taxable year prior to the first taxable year in which we were a PFIC, would be treated as ordinary income; and
- the amount allocated to each other year will be subject to the highest tax rate in effect for that year and the interest charge generally applicable to underpayments of tax will be imposed on the resulting tax attributable to each such year.

The tax liability for amounts allocated to years prior to the year of the disposition or "excess distribution" cannot be offset by any net operating losses for such years, and gains (but not losses) realised on the sale of the stock of a PFIC cannot be treated as capital gains, even if the U.S. Holder holds the stock as a capital asset. If we were a PFIC in any year in which a U.S. Holder held Shares, we generally would continue to be treated as a PFIC with respect to the U.S. Holder for all succeeding years in which the U.S. Holder held the Shares.

In certain circumstances, in lieu of being subject to the excess distribution rules discussed above, a U.S. shareholder of a PFIC may make an election to include gain on the stock of a PFIC as ordinary income under a mark-to-market method, provided that such stock is regularly traded on a qualified exchange.

If a U.S. Holder held Shares in any year in which were a PFIC, such a U.S. Holder would generally be required to comply with certain information reporting requirements. U.S. Holders are urged to consult their own tax advisors regarding the application of the PFIC rules to an investment in the Shares.

Information Reporting and Backup Withholding

Dividend payments with respect to the Shares and proceeds from the sale, exchange, redemption or other disposition of Shares made within the United States or through certain

U.S.-related financial intermediaries may be subject to information reporting and possible U.S. backup withholding at a current rate of 28%. Backup withholding will generally not apply, however, to a U.S. Holder who furnishes a correct taxpayer identification number and makes any other required certification or who is otherwise exempt from backup withholding. Backup withholding is not an additional tax. Backup withholding is not an additional tax. Any amount withheld under the backup withholding rules may generally be credited against a U.S. Holder's U.S. federal income tax liability, provided that the required information is timely filed with the Internal Revenue Service (the "IRS"). U.S. Holders should consult their own tax advisors as to their qualification for exemption from backup withholding and the procedure for obtaining such exemption. In addition, certain U.S. Holders that hold certain foreign financial assets (which may include Shares) are required to report information relating to such assets, subject to exceptions (including an exception for assets held in accounts maintained by certain financial institutions). U.S. Holders are urged to consult their tax advisors regarding the effect, if any, of this reporting requirement on their ownership and disposition of Shares.

Additional Tax on Net Investment Income

For taxable years beginning after 31 December 2012, a U.S. Holder that is an individual or estate, or a trust that does not fall into a special class of trusts that is exempt from such tax, will be subject to an additional 3.8% tax on the lesser of (1) the U.S. Holder's "net investment income," which may include all or a portion of their dividends and net gains from the disposition of Shares, for the relevant taxable year and (2) the excess of the U.S. Holder's modified adjusted gross income for the taxable year over a certain threshold (which in the case of individuals is between $125,000 and $250,000, depending on the individual's circumstances). A U.S. Holder that is an individual, estate or trust should consult its own tax advisors regarding the applicability of this tax to its income and gains in respect of its investment in the Shares.

PLAN OF DISTRIBUTION

THE OFFERING

Credit Suisse (Singapore) Limited, DBS Bank Ltd. and J.P. Morgan (S.E.A.) Limited are acting as the Joint Bookrunners and Joint Lead Managers. We are issuing an aggregate of [●] Offering Shares, in respect of the Offering. The Offering consists of: (i) a Placement of [●] Offering Shares to qualified institutional buyers in reliance on Rule 144A and outside the United States in offshore transactions in reliance on Regulation S and (ii) a Public Offer of [●] Offering Shares in Singapore. The Offering Shares may be reallocated between the Placement and the Public Offer, at the discretion of the Joint Bookrunners and Joint Lead Managers after consultation with us in the event of an excess of applications in one and a deficit in the other.

We and the Joint Bookrunners and Joint Lead Managers have entered into an international purchase agreement dated [●] (the "**International Purchase Agreement**") pursuant to which we will issue and each Joint Bookrunners and Joint Lead Managers will severally (but not jointly) agree to subscribe for, or procure subscribers for, subject to certain conditions, the number of Offering Shares set forth opposite such Joint Bookrunner and Joint Lead Manager's name in the following table, at the Offering Price.

Joint Bookrunners and Joint Lead Managers	Number of Shares
Credit Suisse (Singapore) Limited	[●]
DBS Bank Ltd.	[●]
J.P. Morgan (S.E.A.) Limited	[●]
Total	[●]

The International Purchase Agreement may be terminated at any time prior to delivery of the Offering Shares pursuant to the terms of the International Purchase Agreement, upon the occurrence of certain events, including, among other things, certain *force majeure* events. The closing of the Offering is conditional upon certain events, including the fulfilment, or waiver by the SGX-ST, of all of the conditions contained in the letter of eligibility from the SGX-ST for the listing and quotation of all of our issued Shares, the Offering Shares, the Additional Shares, the Employee Option Plan Shares, the Performance Rights Plan Shares and the CN Shares on the Official List of the SGX-ST.

We and the Joint Bookrunners and Joint Lead Managers have also entered into a Singapore offer agreement dated [●] (the "**Singapore Offer Agreement**" together with International Purchase Agreement, the "**Underwriting Agreements**") for the sale of the Offering Shares to the public in Singapore. Subject to the terms and conditions in the Singapore Offer Agreement, and concurrently with the sale of [●] Shares pursuant to the International Purchase Agreement, we have agreed to appoint the Joint Bookrunners and Joint Lead Managers to procure subscribers, and the Joint Bookrunners and Joint Lead Managers severally have agreed to procure subscribers or, failing which, to subscribe for the number of Offering Shares indicated in the following table, at the Offering Price.

Joint Bookrunners and Joint Lead Managers	Number of Shares
Credit Suisse (Singapore) Limited	[●]
DBS Bank Ltd.	[●]
J.P. Morgan (S.E.A.) Limited	[●]
Total	[●]

The completion of the Public Offer is conditional upon the completion of the Placement and vice versa, except for where the only outstanding condition is the completion of the other Underwriting Agreement.

The Joint Bookrunners and Joint Lead Managers are offering the Offering Shares, subject to prior sale, when, as and if issued or sold to and accepted by them, subject to certain conditions precedent including the receipt by the Joint Bookrunners and Joint Lead Managers of officer's certificates and legal opinions. The Joint Bookrunners and Joint Lead Managers reserve the right to withdraw, cancel or modify such offers and to reject orders in whole or in part.

Expenses and Commission

We will pay the Joint Bookrunners and Joint Lead Managers, as compensation for their services in connection with the offer and sale of the Offering Shares, a combined underwriting, selling and management commission amounting to 3.5% of the total gross proceeds from the sale of Offering Shares and the sale of the Additional Shares (if the Over-allotment Option is exercised).

We may, at our sole discretion, pay one or more of the Joint Bookrunners and Joint Lead Managers an incentive fee of up to [●]% of the gross proceeds from the offering of the Offering Shares and the Additional Shares. The additional incentive fee, if it is to be paid to any of the Joint Bookrunners and Joint Lead Managers, will amount to up to S$[●] per Offering Share.

Purchasers of Shares, other than those in the Singapore Public Offer, may be required to pay to the Joint Bookrunners and Joint Lead Managers a brokerage fee up to 1.0% of the Offering Price at the time of settlement.

Indemnities

We have agreed in the Underwriting Agreements to indemnify the Joint Bookrunners and Joint Lead Managers against certain liabilities. The indemnity provides that where the indemnification is unavailable or insufficient, our Company shall contribute to the amount payable by the Joint Bookrunners and Joint Lead Managers as a result of any claims against them, in such proportion as is appropriate to reflect the relative benefits to be received by our Company and the Joint Bookrunners and Joint Lead Managers from the Offering. Where such allocation is prohibited by applicable law then our Company and the Joint Bookrunners and Joint Lead Managers shall contribute proportionately to reflect both the relative benefits and the relative fault of us or the Joint Bookrunners and Joint Lead Managers, as the case may be, in respect of any misstatement or omission which resulted in such claims and any other relevant equitable considerations. The relative benefits to be received by us and the Joint Bookrunners and Joint Lead Managers pursuant to the Offering will be in the same proportion that the amount of total net proceeds from the Offering (before deducting expenses) to be received by our Company bears to the amount of the total underwriting commissions to be received by the Joint Bookrunners and Joint Lead Managers in respect of the Offering. The relative fault is determined by reference to, among other things, whether the misstatement or omission relates to information supplied by our Company or the Joint Bookrunners and Joint Lead Managers, as the case may be and the respective parties' relative intent, knowledge, access to information and opportunity to correct or prevent such misstatement or omission. No Joint Bookrunner and Joint Lead Manager is required to contribute any amount in excess of the amount by which the total price at which the Shares underwritten by it under the Offering exceeds the amount of any damages which such Joint Bookrunner and Joint Lead Manager has otherwise been required to pay by reason of such untrue or alleged untrue statement or omission or alleged omission.

Agreement among Joint Bookrunners and Joint Lead Managers and Sub-Underwriting

The Joint Bookrunners and Joint Lead Managers will be entering into an agreement among underwriters that provides for the coordination of their activities.

The Joint Bookrunners and Joint Lead Managers have entered and may enter into sub-underwriting and/or sub-placement arrangements in respect of their obligations under the Underwriting Agreements, upon such terms and conditions as they deem fit.

Shares are not Being Registered under the U.S. Securities Act

The Joint Bookrunners and Joint Lead Managers, directly or through their affiliates, propose to offer the Offering Shares for resale in transactions not requiring registration under the U.S. Securities Act or applicable state securities laws, including sales pursuant to Rule 144A and Regulation S. The Joint Bookrunners and Joint Lead Managers will not offer or sell the Offering Shares except:

- within the United States to persons they reasonably believe to be qualified institutional buyers within the meaning of Rule 144A; or

- outside the United States, pursuant to Regulation S.

In addition, until the expiration of 40 days after the commencement of the Offering, an offer or sale of the Offering Shares within the United States by a dealer (whether or not participating in the Offering) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A or pursuant to another exemption from registration under the U.S. Securities Act.

Shares sold pursuant to Regulation S may not be offered or resold within the United States, except under an exemption from the registration requirements of the U.S. Securities Act or under a registration statement declared effective under the U.S. Securities Act.

Each purchaser of the Offering Shares will be deemed to have made the acknowledgements, representations and agreements as described under “Transfer Restrictions”.

OVER-ALLOTMENT OPTION

In connection with the Offering, we have granted the Stabilising Manager on behalf of the Joint Bookrunners and Joint Lead Managers, an Over-allotment Option to subscribe for up to an aggregate of the Additional Shares at the Offering Price, exercisable in full or in part on one or more occasions, from the Listing Date until the earliest of (i) the date falling 30 days from the Listing Date, (ii) the date when the Stabilising Manager or its appointed agent has bought on the SGX-ST, an aggregate of [●] Shares, representing not more than 10.0% of the total Offering Shares, to undertake stabilising actions, or (iii) the date falling 30 days after the date of adequate public disclosure of the Offering Price, solely to cover the over-allotment of the Offering Shares, if any subject to any applicable laws and regulations. In the event the Over-allotment Option is exercised in full, the total number of issued Shares, after the completion of the Offering will be increased to [●] Shares.

SHARE LENDING AGREEMENT

The Stabilising Manager has entered into a share lending agreement with Newtron (the “**Share Lending Agreement**”) to borrow [●] Shares from [●], which will be borrowed before the commencement of trading of our Shares on the SGX-ST, for the purpose of facilitating settlement of over-allotments, if any, in connection with this Offering pending exercise of the Over-allotment Option and stabilising actions. Any Shares that may be borrowed by the Stabilising Manager under the Share Lending Agreement will be returned by the Stabilising Manager to [●] either through the purchase of Shares in the open market by the Stabilising Manager in the conduct stabilisation activities or through exercise of the Over-allotment Option by the Stabilising Manager on behalf of the Joint Bookrunners and Joint Lead Managers.

PRICE STABILISATION

In connection with the Offering, the Stabilising Manager (or persons acting on its behalf) may over-allot Shares or effect transactions which may stabilise or maintain the market price of our Shares at levels above those that might otherwise prevail in the

open market. Such transactions may be effected on the SGX-ST and in other jurisdictions where it is permissible to do so, in each case in compliance with all applicable laws and regulations, including the Securities and Futures Act and any regulations thereunder. However, there is no assurance that the Stabilising Manager (or persons acting on its behalf) will undertake any such stabilisation action. Such transactions may commence on or after the Listing Date and, if commenced, may be discontinued at any time and shall not be effected after the earliest of (i) the date falling 30 days from the Listing Date, (ii) the date when the Stabilising Manager or its appointed agent has bought on the SGX-ST an aggregate of [●] Shares, representing not more than [●]% of the total Offering Shares, to undertake stabilising actions, or (iii) the date falling 30 days after the date of adequate public disclosure of the Offering Price.

Neither we nor the Joint Bookrunners and Joint Lead Managers make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the Shares. In addition, neither we nor the Joint Bookrunners and Joint Lead Managers make any representation that the Stabilising Manager will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice (unless such notice is required by law). The Stabilising Manager will also be required to make a public announcement through the SGX-ST in relation to the cessation of stabilising actions and the number of Shares in respect of which the Over-allotment Option has been exercised not later than 8.30 a.m. (Singapore time) on the trading day of the SGX-ST immediately after the day of cessation of stabilising actions.

LOCK-UP ARRANGEMENTS

Our Company

We have agreed with the Joint Bookrunners and Joint Lead Managers that, from the date of the Singapore Offer Agreement until the date falling six months after the Listing Date (both dates inclusive) (the "**First Lock-up Period**"), we will not, without the prior written consent of the Joint Bookrunners and Joint Lead Managers (such consent not to be unreasonably withheld):

- issue, offer, sell, pledge, contract to pledge, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, lend, hypothecate or encumber or otherwise transfer or dispose of, directly or indirectly, or file with the U.S. Securities and Exchange Commission a registration statement under the Securities Act relating to, any Shares or any securities convertible into or exercisable or exchangeable for any Shares;

- enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of the Shares or any securities convertible into or exercisable or exchangeable for or repayable with Shares or which carry rights to subscribe for or purchase Shares whether such swap, hedge or transaction is to be settled by delivery of Shares or other securities, in cash or otherwise;

- deposit any Shares or any securities convertible into or exchangeable for or which carry rights to subscribe for or purchase Shares in any depository receipt facilities, whether any such transaction described above is to be settled by delivery of Shares or such other securities, in cash or otherwise; or

- publicly announce any intention to do any of the above.

These restrictions shall not apply in respect of Shares issued pursuant to the Offering, the Additional Shares upon the exercise of the Over-allotment Option, the Employee Option Plan Shares, the Performance Rights Plan Shares and the CN Shares.

Newtron, ISNY and Mr. Peter Bond

Each of Newtron and ISNY has agreed with the Joint Bookrunners and Joint Lead Managers that, for the First Lock-up Period and the period commencing on the day immediately following the expiry of the First Lock-up Period until the date falling 12 months after the Listing Date (both dates inclusive) (the "**Second Lock-up Period**"), it will not, without the prior written consent of the Joint Bookrunners and Joint Lead Managers (such consent not to be unreasonably withheld):

- offer, sell, contract to sell, pledge (except for the Pledged Collateral), sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, lend, hypothecate or encumber or otherwise transfer or dispose of, directly or indirectly, or file with the U.S. Securities and Exchange Commission a registration statement under the Securities Act relating to, any Shares or any securities convertible into or exercisable or exchangeable for any Shares;

- enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of the Shares or any securities convertible into or exercisable or exchangeable for or repayable with Shares or which carry rights to subscribe for or purchase Shares whether such swap, hedge or transaction is to be settled by delivery of Shares or other securities, in cash or otherwise;

- deposit any Shares or any securities convertible into or exchangeable for or which carry rights to subscribe for or purchase Shares in any depository receipt facilities, whether any such transaction described above is to be settled by delivery of Shares or such other securities, in cash or otherwise; or

- publicly announce any intention to do any of the above.

In relation to the Pledged Collateral, being the 71,000,000 Shares that had been pledged by Newtron to Equities pursuant to the Master Loan Agreement and the Master Pledge Agreement, Newtron has procured an undertaking from Equities not to exercise its contractual rights to, among others, sell and buy the Pledged Collateral under the relevant terms of the Master Loan Agreement and the Master Pledge Agreement during the First Lock-up Period.

These restrictions shall apply to all Shares held by each of Newtron and ISNY as of the date of the Singapore Offer Agreement and any additional Shares that Newtron and/or ISNY may acquire between the date of the Singapore Offer Agreement and the Listing Date, for the First Lock-up Period. Each of Newtron and ISNY has also agreed with the Joint Bookrunners and Joint Lead Managers that such restrictions shall apply to 50.0% of the Shares held by it as of the Listing Date, for the Second Lock-up Period.

These restrictions shall not, however, apply in respect of the Shares that were the subject matter of a securities lending agreement entered into between Newtron and Credit Suisse Equities (Australia) Limited (the "**SLA Shares**") (being a number of up to 37,453,183 Shares) and the Shares that were the subject matter of the Share Lending Agreement (the "**Loan Shares**") (being a number of up to [●] Shares), provided that the foregoing restrictions shall apply to the SLA Shares and the Loan Shares upon the latter of (i) the termination of the securities lending agreement and the Share Lending Agreement, as the case may be and (ii) the return of all loans of SLA Shares and the Loan Shares (if there are existing loans of SLA Shares and the Loan Shares at the time of termination of the securities lending agreement and the Share Lending Agreement, as the case may be, during the First Lock-up Period or the Second Lock-up Period).

Mr. Peter Bond, the sole shareholder of Newtron and ISNY, has agreed with the Joint Bookrunners and Joint Lead Managers that, for the First Lock-up Period and the Second

Lock-up Period, he will not, without the prior written consent of the Joint Bookrunners and Joint Lead Managers (such consent not to be unreasonably withheld):

- offer, sell, contract to sell, pledge, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, lend, hypothecate or encumber or otherwise transfer or dispose of, directly or indirectly, or file with the U.S. Securities and Exchange Commission a registration statement under the Securities Act relating to, any Shares, any Newtron Shares, any ISNY Shares or any securities convertible into or exercisable or exchangeable for any Shares, Newtron Shares or ISNY Shares;

- enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of the Shares, Newtron Shares, ISNY Shares or any securities convertible into or exercisable or exchangeable for or repayable with Shares, Newtron Shares, ISNY Shares or which carry rights to subscribe for or purchase Shares, Newtron Shares or ISNY Shares whether such swap, hedge or transaction is to be settled by delivery of Shares, Newtron Shares or ISNY shares or other securities, in cash or otherwise;

- deposit any Shares, Newtron Shares, ISNY Shares or any securities convertible into or exchangeable for or which carry rights to subscribe for or purchase Shares, Newtron Shares or ISNY Shares in any depository receipt facilities, whether any such transaction described above is to be settled by delivery of Shares, Newtron Shares, ISNY Shares or such other securities, in cash or otherwise; or

- publicly announce any intention to do any of the above.

These restrictions shall apply to all Newtron Shares and ISNY Shares held by Mr. Peter Bond as of the date of the Singapore Offer Agreement and the Listing and any Shares that Mr. Peter Bond may acquire (the "**Peter Bond Shares**") between the date of the Singapore Offer Agreement and the Listing Date.

An interest in favour of each of the Joint Bookrunners and Joint Lead Managers arises under the Australian *Foreign Acquisitions and Takeovers Act* 1975 ("**FATA**") in relation to the above lock-ups granted by Newtron, ISNY and Mr. Peter Bond as the Joint Bookrunners and Joint Lead Managers will each be entitled to control the exercise of a right attached to the Shares held by Newtron and ISNY as well as the Newtron Shares, ISNY Shares and/or Peter Bond Shares, if any, even though none of them will be registered holders of such Shares, Newtron Shares, ISNY Shares and/or Peter Bond Shares, if any or have voting rights.

As such, to the extent that the Australian Federal Treasurer has not, directly or through the Foreign Investment Review Board, issued a statement of no objections ("**FIRB Approval**") in relation to the above lock-ups granted by Newtron, ISNY and Mr. Peter Bond in favour of any of the Joint Bookrunners and Joint Lead Managers as of the date of the Singapore Offer Agreement, the relevant lock-ups in favour of such Joint Bookrunners and Joint Lead Managers will be subject to FIRB Approval. Credit Suisse (Singapore) Limited is expected to obtain the FIRB Approval as of the date of the Singapore Offer Agreement.

Persons intending to subscribe for Shares in the Offering

We are not aware of any person who intends to subscribe for more than 5.0% of the Shares offered pursuant to the Offering.

Certain employees of our Group, including our Directors and Executive Officers may subscribe for Shares in the Offering.

OTHER RELATIONSHIPS

In addition, some of the Joint Bookrunners and Joint Lead Managers and their affiliates have engaged in, and may in the future engage in, investment banking and other commercial dealings in the ordinary course of business with us or our affiliates. They have received, or may in the future receive, customary fees and commissions for these transactions.

In addition, in the ordinary course of their business activities, the Joint Bookrunners and Joint Lead Managers and their affiliates may make, sell or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities, including but not limited to equity derivatives, warrants and any other structured instruments) and financial instruments (including bank loans, derivatives and other securities) for their own account and for the accounts of their customers. Such investments and securities activities may involve securities and/or instruments of our Company or our affiliates. The Joint Bookrunners and Joint Lead Managers and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

For example, as at the Latest Practicable Date, certain affiliates of Credit Suisse (Singapore) Limited hold an aggregate of approximately 9.5% of the issued share capital of our Company, pursuant to the provision of services related to securities activities, and Credit Suisse (Singapore) Limited acted as advisor to our Company in relation to obtaining approval for amendments to our Company's currently outstanding 2018 Convertible Notes from the holders of these notes, through a meeting of holders, for which it would be paid a fee. Also, 37,453,184 Shares indirectly held by Mr. Peter Bond are the subject matter of a securities lending agreement ("**SLA**") entered into between Newtron as lender, and Credit Suisse Equities (Australia) Limited ("**CS Equities**") as borrower, to enable CS Equities to carry out hedging transactions in relation to the 2018 Convertible Notes. As at the date of this offering document, no Shares have been borrowed under the SLA. In addition, certain affiliates of J.P. Morgan (S.E.A.) Limited hold an aggregate of approximately 0.8% of the issued share capital of our Company, pursuant to investment on their own account and the provision of services related to securities activities.

Our Company has also granted an affiliate of Credit Suisse (Singapore) Limited an upsize option in relation to the 2018 Convertible Notes to purchase up to an additional US$50.0 million in principal amount of notes on or before 10 May 2014.

SELLING RESTRICTIONS

The distribution of this offering document or any offering material and the offering, sale or delivery of the Shares is restricted by law in certain jurisdictions. Therefore, persons who may come into possession of this offering document or any offering material are advised to consult with their own legal advisors as to what restrictions may be applicable to them and to observe such restrictions. This offering document may not be used for the purpose of an offer or invitation in any circumstances in which such offer or invitation is not authorised.

No action has been or will be taken in any jurisdiction that would permit a public offering of the Shares being offered outside Singapore or the possession, circulation or distribution of this offering document or any other material relating to us or the Shares in any jurisdiction where action for the purpose is required. Accordingly, the Shares may not be offered or sold, directly or indirectly, and neither this offering document nor any other offering material or advertisement in connection with the Shares may be distributed or published, in or from any country or jurisdiction except under circumstances that will be in compliance with any applicable rules or regulations of any such country or jurisdiction.

United States of America

The Offering Shares are being offered or sold (i) within the United States to "qualified institutional buyers" in reliance on Rule 144A or another exemption from registration under the U.S. Securities Act and (ii) outside the United States in reliance on Regulation S. The Offering Shares have not been and will not be registered under the U.S. Securities Act and may not be offered, sold, pledged or transferred within the United States except in certain transactions not subject to, or pursuant to an exemption, from the registration requirements of the U.S. Securities Act. Terms used in this paragraph have the meanings given to them by Regulation S under the U.S. Securities Act. In addition, until 40 days after the first date upon which the securities were bona fide offered to the public, an offer or sale of the Offering Shares within the United States (whether or not as part of the Offering) by a dealer may violate the registration requirements of the U.S. Securities Act, if such offer or sale is made otherwise than in accordance with Rule 144A.

The Offering Shares have not been approved or disapproved by the U.S. Securities and Exchange Commission, any state securities commission in the United States or any other U.S. regulatory authority, nor have any of the foregoing authorities passed upon or endorsed the merits of the Offering or the accuracy or adequacy of this document relating to the Offering. Any representation to the contrary is a criminal offence in the United States.

Each purchaser of the Shares in the Offering will be deemed to have made the acknowledgements, representations and agreements as described in “Transfer Restrictions”.

Australia

This offering document does not constitute a prospectus or other disclosure document under the Corporations Act and does not purport to include the information required of a disclosure document under the Australian Corporations Act. This offering document has not been lodged with the ASIC and no steps have been taken to lodge it as such with ASIC. Any offer in Australia of the Offering Shares under this offering document may only be made to persons who are “sophisticated investors” (within the meaning of section 708(8) of the Corporations Act), to “professional investors” (within the meaning of section 708(11) of the Corporations Act) or otherwise pursuant to one or more exemptions under section 708 of the Corporations Act so that it is lawful to offer the Offering Shares in Australia without disclosure to investors under Part 6D.2 of the Corporations Act.

Any offer of Offering Shares for on-sale that is received in Australia within 12 months after their issue by us, or within 12 months after their sale by a selling shareholder (or a Joint Bookrunner and Joint Lead Manager) under the Offering, as applicable, is likely to need prospectus disclosure to investors under Part 6D.2 of the Corporations Act, unless such offer for on-sale in Australia is conducted in reliance on a prospectus disclosure exemption under section 708 of the Corporations Act or otherwise. Any persons acquiring the Offering Shares should observe such Australian on-sale restrictions.

Canada

The Offering Shares may only be offered or sold, directly or indirectly, in Canada in the provinces of Ontario and Québec or to or for the benefit of any resident of such provinces and not in any other province or territory of Canada. Such offer or sales will be made pursuant to an exemption from the requirement to file a prospectus in the province of Ontario or Québec, or the case may be,, and only by a dealer duly registered under the applicable securities laws of that province or territory or in accordance with an exemption from the applicable registered dealer requirements.

China

This offering document has not been and will not be circulated or distributed in the People’s Republic of China, and the Offering Shares may not be offered or sold, and will not be offered or sold to any person for re-offering or resale, directly or indirectly, to any resident of the People’s Republic of China except pursuant to applicable laws and regulations of the People’s Republic of China. For the purpose of this paragraph, People’s Republic of China does not include Taiwan and the special administrative regions of Hong Kong and Macau.

Dubai International Financial Centre

This offering document relates to an Exempt Offer in accordance with the Offered Securities Rules of the Dubai Financial Services Authority ("**DFSA**"). This offering document is intended for distribution only to persons of a type specified in the Offered Securities Rules of the DFSA. It must not be delivered to, or relied on by, any other person. The DFSA has no responsibility for reviewing or verifying any documents in connection with Exempt Offers. The DFSA has not approved this offering document nor taken steps to verify the information set forth herein and has no responsibility for the offering document. The shares to which this offering document relates may be illiquid and/or subject to restrictions on their resale. Prospective purchasers of the shares offered should conduct their own due diligence on the shares. If you do not understand the contents of this offering document you should consult an authorised financial advisor.

European Economic Area

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a "**Relevant Member State**"), an offer to the public of any Offering Shares may not be made in that Relevant Member State except that an offer to the public in that Relevant Member State of any Offering Shares may be made at any time under the following exemptions under the Prospectus Directive, if they have been implemented in that Relevant Member State:

(a) to legal entities which are qualified investors as defined under the Prospectus Directive; or

(b) to fewer than 100, or if the Relevant Member State has implemented the relevant provisions of the 2010 PD Amending Directive, 150, natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the Joint Issuer Managers for any such offer; or

(c) in any other circumstances falling within Article 3(2) of the Prospectus Directive,

provided that no such offer of Offering Shares shall result in a requirement for the publication by us or the Joint Bookrunners and Joint Lead Managers of a prospectus pursuant to Article 3 of the Prospectus Directive or a supplemental prospectus pursuant to Article 16 of the Prospectus Directive.

For the purposes of this provision, the expression an "offer of shares to the public" in relation to any Offering Shares in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and any Offering Shares to be offered so as to enable an investor to decide to purchase or subscribe for the Offering Shares, as the same may be varied in that Relevant Member State by any measure implementing the Prospectus Directive in that Relevant Member State; and the expression "Prospectus Directive" means Directive 2003/71/EC (and amendments thereto including "2010 PD Amending Directive" to the extent implemented in the Relevant Member State) and includes any relevant implementing measure in each Relevant Member State and the expression the 2010 PD Amending Directive means Directive 2010/73/EU.

Each purchaser of the Offering Shares in the Offering located within a member state of the European Economic Area will be deemed to have represented, acknowledged and agreed that it is a "qualified investor" within the meaning of Article 2(1)(e) of the Prospectus Directive and in the case of any Offering Shares acquired by it as a financial intermediary, as that term is used in Article 3(2) of the Prospectus Directive, (i) the Offering Shares acquired by it in the Offering have not been acquired on behalf of, nor have they been acquired with a view to their offer or resale to, persons in any Relevant Member State other than qualified investors, as that term is defined in the Prospectus Directive, or in circumstances in which the prior consent of the Joint Bookrunners and Joint Lead Managers has been given to the offer or resale; or (ii) where Offering Shares have been acquired by it on behalf of persons in any Relevant Member State other than qualified investors, the offer of those Shares to it is not treated under the Prospectus Directive as having been made to such persons. We, each Joint Bookrunner and Joint Lead Manager and their respective affiliates and others will rely upon the truth and accuracy of the foregoing representation, acknowledgement and agreement.

Hong Kong

We have not been authorised, nor has the contents of this offering document been approved by any regulatory authority in Hong Kong. You are advised to exercise caution in relation to the Offering. If you are in any doubt about any of the contents of this offering document, you should obtain independent professional advice. Accordingly, (i) no Offering Shares may be offered or sold in Hong Kong by means of this offering document or any other document other than to professional investors within the meaning of Part I of Schedule 1 to the Securities and Futures Ordinance of Hong Kong (Cap. 571) ("**SFO**") and any rules made thereunder ("**professional investor**"), or in other circumstances which do not result in the document being a "prospectus" as defined in the Companies Ordinance of Hong Kong (Cap. 32) ("**CO**") or which do not constitute an offer or invitation to the public for the purposes of the CO or the SFO, and (ii) no person may issue or have in its possession for the purposes of issue, whether in Hong Kong or elsewhere, this offering document or any other advertisement, invitation or document relating to the Offering Shares which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the securities laws of Hong Kong) other than with respect to Offering Shares which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors".

Indonesia

The Offering is not registered under the Indonesian Capital Market law and its implementing regulations, and is not intended to become a public offering of securities under the Indonesian capital market law and regulations. Accordingly, this offering document may not be distributed or passed on within Indonesia or to citizens of Indonesia (wherever they are domiciled or located) or entities of or residents in Indonesia in a manner which constitutes a public offering of securities under the Indonesian capital market law and regulations. The Offering Shares may not be offered or sold, directly or indirectly, within Indonesia or to Indonesian citizens (wherever they are domiciled or located), entities or residents in a manner which constitutes a public offering of securities under the Indonesian capital market law and regulations.

Japan

The Offering Shares have not been and will not be registered under the Financial Instrument and Exchange Law of Japan (the "**FIEL**"). The Offering Shares have not been offered or sold and will not be offered or sold in Japan or to, or for the benefit of, any resident of Japan (which term shall mean any person resident in Japan or any corporation or other entity organised under the laws of Japan), or to others for reoffering or resale, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the FIEL and other applicable laws, regulations and governmental guidelines in Japan.

Malaysia

No prospectus or other offering material or document in connection with the offer and sale of the Offering Shares has been or will be registered with the Securities Commission of Malaysia (the "**Commission**") pursuant to the Capital Markets and Services Act 2007 and no approval for the offering of the Offering Shares has been obtained from the Commission pursuant to the Capital Markets and Services Act 2007. Accordingly, this offering document and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the Offering Shares may not be circulated or distributed, nor may the Offering Shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Malaysia other than (i) a closed end fund approved by the Commission; (ii) a holder of a Capital Markets Services License who carries on the business of fund management; (iii) a person who acquires the Offering Shares, as principal, if the aggregate consideration for the acquisition is not less than Ringgit 250,000 (or equivalent in a foreign currency); (iv) a corporation with total net assets exceeding Ringgit 10 million (or equivalent in a foreign currency) based on the latest audited accounts; (v) a licensed offshore bank as defined under the Offshore Banking Act 1990; (vi) an offshore insurer as defined under the Offshore Insurance Act 1990; or (vii) any other person as may be specified by the Commission in any guideline issued under section 377 of the Capital Markets and Services Act 2007; provided that, in each of the preceding categories (i) to (vii), the distribution of the Offering Shares is made by a holder of a Capital Markets Services License who carries on the business of dealing in securities. This offering document does not constitute and may not be used for the purpose of a public offering or an issue, offer for subscription or purchase, invitation to subscribe for or purchase any securities requiring the registration of a prospectus with the Commission under the Capital Markets and Services Act 2007.

Switzerland

The Offering Shares may not be publicly offered in Switzerland and will not be listed on the SIX Swiss Exchange ("**SIX**") or on any other stock exchange or regulated trading facility in Switzerland. This offering document has been prepared without regard to the disclosure standards for issuance prospectuses under Article 652a or Article 1156 of the Swiss Code of Obligations or the disclosure standards for listing prospectuses under Articles 27 ff. of the SIX Listing Manual or the listing rules of any other stock exchange or regulated trading facility in Switzerland. Neither this offering document nor any other offering or marketing material relating to the Offering Shares or the Offering may be publicly distributed or otherwise made publicly available in Switzerland.

Neither this offering document nor any other offering or marketing material relating to the Offering Shares or the Offering or us have been or will be filed with or approved by any Swiss regulatory authority. In particular, this offering document will not be filed with, and the Offering will not be supervised by, the Swiss Financial Market Supervisory Authority FINMA ("**FINMA**"), and the Offering has not been and will not be authorised under the Swiss Federal Act on Collective Investment Schemes ("**CISA**"). The investor protection afforded to acquirers of interests in collective investment schemes under the CISA does not extend to acquirers of the Offering Shares.

The Offering Shares are being offered in Switzerland by way of a private placement, i.e., to a small number of selected investors only, without any public offer and only to investors who do not purchase the Offering Shares with the intention to distribute them to the public. The investors will be individually approached from time to time. This offering document, as well as any other offering or marketing material relating to the Offering Shares, is confidential and it is exclusively for the use of the individually addressed investors in connection with the offer of the Offering Shares in Switzerland and it does not constitute an offer to any other person. This offering document may only be used by those investors to whom it has been handed out in connection with the Offering described herein and may neither directly nor indirectly be distributed or made available to other persons without our express consent. It may not be used in connection with any other offer and shall in particular not be copied and/or distributed to the public in or from Switzerland.

Taiwan

The Offering Shares have not and will not be registered with the Financial Supervisory Commission of Taiwan or any other governmental authorities of Taiwan, and are not being offered or sold and may not be offered or sold, directly or indirectly, in Taiwan or otherwise, to, or for the benefit of, any resident or entity of Taiwan, except (a) pursuant to the requirements of the securities related laws and regulations in Taiwan; and (b) in compliance with any other applicable requirements of Taiwan laws.

Thailand

No action has been or will be taken by the Company or by or on behalf of the Joint Bookrunners and Joint Lead Managers which would permit a public offering of any of the Offering Shares or distribution of the offering document, and this offering document is not intended to constitute an offer to sell or the solicitation of an offer to buy the Offering Shares in Thailand in which the offer or solicitation of the securities would be prohibited. No general solicitation has been or will be conducted and no advertisement in whatever form has been employed in Thailand and in other countries where the offer or solicitation of the Offering Shares would be prohibited.

United Arab Emirates (other than the Dubai International Financial Centre)

This offering document has not been, and is not intended to be, approved by the UAE Central Bank, the UAE Ministry of Economy, the Emirates Securities and Commodities Authority or any other authority in the United Arab Emirates (the "**UAE**"), or by the Dubai Financial Services Authority or any other authority in any of the free zones established and operating in the UAE (the "**Free Zones**"). It should not be assumed that any of us, the Joint Bookrunners and Joint Lead Managers or any placement agent (i) has received any authorisation or license from the UAE Central Bank or any other authorities in the UAE or any Free Zone to sell or market the Offering Shares therein; (ii) is a licensed broker, dealer or investment adviser under the laws applicable in the UAE or any Free Zone; or (iii) advises residents of the UAE or any Free Zone as to the appropriateness of investing in or purchasing or selling securities or other financial products.

This offering document does not constitute a public offer of securities in the UAE under the UAE Commercial Companies Law (Federal Law No. 8 of 1984) (as amended) or otherwise. This offering document is being distributed to a limited number of selected institutional and other sophisticated investors in the UAE (a) upon their request and confirmation that they understand that the Offering Shares have not been approved or licensed by or registered with the UAE Central Bank or any other relevant licensing authorities or governmental agencies in the UAE and may not be offered or sold directly or indirectly to the public in the UAE; and (b) on the condition that this offering document will not be provided to any person other than the original recipient, is not for general circulation in the UAE and may not be reproduced or used for any other purpose. The information contained in this offering document is not intended to lead to the sale of any securities or the consummation of any agreement of any nature within the territory of the UAE.

United Kingdom

Each Joint Bookrunner and Joint Lead Manager has severally represented, warranted and agreed that (i) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the Financial Services and Markets Act 2000) (the "**FSMA**") received by it in connection with the issue or sale of the Offering Shares in circumstances in which Section 21(1) of the FSMA does not apply to us; and (ii) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Offering Shares in, from or otherwise involving the United Kingdom.

Any investment or investment activity to which this offering document relates is directed only at, available only to, and will be engaged in only with (i) persons who are outside the United Kingdom or (ii) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "**Order**") or (iii) persons falling within Article 49(2)(a) to (d) ("high net worth companies, unincorporated associations, etc.") of the Order (all such persons together being referred to as "**relevant persons**"). Persons who are not relevant persons should not take any action on the basis of this offering document and should not act or rely on it or any of its contents.

Introduction

A letter-of-eligibility has been obtained from the SGX-ST for the listing and quotation of our Shares on the Main Board of the SGX-ST. For the purpose of trading on the SGX-ST, a board lot for our Shares will comprise 1,000 Shares. Upon listing and quotation on the SGX-ST, our Shares will be traded under the book-entry settlement system of CDP, and all dealings in and transactions of our Shares through the SGX-ST will be effected in accordance with the terms and conditions for the operation of Securities Accounts with CDP, as amended from time to time.

CDP, a wholly-owned subsidiary of Singapore Exchange Limited, is incorporated under the laws of Singapore and acts as a depository and clearing organisation. CDP holds securities for its account holders and facilitates the clearance and settlement of securities transactions between account holders through electronic book-entry changes in the Securities Accounts maintained by such account holders with CDP.

Our Shares will be registered in the name of CDP or its nominees and held by CDP for and on behalf of persons who maintain, either directly or through depository agents, Securities Accounts with CDP. Persons holding Shares through Securities Account with CDP will not be treated, under the Corporations Act and our Constitution, as members of our Company in respect of the number of Shares credited to their respective Securities Accounts with CDP. CDP depositors and depository agents on whose behalf CDP holds Shares for may not be accorded the full rights of membership such as voting rights, the rights to appoint proxies, or the right to receive Shareholders' circulars, proxy forms, annual reports, prospectuses and takeover documents. In such an event, CDP depositors and depository agents will be accorded only such rights as CDP may make available to them pursuant to CDP's Terms and Conditions to act as Depository for foreign securities. All Shares deposited with CDP, for purposes of determining our foreign shareholding levels, if required, will be regarded as being held by CDP, a non-Australian person.

Persons holding our Shares in a securities account with CDP may withdraw the number of Shares they own from the book-entry settlement system in the form of physical share certificates. Such share certificates will not, however, be valid for delivery pursuant to trades transacted on the SGX-ST, although they will be *prima facie* evidence of title and may be transferred in accordance with the Constitution. A fee of S$10 for each withdrawal of 1,000 Shares or less and a fee of S$25 for each withdrawal of more than 1,000 Shares will be payable upon withdrawing our Shares from the book-entry settlement system and obtaining physical share certificates. In addition, a fee of up to S$2 (or such other amount as the Directors may decide) will be payable to our Share Registrar and Share Transfer Agent for each share certificate issued, and stamp duty of S$10 is also payable where our Shares are withdrawn in the name of the person withdrawing our Shares, or S$0.20 per S$100 or part thereof of the last transacted price where our Shares are withdrawn in the name of a third party. Persons holding physical share certificates who wish to trade on the SGX-ST must deposit with CDP their share certificates together with the duly executed and stamped instruments of transfer in favour of CDP, and have their respective Securities Accounts credited with the number of Shares deposited before they can effect the desired trades. A fee of S$10 is payable upon the deposit of each instrument of transfer with CDP. The above fee may be subject to such changes as may be in accordance with CDP's prevailing policies or the current tax policies that may be in force in Singapore from time to time.

CDP depositors and depository agents on whose behalf CDP holds Shares for may not be accorded the full rights of membership such as voting rights, the rights to appoint proxies, or the right to receive Shareholders' circulars, proxy forms, annual reports, prospectuses and takeover documents. In such an event, CDP depositors and depository agents will be accorded only such rights as CDP may make available to them pursuant to CDP's Terms and Conditions to act as Depository for foreign securities.

Transactions in our Shares under the book-entry settlement system will be reflected by the seller's securities account being debited with the number of Shares sold and the buyer's securities account being credited with the number of Shares acquired. No transfer stamp duty is currently payable for the transfer of Shares that are settled on a book-entry basis.

Shares credited to a Securities Account may be traded on the SGX-ST on the basis of a price between a willing buyer and a willing seller. Shares credited into a Securities Account may be transferred to any other Securities Account with CDP, subject to the terms and conditions for the operation of Securities Accounts and a S$10 transfer fee payable to CDP. All persons trading in Shares through the SGX-ST should ensure that the relevant Shares have been credited into their Securities Account, prior to trading in such Shares, since no assurance can be given that the Shares can be credited into the Securities Account in time for settlement following a dealing. If the Shares have not been credited into the Securities Account by the due date for the settlement of the trade, the buy-in procedures of the SGX-ST will be implemented.

A clearing fee for trades in the Shares on the SGX-ST is payable at the rate of 0.04% of the transaction value, subject to a maximum of S$600 per transaction. The clearing fee and instrument of transfer deposit fees may be subject to GST of 7%. Dealings in Shares will be carried out in Singapore dollar and will be effected for settlement in CDP on a scripless basis. Settlement of trades on a normal "ready" basis on the SGX-ST generally takes place on the third Market Day following the transaction date, and payment for the Shares is generally settled on the following Market Day. CDP holds securities on behalf of investors in Securities Accounts. An investor may open a direct securities account with CDP or a securities sub-account with a depository agent. A depository agent may be a member company of the SGX-ST, bank, merchant bank or trust company.

TRANSFER RESTRICTIONS

Because the following restrictions will apply to the International Offering, purchasers are advised to consult their own legal counsel prior to making any offer, resale, pledge or other transfer of the Offering Shares.

Rule 144A Shares

Each purchaser of our Offering Shares within the United States pursuant to Rule 144A, by accepting delivery of this offering document, will be deemed to have represented, agreed and acknowledged that:

(1) It is (a) a qualified institutional buyer within the meaning of Rule 144A, (b) acquiring such Offering Shares for its own account or for the account of a qualified institutional buyer, and (c) aware, and each beneficial owner has been advised, that the sale of such Offering Shares to it is being made in reliance on Rule 144A.

(2) It understands that our Offering Shares have not been and will not be registered under the U.S. Securities Act and may not be offered, sold, pledged or otherwise transferred except (a) in accordance with Rule 144A to a person that it and any person acting on its behalf reasonably believe is a qualified institutional buyer purchasing for its own account or for the account of a qualified institutional buyer, (b) in an offshore transaction in accordance with Rule 903 or Rule 904 of Regulation S or (c) pursuant to an exemption from registration under the U.S. Securities Act provided by Rule 144 (if available), in each case in accordance with any applicable securities laws of any State of the United States.

(3) It understands that our Offering Shares purchased pursuant to Rule 144A, to the extent they are in certificated form, unless we determine otherwise in accordance with applicable law, will bear a legend substantially to the following effect:

THESE SHARES HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933 (THE "U.S. SECURITIES ACT"), OR WITH ANY SECURITIES REGULATORY AUTHORITY OF ANY STATE OR OTHER JURISDICTION OF THE UNITED STATES AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED EXCEPT (1) IN ACCORDANCE WITH RULE 144A UNDER THE U.S. SECURITIES ACT TO A PERSON THAT THE HOLDER AND ANY PERSON ACTING ON ITS BEHALF REASONABLY BELIEVE IS A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A PURCHASING FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QUALIFIED INSTITUTIONAL BUYER, (2) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT OR (3) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE U.S. SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER (IF AVAILABLE), IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES. NO REPRESENTATION CAN BE MADE AS TO THE AVAILABILITY OF THE EXEMPTION PROVIDED BY RULE 144 UNDER THE U.S. SECURITIES ACT FOR RESALES OF THESE SHARES.

(4) We, the Joint Bookrunners and Joint Lead Managers and their affiliates, and others will rely upon the truth and accuracy of the foregoing acknowledgements, representations and agreements and, if any of such acknowledgments, representations or agreements deemed to have been made by it through its purchase of our Offering Shares are no longer accurate, it will promptly notify us. If it is acquiring any Offering Shares for the account of one or more qualified institutional buyers, it represents that it has sole investment discretion with respect to each such account and that it has full power to make the foregoing acknowledgements, representations and agreements on behalf of each such account.

Prospective purchasers are hereby notified that sellers of our Offering Shares may be relying on the exemption from the provisions of Section 5 of the U.S. Securities Act provided by Rule 144A.

Regulation S Shares

Each purchaser of our Offering Shares outside the United States pursuant to Regulation S will be deemed to have represented, agreed and acknowledged that:

(1) It is aware that the Offering Shares have not been and will not be registered under the U.S. Securities Act or with any securities regulatory authority of any state or other jurisdiction of the United States.

(2) It is purchasing the Offering Shares in an offshore transaction meeting the requirements of Regulation S.

(3) It will not offer, sell, pledge or transfer any Offering Shares, except in accordance with the U.S. Securities Act and any applicable laws of any state of the United States and any other jurisdiction.

(4) We, the Joint Bookrunners and Joint Lead Managers and their affiliates, and others will rely upon the truth and accuracy of the foregoing acknowledgements, representations and agreements and, if any of such acknowledgments, representations or agreements deemed to have been made by it through its purchase of our Offering Shares are no longer accurate, it will promptly notify us.

Any resale or other transfer, or attempted resale or other transfer, made other than in compliance with the above-stated restrictions shall not be recognised by our Company.

General

Each purchaser of our Offering Shares in the Offering will be deemed to have represented and agreed that it is relying on this document and not on any other information or representation concerning us or our Offering Shares and none of us nor any other person responsible for this document or any part of it, nor the Joint Bookrunners and Joint Lead Managers, will have any liability for any such other information or representation.

LEGAL MATTERS

Certain matters in connection with the Offering will be passed upon for us by WongPartnership LLP with respect to matters of Singapore Law and by HWL Ebsworth Lawyers with respect to matters of Australian Law.

Certain legal matters in connection with the Offering will be passed upon for the Joint Bookrunners and Joint Lead Managers by Allen & Gledhill LLP with respect to matters of Singapore law and by Shearman & Sterling LLP with respect to matters of U.S. Federal Securities Law and New York Law.

Each of WongPartnership LLP, HWL Ebsworth Lawyers, Allen & Gledhill LLP and Shearman & Sterling LLP does not make, or purport to make, any statement in this offering document and is not aware of any statement in this offering document which purports to be based on a statement made by it, and it makes no representation, express or implied, regarding, and takes no responsibility for, any statement in or omission from this offering document.

INDEPENDENT AUDITORS

The consolidated financial statements of Linc Energy Ltd as of and for each of the three financial years ended 30 June 2013, 2012 and 2011 included in this Offering Document have been audited by KPMG Australia, an independent registered public accounting firm, as set forth in their reports thereon included herein.

The liability of KPMG, in relation to the performance of their professional services provided to Linc Energy Ltd including, without limitation, KPMG's audits of Linc Energy Ltd's consolidated financial statements described above, is limited under the Institute of Chartered Accountants in Australia (NSW) Scheme approved by the New South Wales Professional Standards Council or such other applicable scheme approved pursuant to the Professional Standards Act 1994 (NSW), including the Treasury Legislation Amendment (Professional Standards) Act.

INFORMATION ON DIRECTORS AND EXECUTIVE OFFICERS

1. Except as disclosed below, none of our Directors or Executive Officers is or was involved in any of the following events

   (a) during the last 10 years, an application or a petition under any bankruptcy laws of any jurisdiction was filed against him or against a partnership of which he was a partner at the time when he was a partner or at any time within two years from the date he ceased to be a partner;

   (b) during the last 10 years, an application or a petition under any law of any jurisdiction was filed against an entity (not being a partnership) of which he was a Director or an equivalent person or a key executive, at the time when he was a director or an equivalent person or a key executive of that entity, for the winding-up or dissolution of that entity, or where that entity is the trustee of a business trust, that business trust, on the ground of insolvency;

   (c) any unsatisfied judgements against him;

   (d) a conviction of any offence, in Singapore or elsewhere, involving fraud or dishonesty which is punishable with imprisonment, or has been the subject of any criminal proceedings (including any pending criminal proceedings of which he is aware) for such purpose;

   (e) a conviction of any offence, in Singapore or elsewhere, involving a breach of any law or regulatory requirement that relates to the securities or futures industry in Singapore or elsewhere, or has been the subject of any criminal proceedings (including pending criminal proceedings of which he is aware) for such breach;

   (f) during the last 10 years, judgement entered against him in any civil proceedings in Singapore or elsewhere involving a breach of any law or regulatory requirement that relates to the securities or futures industry in Singapore or elsewhere, or a finding of fraud, misrepresentation or dishonesty on his part, or has been the subject of any civil proceedings (including any pending civil proceedings of which he is aware) involving an allegation of fraud, misrepresentation or dishonesty on his part;

   (g) a conviction in Singapore or elsewhere of any offence in connection with the formation or management of any entity or business trust;

   (h) disqualification from acting as a Director or an equivalent person of any entity (including the trustee of a business trust), or from taking part directly or indirectly in the management of any entity or business trust;

   (i) any order, judgement or ruling of any court, tribunal or governmental body permanently or temporarily enjoining him from engaging in any type of business practice or activity;

   (j) to his knowledge, been concerned with the management or conduct, in Singapore or elsewhere, of affairs of:

      (i) any corporation which has been investigated for a breach of any law or regulatory requirement governing corporations in Singapore or elsewhere;

      (ii) any entity (not being a corporation) which has been investigated for a breach of any law or regulatory requirement governing such entities in Singapore or elsewhere;

(iii) any business trust which has been investigated for a breach of any law or regulatory requirement governing business trusts in Singapore or elsewhere; or

(iv) any entity or business trust which has been investigated for a breach of any law or regulatory requirement that relates to the securities or futures industry in Singapore or elsewhere, in connection with any matter occurring or arising during the period when he was so concerned with the entity or business trust; or

(k) the subject of any current or past investigation or disciplinary proceedings, or has been reprimanded or issued any warning, by the Authority or any other regulatory authority, exchange, professional body or government agency, whether in Singapore or elsewhere.

Mr. Peter Bond was a director of Universal Trading Co. Pty Ltd from 23 January 2007 to 31 March 2009. Due to the inability of Universal Trading Co. Pty Ltd to raise additional capital to continue the development of its technology platform following the exit of Mr. Bond as its major investor in March 2009, a liquidator was appointed by the Supreme Court of New South Wales pursuant to a winding up order made by creditors against Universal Trading Co. Pty Ltd in September 2010. A deregistration request was filed in November 2010 and the company was subsequently deregistered in January 2011. Mr. Bond was not involved in the management of Universal Trading Co. Pty Ltd subsequent to leaving the company in March 2009.

Mr. Lim Ah Doo, our Non-Executive Lead Independent Director, was non-executive Independent Commissioner of PT Indosat Tbk ("**PT Indosat**") from December 2002 to August 2008 and chairman of the audit committee from June 2004 to June 2008.

In November 2007, PT Indosat along with 6 other Indonesian telecommunications companies were investigated by Indonesia's anti competition authority, KPPU, on allegations of price-fixing of SMS and breach of Anti-monopoly Laws of Indonesia. No violation of Anti-monopoly Laws was found against PT Indosat.

Temasek Holdings Pte Ltd, ST Telemendia Ltd, STT Communications Ltd, Asia Mobile Holding Company Pte Ltd, ICL, ICLS, SingTel, SingTel Mobile and PT Indosat were investigated by KPPU on concerns of breaches of Article 27(a) of the Antimonopoly Laws of Indonesia. There was no finding of breach of law by PT Indosat.

Mr. Lim was president of RGM International Pte Ltd (which is now known as "RGE Pte. Ltd.") from October 2003 to June 2007 and the non-executive vice chairman of the RGM Group from June 2007 to November 2008. Mr. Lim was also the acting president of AAA Oils & Fats Pte. Ltd. from June 2007 to November 2007 and the non-executive deputy chairman of AAA Oils & Fats Pte. Ltd. from November 2007 to November 2008. RGE Pte. Ltd. provides strategy services and support to a global group of independent companies (the "**RGE Group**") operating in the resources development sector. Asian Agri is a member of the RGE Group and AAA Oils & Fats is a member of Asian Agri. Each business group of the RGE operates independently with its own holding company and directors responsible for the operations of that group. Certain Indonesian companies of Asian Agri operating in Indonesia, were investigated by the tax authorities of Indonesia in November 2006 for alleged non-payment of certain tax. The tax authorities of Indonesia had not confirmed any findings of breach of law at the time when Mr. Lim left RGE Group in November 2008. Mr. Lim was not a member of the board nor was he concerned with the management of the companies under investigation.

Mr. Stuart Jones, our Chief Financial Officer, was previously appointed as CFO of privately owned Viking Oil & Gas International Ltd ("**VOGIL**"), based in London, in May 2008. VOGIL owned 100% of Viking Field Development Solutions Pte Ltd ("**VFDS**") which owned two crude oil trading tankers. Mr. Jones was engaged by VOGIL specifically to seek project financing for the conversion of one of the two tankers owned by VFDS, into floating production storage and off-take vessels ("**FPSO**"). VFDS and another company (the "**Customer Co**") entered into a memorandum of understanding ("**MOU**") to undertake the conversion whereby Customer Co would take a long lease over the converted vessel at completion of the works. As there was a casual vacancy on the board of VFDS and the board was inquorate, he was approached by VOGIL shareholders to be appointed as an unpaid director of VFDS in June 2008. In or around November 2008, Customer Co terminated the MOU which lead to a departure of all VFDS' senior staff including the Chief Operating Officer and Managing Director. VOGIL sought compensation from Customer Co under the MOU and simultaneously entered into debt restructuring discussions with its banker under a revised strategy to lease the vessels to another energy company. Due to the Global Financial Crisis, the bankers, who had initially been supportive, refused the restructure plan for their own reasons and exercised their security over the tankers in July 2009.

Mr. Jones, by way of a resignation letter, resigned from his position as CFO at VOGIL and as director of VFDS in July 2009 due to a lack of support from bankers and the VOGIL shareholders. Mr. Jones was never paid for his director position at VFDS. Mr. Jones requested that the VOGIL remove his directorship from the register of directors. In August 2010, a third party commenced compulsory winding up proceedings against VFDS, on the grounds of insolvency. Mr. Jones was never employed by VFDS and was not involved in the day-to-day operational management of VFDS except by necessity to restore some order after all senior VFDS executives and employees left.

Mr. Scott Broussard, our President, Oil and Gas, was the chief executive officer and chairman of the board of directors of Probe Resources Ltd., a Canadian listed company from early 2008 to late 2010. As announced in November 2010, due to events such as Hurricane Ike, unprecedented declines in commodity prices, and the mechanical failure of a well, Probe Resources Ltd. faced difficulties accessing affordable capital. Upon the expiration of a debt restructuring agreement that it was a party to, Probe Resources Ltd. appointed a restructuring agent, and subsequently filed a voluntary petition under the Chapter 11 of the U.S. Bankruptcy Code in December 2010, after Mr. Broussard stepped down from his position as the chief executive officer and chairman of Probe Resources Ltd. Probe Resources Ltd. subsequently emerged from its voluntary Chapter 11 bankruptcy filing in April 2011.

Mr. Donald Schofield, our President, SAPEX, was a director of White Sands Petroleum Limited (now known as "Triangle Energy (Global) Ltd") ("**White Sands**") from August 2004 to July 2008. As at December 2006, the directors of White Sands formed the view that the investment to address their liquidity issues might not have come through and appointed Jefferson Collins Joiner ("**JCJ**") as administrators with effect from 20 December 2006. Pursuant to creditors' meetings, White Sands entered into a deed of company arrangement which was executed on 27 June 2007. On 26 July 2007, White Sands announced a proposal to repay its creditors in full, be recapitalised and have its ordinary shares reinstated for quotation on the ASX. Under the proposal, the administrators executed the deed of company arrangement which transferred the claims of White Sands' unsecured creditors to a creditors trust for repayment over a 12 month period (commencing on completion of restructuring). It was also proposed that White Sands would raise up to US$60.0 million from qualified and institutional investors and White Sands would acquire Maverick Drilling Company, a contract drilling company based in Texas, United States. Mr. Schofield, and the directors of White Sands, recommended that shareholders support the proposal. On 24 August 2007, White Sands changed its name to "Maverick Drilling International Ltd" and carried out the capital reorganisation. The initial proposal to restructure Maverick Drilling International Ltd and reinstate the company to the official list of the ASX in 2007 was unsuccessful. However, after another creditors meeting at the end of 2007, further proposals to recapitalise and relist Maverick Drilling International Ltd were made. On 3 July 2008, the securities of Maverick Drilling International Ltd were reinstated to the official list of the ASX and commenced trading on 7 July 2008. Maverick Drilling International Ltd continues to be listed on the ASX under the name “Triangle Energy (Global) Ltd” at present. Mr. Donald Schofield left the board on 2 July 2008.

A class action claim has been commenced by shareholders, who purchased shares in White Sands between 28 November 2005 and 20 December 2006 and who sold them at a loss during that time or who continued to hold the shares on 20 December 2006, against the former directors of White Sands for alleged misleading statements made in the prospectus dated 29 November 2005 and alleged misleading announcements made on the ASX announcement platform and/or failure to make proper disclosure to the market. The alleged misleading disclosures relate to the capabilities of a drill rig which was newly acquired by White Sands as well as the reasonableness of the drilling schedule and the forecast cash flow associated with this drilling rig. In particular, this drill rig was purchased in Norway and transported to Australia where it underwent the necessary work to be deemed fit for purpose under Australian regulations. Details of the work required were provided by the rig manufacturer in Norway prior to the purchase, and the work was undertaken using technical audits from two separate experienced independent rig engineering auditors. This work required more time and money than which was estimated as disclosed in the prospectus of White Sands due primarily to shortage of supplies as a result of increased demand which occurred after the issue of the such prospectus and during the necessary work conducted. The aggregate claim is for the amount of A$3.5 million representing the decrease in total market value of the shares as a result of the restructuring. This matter is currently being heard in the Federal Court of Australia, South Australia.

In relation to the aforementioned, these allegations are being defended and none of the allegations were instituted solely against Mr. Schofield.

Mr. Michael Mapp, our President, Coal, was Operators Representative and General Manager of Integra Coal Operations Pty Ltd (“**ICO**”) and Glennies Creek Management Pty Ltd (“**GCCM**”) between December 2005 and May 2007. By virtue of his positions then, he assisted with the investigations where an employee sustained a serious eye injury at the Integra coal mine site. This incident was investigated by the NSW Department of Primary Industries, and ICO and GCCM were fined pursuant to a breach of the Occupational Health & Safety Act. GCCM was convicted of a breach of section 8(1) and fined A$55,000 and ICO was convicted of a breach of section 8(2) and fined A$55,000. The employee was able to claim compensation for his injuries. Mr. Mapp was not the subject of these investigations.

In addition, Mr. Mapp was director of Coal Operations Australia at Vale Australia Pty Ltd. between October 2008 and February 2010. In April 2009, there was a fatality at the Intergra coal mine site and by virtue of his position then, he assisted with the investigations. This incident was investigated by the NSW Department of Primary Industries, and ICO and GCCM (being owned by Vale Australia Pty Ltd) were being investigated in connection a breach of the Occupational Health & Safety Act. These matters are still pending hearing. Mr. Mapp was not the subject of these investigations.

SHARE CAPITAL

2. As at the Latest Practicable Date, there is only one class of Shares in the capital of our Company. The rights and privileges attached to our Shares are stated in our Constitution. There are no founders, management or deferred shares. Substantial Shareholders, Directors and Chief Executive Officer of our Company are not entitled to any different voting rights from the other Shareholders.

3. Save for the Over-allotment Option, the 2018 Convertible Notes and as disclosed in “Share-Based Incentive Plans”, as at the date of this offering document, no person (including any Director or Executive Officer) has been, or has the right to be, given an option to subscribe for or purchase any securities of our Company or any of our subsidiaries.

WORKING CAPITAL

4. Our Directors are of the reasonable opinion that, after taking into account our cash and bank balance, existing banking facilities, net proceeds raised from the Offering and cash generated from our operating activities, our targeted production schedule, our planned capital expenditure for our assets, our working capital as at the date of this offering document is sufficient for our present requirements and for 18 months after Listing which includes (i) operating, general and administrative and financing costs; (ii) property holding costs; and (iii) costs of any proposed exploration and/or development. For a further description of our working capital, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources".

MATERIAL CONTRACTS

5. We have not entered into any material contracts, which are not in the ordinary course of our business, within the two years preceding the date of lodgement of this offering document.

CONSENTS

6. Credit Suisse (Singapore) Limited, DBS Bank Ltd. and J.P. Morgan (S.E.A.) Limited, named as the Joint Issue Managers, Joint Bookrunners and Joint Lead Managers, have each given, and not withdrawn, their written consent to the issue of this offering document with the inclusion herein of, and all references to, their name and all references thereto in the form and context in which they appear in this offering document, and to act in such capacity in relation to this offering document.

7. KPMG Australia as the Independent Auditor with respect to Independent Auditors' Report on the Consolidated Financial Statements for the years ended 30 June 2011, 2012 and 2013 has given and has not withdrawn its written consent to the issue of this offering document with the inclusion herein of, and all references to its name and references thereto in the form and context in which it appears and the inclusion herein of the section "Appendix F—Independent Auditors' Report on the Consolidated Financial Statements for the Years Ended 30 June 2011, 2012 and 2013" which was prepared for purposes of inclusion in this offering document and to act in such capacity in relation to this document.

8. Wood Mackenzie (Australia) Pty Ltd as the Industry Consultant has given and has not withdrawn its written consent to the issue of this offering document with the inclusion herein of its name and references thereto in the form and context which it appears and the inclusion herein of the section "Appendix G—Industry Overview" which was prepared for purposes of inclusion in this offering document and to act in such capacity in relation to this offering document.

9. Haas Petroleum Engineering Services, Inc., the Qualified Person with respect to our oil and gas assets in the Gulf Coast Region, has given and has not withdrawn its written consent to the issue of this offering document with the inclusion herein of its name and references thereto in the form and context which it appears and the inclusion herein of its report titled "Appraisal of Certain Oil and Gas Interests owned by Linc Gulf Coast Petroleum, Inc. located in Louisiana and Texas as of 1 September 2013" in the section "Appendix I—Qualified Persons' Reports" which was prepared for purposes of inclusion in this offering document and to act in such capacity in relation to this offering document.

10. Ryder Scott Company, L.P., the Qualified Person with respect to our oil and gas assets in Wyoming and Alaska, has given and has not withdrawn its written consent to the issue of this offering document with the inclusion herein of its name and references

thereto in the form and context which it appears and the inclusion herein of its reports titled "Competent Person's Report on Linc Energy Umiat Field, Alaska" and "Competent Person's Report on Linc Energy Petroleum (Wyoming), Inc" on in the section "Appendix I—Qualified Persons' Reports" which was prepared for purposes of inclusion in this offering document and to act in such capacity in relation to this offering document.

11. DeGolyer and MacNaughton, the Qualified Person with respect to our oil and gas assets in the Arckaringa Basin, Australia, has given and has not withdrawn its written consent to the issue of this offering document with the inclusion herein of its name and references thereto in the form and context which it appears and the inclusion herein of its report titled "Report as at 15 September 2013 on the Prospective Resources attributable to Certain Prospects owned by Linc Energy Ltd. in Various License Blocks in the Arckaringa Basin, South Australia" in the section "Appendix I—Qualified Persons' Reports" which was prepared for purposes of inclusion in this offering document and to act in such capacity in relation to this offering document.

12. Gustavson Associates LLC, the Qualified Person with respect to our oil and gas assets in the Arckaringa Basin, Australia, has given and has not withdrawn its written consent to the issue of this offering document with the inclusion herein of its name and references thereto in the form and context which it appears and the inclusion herein of its report titled "Resource and Evaluation Report of the Arckaringa Basin, South Australia" in the section "Appendix I—Qualified Persons' Reports" which was prepared for purposes of inclusion in this offering document and to act in such capacity in relation to this offering document.

13. Snowden Mining Industry Consultant Pty Ltd, the Qualified Person with respect to our conventional coal mining assets in Queensland, Australia, has given and has not withdrawn its written consent to the issue of this offering document with the inclusion herein of its name and references thereto in the form and context which it appears and the inclusion herein of its report titled "Independent Qualified Persons' Report on the Mineral Assets of New Emerald Coal Pty Ltd" in the section "Appendix I—Qualified Persons' Reports" which was prepared for purposes of inclusion in this offering document and to act in such capacity in relation to this offering document.

14. Xenith Consulting Pty Ltd the Qualified Person with respect to our conventional coal reserves and resources in the Blair Athol Mine and coal resources in the Teresa Project, has given and has not withdrawn its written consent to the issue of this offering document with the inclusion herein of its name and references thereto in the form and context which it appears and the inclusion herein of its reports titled "Blair Athol Reserve QP Report", "JORC Reserves Estimate Project Bill", "Blair Athol Resource QP Reserve Report", "New Emerald Coal Pty Ltd Blair Athol Project Coal Resource Estimate", "Teresa Reserve QP Reserve Report", "New Emerald Coal Pty Ltd JORC Resource Estimate Statement Teresa Project", "Dalby Resource QP Reserve Report", "New Emerald Coal Pty Ltd Independent Geological Appraisal Tipton Project", "Pentland Resource QP Reserve Report", and "New Emerald Coal Pty Ltd Independent Geological Appraisal Pentland Project" in the section "Appendix I—Qualified Persons' Reports" which was prepared for purposes of inclusion in this offering document and to act in such capacity in relation to this offering document.

15. MineCraft Consulting Pty Ltd, the Qualified Person with respect to our conventional coal reserves in the Teresa Project, has given and has not withdrawn its written consent to the issue of this offering document with the inclusion herein of its name and references thereto in the form and context which it appears and the inclusion herein of its reports titled "Teresa Project JORC Reserves Qualified Persons Report" and "New Emerald Coal Pty Ltd Independent Geological Appraisal Pentland Project" in the

section "Appendix I—Qualified Persons' Reports" which was prepared for purposes of inclusion in this offering document and to act in such capacity in relation to this offering document.

16. We are not aware of any matter that has caused us to believe that our Group:

(a) has not obtained all material licences, permits or certificates necessary to conduct our operations from the relevant governmental bodies in the jurisdictions where our Group operates;

(b) is not in compliance with all laws, rules and regulations in all jurisdictions in which our Group operates, including but not limited to, the proper incorporation and good standing of any incorporated subsidiary or interest, except where such non-compliance is not material to our Group's business operations; and

(c) does not possess title to or valid and enforceable rights to any assets (including licenses and agreements) as is appropriate to our Company or our Group, except where such lack of, or defect in, such title or rights is not material to our Group's business operations.

RESPONSIBILITY STATEMENT BY THE DIRECTORS

17. Our Directors collectively and individually accept full responsibility for the accuracy of the information given in this offering document and confirm after making all reasonable enquiries that, to the best of their knowledge and belief, this offering document constitutes full and true disclosure of all material facts about the Offering, our Company and our subsidiaries, and our Directors are not aware of any facts the omission of which would make any statement in this offering document misleading. Where information in this offering document has been extracted from published or otherwise publicly available sources or obtained from a named source, the sole responsibility of our Directors has been to ensure that such information has been accurately and correctly extracted from those sources and/or reproduced in this offering document in its proper form and context.

DOCUMENTS AVAILABLE FOR INSPECTION

18. Copies of the following documents may be inspected at 50 Raffles Place #32-01, Singapore Land Tower, Singapore 048623 during normal business hours for a period of six months from the date of registration of this offering document by the Authority (prior appointment would be appreciated):

(a) our Company's Constitution;

(b) our consolidated financial statements for FY2011, FY2012 and FY2013;

(c) the audited statements of our Company for FY2011, FY2012 and FY2013;

(d) the audited financial statements of SAPEX Limited, Linc Energy (Europe) Ltd and Linc Energy Operations Pty Ltd (being subsidiaries which have audited financial statements) for FY2012;

(e) the letters of consent and reports referred to in paragraphs 6 to 15 above;

(f) the service contracts referred to in the "Management—Directors—Service Agreements"; and

(g) the rules of the Employee Option Plan and the Performance Rights Plan.

MISCELLANEOUS

19. No expert is employed on a contingent basis by our Company or any of our subsidiaries, or has a material interest, whether direct or indirect, in the shares of our Company or our subsidiaries, or has a material economic interest, whether direct or indirect, in our Company including an interest in the success of the Offering.

    Except as disclosed in "Plan of Distribution—Other Relationships", our Company does not have any material relationship with the Joint Bookrunners and Joint Lead Managers or any other financial adviser in relation to the Offering.

20. There was no public take-over offer by a third party in respect of our Shares or by our Company in respect of the shares of another corporation or the units of a business trust during FY2013 and from 1 July 2013 to the Latest Practicable Date.

21. Except as disclosed under "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations", and barring any unforeseen circumstances, our Directors are not aware of any known trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on net sales or revenues, profitability, liquidity or capital resources, or that would cause financial information disclosed in this offering document to be not necessarily indicative of our future operating results or financial condition.

22. As at the date of this offering document, no material changes have occurred since the effective dates of the Qualified Persons' Reports.

23. Except as disclosed in this document, no event has occurred since 30 June 2013 and up till the Latest Practicable Date that may have a material effect on the financial position and results of our Group.

24. Except as disclosed below, there were no changes in the issued and paid up share capital of our Company and our subsidiaries within three years preceding the Latest Practicable Date, save for Linc Alaska Resources, LLC which is based on information available to us as of the date of its acquisition in June 2011 and Diasu Oil & Gas Company, which is based on information available to us as of January 2011. Except as provided below, none of the issues of Shares or of instruments convertible into Shares was for consideration other than in cash.

Our Company

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
18 November 2010	33,000	1.88	Exercise of Options	497,493,572
18 November 2010	50,000	0.97	Exercise of Options	497,543,572
22 November 2010	116,667	0.60	Exercise of Options	497,660,239
22 November 2010	50,000	0.97	Exercise of Options	497,710,239
23 November 2010	5,333	0.60	Exercise of Options	497,715,572
1 December 2010	10,000	0.76	Exercise of Options	497,725,572
1 December 2010	30,000	2.70	Issue of shares in accordance with an exploration agreement with three landowners	497,755,572
2 December 2010	10,000	0.97	Exercise of Options	497,765,572
7 December 2010	20,000	0.70	Exercise of Options	497,785,572
7 December 2010	500,000	0.70	Exercise of Options	498,285,572
7 December 2010	500,000	0.70	Exercise of Options	498,785,572
9 December 2010	66,667	2.45	Exercise of Options	498,852,239
9 December 2010	50,000	0.75	Exercise of Options	498,902,239
9 December 2010	350,000	0.76	Exercise of Options	499,252,239

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
13 December 2010	3,000	0.60	Exercise of Options	499,255,239
13 December 2010	25,000	0.60	Exercise of Options	499,280,239
14 December 2010	10,827	0.25	Exercise of Options	499,291,066
16 December 2010	50,000	0.97	Exercise of Options	499,341,066
20 December 2010	33,333	0.60	Exercise of Options	499,374,399
20 December 2010	66,667	2.16	Exercise of Options	499,441,066
20 December 2010	10,000	0.60	Exercise of Options	499,451,066
22 December 2010	1,000,000	0.25	Exercise of Options	500,451,066
22 December 2010	125,000	0.60	Exercise of Options	500,576,066
23 December 2010	60,000	0.25	Exercise of Options	500,636,066
23 December 2010	100,000	0.25	Exercise of Options	500,736,066
30 December 2010	50,000	0.60	Exercise of Options	500,786,066
31 December 2010	333,334	0.60	Exercise of Options	501,119,400
31 December 2010	500,000	-	Vesting of Rights	501,619,400
31 December 2010	500,000	-	Vesting of Rights	502,119,400
5 January 2011	66,667	1.53	Exercise of Options	502,186,067
5 January 2011	166,667	1.64	Exercise of Options	502,352,734
5 January 2011	166,666	0.60	Exercise of Options	502,519,400
10 January 2011	116,666	0.25	Exercise of Options	502,636,066
17 January 2011	20,000	0.25	Exercise of Options	502,656,066
17 January 2011	40,000	0.25	Exercise of Options	502,696,066
21 January 2011	26,667	1.40	Exercise of Options	502,722,733
21 January 2011	33,334	1.60	Exercise of Options	502,756,067
21 January 2011	66,667	1.97	Exercise of Options	502,822,734
21 January 2011	33,334	1.66	Exercise of Options	502,856,068
21 January 2011	16,667	1.79	Exercise of Options	502,872,735
21 January 2011	9,500	1.53	Exercise of Options	502,882,235
21 January 2011	66,666	0.60	Exercise of Options	502,948,901
21 January 2011	10,000	0.97	Exercise of Options	502,958,901
25 January 2011	33,334	1.52	Exercise of Options	502,992,235
28 January 2011	66,666	0.60	Exercise of Options	503,058,901
28 January 2011	10,000	1.51	Exercise of Options	503,068,901
31 January 2011	350,000	1.95	Exercise of Options	503,418,901
1 February 2011	50,000	0.60	Exercise of Options	503,468,901
14 February 2011	30,000	1.53	Exercise of Options	503,498,901
23 February 2011	25,000	0.25	Exercise of Options	503,523,901
1 March 2011	666,667	-	Vesting of Rights	504,190,568
14 March 2011	5,000	1.79	Exercise of Options	504,195,568
14 March 2011	6,667	0.25	Exercise of Options	504,202,235
23 March 2011	20,000	0.76	Exercise of Options	504,222,235
25 March 2011	30,000	0.97	Exercise of Options	504,252,235
29 March 2011	20,000	0.97	Exercise of Options	504,272,235
30 March 2011	66,667	1.53	Exercise of Options	504,338,902
30 March 2011	50,000	0.60	Exercise of Options	504,388,902
5 April 2011	10,000	1.88	Exercise of Options	504,398,902
5 April 2011	200,000	1.53	Exercise of Options	504,598,902
7 April 2011	300,000	1.91	Exercise of Options	504,898,902
8 April 2011	8,334	1.50	Exercise of Options	504,907,236
8 April 2011	20,000	0.76	Exercise of Options	504,927,236
8 April 2011	66,666	0.60	Exercise of Options	504,993,902
18 April 2011	8,333	0.75	Exercise of Options	505,002,235
29 April 2011	50,000	0.76	Exercise of Options	505,052,235
3 May 2011	6,667	1.62	Exercise of Options	505,058,902
3 May 2011	10,000	1.50	Exercise of Options	505,068,902
3 May 2011	10,000	2.55	Exercise of Options	505,078,902
3 May 2011	10,000	2.55	Exercise of Options	505,088,902
3 May 2011	6,667	1.62	Exercise of Options	505,095,569

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
17 May 2011	16,667	0.70	Exercise of Options	505,112,236
17 May 2011	16,667	0.70	Exercise of Options	505,128,903
20 May 2011	74,999	0.25	Exercise of Options	505,203,902
25 May 2011	500,000	0.25	Exercise of Options	505,703,902
25 May 2011	334	1.88	Exercise of Options	505,704,236
26 May 2011	23,333	1.88	Exercise of Options	505,727,569
7 June 2011	66,667	2.45	Exercise of Options	505,794,236
7 June 2011	50,000	0.97	Exercise of Options	505,844,236
9 June 2011	75,000	0.25	Exercise of Options	505,919,236
9 June 2011	100,000	0.25	Exercise of Options	506,019,236
10 June 2011	50,000	0.60	Exercise of Options	506,069,236
14 June 2011	2,530	-	Vesting of Rights	506,071,766
14 June 2011	20,000	0.97	Exercise of Options	506,091,766
16 June 2011	500,000	0.25	Exercise of Options	506,591,766
21 June 2011	15,000	0.25	Exercise of Options	506,606,766
27 June 2011	2,847	-	Vesting of Rights	506,609,613
27 June 2011	100,000	0.76	Exercise of Options	506,709,613
30 June 2011	100,000	-	Vesting of Rights	506,809,613
1 July 2011	40,000	-	Vesting of Rights	506,849,613
1 July 2011	13,000	-	Vesting of Rights	506,862,613
1 July 2011	65,000	-	Vesting of Rights	506,927,613
1 July 2011	500,000	-	Vesting of Rights	507,427,613
1 July 2011	48,334	-	Vesting of Rights	507,475,947
1 July 2011	23,000	-	Vesting of Rights	507,498,947
1 July 2011	500,000	-	Vesting of Rights	507,998,947
1 July 2011	10,000	-	Vesting of Rights	508,008,947
1 July 2011	10,000	-	Vesting of Rights	508,018,947
1 July 2011	12,000	-	Vesting of Rights	508,030,947
1 July 2011	50,000	-	Vesting of Rights	508,080,947
1 July 2011	15,000	-	Vesting of Rights	508,095,947
4 July 2011	6,650	-	Vesting of Rights	508,102,597
11 July 2011	2,580	-	Vesting of Rights	508,105,177
27 July 2011	20,675	-	Vesting of Rights	508,125,852
27 July 2011	20,000	0.75	Exercise of Options	508,145,852
29 July 2011	50,000	0.97	Exercise of Options	508,195,852
29 July 2011	200,000	1.53	Exercise of Options	508,395,852
2 August 2011	100,000	0.25	Exercise of Options	508,495,852
3 August 2011	50,000	0.97	Exercise of Options	508,545,852
8 August 2011	10,000	1.42	Exercise of Options	508,555,852
15 August 2011	33,334	-	Vesting of Rights	508,589,186
15 August 2011	7,000	-	Vesting of Rights	508,596,186
15 August 2011	20,000	-	Vesting of Rights	508,616,186
19 August 2011	10,000	0.79	Exercise of Options	508,626,186
22 August 2011	2,500	-	Vesting Rights	508,628,686
23 August 2011	65,232	0.25	Exercise of Options	508,693,918
25 August 2011	5,000	1.79	Exercise of Options	508,698,918
1 September 2011	35,625	-	Vesting of Rights	508,734,543
14 September 2011	225,000	-	Vesting of Rights	508,959,543
15 September 2011	17,500	-	Vesting of Rights	508,977,043
19 September 2011	18,750	-	Vesting of Rights	508,995,793
21 September 2011	2,110	-	Vesting of Rights	508,997,903
28 September 2011	33,334	-	Vesting of Rights	509,031,237
28 September 2011	20,000	0.97	Exercise of Options	509,051,237
29 September 2011	2,438	-	Vesting of Rights	509,053,675
1 October 2011	(1,165,000)	Highest: 1.87 Lowest: 1.66	Share cancellation from an on-market buy-back(1)	507,888,675

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
4 October 2011	(30,000)	Highest: 1.89 Lowest: 1.89	Share cancellation from an on-market buy-back(1)	507,858,675
5 October 2011	(60,280)	Highest: 1.96 Lowest: 1.83	Share cancellation from an on-market buy-back(1)	507,798,395
6 October 2011	(319,720)	Highest: 1.96 Lowest: 1.83	Share cancellation from an on-market buy-back(1)	507,478,675
7 October 2011	(95,000)	Highest: 1.882 Lowest: 1.78	Share cancellation from an on-market buy-back(1)	507,383,675
10 October 2011	(75,000)	Highest: 1.835 Lowest: 1.805	Share cancellation from an on-market buy-back(1)	507,308,675
11 October 2011	20,000	0.25	Exercise of Options	507,328,675
11 October 2011	2,584	-	Vesting of Rights	507,331,259
13 October 2011	150,000	0.25	Exercise of Options	507,481,259
20 October 2011	75,000	0.25	Exercise of Options	507,556,259
25 October 2011	20,000	0.25	Exercise of Options	507,576,259
25 October 2011	2,500	0.25	Exercise of Options	507,578,759
25 October 2011	2,000	0.60	Exercise of Options	507,580,759
31 October 2011	(80,000)	Highest: 2.12 Lowest: 2.10	Share cancellation from an on-market buy-back(1)	507,500,759
31 October 2011	(70,000)	Highest: 2.06 Lowest: 2.04	Share cancellation from an on-market buy-back(1)	507,430,759
31 October 2011	(50,000)	Highest: 2.07 Lowest: 2.07	Share cancellation from an on-market buy-back(1)	507,380,759
31 October 2011	(60,000)	Highest: 2.07 Lowest: 2.06	Share cancellation from an on-market buy-back(1)	507,320,759
31 October 2011	(100,000)	Highest: 2.05 Lowest: 2.02	Share cancellation from an on-market buy-back(1)	507,220,759
1 November 2011	116,667	-	Vesting of Rights	507,337,426
2 November 2011	3,000	0.25	Exercise of Options	507,340,426
3 November 2011	6,634	-	Vesting of Rights	507,347,060
3 November 2011	8,203	-	Vesting of Rights	507,355,263
7 November 2011	2,720	-	Vesting of Rights	507,357,983
7 November 2011	(140,000)	Highest: 1.985 Lowest: 1.96	Share cancellation from an on-market buy-back(1)	507,217,983
8 November 2011	(140,000)	Highest: 1.97 Lowest: 1.90	Share cancellation from an on-market buy-back(1)	507,077,983
9 November 2011	33,334	-	Vesting of Rights	507,111,317
14 November 2011	10,000	0.25	Exercise of Options	507,121,317
15 November 2011	(200,000)	Highest: 2.00 Lowest: 1.95	Share cancellation from an on-market buy-back(1)	506,921,317
24 November 2011	50,000	0.70	Exercise of Options	506,971,317
25 November 2011	375,000	-	Vesting of Rights	507,346,317
30 November 2011	(1,150,000)	Highest: 1.92 Lowest: 1.89	Share cancellation from an on-market buy-back(1)	506,196,317
30 November 2011	(1,000,000)	Highest: 1.92 Lowest: 1.89	Share cancellation from an on-market buy-back(1)	505,196,317
30 November 2011	(800,000)	Highest: 1.86 Lowest: 1.83	Share cancellation from an on-market buy-back(1)	504,396,317
30 November 2011	8,600	-	Vesting of Rights	504,404,917
6 December 2011	30,000	0.75	Exercise of Options	504,434,917
8 December 2011	50,000	0.70	Exercise of Options	504,484,917
14 December 2011	11,407	-	Vesting of Rights	504,496,324
14 December 2011	6,650	-	Vesting of Rights	504,502,974
14 December 2011	48,333	0.60	Exercise of Options	504,551,307
14 December 2011	20,000	0.97	Exercise of Options	504,571,307
16 December 2011	5,000	0.60	Exercise of Options	504,576,307
20 December 2011	5,834	-	Vesting of Rights	504,582,141

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
20 December 2011	81,333	0.60	Exercise of Options	504,663,474
21 December 2011	67,666	0.25	Exercise of Options	504,731,140
21 December 2011	200,000	0.60	Exercise of Options	504,931,140
21 December 2011	483,334	0.76	Exercise of Options	505,414,474
29 December 2011	2,345	-	Vesting of Rights	505,416,819
30 December 2011	1,000,000	0.25	Exercise of Options	506,416,819
30 December 2011	28,102	0.25	Exercise of Options	506,444,921
30 December 2011	100,000	0.25	Exercise of Options	506,544,921
30 December 2011	60,001	0.60	Exercise of Options	506,604,922
30 December 2011	333,333	0.60	Exercise of Options	506,938,255
30 December 2011	100,000	0.60	Exercise of Options	507,038,255
30 December 2011	20,000	0.60	Exercise of Options	507,058,255
30 December 2011	72,339	-	Vesting of Rights	507,130,594
31 December 2011	(250,000)	Highest: 1.225 Lowest: 1.20	Share cancellation from an on-market buy-back(1)	506,880,594
31 December 2011	(250,000)	Highest: 1.13 Lowest: 1.13	Share cancellation from an on-market buy-back(1)	506,630,594
31 December 2011	(250,000)	Highest: 1.135 Lowest: 1.065	Share cancellation from an on-market buy-back(1)	506,380,594
31 December 2011	(250,000)	Highest: 1.115 Lowest: 1.065	Share cancellation from an on-market buy-back(1)	506,130,594
31 December 2011	(300,000)	Highest: 1.135 Lowest: 1.065	Share cancellation from an on-market buy-back(1)	505,830,594
3 January 2012	33,750	-	Vesting of Rights	505,864,344
3 January 2012	16,250	-	Vesting of Rights	505,880,594
3 January 2012	500,000	-	Vesting of Rights	506,380,594
3 January 2012	500,000	-	Vesting of Rights	506,880,594
3 January 2012	50,000	-	Vesting of Rights	506,930,594
3 January 2012	10,000	-	Vesting of Rights	506,940,594
3 January 2012	25,000	-	Vesting of Rights	506,965,594
3 January 2012	25,000	-	Vesting of Rights	506,990,594
3 January 2012	30,000	-	Vesting of Rights	507,020,594
3 January 2012	25,000	-	Vesting of Rights	507,045,594
3 January 2012	25,000	-	Vesting of Rights	507,070,594
3 January 2012	396,861	-	Vesting of Rights	507,467,455
3 January 2012	25,000	-	Vesting of Rights	507,492,455
3 January 2012	500,000	-	Vesting of Rights	507,992,455
6 January 2012	17,875	-	Vesting of Rights	508,010,330
9 January 2012	(18,657)	Highest: 1.13 Lowest: 1.13	Share cancellation from an on-market buy-back(1)	507,991,673
13 January 2012	3,029	-	Vesting of Rights	507,994,702
18 January 2012	8,668	-	Vesting of Rights	508,003,370
31 January 2012	(75,000)	Highest: 1.105 Lowest: 1.075	Share Cancellation from an on-market buy-back(1)	507,928,370
31 January 2012	(156,343)	Highest: 1.14 Lowest: 1.135	Share cancellation from an on-market buy-back(1)	507,772,027
1 February 2012	26,280	-	Vesting of Rights	507,798,307
3 February 2012	50,000	0.60	Exercise of Options	507,848,307
7 February 2012	333,333	0.60	Exercise of Options	508,181,640
9 February 2012	50,000	0.70	Exercise of Options	508,231,640
15 February 2012	15,000	-	Vesting of Rights	508,246,640
24 February 2012	50,000	-	Vesting of Rights	508,296,640
1 March 2012	666,667	-	Vesting of Rights	508,963,307
1 March 2012	100	-	Vesting of Rights	508,963,407
1 March 2012	(1,861)	-	Reversal of Duplicate Rights Issue	508,961,546
5 March 2012	100,000	-	Vesting of Rights	509,061,546

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
5 March 2012	9,822	-	Vesting of Rights	509,071,368
19 March 2012	2,518	-	Vesting of Rights	509,073,886
19 March 2012	7,701	-	Vesting of Rights	509,081,587
2 April 2012	500,000	-	Vesting of Rights	509,581,587
10 April 2012	18,750	-	Vesting of Rights	509,600,337
11 April 2012	22,857	-	Vesting of Rights	509,623,194
18 April 2012	20,714	-	Vesting of Rights	509,643,908
25 April 2012	2,036	-	Vesting of Rights	509,645,944
25 April 2012	9,375	-	Vesting of Rights	509,655,319
30 April 2012	100,001	-	Vesting of Rights	509,755,320
30 April 2012	31,072	-	Vesting of Rights	509,786,392
30 April 2012	25,000	-	Vesting of Rights	509,811,392
1 May 2012	7,000	-	Vesting of Rights	509,818,392
2 May 2012	2,680	-	Vesting of Rights	509,821,072
2 May 2012	11,161	-	Vesting of Rights	509,832,233
11 May 2011	8,594	-	Vesting of Rights	509,840,827
16 May 2012	(1,892)	-	Reversal of the issue and vesting of Rights	509,838,935
17 May 2012	1,892	-	Vesting of Rights	509,840,827
21 May 2012	13,164	-	Vesting of Rights	509,853,991
21 May 2012	8,040	-	Vesting of Rights	509,862,031
23 May 2012	2,304	-	Vesting of Rights	509,864,335
23 May 2012	8,929	-	Vesting of Rights	509,873,264
28 May 2012	7,589	-	Vesting of Rights	509,880,853
4 June 2012	37,500	-	Vesting of Rights	509,918,353
19 June 2012	10,811	-	Vesting of Rights	509,929,164
21 June 2012	20,675	-	Vesting of Rights	509,949,839
27 June 2012	2,846	-	Vesting of Rights	509,952,685
2 July 2012	150,000	-	Vesting of Rights	510,102,685
2 July 2012	35,000	-	Vesting of Rights	510,137,685
2 July 2012	13,000	-	Vesting of Rights	510,150,685
2 July 2012	65,000	-	Vesting of Rights	510,215,685
2 July 2012	48,333	-	Vesting of Rights	510,264,018
2 July 2012	23,000	-	Vesting of Rights	510,287,018
2 July 2012	500,000	-	Vesting of Rights	510,787,018
2 July 2012	10,000	-	Vesting of Rights	510,797,018
2 July 2012	10,000	-	Vesting of Rights	510,807,018
2 July 2012	12,000	-	Vesting of Rights	510,819,018
2 July 2012	50,000	-	Vesting of Rights	510,869,018
2 July 2012	15,000	-	Vesting of Rights	510,884,018
3 July 2012	1,858	-	Vesting of Rights	510,885,876
3 July 2012	7,000	-	Vesting of Rights	510,892,876
3 July 2012	6,650	-	Vesting of Rights	510,899,526
8 July 2012	19,286	-	Vesting of Rights	510,918,812
10 July 2012	2,580	-	Vesting of Rights	510,921,392
25 July 2012	5,349	-	Vesting of Rights	510,926,741
25 July 2012	1,689	-	Vesting of Rights	510,928,430
29 July 2012	4,224	-	Vesting of Rights	510,932,654
31 July 2012	20,000	-	Vesting of Rights	510,952,654
31 July 2012	4,730	-	Vesting of Rights	510,957,384
31 July 2012	2,130	-	Vesting of Rights	510,959,514
6 August 2012	13,063	-	Vesting of Rights	510,972,577
13 August 2012	16,666	-	Vesting of Rights	510,989,243
13 August 2012	33,333	-	Vesting of Rights	511,022,576
15 August 2012	100,000	-	Vesting of Rights	511,122,576
27 August 2012	20,000	-	Vesting of Rights	511,142,576
30 August 2012	120,963	-	Vesting of Rights	511,263,539

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
29 August 2012	12,162	-	Vesting of Rights	511,275,701
29 August 2012	6,757	-	Vesting of Rights	511,282,458
3 September 2012	35,625	-	Vesting of Rights	511,318,083
6 September 2012	1,284	-	Vesting of Rights	511,319,367
6 September 2012	27,027	-	Vesting of Rights	511,346,394
6 September 2012	13,063	-	Vesting of Rights	511,359,457
7 September 2012	20,270	-	Vesting of Rights	511,379,727
13 September 2012	5,349	-	Vesting of Rights	511,385,076
13 September 2012	2,667	-	Vesting of Rights	511,387,743
14 September 2012	1,859	-	Vesting of Rights	511,389,602
14 September 2012	14,054	-	Vesting of Rights	511,403,656
17 September 2012	17,500	-	Vesting of Rights	511,421,156
17 September 2012	1,966	-	Vesting of Rights	511,423,122
17 September 2012	1,824	-	Vesting of Rights	511,424,946
17 September 2012	18,750	-	Vesting of Rights	511,443,696
17 September 2012	4,955	-	Vesting of Rights	511,448,651
1 October 2012	2,365	-	Vesting of Rights	511,451,016
3 October 2012	16,667	-	Vesting of Rights	511,467,683
3 October 2012	14,865	-	Vesting of Rights	511,482,548
3 October 2012	1,579	-	Vesting of Rights	511,484,127
10 October 2012	12,226	-	Vesting of Rights	511,496,353
10 October 2012	13,514	-	Vesting of Rights	511,509,867
10 October 2012	4,786	-	Vesting of Rights	511,514,653
11 October 2012	2,583	-	Vesting of Rights	511,517,236
15 October 2012	11,757	-	Vesting of Rights	511,528,993
26 October 2012	5,818	-	Vesting of Rights	511,534,811
27 October 2012	1,994	-	Vesting of Rights	511,536,805
5 November 2012	6,633	-	Vesting of Rights	511,543,438
5 November 2012	6,757	-	Vesting of Rights	511,550,195
5 November 2012	8,203	-	Vesting of Rights	511,558,398
9 November 2012	33,333	-	Vesting of Rights	511,591,731
26 November 2012	5,349	-	Vesting of Rights	511,597,080
26 November 2012	125,000	-	Vesting of Rights	511,722,080
29 November 2012	6,082	-	Vesting of Rights	511,275,701
29 November 2012	27,432	-	Vesting of Rights	511,282,458
4 December 2012	1,857	-	Vesting of Rights	511,318,083
6 December 2012	1,774	-	Vesting of Rights	511,319,367
10 December 2012	30,000	0.75	Exercise of Options	511,346,394
12 December 2012	100,000	0.60	Exercise of Options	511,359,457
12 December 2012	66,666	0.60	Exercise of Options	511,379,727
13 December 2012	30,000	0.97	Exercise of Options	511,385,076
13 December 2012	4,505	-	Vesting of Rights	511,387,743
13 December 2012	66,667	0.59	Exercise of Options	511,389,602
13 December 2012	83,333	0.59	Exercise of Options	511,403,656
13 December 2012	666,666	0.60	Exercise of Options	511,421,156
14 December 2012	50,000	0.70	Exercise of Options	511,423,122
14 December 2012	11,407	-	Vesting of Rights	511,424,946
14 December 2012	6,650	-	Vesting of Rights	511,443,696
18 December 2012	(27,432)	-	Reversal of vesting of Rights	511,448,651
18 December 2012	(6,082)	-	Reversal of vesting of Rights	511,451,016
20 December 2012	500,000	0.70	Exercise of Options	511,467,683
20 December 2012	5,833	-	Vesting of Rights	511,482,548
20 December 2012	75,000	-	Vesting of Rights	511,484,127
20 December 2012	12,613	-	Vesting of Rights	511,496,353
20 December 2012	6,475	-	Vesting of Rights	511,509,867

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
20 December 2012	4,561	-	Vesting of Rights	511,514,653
20 December 2012	(4,561)	-	Vesting of Rights	511,517,236
20 December 2012	1,521	-	Vesting of Rights	511,528,993
20 December 2012	4,786	-	Vesting of Rights	511,534,811
20 December 2012	15,315	-	Vesting of Rights	511,536,805
20 December 2012	1,875	-	Vesting of Rights	511,543,438
20 December 2012	13,064	-	Vesting of Rights	511,550,195
21 December 2012	13,333	0.60	Exercise of Options	511,558,398
21 December 2012	116,667	0.79	Exercise of Options	511,591,731
21 December 2012	50,000	0.75	Exercise of Options	513,798,087
21 December 2012	50,000	0.97	Exercise of Options	513,814,753
21 December 2012	20,000	0.97	Exercise of Options	513,864,753
21 December 2012	20,000	0.97	Exercise of Options	513,876,915
21 December 2012	50,000	0.97	Exercise of Options	513,879,260
21 December 2012	16,666	0.25	Exercise of Options	514,733,960
21 December 2012	50,000	0.97	Exercise of Options	513,798,087
27 December 2012	12,162	-	Vesting of Rights	513,814,753
27 December 2012	2,345	-	Vesting of Rights	513,864,753
31 December 2012	854,700	-	Vesting of Rights	513,876,915
31 December 2012	500,000	-	Vesting of Rights	515,233,960
31 December 2012	25,000	-	Vesting of Rights	515,258,960
31 December 2012	33,750	-	Vesting of Rights	515,292,710
31 December 2012	100,000	-	Vesting of Rights	515,392,710
31 December 2012	200,000	0.60	Exercise of Options	515,592,710
31 December 2012	100,000	0.60	Exercise of Options	515,692,710
16 January 2013	14,000	1.42	Exercise of Options	515,706,710
22 January 2013	5,242	1.42	Exercise of Options	515,711,952
23 January 2013	150,000	1.91	Exercise of Options	515,861,952
24 January 2013	14,000	1.42	Exercise of Options	515,875,952
24 January 2013	60,000	1.91	Exercise of Options	515,935,952
24 January 2013	100,000	1.91	Exercise of Options	516,035,952
25 January 2013	100,000	1.91	Exercise of Options	516,135,952
31 January 2013	50,091	1.42	Exercise of Options	516,186,043
31 January 2013	83,333	1.42	Exercise of Options	516,269,376
31 January 2013	33,333	1.66	Exercise of Options	516,302,709
31 January 2013	33,333	1.66	Exercise of Options	516,336,042
1 February 2013	26,280	-	Vesting of Rights	516,362,322
5 February 2013	66,231	-	Vesting of Rights	516,428,553
7 February 2013	100,000	-	Vesting of Rights	516,528,553
7 February 2013	42,343	-	Vesting of Rights	516,570,896
8 February 2013	100,000	1.91	Exercise of Options	516,670,896
12 February 2013	15,000	1.42	Exercise of Options	516,685,896
13 February 2013	66,667	1.53	Exercise of Options	516,752,563
15 February 2013	6,757	-	Vesting of Rights	516,759,320
5 March 2013	666,666	-	Vesting of Rights	517,425,986
11 March 2013	250,000	-	Vesting of Rights	517,675,986
18 March 2013	5,279	-	Vesting of Rights	517,681,265
18 March 2013	20,947	-	Vesting of Rights	517,702,212
18 March 2013	20,000	-	Vesting of Rights	517,722,212
18 March 2013	5,068	-	Vesting of Rights	517,727,280
18 March 2013	225,198	-	Vesting of Rights	517,952,478
18 March 2013	2,518	-	Vesting of Rights	517,954,996
22 March 2013	13,000	0.97	Exercise of Options	517,967,996
22 March 2013	2,196	-	Vesting of Rights	517,970,192
26 March 2013	6,757	-	Vesting of Rights	517,976,949
28 March 2013	15,000	1.42	Exercise of Options	517,991,949
2 April 2013	500,000	-	Vesting of Rights	518,491,949

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
2 April 2013	2,095	-	Vesting of Rights	518,494,044
2 April 2013	24,326	-	Vesting of Rights	518,518,370
2 April 2013	1,217	-	Vesting of Rights	518,519,587
2 April 2013	1,352	-	Vesting of Rights	518,520,939
2 April 2013	1,285	-	Vesting of Rights	518,522,224
2 April 2013	2,264	-	Vesting of Rights	518,524,488
3 April 2013	10,271	-	Vesting of Rights	518,534,759
8 April 2013	18,750	-	Vesting of Rights	518,553,509
11 April 2013	33,800	0.59	Exercise of Options	518,587,309
11 April 2013	50,000	0.97	Exercise of Options	518,637,309
12 April 2013	1,470	-	Vesting of Rights	518,638,779
15 April 2013	50,000	0.97	Exercise of Options	518,688,779
15 April 2013	(1,217)	-	Reversal of vesting of Rights	518,687,562
18 April 2013	20,714	-	Vesting of Rights	518,708,276
26 April 2013	2,036	-	Vesting of Rights	518,710,312
26 April 2013	9,375	-	Vesting of Rights	518,719,687
26 April 2013	100,000	-	Vesting of Rights	518,819,687
29 April 2013	31,071	-	Vesting of Rights	518,850,758
29 April 2013	25,000	-	Vesting of Rights	518,875,758
30 April 2013	4,646	-	Vesting of Rights	518,880,404
30 April 2013	100,000	-	Vesting of Rights	518,980,404
30 April 2013	1,630	-	Vesting of Rights	518,982,034
30 April 2013	18,500	-	Vesting of Rights	519,000,534
30 April 2013	2,720	-	Vesting of Rights	519,003,254
1 April 2013	1,774	-	Vesting of Rights	519,005,028
2 May 2013	2,680	-	Vesting of Rights	519,007,708
10 May 2013	2,534	-	Vesting of Rights	519,010,242
13 May 2013	8,593	-	Vesting of Rights	519,018,835
14 May 2013	913	-	Vesting of Rights	519,019,748
15 May 2103	225,198	-	Vesting of Rights	519,244,946
15 May 2013	12,163	-	Vesting of Rights	519,257,109
15 May 2013	6,081	-	Vesting of Rights	519,263,190
20 May 2013	8,040	-	Vesting of Rights	519,271,230
21 May 2013	20,017	-	Vesting of Rights	519,291,247
23 May 2013	2,303	-	Vesting of Rights	519,293,550
24 May 2013	3,295	-	Vesting of Rights	519,296,845
24 May 2013	16,865	-	Vesting of Rights	519,313,710
24 May 2013	1,844	-	Vesting of Rights	519,315,554
24 May 2013	1,242	-	Vesting of Rights	519,316,796
24 May 2013	1,054	-	Vesting of Rights	519,317,850
24 May 2013	1,402	-	Vesting of Rights	519,319,252
24 May 2013	1,352	-	Vesting of Rights	519,320,604
24 May 2013	34,797	-	Vesting of Rights	519,355,401
24 May 2013	10,136	-	Vesting of Rights	519,365,537
24 May 2013	4,645	-	Vesting of Rights	519,370,182
24 May 2013	18,000	-	Vesting of Rights	519,388,182
27 May 2013	7,589	-	Vesting of Rights	519,395,771
3 June 2013	37,500	-	Vesting of Rights	519,433,271
14 June 2013	10,811	-	Vesting of Rights	519,444,082
14 June 2013	1,318	-	Vesting of Rights	519,445,400
14 June 2013	1,394	-	Vesting of Rights	519,446,794
14 June 2013	4,000	-	Vesting of Rights	519,450,794
14 June 2013	4,109	-	Vesting of Rights	519,454,903
27 June 2013	13,513	-	Vesting of Rights	519,468,416
1 July 2013	150,000	-	Vesting of Rights	519,618,416
1 July 2013	35,000	-	Vesting of Rights	519,653,416
1 July 2013	13,000	-	Vesting of Rights	519,666,416

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
1 July 2013	65,000	-	Vesting of Rights	519,731,416
1 July 2013	48,333	-	Vesting of Rights	519,779,749
1 July 2013	148,000	-	Vesting of Rights	519,927,749
1 July 2013	500,000	-	Vesting of Rights	520,427,749
1 July 2013	10,000	-	Vesting of Rights	520,437,749
1 July 2013	10,000	-	Vesting of Rights	520,447,749
1 July 2013	30,000	-	Vesting of Rights	520,477,749
1 July 2013	100,000	-	Vesting of Rights	520,577,749
1 July 2013	19,000	-	Vesting of Rights	520,596,749
1 July 2013	15,000	-	Vesting of Rights	520,611,749
1 July 2013	400,000	-	Vesting of Rights	521,011,749
1 July 2013	50,000	-	Vesting of Rights	521,061,749
1 July 2013	50,000	-	Vesting of Rights	521,111,749
1 July 2013	30,000	-	Vesting of Rights	521,141,749
1 July 2013	3,590	-	Vesting of Rights	521,145,339
1 July 2013	2,000	-	Vesting of Rights	521,147,339
3 July 2013	7,000	-	Vesting of Rights	521,154,339
3 July 2013	6,650	-	Vesting of Rights	521,160,989
3 July 2013	3,590	-	Vesting of Rights	521,164,579
4 July 2013	11,825	-	Vesting of Rights	521,176,404
8 July 2013	19,286	-	Vesting of Rights	521,195,690
9 July 2013	1,356	-	Vesting of Rights	521,197,046
10 July 2013	2,580	-	Vesting of Rights	521,199,626
16 July 2013	22,805	-	Vesting of Rights	521,222,431
16 July 2013	35,135	-	Vesting of Rights	521,257,566
22 July 2013	33,333	1.48	Exercise of Options	521,290,900
22 July 2013	33,333	1.48	Exercise of Options	521,324,235
23 July 2013	5,349	-	Vesting of Rights	521,329,584
24 July 2013	13,063	-	Vesting of Rights	521,342,647
24 July 2013	50,000	0.70	Exercise of Options	521,392,648
28 July 2013	40,000	-	Vesting of Rights	521,432,648
29 July 2013	4,223	-	Vesting of Rights	521,436,871
31 July 2013	4,730	-	Vesting of Rights	521,441,601
31 July 2013	20,000	-	Vesting of Rights	521,461,601
6 August 2013	1,520	-	Vesting of Rights	521,463,121
7 August 2013	6,757	-	Vesting of Rights	521,469,878
9 August 2013	3,942	-	Vesting of Rights	521,473,820
9 August 2013	1,334	-	Vesting of Rights	521,475,154
9 August 2013	3,463	-	Vesting of Rights	521,478,617
9 August 2013	4,561	-	Vesting of Rights	521,483,178
9 August 2013	100	-	Vesting of Rights	521,483,278
12 August 2013	16,667	-	Vesting of Rights	521,499,945
13 August 2013	33,333	-	Vesting of Rights	521,533,278
15 August 2013	100,000	-	Vesting of Rights	521,633,278
19 August 2013	12,162	-	Vesting of Rights	521,645,440
27 August 2013	1,217	-	Vesting of Rights	521,646,657
29 August 2013	1,356	-	Vesting of Rights	521,648,013
2 September 2013	150,000	-	Vesting of Rights	521,798,013
2 September 2013	35,625	-	Vesting of Rights	521,833,638
6 September 2013	27,027	-	Vesting of Rights	521,860,665
6 September 2013	1,283	-	Vesting of Rights	521,861,948
6 September 2013	13,063	-	Vesting of Rights	521,875,011
6 September 2013	20,270	-	Vesting of Rights	521,895,281
9 September 2013	2,667	-	Vesting of Rights	521,897,948
13 September 2013	5,349	-	Vesting of Rights	521,903,297
14 September 2013	1,858	-	Vesting of Rights	521,905,155
14 September 2013	14,054	-	Vesting of Rights	521,919,209

Date	Number of shares issued/(reduced)	Price per Share	Purpose of issue/reduction	Resultant issued shares
		(A$)		
14 September 2013	15,315	-	Vesting of Rights	521,934,524
16 September 2013	1,966	-	Vesting of Rights	521,936,490
16 September 2013	4,955	-	Vesting of Rights	521,941,445
16 September 2013	1,823	-	Vesting of Rights	521,943,268
18 September 2013		-	Issue of Rights	521,943,268
18 September 2013	350,877	-	Vesting of Rights	522,294,145
23 September 2013	21,588	-	Vesting of Rights	522,315,733
30 September 2013	2,365	-	Vesting of Rights	522,318,098
30 September 2013	1,875	-	Vesting of Rights	522,319,973
30 September 2013	3,941	-	Vesting of Rights	522,323,914
1 October 2013	4,645	-	Vesting of Rights	522,328,559
1 October 2103	28,340	-	Vesting of Rights	522,356,899
2 October 2013	25,000	-	Vesting of Rights	522,381,899
3 October 2013	1,579	-	Vesting of Rights	522,383,478
3 October 2013	14,865	-	Vesting of Rights	522,398,343
3 October 2013	16,667	-	Vesting of Rights	522,415,010
9 October 2013	19,257	-	Vesting of Rights	522,434,267
10 October 2013	13,514	-	Vesting of Rights	522,447,781
10 October 2013	12,225	-	Vesting of Rights	522,460,006
10 October 2013	37,607	-	Vesting of Rights	522,497,613
11 October 2013	2,583	-	Vesting of Rights	522,500,196
14 October 2013	11,757	-	Vesting of Rights	522,511,953
22 October 2013	15,203	-	Vesting of Rights	522,527,156
23 October 2013	32,866	0.59	Exercise of Options	522,560,022
28 October 2013	1,993	-	Vesting of Rights	522,562,015
30 October 2013	3,907	-	Vesting of Rights	522,565,922
1 November 2013	4,646	-	Vesting of Rights	522,570,568
1 November 2013	10,000	0.79	Exercise of Options	522,580,569
4 November 2013	6,756	-	Vesting of Rights	522,587,325
7 November 2013	3,379	-	Vesting of Rights	522,590,704
7 November 2013	1,419	-	Vesting of Rights	522,592,123
7 November 2013	3,463	-	Vesting of Rights	522,595,586
7 November 2013	1,107	-	Vesting of Rights	522,596,693
7 November 2013	25,000	-	Vesting of Rights	522,621,693
7 November 2013	11,217	-	Vesting of Rights	522,632,910
9 November 2013	63,333	-	Vesting of Rights	522,696,243
14 November 2013	50,000	0.97	Exercise of Options	522,746,244
14 November 2013	25,000	0.97	Exercise of Options	522,771,245
14 November 2013	20,271	-	Vesting of Rights	522,791,516
14 November 2013	100,000	-	Vesting of Rights	522,891,516
14 November 2013	28,340	-	Vesting of Rights	522,919,856
14 November 2013	20,777	-	Vesting of Rights	522,940,633
14 November 2013	27,872	-	Vesting of Rights	522,968,505
14 November 2013	1,480	-	Vesting of Rights	522,969,985
14 November 2013	25,000	-	Vesting of Rights	522,994,985
14 November 2013	1,217	-	Vesting of Rights	522,996,202

Note:

(1) Our Company announced on 12 September 2011, its intention to conduct an on-market buy-back of up to 5% of our Company's fully paid ordinary shares. Our Company elected to undertake an on-market securities buy-back as a capital management strategy due to the opportunity presented by the current share price.

New Emerald Coal Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
20 January 2011	100	A$1	Incorporation	A$100

New Emerald Coal 1 Pty Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
23 July 2013	100	A$1	Incorporation	A$100

New Emerald Coal 2 Pty Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
23 July 2013	100	A$1	Incorporation	A$100

New Emerald Coal Operations Pty Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
18 May 2012	100	A$1	Incorporation	A$100

New Pentland Coal Pty Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
6 March 2012	100	A$1	Incorporation	A$100

Linc Energy GP1 Pty Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
3 September 2012	100	A$1	Incorporation	A$100

Linc Energy GP2 Pty Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
3 September 2012	100	A$1	Incorporation	A$100

Linc Energy (Africa) Pty Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
3 August 2011	2	A$1	Incorporation	A$2

Linc Energy Operations Pty Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
23 February 2011	100	A$1	Incorporation	A$100

Linc Energy (Europe) Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
27 January 2011	100	£1	Incorporation	£100

Linc Energy (Africa) Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
27 January 2011	100	£1	Incorporation	£100

Linc Energy Operations Ltd

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
27 January 2011	100	£1	Incorporation	£100

Linc Energy (Poland) (S.p. z.o.o.)

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
8 March 2011	100	50 Polish Zloty	Incorporation	5,000 Polish Zloty

Linc Energy Operations (Africa) Proprietary Limited

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued shares
8 February 2013	100	ZAR1.00	Incorporation	100

Linc USA GP

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
13 September 2012	100	US$1	Formation of partnership	US$100

Linc Energy Finance (USA) Inc.

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
21 August 2012	100	US$0.01	Incorporation	US$1.00

Linc Energy Petroleum (Wyoming), Inc

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
8 December 2010	100	US$1.00	Incorporation	US$100

Linc Energy Resources, Inc.

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
30 June 2012	100	Shares of Linc Gulf Coast Petroleum, Inc.	Restructuring	US$100
30 June 2012	100	Shares of Linc Energy Petroleum (Louisiana), Inc.	Restructuring	US$200
30 June 2012	100	Shares of Linc Alaska Resources, Inc.	Restructuring	US$300
7 July 2012	100	US$1	Restructuring	US$400

Linc Clean Energy, Inc.

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
4 June 2012	100	US$0.01	Incorporation	US$1.00
7 July 2012	400	Shares of Linc Energy Alaska, Inc., Linc Energy (Montana), Inc, and Linc Energy (Wyoming), Inc, and Linc Energy (Louisiana) L.L.C.(1)	Restructuring	US$301.00

Linc Energy Operations (Singapore) Pte. Ltd.

Date	Number of shares issued	Price per share	Purpose of issue	Resultant issued share capital
8 November 2013	100	S$1	Incorporation	S$100

Note:

(1) Linc Energy (Montana), Inc., and Linc Energy (Louisana) L.L.C. have been dissolved.

DEFINITIONS

The following terms when used in this document shall bear the same meanings as set forth below unless otherwise defined herein or the context otherwise requires:

OUR GROUP COMPANIES AND OTHER ENTITIES

Adani	:	Adani Mining Pty Ltd
Company	:	Linc Energy Ltd
DTEK Oil and Gas	:	DTEK Holdings Limited
Exxaro Resources	:	Exxaro Resources Limited
Group	:	Our Company and its Subsidiaries
Gustavson Associates	:	Gustavson Associates LLC
Haas Petroleum	:	Haas Petroleum Engineering Services, Inc
Industry Consultant	:	Wood Mackenzie (Australia) Pty Ltd
Minecraft	:	Minecraft Consulting Pty Ltd.
New Emerald Coal	:	New Emerald Coal Ltd formerly known as New Emerald Coal Pty Ltd and Teresa Coal Pty Ltd
Ryder Scott	:	Ryder Scott Company, L.P.
Snowden	:	Snowden Mining Industry Consultant Pty Ltd
Xenith	:	Xenith Consulting Pty Ltd

GLOSSARY OF TECHNICAL TERMS

1C	:	Low estimate scenario of contingent resources
1P	:	Equivalent to proved reserves; denotes low estimate scenario of reserves
2C	:	Best estimate scenario of contingent resources
2D seismic	:	Geophysical data that depicts the subsurface strata in two dimensions
2P	:	Equivalent to proved plus probable reserves; denotes best estimate scenario of reserves
3C	:	High estimate scenario of contingent resources
3D seismic	:	Geophysical data that depicts the subsurface strata in three dimensions. 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic
3P	:	Equivalent to proved plus probable plus possible reserves; denotes high estimate scenario of reserves

Ash	:	Impurities consisting of iron, alumina and other incombustible matter that are contained in coal. Since ash increases the weight of coal, it adds to the cost of handling and can affect the burning characteristics of coal
BBL	:	One stock tank barrel, or 42 U.S. gallons liquid volume, used in this offering document in reference to oil and other liquid hydrocarbons
BNBOE	:	Billion barrels of oil equivalent
BOEPD	:	Barrels of oil equivalent per day, determined using the ratio of 6 MCF of gas to one BBL of crude oil, condensate or gas liquids per day
BOPD	:	BBLs per day
Btu	:	One British thermal unit
CO_2	:	Carbon dioxide
calorific value or ***cv***	:	A coal sample's energy content measured as the heat released on complete combustion in air or oxygen, usually expressed as the amount of heat (measured in kilo calories) per unit weight of coal (measured in kilograms) or (kcal/kg)
coal	:	A readily combustible black or brownish-black rock usually found in rock strata in layers or veins called coal beds or coal seams. It is formed from plant remains that have been compacted, hardened, chemically altered and metamorphosed by heat and pressure over time
coal seam *or* ***seam***	:	Coal deposits occur in layers in a bed of coal lying between a roof and floor with each layer called a "seam"
DCF-10	:	Present value of estimated future coal cash flows, discounted at an annual rate of 10%
exit rate	:	Refers to the rate of production of oil and/or gas as at a specified date
Equity Interest	:	In respect of our coal assets refers to our ownership percentage of the asset. Our rights to a financial return from the assets are in proportion to the equity ownership once all other costs of the business have been met
EL *or* ***ELs***	:	Exploration licence(s)
Contingent Resources	:	Those quantities of petroleum estimated, as at 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.
EOR	:	Enhanced oil recovery

EPC *or* ***EPCs***	:	Exploration permit(s) for coal
geology	:	The scientific study of the origin, history and structure of the earth
geophysics	:	Matters concerning the physics of the earth and its environment, including the physics of fields such as meteorology, oceanography, and seismology. In oil, gas and coal exploration, this refers to geophysical methods of imaging the subsurface such as gravity, magnetic and seismic
GHG	:	Greenhouse gas
highwall	:	An unexcavated face of exposed overburden and coal in a surface mine or bank on the uphill side of a contour mine excavation
indicated resources	:	That part of a coal resource for which tonnage, densities, shape, physical characteristics, quality and mineral content can be estimated with a reasonable level of confidence. It is based on detailed and reliable exploration, sampling and testing information gathered through appropriate techniques from locations such as outcrops, trenches, pits, workings and drill holes. The locations are too widely or inappropriately spaced to confirm geological and/or quality, but are spaced closely enough for continuity to be assumed
inferred resources	:	That part of a coal resource for which tonnage, densities, shape, physical characteristics, quality and mineral content can be estimated with a low level of confidence. It is inferred from geological evidence and assumed, but not verified on geological and/or quality continuity. It is based on information gathered through appropriate techniques from locations such as outcrops, trenches, puts, workings and drill holes which may be limited or of uncertain quality and reliability
JORC	:	The Joint Ore Reserves Committee
JORC Code	:	The Australasian Code for Reporting of Exploration Results, Mineral Resources and Ore Reserves (2004 Edition or the 2012 Edition, as the case may be)
MBBL	:	One thousand barrels of oil or other liquid hydrocarbons
MBOE	:	Thousand barrels of crude oil equivalent, determined using the ratio of 6 MCF of gas to one BBL of crude oil, condensate or gas liquids, based on energy value and is not reflective of its underlying economic value
MMBOE	:	Million barrels of crude oil equivalent, determined using the ratio of 6 MCF of gas to one BBL of crude oil, condensate or gas liquids, based on energy value and is not reflective of its underlying economic value
MBOPD	:	One thousand barrels of oil or other liquid hydrocarbons per day

MBOEPD	:	Thousand barrels of crude oil equivalent, determined using the ratio of 6 MCF of gas to one BBL of crude oil, condensate or gas liquids per day
MCF	:	One thousand cubic feet of gas
measured resource	:	That part of a coal resource for which tonnage, densities, shape, physical characteristics, quality and mineral content can be estimated with a high level of confidence. It is based on detailed and reliable exploration, sampling and testing information gathered through appropriate techniques from locations such as outcrops, trenches, pits, workings and drill holes. The locations are spaced closely to confirm geological quality and continuity
MDL *or* ***MDLs***	:	Mineral development lease(s)
MDLa *or* ***MDLas***	:	Mining development lease application(s)
ML *or* ***MLs***	:	Mining lease(s)
MLa *or* ***MLas***	:	Mining lease application(s)
MMBBL	:	Million barrels of oil or other liquid hydrocarbons
MMBtu	:	One million British thermal units
MMCF	:	One million cubic feet of gas
Mt	:	Million tonnes
Mtpa	:	Million tonnes per annum
Net Revenue Interest	:	In respect of our conventional and unconventional oil and gas assets refers to our share of production after the government's interest or petroleum under the relevant licence, all royalty burdens and interests owned by others have been deducted
OOIP	:	Original oil in place
PLa *or* ***PLas***	:	Petroleum lease application(s)
Possible reserves	:	Those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than probable reserves
Probable reserves	:	With regards to oil and gas, 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 or (ii) with regards to coal, the economically mineable part of an indicated, and in some circumstances, a measured resource. Assessments and studies carried out demonstrate at the time of reporting that extraction is justified.
Prospective resources	:	Those quantities of petroleum which are estimated, as at a given date, to be potentially recoverable from undiscovered accumulations

Proved developed reserves	:	Proved oil, gas and coal reserves that can be expected to be recovered through existing wells, facilities and mines with the existing equipment and under the existing operating methods
Proved reserves	:	With regards to oil and gas, 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 or (ii) with regards to coal, the economically mineable part of a measured resource. Assessments and studies carried out demonstrate at the time of reporting that extraction is justified
Proved undeveloped reserves	:	Proved oil, gas and coal reserves that are expected to be recovered from future wells, facilities and mines, including future improved recovery projects
PV-10	:	Present value of estimated future oil and gas revenues, net of estimated direct expenses, discounted at an annual rate of 10%
Recompletion	:	Completion for production of an existing well bore in another formation from that in which the well has been previously completed
Reserves	:	With regards to oil and gas, 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 or (ii) with regards to coal, the economically mineable part of a resource. It includes diluting materials and allowances for losses which may occur when the material is mined. Appropriate assessments and studies have been carried out, and include considerations of and modification by realistically assumed mining, metallurgical, economic, marketing, legal, environmental, social and governmental factors
Resources	:	With regards to oil and gas, all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the earth's crust, discovered and undiscovered, plus those quantities already produced or (ii) with regards to coal, a concentration or occurrence of material of intrinsic economic interest in or on the earth's crust in such form, quality and quantity that there are reasonable prospects for economic extraction. The location, quality, grade, geological characteristics and continuity of a resource are known estimated or interpreted from specific geological evidence and knowledge
ROM	:	Run-of-mine

sulphur : One of the elements present, in varying quantities, in coal that contributes to environmental degradation when coal is burned. Sulphur dioxide is produced as a gaseous by-product of coal combustion

sulphur content : Coal is commonly described by its sulphur content due to the importance of sulphur to customers concerned about compliance with environmental regulations. "Low sulphur" coal has a variety of definitions, but typically is used to describe coal consisting of 1.0% or less sulphur

syngas : Synthetics gas

TCF : One trillion cubic feet of gas

thermal coal : Coal used in thermal plants to generate electricity

UCG : Underground coal gasification

VALMIN Code : Code for the Technical Assessment and Valuation of Mineral and Petroleum Assets and Securities for Independent Expert Reports 2005 Edition, prepared by the VALMIN Committee, a joint committee of the Australasian Institute of Mining and Metallurgy, the Australian Institute of Geoscientists and the Mineral Industry Consultants Association with the participation of the Australian Securities and Investment Commission, the Australian Stock Exchange Limited, the Minerals Council of Australia, the Petroleum Exploration Society of Australia, the Securities Association of Australia and representatives from the Australian finance sector

wash : The removal or reduction of impurities from coal

Working Interest : An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations

GENERAL

Application Forms : The Public Offer Shares Application Forms and the Placement Shares Application Forms

Application List : The list of applications for subscriptions of the Offering Shares

Associate : (a) in relation to any director, chief executive officer, substantial shareholder or controlling shareholder of a corporation (being an individual) means:

(i) his immediate family;

(ii) a trustee, acting in his capacity as such trustee, of any trust of which the individual or his immediate family is a beneficiary or, in the case of a discretionary trust, is a discretionary object; and

(iii) any corporation in which he and his immediate family together (directly or indirectly) have an interest of 30% or more;

(b) in relation to a substantial shareholder or controlling shareholder of a corporation (being a corporation) any other corporation which is its subsidiary or holding company or is a subsidiary of such holding company or one in the equity of which it and/or such other company or companies taken together (directly or indirectly) have an interest of 30% or more

ASX : Australian Securities Exchange

ATM : Automated teller machine

ATM Electronic Applications : Applications for the Public Offer Shares made through an ATM of one of the Participating Banks in accordance with the terms and conditions of this Prospectus

Authority : Monetary Authority of Singapore

Australia : The Commonwealth of Australia

Board *or* ***Board of Directors*** : The Board of Directors of our Company or committee constituted thereof

Blair Athol Joint Venture Party : The vendor of the Blair Athol Mine, comprising Queensland Coal Pty Limited, Leichhardt Coal Pty Limited, J-Power Australia Pty Ltd and JCD Australia Pty Ltd

Carmichael Project : The mining of coal by Adani from its Carmichael coal tenement further to the transaction described in the section titled "Management's Discussion and Analysis of Financial Conditions and Results of Operations—Factors affecting our Results of Operations—Acquisitions and disposal of our assets"

Clermont Joint Venture Party : The owner of the Clermont Mine comprising Mitsubishi Development Pty Ltd, Queensland Coal Pty Ltd, J-Power Australia Pty Ltd and J.C.D. Australia Pty Ltd

Constitution : The constitution of our Company, as amended, supplemented or modified from time to time

Controlling Shareholder : In relation to a corporation, means a person who:

(A) holds directly or indirectly 15.0% or more of the total number of issued shares excluding treasury shares in the corporation; or

(B) in fact exercises control over the corporation

Conventional Coal Mining Assets : Interest in the mining tenements comprising eight coal mining assets held by us as at the date of this offering document

Corporations Act : Australian Corporations Act 2001 (Cth)

CDP : The Central Depository (Pte) Ltd

CN Shares : The new Shares issued pursuant to the conversion of the 2018 Convertible Notes

Director(s) : The director(s) on the Board of our Company

Electronic Applications : ATM Electronic Applications and Internet Electronic Applications

EBITDAX : Net profit (loss) before income tax, non-controlling interest, interest income, finance costs, depreciation, depletion and amortisation, loss on sales of assets, impairment expense, accretion expense, unrealised commodity derivative loss, plug and abandonment and bad debt expense

EGM : Extraordinary General Meeting

Employee Option Plan Share : Share upon conversion from the Option

EPS : Earnings Per Share

Executive Director : A Director of our Group who performs an executive function

Existing ASX Shareholders : The registered owners of Shares as at such books closure date to be determined, in connection with the delisting of our Company from ASX as described in the section titled "Share Ownership—Delisting from ASX" of this offering document

Financial Year or ***FY*** : Financial year ended or, as the case may be, ending 30 June

GDP : Gross domestic product

Goods and Services Tax Act : The Goods and Services Tax Act, Chapter 117A of Singapore, as amended, supplemented or modified from time to time

Gulf Coast Region : The Gulf Coast region of Texas and Louisiana

Internet Electronic Applications : Applications for the Public Offer Shares made through the internet banking websites of the relevant Participating Banks

IFRS : International Financial Reporting Standards

International Purchase Agreement : The international purchase agreement dated [●] entered into between ourselves and the Joint Bookrunners and Joint Lead Managers in relation to the Placement

Joint Issue Managers *or* ***Joint Bookrunners and Joint Lead Managers***	:	Credit Suisse (Singapore) Limited, DBS Bank Ltd. and J.P. Morgan (S.E.A.) Limited
Latest Practicable Date	:	15 November 2013 being the latest practicable date prior to the lodgement of this Prospectus with the Authority
Listing Date	:	The date trading of the Shares on the SGX-ST commences
Listing Manual	:	The listing manual of the SGX-ST
Lock-up Shares	:	The Shares which are held by the Newtron Pty Ltd, an entity which Mr. Peter Bond is the sole shareholder of, which are subject to the lock-up arrangement
Market Day	:	A day on which the SGX-ST is open for trading in securities
NAV	:	Net asset value
Non-Executive Director	:	A Director of our Group who is not an Executive Director (including a Non-Executive Independent Director)
Non-Executive Independent Directors	:	The non-executive independent Directors of our Company
NTA	:	Net tangible assets
Offering	:	The Placement and Public Offer
Offering Price	:	The Offering price per Offering Share to be determined following a book-building process by agreement between ourselves and the Joint Bookrunners and Joint Lead Managers on the Price Determination Date
Offering Shares	:	The [●] Offering Shares to be determined following a book-building process by agreement between ourselves and the Joint Bookrunners and Joint Lead Managers on the Price Determination Date
Participating banks	:	DBS Bank Ltd. (including POSB) ("**DBS**"), Oversea-Chinese Banking Corporation Limited ("**OCBC**") and United Overseas Bank Limited and its subsidiary, Far Eastern Bank Limited (the "**UOB Group**")
Performance Rights Plan Share	:	Share upon vesting of Right
Placement	:	The international placement of Offering Shares to investors, including institutional and other investors in Singapore
Public Offer	:	An offering of Offering Shares to the public in Singapore
Public Offer Shares Application Forms	:	The Public Offer Shares application forms issued together with this Prospectus in respect of the Offering Shares which are the subject of the Public Offer
Options	:	The options granted under our Employee Option Plan which was adopted

qualified institutional buyers	Has the meaning as ascribed to it under Rule 144A
Qualified Persons	Haas Petroleum Engineering Services, Inc, Ryder Scott Company, L.P., DeGolyer and MacNaughton, Gustavson Associates and Snowden Mining Industry Consultant Pty Ltd
Qualified Persons' Reports	The summary of an estimate of our reserves and contingent and prospective resources prepared by the Qualified Persons and set out in Appendix I of this offering document
Regulation S	Regulation S under the U.S. Securities Act
Rights	The Rights issued the Performance Rights Plan approved by our Shareholders at our annual general meeting dated 26 November 2009
Rule 144A	Rule 144A under the U.S. Securities Act
Securities and Futures Act	The Securities and Futures Act, Chapter 289 of Singapore, as amended from time to time
Securities Act	The U.S. Securities Act of 1933, as amended
Shareholders	The registered holders of our Shares
Shares	Fully paid ordinary shares of our Company
Singapore Companies Act	The Companies Act, Chapter 50 of Singapore, as amended from time to time
Singapore Take-over Code	The Singapore Code on Take-overs and Mergers
Singapore Take-over and Merger Laws and Regulations	Sections 138, 139 and 140 of the Securities and Futures Act and the Singapore Take-over Code
Singapore Offer Agreement	The offer agreement dated [●], entered into between ourselves and the Joint Bookrunners and Joint Lead Managers in relation to the Public Offer
Substantial Shareholder	A person who has an interest or interests in the Shares, where the total votes attached to those Shares is not less than 5% of the total votes attached to all Shares
SFR	Securities and Futures (Offers of Investments) (Shares and Debentures) Regulations 2005
Underwriting Agreements	International Purchase Agreement and Singapore Offer Agreement
United States	United States of America
U.S. GAAP	United States Generally Accepted Accounting Principles
U.S. Securities Act	U.S. Securities Act of 1933, as amended
VAT	Value added tax

CURRENCIES AND MEASUREMENTS

A$ *or* ***Australian dollar***	:	The lawful currency of the Commonwealth of Australia
S$ or ***Singapore dollar***	:	The lawful currency of the Republic of Singapore
sq km	:	square kilometres
US$ or ***United States dollar***	:	The lawful currency of the United States

The terms "depositor", "depository agent" and "depository register" have the meanings ascribed to them respectively in Section 130A of the Singapore Companies Act.

Words importing the singular include, where applicable, the plural and vice versa, and words importing the masculine gender include, where applicable, the feminine and neuter gender.

Any reference in this document to any legislation or enactment refers to the legislation or enactment as amended or re-enacted unless the context otherwise requires.

Unless we specify otherwise or the context otherwise requires, all references to our "Shares" refer to ordinary shares in the capital of our Company.

References herein to "this document" should be construed as being references to the "offering document" in the context of the offering circular distributed outside Singapore or the "Singapore Prospectus" or the "Prospectus" in the context of the prospectus registered by the Authority and distributed in Singapore.

APPENDIX A—REGULATIONS

SUMMARY OF RELEVANT U.S. LAWS AND REGULATIONS

The oil and gas industry is extensively regulated by numerous federal, state and local authorities. Oil and gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which the Company owns or operate properties for oil and gas production are subject to statutory provisions regulating the exploration for and production of oil and gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and regulations addressing the abandonment of wells. The Company's properties and operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitisation or pooling of oil and gas wells and properties, as well as regulations that generally prohibit the venting or flaring of gas and in certain cases may impose requirements regarding the rateability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. The Company believes that it is in substantial compliance with currently applicable laws relating to environmental protection, health and safety, and resource conservation and is undertaking corrective actions where noncompliance has been identified. Where appropriate, the Company is developing a plan to achieve and maintain substantial compliance with such laws and regulations. Further, the Company believes that ongoing substantial compliance with existing requirements should not have a material adverse effect on the Company's financial condition, results of operations or cash flows. Nevertheless, such laws and regulations are frequently amended or reinterpreted. Therefore, the Company is unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and gas industry are regularly considered by the United States Congress, the states, the Federal Energy Regulatory Commission ("**FERC**") and the courts. We cannot predict when or whether any such proposals may become effective.

Drilling and Production

The Company's operations and properties are subject to various types of regulation at the federal, state and local levels. As noted above, these types of regulation typically include requiring permits for the drilling of wells, drilling bonds and ongoing reports concerning operations. In addition, the states and some counties and municipalities in which the Company operates also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled; and
- the plugging and abandoning of wells.

State and federal laws and regulations prescribe the size and shape of drilling and spacing units or proration units and govern the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate exploitation while other states, such as Texas, generally rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitisation may be implemented by third parties and may reduce the Company's interest in the unitised properties. In addition, state conservation laws can establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas the Company can produce from the Company's wells or limit the number of wells or the locations at which the Company can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and gas within its jurisdiction.

The Company does not control the availability of transportation and processing facilities used in the marketing of its production. For example, the Company may have to shut in a productive gas well because of a lack of available gas gathering or transportation facilities.

The Company conducts operations on state oil and gas leases and these operations must comply with numerous regulatory restrictions, including royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain specific regulations and other appropriate permits issued by the appropriate federal or state agencies

The Company's sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and service regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Effective 1 January 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that, on an annual basis, allows for an increase or decrease in the cost of transporting oil to the shipper. Following the FERC's most recent five-year review of the indexing methodology, the FERC issued orders in 2011 and 2012 revising the methodology and increasing the annual index ceilings, the most recent of which became effective July 2012. The FERC's revised indexing methodology is the subject of pending appeals by several shippers and an association of Canadian oil producers.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, the Company believes that the regulation of oil transportation rates will not affect the Company's operations in any way that is of material difference from those of the Company's competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this statutory standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, the Company believes that access to oil pipeline transportation services generally will be available to the Company to the same extent as to the Company's similarly situated competitors.

Transport and Sale of Gas

Historically, the transportation and sale for resale of gas in interstate commerce have been regulated by the FERC under the Natural Gas Act of 1938 ("**NGA**"), the Natural Gas Policy Act of 1978 ("**NGPA**"), and regulations issued under those statutes. In the past, the federal government has regulated the prices at which gas could be sold. While sales by producers of gas can currently be made at market prices, the United State Congress could reenact price controls in the future. Deregulation of wellhead gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act, which removed all price controls affecting wellhead sales of gas effective 1 January 1993.

FERC regulates interstate gas transportation rates, and terms and conditions of service, which affects the marketing of gas that the Company produce, as well as the revenues the

Company receive for sales of the Company's gas. Since 1985, the FERC has endeavored to make gas transportation more accessible to gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate gas pipeline industry and to create a regulatory framework that will put gas sellers into more direct contractual relations with gas buyers by, among other things, unbundling the sale of gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell gas. Although the FERC's orders do not directly regulate gas producers, they are intended to foster increased competition within all phases of the gas industry.

Beginning in 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in gas markets. Among other things, these orders revised the FERC's pricing policy by waiving price ceilings for short-term released capacity, and effected changes in the FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

The gas industry historically has been very heavily regulated. Therefore, the Company cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, the Company does not believe that any action taken will affect the Company in a way that materially differs from the way it affects other gas producers.

The price at which the Company sells gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to the Company's physical sales of these energy commodities, the Company is required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission, or the CFTC. Should the Company violate the anti-market manipulation laws and regulations, the Company could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of the Company's operations may be required to annually report to the FERC on May 1 of each year for the previous calendar year. Currently, Order No. 704 requires certain gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical gas transactions for the previous calendar year depending on the volume of gas transacted.

Gathering services, which occur upstream of jurisdictional transmission services, are regulated by the states. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities are done on a case by case basis. To the extent that the FERC issues an order that reclassifies transmission facilities as gathering facilities, and depending on the scope of that decision, the Company's costs of getting gas to point of sale locations may increase. State regulation of gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, gas gathering may receive greater regulatory scrutiny in the future.

Intrastate gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by the FERC. The basis for intrastate regulation of gas transportation and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate gas shippers within the state on a comparable basis, the Company believes that the regulation of similarly situated intrastate gas transportation in any states in which the Company operate and ship gas on an intrastate basis will not affect the Company's operations in any way that is of material difference from those of the Company's competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of gas that the Company produce, as well as the revenues the Company receive for sales of the Company's gas.

Environment

Federal and state environmental laws can affect the operations which may be conducted on the Company's properties. State conservation laws will have a similar effect. More specifically, the Company's operations and properties are subject to numerous federal, regional, state, and local, laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- issuance of permits in connection with exploration, drilling and production activities;
- protection of endangered species;
- amounts and types of emissions and discharges;
- generation, management, and disposition of waste materials;
- reclamation and abandonment of wells and facility sites; and
- remediation of contaminated sites.

Air

One of the most significant laws affecting the Company's operations is the Clean Air Act ("**CAA**") which was first passed as the 1967 Air Quality Act. The 1967 Act established the concept of air quality control regions. Under the Act, the federal government developed air quality criteria for selected pollutants (e.g., SO2, NOx, and particulate matter) reflecting the latest scientific knowledge about air pollutants. The states, in turn, were to use the criteria as the basis for air quality standards for the designated regions.

The CAA was amended in 1970 to give the federal government a more central role and established the basic regulatory structure that exists today. Under the 1970 amendments, the newly created Environmental Protection Agency ("**EPA**") was directed to establish national ambient air quality standards ("**NAAQS**") for the criteria pollutants. The NAAQS were to be used by states as the basis for individual source emission limitations in state implementation plans ("**SIPs**"). SIPs remain the principal CAA tool for control of criteria pollutant emissions from existing stationary sources. The 1970 amendments also contained provisions to regulate hazardous air pollutants and to establish a special set of standards for certain new sources (i.e., New Source Performance Standards).

The CAA was amended again in 1977, and established the prevention of significant deterioration ("**PSD**") programme, added nonattainment provisions applicable to areas not meeting the NAAQS, expanded the programme for hazardous air pollutants to include certain specific pollutants, and required EPA to review the air quality criteria and NAAQS every five years.

The most recent legislative action, the 1990 CAA amendments added many substantive provisions to the CAA while leaving in place much of the pre-existing system of air pollution control. Specifically, the 1990 amendments contained, among other provisions, new requirements for areas that do not meet ambient air quality standards, tightened mobile source emission standards, significantly altered the approach for regulation of hazardous air pollutants and established a new operating permit programme.

To limit pollution air permits have been issued for construction and use of equipment and operations found to release air contaminates. There are both state and federal clean air permit programmes. Two programmes discussed further in this section are New Source Review (“**NSR**”) permits, and Clean Air Act Amendments, Title V operating permits

New major stationary sources or major modifications of existing major sources which would emit a nonattainment pollutant must obtain a nonattainment permit before construction begins. This permit will include requirements to: 1) offset projected emissions of the specific pollutants which do not meet the NAAQS with emission reductions of the pollutants at existing facilities, and 2) install pollution control technology to achieve the lowest achievable emission rate.

A “major” source is generally one with the potential to emit more than 100 tons per year (tpy) or more of a nonattainment pollutant. In ozone nonattainment areas, this level is reduced to 10 – 50 tpy depending on the severity of the ozone nonattainment area. For serious carbon monoxide nonattainment areas, any source with the potential to emit 50 tpy or more would need a nonattainment permit. For serious particulate matter nonattainment areas, a major source is one with emissions of 70 tpy or more.

In a parallel track, new sources in areas that attain the NAAQS must obtain a Prevention of Significant Degradation (“**PSD**”) preconstruction permit. The PSD permit includes a requirement to comply with ambient air quality levels and to install “best available control technology” (“**BACT**”) for criteria pollutants emitted in “significant” levels. (Note that some states extend BACT coverage to air toxics as well.) A “new” source for PSD purposes is one of 28 listed sources in sec. 169 of the CAA with the potential to emit 100 tpy or more of any air pollutant subject to regulation under the CAA or any other source with the potential to emit 250 tpy of any air pollutant subject to regulation under the CAA.

For both nonattainment and PSD new source review, a modified source is “any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted”. However, in its implementing regulations, EPA has limited application of PSD and nonattainment permit requirements to those major modifications that constitute a nonroutine physical or operational change and which result in a significant net increase in emissions.

EPA’s operating permit rule implements Title V of the 1990 CAA Amendments. The Title V operating permit requirements are primarily procedural and were not intended by Congress to create new substantive requirements. The Title V requirements do not change the review process for new or modified sources of air pollutants. Congress intended that the states administer the operating permit programme. States retain the right to impose more stringent operating permit requirements.

In this regard, the EPA has published New Source Performance Standards (“**NSPS**”) and National Emissions Standards for Hazardous Air Pollutants (“**NESHAP**”) that amended existing NSPS and NESHAP standards for oil and gas facilities and created new NSPS standards for oil and gas production, transmission and distribution facilities. The Agency has indicated that it will reexamine and reissue these rules over the next three years, but the outcome of this process remains uncertain. In addition, the EPA has issued rules requiring monitoring and reporting of greenhouse gas emissions from petroleum and natural gas systems. The EPA is also conducting a review of the National Ambient Air Quality Standards (“**NAAQS**”) for ozone, which is expected to be completed in 2013 and could result in more stringent air emissions standards applicable to the Company’s operations.

Water

The Company is subject to laws and regulations designed to protect water quality. Waste and ground water protection requirements typically originate at the state level (often implementing federal statues) for exploration and production operations. Water discharge requirements are mostly federal requirements.

Every facility that drills, produces, refines, handles, processes, and/or stores oil has developed a spill prevention, control, and countermeasure ("**SPCC**") plan, documenting that facility's procedures and equipment for spill prevention. Equipment for spill prevention includes dikes, terms, or other forms of secondary containment installed around tanks and other processing vessels, to retain oil in the event of a release. Spill prevention procedures include tank integrity testing and leak testing to ensure that oil storage and process vessels are in sound operating condition. In addition, each facility, platform and pipeline must develop a plan that identifies the personnel, equipment and materials it needs to deal with a spill.

In addition, certain of the Company's properties are located on or near "wetlands", which are generally described as lands where saturation with water is the dominant factor determining the nature of soil development and the types of plant and animal communities living in the soil and on its surface. Operations on "wetlands" are subject to regulation by the EPA and the U.S. Army Corps of Engineers, and permits are generally required before operations may be conducted, or facilities constructed, in wetlands areas.

Health and Safety

The Company's operations are subject to health and safety regulation, including regulation by the U.S. Occupational Health and Safety Administration ("**OSHA**"). Employers must protect the safety and health of workers involved in oil and gas operations according to:

- OSHA's General Industry Standards (29 CFR 1910)
- OSHA's Construction Standards (29 CFR 1926)
- General Duty Clause of the Occupational Safety and Health (OSH) Act

Future Regulation

There are numerous additional statutory and regulatory requirements which may or will affect the operations of our Company and our properties. For example, federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Hydraulic fracturing involves the injection of water, sand or other propping agents and chemicals under pressure into rock formations to stimulate oil and natural gas production. Although our Company does not currently utilise "hydraulic fracturing", as that term is normally interpreted, recent developments and controversy could nevertheless impact our Company. The EPA is conducting a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water and groundwater. A progress report was released in December 2012, with final results expected in 2014. Consequently, even if federal legislation is not adopted soon or at all, the performance of the hydraulic fracturing study by the EPA could spur further action towards federal legislation and regulation of hydraulic fracturing or similar production operations. Also at the federal level, the U. S. Bureau of Land Management "BLM" has indicated that it is considering proposed rules to regulate hydraulic fracturing on federal lands. Additionally, the EPA has announced an initiative under the Toxic Substances Control Act to develop regulations governing the disclosure of hydraulic fracturing chemicals.

In addition, a number of states and local regulatory authorities are considering or have implemented more stringent regulatory requirements applicable to hydraulic fracturing, which could include a moratorium on drilling and effectively prohibit further production of oil and natural gas through the use of hydraulic fracturing or similar operations. Texas and Wyoming have adopted legislation that requires the disclosure of information regarding the substances used in the hydraulic fracturing process. This legislation and any implementing regulations could increase the Company's costs of compliance and doing business.

The adoption of new laws or regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in unconventional resource plays. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, hydraulic fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in cost, which could adversely affect the Company's business and results of operations.

Legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs. The EPA has published its final findings that emissions of CO_2, methane and other greenhouse gases present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Accordingly, the EPA has adopted rules under the CAA for the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration ("**PSD**") and Title V permitting programmes. The EPA has adopted a multi-tiered approach to this permitting, with the largest sources first subject to permitting. In addition, on 30 October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On 30 November 2010, the EPA released a final rule that expands its rule on reporting of greenhouse gas emissions to include owners and operators of petroleum and natural gas systems. Monitoring of those newly covered emissions commenced on 1 January 2011, with the first annual reports filed in 2012.

New regulations on all emissions from operations could cause the Company to incur significant costs. On 17 April 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the NSPS and NESHAPS, programmes under the CAA, and to impose new and amended requirements under both programmes. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before 1 January 2015, these standards require owners/operators to reduce volatile organic compound ("**VOC**") emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the natural gas using green completions with a completion combustion device. Beginning 1 January 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. As noted above, the Company does not currently utilise hydraulic fracturing in its oil and gas operations. However, the finalised regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment which is used by the Company. These rules may require changes to the Company's operations, including the installation of new equipment to control emissions. The Company is currently evaluating the effect these rules will have on the Company's business.

The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, the Company's equipment and operations could require the Company to incur costs to reduce emissions of greenhouse gases associated with the Company's operations. There were attempts at comprehensive federal legislation establishing a cap and trade programme, but that legislation did not pass. Further, various states have considered or adopted legislation that seeks to control or reduce emissions of greenhouse gases from a wide range of sources. Any such legislation could adversely affect demand for the oil, natural gas and natural gas liquids that the Company produces.

State of Texas Oil and Gas Regulation

The State of Texas regulates the drilling for, and the production, gathering and sale of, oil and gas, including imposing severance taxes and requirements for obtaining drilling permits. The State of Texas also regulates the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources, and may regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. Texas does not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that it will not do so in the future. The effect of these regulations may be to limit the amounts of hydrocarbons that may be produced from the Company's wells and to limit the number of wells or locations the Company can drill.

The primary regulatory agencies within the State of Texas which impact the Company's oil and gas operations are the Railroad Commission of Texas ("**RRC**") and the Texas Commission on Environmental Quality ("**TCEQ**"). The RRC regulates the exploration for and production of oil and natural gas within the State. As generally discussed above, RRC regulations control where and how oil and gas wells may be drilled and require monthly production reporting. Additionally, the RRC rules specify requirements for the plugging and abandonment of wells and the clean-up of facilities. In this regard, the RRC recently passed a rule to strengthen the construction of oil and gas wells. The rule, known as the "well-integrity rule," will take effect next January, and will update the RRC's requirements for the process of drilling wells, putting pipe down them and cementing things in place.

The TCEQ is charged with implementing U.S. law and regulation on protection of the environment, including air emissions controls. In this regard, the TCEQ requires emissions inventories of oil and gas facilities and has implemented a hierarchical system of permitting requirements, beginning with permit by rule for sources producing minimal emissions and increasing in detail and severity thereafter. The TCEQ recently adopted requirements for reporting, permitting and control of emissions from planned maintenance, startup or shutdown ("**MSS**") of facilities which will be effective in 2014. The Company is in the process of analysing these rules to ensure its compliance with them.

State of Wyoming Oil and Gas Regulation

The State of Wyoming regulates the drilling for, and the production, gathering and sale of, oil and gas, including imposing severance taxes and requirements for obtaining drilling permits. The State of Wyoming also regulates the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources, and may regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. Wyoming does not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that it will not do so in the future. The effect of these regulations may be to limit the amounts of hydrocarbons that may be produced from the Company's wells and to limit the number of wells or locations the Company can drill.

The primary regulatory agencies within the State of Wyoming which impact the Company's oil and gas operations are the Wyoming Oil and Gas Commission ("**WOGCC**"), Bureau of Land Management ("**BLM**"), Office of State Lands and Investments ("**OSLI**"), and the Wyoming Department of Environment Quality ("**WDEQ**"). The WOGCC regulates the exploration for and production of oil and natural gas within the State. The WOGCC controls and regulates all aspects of the Oil and Gas industry in Wyoming. Drilling approvals, completions, production filing, well spacing, conservation tax remittal, and sundry notices are controlled by the WOGCC. Additionally, the WOGCC rules specify requirements for the plugging and abandonment of wells, clean-up of facilities, baseline water testing, and new fracking rules. The WOGCC is the liaison between the oil and gas industry and the State of Wyoming governmental agencies.

The BLM and OSLI control roughly 75% of the mineral acreage within our Glenrock assets. Both the OSLI and the BLM work closely with the WOGCC to promote federal and state acreage. Both entities require monthly submittal of production, surface and mineral rentals and yearly Plan of Developments for all units.

The WDEQ is charged with implementing U.S. law and regulation on protection of the environment, including air emissions controls. In this regard, the WDEQ requires emissions inventories of oil and gas facilities and has implemented a hierarchical system of permitting requirements, beginning with permit by rule for sources producing minimal emissions and increasing in detail and severity thereafter.

State of Louisiana Oil and Gas Regulation

The State of Louisiana regulates the drilling for, and the production, gathering and sale of, oil and gas, including imposing severance taxes and requirements for obtaining drilling permits.

The State of Louisiana also regulates the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources, and may regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. Louisiana does not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that it will not do so in the future. The effect of these regulations may be to limit the amounts of hydrocarbons that may be produced from the Company's wells and to limit the number of wells or locations the Company can drill.

Louisiana's resources of oil and gas are overseen by the Office of Conservation and the Office of Mineral Resources of the Louisiana Department of Natural Resources. Similar to the RRC, the Office of Conservation regulates the exploration for and production of oil and natural gas within the State and control where and how oil and gas wells may be drilled and requires monthly production reporting. In Louisiana, the Louisiana Department of Environmental Quality ("**LDEQ**") is responsible for, among other matters, air emission controls.

State of Alaska Oil and Gas Regulation

The State of Alaska regulates the drilling for, and the production, gathering and sale of, oil and gas, including imposing severance taxes and requirements for obtaining drilling permits. The State of Alaska also regulates the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources, and may regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. Alaska does not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that it will not do so in the future. The effect of these regulations may be to limit the amounts of hydrocarbons that may be produced from our wells and to limit the number of wells or locations we can drill in.

The primary regulatory agencies within the State of Alaska which impact the Company's oil and gas operations are the Bureau of Land Management ("**BLM**"), the Alaska Department of Environmental Conservation ("**ADEC**"), the Alaska Department of Fish and Game ("**ADF&G**"), the Alaska Oil and Gas Conservation Commission ("**AOGCC**") and the Alaska Department of Natural Resources. In the case of Umiat, the BLM is the leaseholder and specific lease stipulations and required operating procedures regarding the exploration for and development of their oil and gas leases. The ADEC controls water, land, and air pollution within the State of Alaska. Waste generation, water discharges and air discharges associated with oil and gas exploration and production are permitted through ADEC. The ADF&G manages Alaska's fish, game, and aquatic plant resources. The AOGCC is an independent, quasi-judicial agency of the State of Alaska. The Commission oversees oil and gas drilling, development and production, reservoir depletion and metering operations on all lands subject to Alaska's police powers. The ADNR manages all state-owned land, water and natural resources, except for fish and game. Within ADNR, the Division of Oil and Gas develops and manages Alaska's oil and gas leasing programmes. The Oil & Gas division staff identifies prospective lease areas; performs geologic, economic, environmental and social analyses, develops a five-year leasing schedule, and conducts public review of proposed sales. The division conducts competitive oil and gas lease sales and monitors collection of all funds resulting from its programmes.

SUMMARY OF RELEVANT AUSTRALIAN LAWS AND REGULATIONS

Native Title

Commonwealth Native Title Legislation

Native Title Act 1993

The Native Title Act 1993 ("**NTA**") is intended to:

(a) provide for the recognition and protection of native title;

(b) establish ways in which future dealings affecting native title may proceed and to set standards for those dealings;

(c) establish a mechanism for determining claims to native title;

(d) provide for, or permit, the validation of past acts, and intermediate period acts, invalidated because of the existence of native title; and

(e) confirm that certain dealings have extinguished native title.

The NTA established the National Native Title Tribunal, which administers a wide range of functions and delivers a range of services pursuant to the NTA whilst the Federal Court of Australia is responsible for the management of all applications made under the NTA, being applications for determinations of native title, non-claimant applications and/or compensation applications for the loss or impairment of native title.

The NTA makes provision for the States and Territories to enact complimentary legislation to validate certain acts done by the relevant State or Territory that took place before 1 January 1994 or 23 December 1996, depending on the nature of the act, that would otherwise be invalid because of native title. The NTA also confirms the past extinguishment of native title by previous exclusive possession acts and previous non-exclusive possession acts.

Queensland Native Title Legislation

Native Title (Queensland) Act 1993

The Native Title (Queensland) Act 1993 ("**NTQA**") is intended to:

(a) validate (in accordance with the NTA) past acts and intermediate period acts that were invalidated because of the existence of native title and to confirm certain rights;

(b) confirm (in accordance with the NTA) the past extinguishment of native title by previous exclusive possession acts and previous non-exclusive possession acts that were done by the State; and

(c) to ensure that Queensland law is consistent with standards set by the NTA for future dealings affecting native title.

The Queensland Department of Natural Resources and Mines (**DNRM**) is responsible for administering the NTQA as well as having primary responsibility for implementing the NTA in Queensland.

South Australian Native Title Legislation

Native Title (South Australia) Act 1994

The Native Title (South Australia) Act 1994 ("**NTSA**") is administered by the Crown Solicitor's office of the South Australian Attorney-General's department.

The NTSA:

(a) in accordance with the NTA, validates past and intermediate period acts in accordance with the terms and requirements of the NTA;

(b) in accordance with the NTA, confirms the past extinguishment of native title by certain past acts that were done by the State, including previous exclusive possession acts; and

(c) confirms South Australia's existing ownership of any natural resources, existing rights to use, control and regulate the flow of water, existing fishing access rights and existing public access to waterways and public places.

Cultural Heritage

Commonwealth Cultural Heritage Legislation

Aboriginal and Torres Strait Islander Heritage Protection Act 1994

The Aboriginal and Torres Strait Islander Heritage Protection Act 1994 ("**ATSIHP Act**") is regulated by the Commonwealth Department of Sustainability, Environment, Water, Population and Communities ("**SEWPAC**").

The purpose of the ATSIHP Act is the protection and preservation of areas that are of heritage significant to Aboriginal and Torres Strait Islander people in accordance with their traditions.

If it appears that state or territory laws have not provided effective protection, then under the ATSIHP Act, the Australian Government can make declarations to protect significant Aboriginal areas and objects from threats of injury or desecration.

However, the Australian Government can only make a declaration if an Aboriginal or Torres Strait Islander person has requested it and has provided satisfactory evidence of a body of traditions, customs, observances and beliefs that explains, firstly, why there is a threat of injury or desecration and, secondly, why the area, object or class of objects is of particular significance to Aboriginal or Torres Strait Islander people.

Queensland Cultural Heritage Legislation

Aboriginal Cultural Heritage Act 2003

The Aboriginal Cultural Heritage Act 2003 ("**ACH Act**") is administered by the Queensland Department of Aboriginal and Torres Strait Islander and Multicultural Affairs ("**DATSIMA**").

The ACH Act's main purpose is to provide effective recognition, protection and conservation of Aboriginal cultural heritage by providing for, among other things, the establishment of:

(a) a duty of care for activities that may harm Aboriginal cultural heritage;

(b) powers of protection, investigation and enforcement; and

(c) processes for the timely and efficient management of activities to avoid or minimise harm to Aboriginal cultural heritage.

Maximum penalties for contravening the cultural heritage duty of care are $100,000 for an individual and $1,000,000 for a corporation.

South Australian Cultural Heritage Legislation

Aboriginal Heritage Act 1988

The Aboriginal Heritage Act 1988 ("**AHA**") is administered by the South Australian Aboriginal Affairs and Reconciliation Division ("**AARD**").

The AHA aims to protect and preserve Aboriginal heritage sites, objects and remains by, among other things:

(a) requiring an owner or occupier of private land who discovers an Aboriginal site, object or remains to notify the Minister about the nature and location of the site and take any protection action directed by the Minister; and

(b) preventing a person from interfering with, damaging or disturbing an Aboriginal site, damaging an Aboriginal object or disturbing, interfering or removing an Aboriginal object or remains without Ministerial approval.

The penalty for breaching the above provisions is $50,000 for a company and $10,000 or six months imprisonment for a person.

Aboriginal and Torres Strait Islander Land

Queensland Aboriginal and Torres Strait Islander Land Legislation

Aboriginal Land Act 1991 and Torres Strait Islander Land Act 1991

The Aboriginal Land Act 1991 and Torres Strait Islander Land Act 1991 ("**the Acts**") were introduced to allow for the transfer or grant of certain land (including the existing community lands and some lands reserved for particular purposes) to Aboriginal or Torres Strait Islander people to enable them to manage the land according to their tradition or custom.

Whilst the land that had been granted or transferred was originally handed over to a land trust that was established to hold the land in trust for the benefit of certain Aboriginal or Torres Strait Islander people, recent amendments have resulted in the relevant land now being granted to Indigenous corporations registered under the Commonwealth Government's Corporations (Aboriginal and Torres Strait Islander) Act 2006 which is administered by the Commonwealth Office of the Registrar of Indigenous Corporations.

The DNRM is responsible for transferring and granting land under the Acts on behalf of the Minister as well as for administering all existing land trusts.

Aboriginal and Torres Strait Islander Land Holding Act 2013

The Aboriginal and Torres Strait Islander Land Holding Act 2013 ("**ATSILH Act**") received assent on 19 February 2013 and, upon proclamation (which is expected to occur by late 2013), will repeal the Aborigines and Torres Strait Islanders (Land Holding) Act 1985, which was established to enable residents of Queensland's Aboriginal and Torres Strait Islander Deed of Grant in Trust and reserve communities to obtain perpetual leases for residential purposes and term leases for other purposes.

The ATSILH Act aligns with the Acts, protects and continues leases and lease entitlements under the repealed act and provides a number of mechanisms to facilitate resolution of outstanding issues by agreement.

DATSIMA is responsible for resolving technical issues around granted leases and lease entitlements, including boundary alignments and identifying beneficiaries of deceased lease and lease entitlement holders.

Energy and Resources

Commonwealth Energy and Resources Legislation

Petroleum Resource Rent Tax Assessment Act 1987

The Petroleum Resource Rent Tax Assessment Act 1987 is the enabling legislation for the Petroleum Resources Rent Tax ("**PRRT**"), which is profit-based tax that is levied on a petroleum project.

From 1 July 2012, the PRRT became a compulsory tax applied to all Australian onshore and offshore oil and gas projects, including the North West Shelf, oil shale and coal seam gas projects.

Each entity with an interest in a PRRT liable project will be liable for that PRRT. A 'project' consists of facilities in the project title area and any facilities outside that area necessary for the production and initial storage of marketable petroleum commodities such as stabilised crude oil, condensate, natural gas, liquefied petroleum gas and ethane (but excluding value added projects such as LNG).

PRRT is levied at a rate of 40% of a project's taxable profit, which is the project's income after all project and 'other' exploration expenditures (including a compounded amount for carried forward expenditures) have been deducted from all assessable receipts.

The Australian Taxation Office ("**ATO**") administers the PRRT.

Mineral Resources Rent Tax Act 2012

The *Mineral Resources Rent Tax Act 2012* outlines the process for calculating the Mineral Resources Rent Tax ("**MRRT**") imposed on mining profits derived from the extraction of iron ore, coal or coal seam gas.

Each financial year, an entity with mining project interests (ie. an entitlement to extract iron ore, coal or coal seam gas or a right to share in the output of an undertaking with the purpose of performing such extraction) is liable to pay MRRT equal to the sum of its MRRT liabilities for each of its mining project interests.

Only companies with profits above $75 million will incur an MRRT liability.

The MRRT liability for a mining project interest is calculated according to the formula:

"MRRT rate multiplied by (mining profit—MRRT allowances)"

The MRRT rate is 22.5% (ie. a nominal rate of 30% less a 25% extraction allowance to recognise the use of specialist skills).

Mining profit is calculated by reference to 'mining revenue' less 'mining expenditure', whilst royalties paid under Commonwealth, state and territory laws are taken into account as MRRT allowances.

The ATO administers the MRRT.

Queensland Energy and Resources Legislation

Mineral Resources Act 1989

The Mineral Resources Act 1989 ("**MRA**") is administered by DNRM and provides the legislative framework for exploration, development and mining tenure in Queensland. In accordance with the MRA, Queensland is the beneficiary of all mineral resources and as such, these resources can only be mined or extracted by a holder of a mining tenement issued in accordance with the MRA.

The types of mining tenements that are granted and administered under the MRA are prospecting permits, exploration permits, mineral development licences, mining claims and mining leases.

The MRA also:

(a) clarifies the rights under the MRA to mine coal seam gas;

(b) outlines the additional native title requirements (including compensation requirements) that apply for certain grants, renewals and variations of, and certain other acts concerning, mining tenements;

(c) administers various other administrative and miscellaneous matters; and

(d) outlines the penalties for contravention of any of the provisions of the MRA.

Petroleum and Gas (Production & Safety) Act 2004

The Petroleum and Gas (Production & Safety) Act 2004 ("**PAG Act**") is administered by DNRM and, together with the *Petroleum Act 1923*, provides the framework for accessing land to explore and develop petroleum and coal seam gas resources in Queensland. The PAG Act addresses the grant and management of petroleum authorities, coal seam gas, underground storage and safety and landholder issues (including compensation).

In accordance with the PAG Act, Queensland is the beneficiary of all petroleum and as such, petroleum can only be produced by a holder of a petroleum authority issued in accordance with the PAG Act.

The types of petroleum authorities that are granted and administered under the PAG Act are authorities to prospect, petroleum leases, petroleum pipeline licences, petroleum facility licences, petroleum survey licences, data acquisition authorities and water monitoring authorities.

Coal Mining Safety and Health Act 1999

The Coal Mining Safety and Health Act 1999 ("**CMSH Act**") is administered by DNRM and regulates the operation of coal mines in order to protect the safety and health of persons at coal mines and persons who may be affected by coal mining operations.

The CMSH Act sets the framework for mining legislation and incorporates 'duty of care' obligations encompassed in modern Workplace Health and Safety Acts.

Mining tenure

Mining Legislation

Mineral Resources Act 1989

The MRA sets out (amongst others) the following types of tenures:

(a) Exploration Permits ("**EP**");

(b) Mineral Development Licences ("**MDL**"); and

(c) Mining Leases ("**ML**")

<u>*Exploration Permits*</u>

The holder of an EP may enter:

(a) any part of the area of the EP that is not the surface area of a reserve; and

(b) with the consent of the owner, or the consent of the Governor in Council, any part of the area of the exploration permit that is the surface area of a reserve,

for the purposes of facilitating exploration of the mineral the subject of the permit.

A reserve is defined under the MRA as a road, State forest or timber reserve, resources reserve, Aboriginal land or Torres Strait Islander land.

The area of an EP comprises specified sub-blocks of land. Each sub-block must have at least 1 side in common with another sub-block within the subject land.

A sub-block is a subdivision of a block which is defined under the MRA as the land contained within 2 meridians 5' of longitude apart each meridian being a multiple of 5' of longitude from the meridian of Greenwich and within 2 parallels of latitude 5’ apart each parallel of latitude being a multiple of 5’ of latitude from the equator. A block is divided into 25 sub-blocks each sub-block being bounded by 2 meridians 1’ of longitude apart and 2 parallels of latitude and 1’ of latitude apart.

A holder of an EP may be considered, in priority to all other persons, for a grant of MDL or ML for all or part of the area of the permit. EPs may be granted with respect to coal (“**EPC**”) and for minerals other than coal (“**EPM**”). The holder of an EP must pay annual rental for the permit. The annual rental amount prescribed under the regulation for the current financial year is $135.90 for each sub-block. An EP is, unless the Minister otherwise decides, is subject to a statutory reduction of its area as follows:

(a) by 40% by the end of the first 3 years after the permit is granted; and

(b) by a further 50% of the remaining area of the permit by the end of the first 5 years after the permit is granted;

and, each time the permit is renewed:

(c) by a further 40% of the remaining area of the permit by the end of the first 3 years after the day the renewed permit started; and

(d) by a further 50% of the remaining area of the permit by the end of the first 5 years after the day the renewed permit started.

The holder of an EP must:

(a) comply with the mandatory provisions of the land access code and the provisions on access and compensation set out in Schedule 1 of the MRA;

(b) carry out such work programmes and studies required under the permit;

(c) remove plant and equipment at termination of the permit;

(d) provide reports to the Minister in relation to its activities;

(amongst other obligations).

The Minister may require, taking into consideration the activities to be carried out by the holder of an EP, a security for compliance with the conditions of the permit and the MRA, rectification of damages and amounts payable to the State. The initial terms of an EP is 5 years except in the case of EPs granted in response to a call for a tender in which case the initial term will be the period that the call states is the period for which the programme must apply. An EP may be renewed for further terms of not more than 5 years. The holder of an EP must, within 14 days after discovery of any mineral of commercial value in what appears to be payable quantities within the area specified in the EP, report to the Minister the fact of that discovery.

Mineral Development Licences

A MDL may be applied by the holder of an EP or a MDL with respect to the land the subject of the MDL application and in connection with the same mineral. The holder of a MDL may carry out those activities specified in the licence and the Minister may specify also such other activities leading to the evaluation and economic development of an ore body by or on behalf of the holder. The holder of a MDL may enter:

(a) any part of the area of the mineral development licence that is not the surface area of a reserve; and

(b) with the consent of the owner, or the consent of the Governor in Council, any part of the area of the mineral development licence that is the surface area of a reserve,

for any purpose permitted or required under the licence or by the MRA.

The holder of a MDL may be considered for grant, in priority to all other persons, any number of MDLs and MLs relating to any minerals specified in the MDL in respect of any land in the area of the MDL. The Minister may require security from the holder of a MDL for compliance with the conditions of the licence and the MRA, for rectification of damages and for amounts payable to the State. Annual rental is payable by the holder with respect to MDLs. The initial term of a MDL is 5 years. An MDL may be renewed for the further term of not more than 5 years. The holder of a MDL must:

(a) comply with the mandatory provisions of the land access code and the provisions on access and compensation set out in Schedule 1 of the MRA;

(b) carry out improvement restoration for the MDL;

(c) on termination of the licence, remove all plant and equipment; and

(d) provide reports to the Minister on the activities carried out on the area of the licence;

Where the holder of a MDL discovers or takes any mineral does not thereby acquire property therein and must not dispose of any such mineral except with the consent of the Minister whose consent may be subject to such terms and conditions as the Minister thinks fit.

Mining Lease

The holder of a ML may:

(a) enter and be:

  (i) within the area of the mining lease; and

  (ii) upon the surface area comprised in the mining lease;

for any purpose for which the mining lease is granted or for any purpose permitted or required under the lease or by the MRA; and

(b) may do all such things as are permitted or required under the lease or by the MRA.

The holder of a ML must:

(a) use the area of the mining lease bona fide for the purpose for which the ML was granted and in accordance with the MRA and the conditions of the mining lease and for no other purpose;

(b) on termination of the lease, remove all equipment and plant;

(c) carry out improvement restoration for the ML;

(d) pay compensation to landholders as determined under the MRA;

(e) pay annual rental;

(f) pay royalty as set out in the MRA

The holder of a ML must pay annual rental for the licence. The annual rental for the current financial year is $52.50 for each hectare to which the ML relates. The initial term of a ML is the period approved by the Minister. The holder of a ML may apply for renewal for an appropriate term. All minerals lawfully mined under the authority of a ML cease to be the property of the Crown or person who had property therein and become the property of the holder of the ML holder subject to the payment of royalty under the MRA.

South Australia Energy and Resources Legislation

Mining Act 1971

Exploration for minerals and mining in South Australia cannot be undertaken (either on Crown or private land) unless it is done so in accordance with (among other acts) the provisions of the Mining Act 1971 ("**MA**"), which is administered by the Department for Manufacturing, Innovation, Trade, Resources and Energy ("**DMITRE**").

The MA and the regulations made under the MA:

(a) provide that all minerals are the property of the Crown;

(b) provide for the issue of mineral tenements that give rights with respect to mineral exploration and production;

(c) establish landholder and licensee rights with regard to access to land and provide for compensation for any resulting damage;

(d) provide for the regulation of operations within tenements;

(e) provide for the collection of royalties on production plus a range of fees for required approvals, annual tenement fees and penalties for breaches of the legislation; and

(f) provide for the appointment of inspectors and authorised persons to have access to tenements.

The types of mineral tenements that are granted and administered under the MA are (inter alia) general rights to prospect, exploration licences, retention leases, mineral claims and mining leases.

Petroleum and Geothermal Energy Act 2000

The Petroleum and Geothermal Energy Act 2000 ("**PGE Act**") is administered by DMITRE and covers all exploration and production activities for petroleum, gas storage and geothermal resources for onshore South Australia, as well as the construction and operation of transmission pipelines for conveying petroleum and other regulated substances such as CO_2. The key objects of the PGE Act include:

(a) providing security of tenure to licensees for the resources covered by the PGE Act;

(b) protecting the environment and public from the inherent risks associated with the activities undertaken to explore these resources;

(c) enabling appropriate consultative processes involving people directly affected by regulated activities;

(d) where relevant, ensuring appropriate levels of security of natural gas supply are provided for; and

(e) promoting and facilitating competitive development of South Australia's petroleum, gas storage and geothermal resources through the acquisition and release of relevant geotechnical and engineering data and information.

Petroleum tenure

South Australian Petroleum Legislation

Petroleum and Geothermal Energy Act 2000

The PGE Act sets out (amongst others) the following types of petroleum tenures:

(a) Petroleum Exploration Licences ("**PEL**");

(b) Petroleum Retention Licences ("**PRL**"); and

(c) Petroleum Production Licences ("**PPL**").

Petroleum is defined in the PGE Act as a naturally occurring substance consisting of a hydrocarbon or mixture of hydrocarbons in gaseous, liquid or solid state but does not include coal or shale unless occurring in circumstances in which the use of techniques for coal seam methane production or in situ gasification would be appropriate or unless constituting a product of coal gasification (whether produced below or above the ground) for the purposes of the production of synthetic petroleum.

Petroleum Exploration Licences

The holder of a PEL is authorised under the PGE Act to carry out in the licence area the following activities:

(a) exploratory operations for petroleum;

(b) establish the nature and extent of a discovery of petroleum; and

(c) establish the feasibility of production and appropriate production techniques.

It is a mandatory condition of a PEL that the licence holder must carry out a work programme in the licence area in accordance with the conditions of the licence set out by the Minister.

The total licence area cannot exceed 10,000 square kilometres.

The term of a PEL is 5 years and it may be renewed for a further term or 2 further terms. A PEL that is renewable for one further term must provide for the excision, on renewal, of an area equal to at least 50% of the original licence area and a licence that is renewable for 2 further terms must provide for the excision, on each renewal, of an area equal to at least 33⅓% of the original licence area.

The holder of a PEL is entitled to the grant of a corresponding PRL or PPL for petroleum discovered in the licence area.

Petroleum Retention Licences

A PRL is intended to protect the interest of a licensee in connection with the following purposes:

(a) facilitate proper evaluation of a discovery;

(b) carry the necessary work to bring the discovery to production;

(c) protect interest of a licensee until commercial production is feasible; or

(d) facilitate other activities considered appropriate by the Minister.

The holder of a PRL may carry out:

(a) activities to determine the nature and extent of a discovery;

(b) operations to establish the commercial feasibility of a discovery; and

(c) other regulated activities specified in the licence.

Subject to the PEG Act, a person is entitled to the grant of a PRL if:

(a) petroleum has been discovered in the area the subject of the application;

(b) the person holds a PEL or a PPL over the area of the application;

(c) the Minister is satisfied that petroleum production is not currently feasible but it is more likely than not to become feasible within 15 years.

The area of a PRL must not exceed either twice the area under which the discovery is likely to extend or 100 square kilometres.

The term of a PRL is 5 years, renewable from time to time if the Minister is satisfied that petroleum production is not currently feasible but it is more likely than not to become feasible within 15 years.

A PRL may include a work programme approved by the Minister to establish the nature and extent of the commercial discovery and the commercial feasibility of production and appropriate production techniques.

Petroleum Production Licences

A PPL authorises the holder to carry out:

(a) operations for the recovery of petroleum from the ground including:

    (i) operations involving the injection of petroleum or another substance into a natural reservoir for the recovery (or enhanced recovery) of petroleum; and

    (ii) if the licence so provides, the extraction of petroleum by an artificial means such as in situ gasification or the techniques used to recover coal seam methane;

(b) operations for the processing of petroleum;

(c) operations for the storage or withdrawal of petroleum for the prudent supply or delivery of the petroleum or other regulated substance to the market.

Subject to the PEG Act, a person is entitled to the grant of a PPL if:

(a) petroleum exists in the area the subject of the application;

(b) the person holds at the time of the application a PEL, PRL, or a mining tenement granted under the Mining Act 1971 (SA) (but for the purpose of in situ gasification or coal seam production) in relation to the area the subject of the application;

(c) production is commercially feasible or is more likely than not to become commercially feasible within the next 24 months.

The area of a PPL must not exceed either the area under which the discovery is more likely than not to extend or 100 square kilometres.

A PPL may include a work programme for the development of the licence area and the production of petroleum.

A PPL is granted for an unlimited term.

Environment

Commonwealth Environment Legislation

Environment Protection and Biodiversity Conservation Act 1999

The Environment Protection and Biodiversity Conservation Act 1999 ("**EPBC Act**") is administered by SEWPAC and is the Australian Government's key piece of environmental legislation.

The objectives of the EPBC Act are to:

(a) provide for the protection of the environment, especially matters of national environmental significance;

(b) conserve Australian biodiversity;

(c) provide a streamlined national environmental assessment and approvals process;

(d) enhance the protection and management of important natural and cultural places;

(e) control the international movement of wildlife, wildlife specimens and products made or derived from wildlife; and

(f) promote ecologically sustainable development through the conservation and ecologically sustainable use of natural resources.

Any action that has a significant impact on matters of national environmental significance are termed ‘controlled actions’ and require approval under the EPBC Act. An ‘action’ under the EPBC Act is a physical activity or series of activities such as the construction and operation of a mine, dam or factory. Under the EPBC Act a ‘significant impact’ is an impact that is important, notable or of consequence having regard to its context or intensity.

Recent amendments to the EPBC Act have classified water resources that relate to coal seam gas and large coal mining developments as a matter of national environmental significance. Whilst before this amendment was made projects with water related risks could only be regulated if they had flow on impacts to existing matters of national environmental significance (eg. nationally endangered plants and animals), these recent amendments mean that such projects will (regardless of their flow on impacts) require federal assessment and approval to ensure the protection of water resources.

Water Act 2007

The Water Act 2007 establishes joint control of the Murray-Darling River Basin and is jointly administered by SEWPAC, the National Water Commission and the Murray Darling Basin Commission.

Several river systems in southern Queensland (Condamine-Balonne, Warrego and MacIntyre Rivers) all form part of the Murray-Darling River Basin.

The act is intended to operate concurrently with State water laws (including the *Water Act 2000* (Qld)) and establishes a framework for water charges, water trading and a water market within the Murray-Darling River Basin. It aims, in particular, to address over-allocation of water to irrigation.

Queensland Environment Legislation

Environmental Protection Act 1994

The Environmental Protection Act 1994 (Qld) (“**EPA**”) is administered by the Department of Environment and Heritage Protection (“**DEHP**”) and is a major component of the Queensland environmental legal system.

The EPA’s object is environmental protection within the context of ecologically sustainable development and provides for (among other things):

(a) environmental protection policies;

(b) an environmental impact statement process for mining and petroleum activities;

(c) a system for development approvals integrated into the *Sustainable Planning Act 2009* (Qld) for environmentally relevant activities;

(d) environmental authorities for mining and petroleum activities;

(e) environmental authorities for greenhouse gas storage and petroleum exploration, extraction and pipelines (including petroleum in both liquid and gas forms);

(f) a general environmental duty and a duty to notify of environmental harm;

(g) environmental evaluations and audits;

(h) environmental protection orders;

(i) a system for managing contaminated land;

(j) environmental offences and executive officer liability;

(k) investigative powers of authorised officers including power to give an emergency direction; and

(l) civil enforcement provisions to restrain breaches of the EPA.

Under the EPA, an activity that causes serious or material environmental harm or environmental nuisance is unlawful unless it is approved under the EPA or the general environmental duty is complied with.

Water Act 2000

The Water Act 2000 is administered by DEHP in conjunction with the Queensland Water Commission, water authorities and local governments.

The act provides a framework for the planning and regulation of the use and control of water in Queensland, including the regulation both of major water impoundments (dams, weirs and barrages) and extraction by pumping for irrigation and other uses.

The act also provides a wide range of tools for the regulation of in-stream (ie. watercourses, lakes and springs) and overland water flow and groundwater within the context of sustainable management and efficient use of water.

The act provides for Water Resource Plans, generally on a catchment-by-catchment basis, to be prepared through a consultative process. These plans are meant to balance water allocations (ie. human use) with environmental flows (ie. leaving water in a watercourse to maintain natural processes). Resource Operations Plans provide practical operational details of the implementation of a Water Resource Plan under which Resources Operations Licences, Water Allocations, Water Licences and Water Permits may be granted.

Wild Rivers Act 2005

The Wild Rivers Act 2005 ("**WRA**") is administered by DEHP and provides an additional layer of protection for undeveloped river systems in Queensland by establishing a process for the declaration of wild rivers and prohibition of the carrying out of prescribed activities within these declared wild river areas.

A declared wild river area will or may include high preservation areas, preservation areas, floodplain management areas, special floodplain management areas and/or subartesian management areas. These management areas dictate the type of mining or exploration activities that may be conducted within them.

To date, wild river areas have been declared over the Fraser, Gregory, Hinchinbrook, Morning Inlet, Settlement, Staaten, Lockhart, Stewart, Archer, Wenlock Basin, Georgina and Diamantina Basin and Cooper Creek Basin rivers.

Strategic Cropping Land Act 2011

The Strategic Cropping Land Act 2011 ("**SCL Act**") is administered by DNRM and aims to:

(a) protect land that is highly suitable for cropping;

(b) manage the impacts of development on that land; and

(c) preserve the productive capacity of that land for future generations.

To achieve this aim, the SCL Act outlines processes for:

(a) identifying potential strategic cropping land;

(b) providing criteria to decide whether or not land is strategic cropping land;

(c) establishing protection and management areas;

(d) providing for development assessment;

(e) imposing conditions on development;

(f) preventing permanent impacts on strategic cropping land in protection areas (unless the development is in exceptional circumstances); and

(g) requiring mitigation to be paid by developers if strategic cropping land is permanently impacted in the management area, or by a development in exceptional circumstances.

South Australia Environment Legislation

Environment Protection Act 1993

The Environment Protection Act 1993 is administered by the Environment Protection Authority of South Australia and provides the regulatory framework (through a suite of legislative and non-legislative policies and regulatory tools) to protect South Australia's environment, including land, air and water.

Regulatory tools available to the Environment Protection Authority under the act include Environment Protection Policies, Codes of Practice, National Environment Protection Measures, Guidelines and Position Statements.

Environment Protection Policies issued under the act have the force of a standard imposed by Parliament, may impose mandatory provisions with penalties and are developed for a specific area (eg. waste, water, air, noise).

Codes of Practice regulate a specific activity and are enforceable via an Environment Protection Order or mandatory provisions of an Environment Protection Policy. They provide direction and control over an industry, set measurable outcomes and require extensive consultation in development and alteration.

National Environment Protection Measures are broad framework-setting statutory instruments that outline agreed national objectives for protecting or managing particular aspects of the environment. National Environment Protection Measures may relate to any one or more of the following:

(a) ambient air quality;

(b) ambient marine, estuarine and fresh water quality;

(c) the protection of amenity in relation to noise (but only if differences in markets for goods & services);

(d) general guidelines for the assessment of site contamination;

(e) environmental impacts associated with hazardous wastes; and

(f) the re-use and recycling of used materials.

Natural Resources Management Act 2004

The Natural Resources Management Act 2004 ("**NRM Act**") is administered by the Department of Environment, Water and Natural Resources and aims to assist in the achievement of ecologically sustainable development in South Australia by establishing an integrated scheme to promote the use and management of natural resources in a manner that (among other things):

(a) recognises and protects the intrinsic values of natural resources;

(b) seeks to protect biological diversity and, insofar as is reasonably practicable, to support and encourage the restoration or rehabilitation of ecological systems and processes that have been lost or degraded; and

(c) provides for the protection and management of catchments and the sustainable use of land and water resources and, insofar as is reasonably practicable, seeks to enhance and restore or rehabilitate land and water resources that have been degraded.

The NRM Council was established under the NRM Act and provides advice to the Minister for Sustainability, Environment and Conservation primarily through the development of the South Australian Natural Resources Management Plan ("**Plan**").

The Plan contains strategic policy at a state level for managing South Australia's natural resources, fulfilling obligations under several Commonwealth-South Australian Government bilateral agreements as well as providing a framework for all natural resources management initiatives (including regional Natural Resource Management Plans and agency activities).

South Australia has eight Natural Resource Management regions: Adelaide and Mount Lofty Ranges, Alinytjara Wilurara (taking in the Aboriginal lands of the far west), Eyre Peninsula, Kangaroo Island, Northern and Yorke, South Australian Arid Lands (covering the outback and far north), South Australian Murray-Darling Basin and the South East.

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APPENDIX B—SUMMARY OF CERTAIN PROVISIONS OF THE AUSTRALIA CORPORATIONS LAW AND THE CONSTITUTION OF OUR COMPANY

REGISTRATION NUMBER

The Company was incorporated on 29 October 1996. The Company's registration number is ACN 076 157 045.

SUMMARY OF CERTAIN PROVISIONS OF THE CORPORATIONS ACT

Our Company is incorporated in the Commonwealth of Australia and is subject to the Corporations Act and therefore, operates subject to Australian law. Set out below is a summary of certain provisions of the Corporations Act, although this does not purport to contain all applicable qualifications and exceptions to or be a complete review of all matters of Australian corporations law and taxation, which may differ from equivalent provisions in jurisdictions with which interested parties may be more familiar.

Operations

The Corporations Act does not require a company to detail its scope of operations in its Constitution nor does it limit the conduct of its operations to any particular jurisdiction.

Share Capital

Under Australian law, there is no such thing as 'par value' or 'authorised share capital'. In Australia a company increases its share capital by issuing additional shares.

Under the Corporations Act, the directors have the power to issue shares, or grant options in respect of further shares, on such terms and conditions as the Directors decide by resolution. This includes the power to issue:

(a) bonus shares (shares for whose issue no consideration is payable to the company);

(b) preference shares (including redeemable preference shares); and

(c) partly-paid shares.

Under Australian law shareholder general authorisation (including a general mandate) is not required for the issue of further shares.

Under the Australian law, the power of directors to issue shares in a company is subject to:

(a) the takeover provisions of the Corporations Act;

(b) any rights and restrictions attached to a class of shares expressed or implied in the constitution of the company;

(c) restrictions with respect to preference shares; and

(d) the provisions in the Corporations Act dealing with the issue of shares and other securities to related parties of the company.

A company may issue preference shares under the Corporations Act only if the rights attached to the preference shares are set out in the company's constitution or have been approved by way of a special resolution (75.0% approval) of the company's shareholders.

Any share issue which will fall within the above restrictions will be subject to the procedures contained in the Corporations Act, which may include Shareholder approval in general meeting.

Share Consolidations, Subdivisions and Reductions

The Corporations Act governs share consolidations, share subdivisions and reductions in share capital.

Under the Corporations Act, a company may consolidate or subdivide its shares if the consolidation is approved by an ordinary resolution of shareholders at a general meeting. The consolidation or subdivision (as the case may be) takes effect on the latter of the day the resolution is passed or the date specified in the resolution.

A reduction of share capital occurs when any money paid to a company in respect of a member's share is returned to the member. The Corporations Act provides that a company may reduce its share capital in a way that is not otherwise authorised by the Corporations Act if the reduction:

(a) is fair and reasonable to the company's members as a whole;

(b) does not materially prejudice the company's ability to pay its creditors; and

(c) is approved by members.

The reduction is either an equal reduction or a selective reduction.

An equal reduction must meet the following three conditions:

(a) It relates only to ordinary shares.

(b) It applies to each holder of ordinary shares in proportion to the number of ordinary shares they hold.

(c) The terms of the reduction are the same for each holder of ordinary shares.

If any of these three conditions do not apply, it must be a selective reduction.

If the reduction is an equal reduction, it must be approved by an ordinary resolution of shareholders at a general meeting. If the reduction is a selective reduction, the reduction must be approved by either:

(a) a special resolution with no votes being cast in favour of the resolution by any person who is to receive consideration as part of the reduction or whose liability to pay amounts unpaid on shares is to be reduced, or by their associates; or

(b) an ordinary resolution of shareholders agreed to by all ordinary members.

If the selective reduction involves the cancellation of shares the reduction must also be approved by a special resolution passed at a separate meeting of the members whose shares are to be cancelled.

Related party transactions

Chapter 2E of the Corporations Act covers 'related party benefits'—designed to protect the interests of a company's shareholders as a whole, by requiring shareholder approval before giving financial benefits which could otherwise endanger those interests.

The Corporations Act requires, for a public company, that:

(a) shareholder approval must be obtained before giving a financial benefit to a related party; or

(b) the benefit must fall within a specified exception.

The most relevant exception provides that:

(a) where any benefit would be reasonable in the circumstances if the public company and the director/related party were dealing at arm's length and/or on commercial terms; or

(b) the terms are less favourable to the director/related party than the terms referred to above,

then shareholder approval is not required.

Other exceptions include reasonable remuneration payments to directors, director insurance, and small amounts given to directors/related parties.

'Related party' is defined in the Corporations Act to include:

(a) a director of the company and any controlling entity;

(b) the spouse of a director;

(c) parents and children (of both directors and/or spouses);

(d) an entity controlled by any of the above; or

(e) any other entity acting in concert with a related party.

Removal of directors

The Corporations Act contains various provisions regarding resignation, removal and retirement of directors.

The Corporations Act provides that a director may be removed by resolution at a general meeting, subject to a company receiving at least two months' notice of the intention to move the resolution and notifying the relevant director as soon as possible after receiving notice of that intention.

The Corporations Act also provides what is termed the 'two-strikes' law which is designed to hold directors accountable for executive salaries and bonuses. It means an entire company board can face re-election if shareholders disagree with how much executives are being paid.

The 'first strike' occurs when a company's remuneration report—which outlines each director's individual salary and bonus—receives a 'no' vote of 25 per cent or more by shareholders at the company's annual general meeting.

The 'second strike' occurs when a company's subsequent remuneration report also receives a 'no' vote of 25 per cent or more.

When a 'second strike' occurs, the shareholders will vote at the same AGM to determine whether all the directors will need to stand for re-election. If this 'spill' resolution passes with 50 per cent or more of eligible votes cast, then a 'spill meeting' will take place within 90 days.

At the spill meeting, those individuals who were directors when the directors' report was considered at the most recent Annual General Meeting will be required to stand for re-election (other than the managing director, who is permitted to continue to run the company).

Directors' duties

The laws governing directors' duties and responsibilities come from four areas, namely; the common law (judge-made law), statute law, under the Corporations Act, a company's constitution and such other duties as are expressed or implied in the contractual arrangement under which the director is employed or appointed. The duties of directors are owed to the company, which is made up of its members.

Common law duties include:

(a) Duty to act bona fide (In good faith) in the interests of the company as a whole;

(b) Duty not to act for an improper purpose;

(c) Duties of care and Diligence;

(d) Duty to retain Discretion;

(e) Duty to avoid conflicts of interest;

(f) Duty not to disclose confidential information; and

(g) Duty not to abuse corporate opportunities.

Statutory duties include:

(a) Duty of care and diligence and the business judgment rule;

(b) Duty of good faith;

(c) Duty not to make improper use of position;

(d) Duty not to make improper use of information;

(e) Duty not to trade while insolvent;

(f) Duty to disclose material personal interests;

(g) Duty not to provide financial benefits to related parties of public companies; and

(h) Duty to ensure all financial reporting is completed.

Membership

Under the Corporations Act, only those persons who agree to become members of an Australian company and whose names are entered into the register of members of such company are considered members. An Australian company is not bound to see to the execution of any trust, whether express, implied or constructive, to which any of its shares are subject and whether or not the company had notice of such trust. Accordingly, persons holding shares through a trustee, nominee or depository will not be recognised as members of an Australian company under Australian law and may only have the benefits of rights attached to the shares or remedies conferred by law on members through or with the assistance of the trustee, nominee or depository.

Financial Assistance to Purchase Shares of a Company or its Holding Company

The Corporations Act prohibits a company from providing financial assistance to a person to acquire shares in the company or in its holding company unless either:

(a) The giving of the financial assistance does not materially prejudice the interests of the company or its shareholders or the company's ability to pay its creditors; or

(b) The assistance is approved by shareholders; or

(c) The assistance is exempted under the provisions of the Corporations Act.

Breach of the provision does not invalidate the giving of the financial assistance nor is the company guilty of an offence. However, a person who is involved in a company's contravention of the restriction contravenes the Corporations Act and, if their involvement is dishonest, the person commits an offence under the Corporations Act. The breach of the restriction is a civil penalty provision which may result in orders to compensate a corporation for damage suffered by the corporation as a result of a contravention. In addition, if the contravention materially prejudices the interests of the corporation or its members, or materially prejudices the corporation's ability to pay its creditors or is serious, the Court may order a pecuniary penalty be paid.

Purchase of Shares by a Company

Under the Corporations Act, a company can either:

(a) purchase shares in itself on the terms on which they are issued (for instance redeemable preference shares); or

(b) purchase shares in itself by way of a regulated share buy-back.

With respect to redeemable preference shares, With respect to preference shares, under the Corporations Act a company can issue redeemable preference shares only if the rights attached to the preference shares are set out in the company's constitution or have been approved by way of a special resolution (75% approval) of the company's shareholders.

With respect to the buy-back of shares, the Corporations Act empowers a company to buy back its shares if the buy-back does not materially prejudice the company's ability to pay its creditors, and the company follows the procedures laid down in the Corporations Act.

Under Australian law a subsidiary can never hold shares in its holding company.

See "Appendix D—Description of our Shares—Purchase by our Company of our own Shares" for further details.

Dividends

See "Appendix D—Description of our Shares—Dividends" for further details.

Protection of Minorities

The Corporations Act contains provisions to protect minority shareholders. These statutory rights include:

(a) being able to bring legal proceedings in the name of the company (e.g. against directors) with the court's permission;

(b) being able to inspect the company's books, with the court's permission;

(c) being able to seek court orders (including orders to wind up the company or for a sale of a shareholder's shares) where the company has been run in a way which is unfairly prejudicial to a member or not in the interest of all members as a whole;

(d) the right to approve some transactions between public companies and their related parties (such as majority shareholders and directors); and

(e) being able to call shareholder meetings or require the company to put a resolution (e.g. to appoint or remove a director) to shareholders for approval.

See "Appendix D—Description of our Shares—Minority Rights".

Accounting and Auditing Requirements

Under Australian law, the Company is required to compile and lodge with ASIC its financial statements for each half year and each full year. The financial statements consist of the Company's statement of profit or loss and comprehensive income, statement of financial position and cashflow statement. The annual financial statements along with the Directors' Report on the operations of the Company must be presented to Shareholders for consideration at each annual general meeting. The annual general meeting must be held not later than five months after the end of its financial year.

Exchange Control

There are no exchange controls or currency restrictions in Australia

Stamp Duty on Transfers

No stamp duty is payable in Australia on transfers of shares in a Queensland registered company which is admitted to the official list of a "recognised stock exchange". This includes an exchange that is a member of the World Federation of Exchanges which includes the SGX-ST.

Loans to Directors

The making of loans by a company to any of its directors is restricted by Chapter 2E of the Corporations Act which covers 'related party benefits'. This Chapter is designed to protect the interests of a company's shareholders as a whole, by requiring shareholder approval before giving financial benefits which could otherwise endanger those interests.

The Corporations Act requires that shareholder approval must be obtained before a public company gives a financial benefit to a related party (which includes directors) unless:

(a) the benefit would be reasonable in the circumstances if the public company and the director/related party were dealing at arm's length and/or on commercial terms; or

(b) the terms are less favourable to the director/related party than the terms referred to above.

Inspection of Corporate Records

The Corporations Act requires a corporation to file various documents with ASIC, including its accounts, notification of changes to its constitution and notifications regarding changes to the director, secretary and share capital.

Documents filed with ASIC are available to the public.

The Corporations Act also provides that anyone may inspect the register of a company and request a copy following the provision of an application made to the company in the correct form.

Winding Up—solvent companies

A company remains registered as a company even after it ceases trading. While registered it is still subject to the legal requirements of a registered company, including payment of the annual review fee each year.

If the company is no longer required and it is not in financial difficulty or insolvent, the company may be deregistered.

A company ceases to exist on deregistration. There are two ways you can deregister a company:

(a) through a members' voluntary winding-up. This is a procedure for solvent companies initiated by the company's members and involves the orderly winding-up of the company's affairs, the appointment of a liquidator to manage the process of realising the company's assets, ceasing or sale of its operations, payment of its debts (if any) and distribution of surplus assets (if any) among its members.

(b) by applying to ASIC to voluntarily deregister a company assuming it meets certain legal requirements.

To commence a members' voluntary winding-up, the majority of the directors must make a written declaration that they have made an inquiry into the affairs of the company and that at a meeting of directors they have formed the opinion that the company will be able to pay its debts in full within 12 months after the commencement of the winding-up. This is often referred to as a solvency declaration.

After the solvency declaration the members of the company must make a special resolution to wind up the company. All members must be given at least 21 days notice in writing of the special resolution and at the meeting at least 75% of the votes cast by members entitled to vote on a special resolution must be in favour of the resolution for it to be passed.

Notice of the resolution must be published on the Insolvency notices website within 21 days after the date of the resolution being passed.

Where the company has been under no other form of external administration, the winding-up commences from the time the special resolution is passed.

The advantage of a members' voluntary winding-up is that the members can choose the liquidator to take control of the affairs of the company, fix the remuneration of the liquidator, and in general terms, supervise their conduct.

During the course of a members' voluntary winding-up, a creditor or a member may ask a court to determine any question arising in the winding-up, review the liquidator's remuneration or exercise any power that a court possesses in a compulsory winding-up, such as choosing a liquidator.

The leave of a court must be obtained before a company can be voluntarily wound up if an application for the company to be wound up as insolvent has been filed in a court, or if a court has already ordered that the company be wound up.

If at any time during a members' voluntary winding-up the liquidator forms the opinion that the company will be unable to pay its debts in full, then the liquidator must either apply to the court for the company to be wound up in insolvency, appoint an administrator or convene a meeting of creditors.

Winding Up—insolvent companies

Where the company is insolvent, unless it is possible to promptly restructure, refinance or obtain equity funding to recapitalise the company, the only options under Australian law are to appoint a voluntary administrator or a liquidator.

Administrator

Voluntary administration is designed to resolve the company's future direction quickly. An independent and suitably qualified person (the voluntary administrator) takes full control of the company to try to work out a way to save either the company or the company's business.

If it isn't possible to save the company or its business, the aim is to administer the affairs of the company in a way that results in a better return to creditors than they would have received if the company had instead been placed straight into liquidation.

A mechanism for achieving these aims is a deed of company arrangement.

Putting a company into voluntary administration can be done by the board of the company resolving that the company is insolvent, or likely to become insolvent, and an administrator should be appointed. The directors also need to obtain the written consent of a registered liquidator to act as voluntary administrator.

Liquidator

The purpose of liquidation of an insolvent company is to have an independent and suitably qualified person (the liquidator) take control of the company so that its affairs can be wound up in an orderly and fair way for the benefit of its creditors.

Generally, a director-initiated liquidation involves calling a meeting of members to vote on winding up the company and the appointment of a liquidator or applying to Court to wind up the company.

A company most commonly goes into receivership when a receiver is appointed by a secured creditor who holds security over some or all of the company's assets. The receiver's primary role is to collect and sell sufficient of the company's charged assets to repay the debt owed to the secured creditor.

Reconstructions and Takeovers

For detail on the takeover provisions of the Corporations Act, see "Appendix D—Description of our Shares—Takeovers".

With respect to reconstructions, the Corporations Act contains statutory provisions which facilitate reconstructions and amalgamations approved by a special resolution (75.0% approval) and thereafter approved by either the Australian Federal Court or a State Supreme Court. These are generally referred to as 'schemes of arrangement'. While a dissenting shareholder would have the right to express to the Court his or her view that the transaction for which approval is sought would not provide the shareholders with a fair value for their shares, the Court is unlikely to disapprove the transaction on that ground alone in the absence of evidence of fraud or bad faith on behalf of management.

Mergers and Consolidations

With respect to mergers or consolidations, the Corporations Act contains statutory provisions which facilitate mergers or consolidations approved by a special resolution (75% approval) and thereafter approved by either the Australian Federal Court or a State Supreme Court. These are also generally referred to as 'schemes of arrangement'. While a dissenting shareholder would have the right to express to the Court his or her view that the transaction for which approval is sought would not provide the shareholders with a fair value for their shares, the Court is unlikely to disapprove the transaction on that ground alone in the absence of evidence of fraud or bad faith on behalf of management.

Directors in forming of a view on whether to proceed with a merger or a consolidation need to be aware, however, of the following:

(a) Their director's duties under the Corporations Act (see "Appendix D—Summary of Certain Provision of the Australia Corporations Law and Constitution of our Company—Summary of Certain Provisions of the Corporations Act—Directors' duties" for information on director's duties)

(b) The restrictions with respect to related party transactions (see "Appendix D—Summary of Certain Provision of the Australia Corporations Law and Constitution of our Company—Summary of Certain Provisions of the Corporations Act—Related party transactions" for information on related party transactions).

Further, where an Australian company mergers or consolidates with a foreign entity and that foreign entity could be deemed to be 'carrying on a business in Australia' there may be a requirement for the foreign entity to register as an Australian business with ASIC. Registering as an Australian business requires the lodgement of company details and financial information with ASIC on an annual basis.

Application of the FATA to Takeovers, Reconstructions and Mergers and Consolidations

Prior to the commencement of a takeover, reconstruction, merger or consolidation, the implications of the Foreign Acquisitions and Takeovers Act 1975 ("**FATA**") must always be considered. For detail on ownership restrictions under the FATA, see "Appendix D—Description of Our Shares—Ownership Restrictions" of this offering document.

Compulsory Acquisition

In certain circumstances a shareholder who holds/controls at least 90% of the shares in a company ("**Major Shareholder**")—acquired or obtained in any way, not necessarily through a takeover bid—may move to compulsorily acquire the balance of shares not held by him or her.

The procedures and requirements governing the compulsory acquisition of shares in a company are detailed in the Corporations Act. The Corporations Act contains provisions designed to protect shareholders (in a target company) who are having their shares compulsorily acquired to ensure that they receive adequate information and a fair price for their shares.

The process is essentially as follows:

(a) The Major Shareholder must take action within six months of reaching the 90.0% level.

(b) The Acquisition consideration must be cash only and the same price paid for all shares.

(c) The Major Shareholder must arrange an expert's report on the fair value of the shares. The expert must be approved by ASIC. The report must state whether, in the expert's opinion, the terms proposed for the compulsory acquisition give a fair value for the shares concerned and set out the reasons for forming that opinion.

(d) The Major Shareholder must lodge a Notice of Compulsory Acquisition (including the expert's report and an objection form) with ASIC and then send it to all shareholders.

(e) if objections are received from holders of less than 10% of the shares within the objection period (being at least 1 month), the Major Shareholder may proceed with the compulsory acquisition.

(f) if objections are received from holders of at least 10% of the shares apply, within 1 month (of the end of the objection period), the Major Shareholder may apply to the Court for approval.

Indemnification

The Corporations Act prohibits a company from indemnifying its officers against:

(a) liabilities owed to the company or to a related body corporate;

(b) liabilities for certain pecuniary penalty orders or compensation orders under the Corporations Act; and

(c) liabilities owed to third parties which did not arise out of conduct in good faith.

The Corporations Act also prohibits a company from indemnifying its officers against legal costs incurred in defending claims in certain circumstances, such as:

(a) proceedings in which the officer is found to have a liability for which they could not be indemnified (as above);

(b) criminal proceedings in which the director is found guilty; and

(c) proceedings brought by ASIC or a liquidator for orders where grounds for making the order are established.

SUMMARY OF CERTAIN PROVISIONS OF THE CONSTITUTION

This summary provides information about certain provisions of our Constitution and certain aspects of the Corporations Act, and is qualified in its entirety by reference to our Constitution and the Corporations Act.

Registration number and Constitution

The registration number with which our Company was incorporated is 076 157 054. The liability of our Shareholders is limited.

Directors

Ability of Interested Directors to Vote (Rule 13.6)

No Director may as a Director vote in respect of any contract or arrangement in which our Director has directly or indirectly any material interest and if our Director does vote his vote may not be counted nor shall our Director be counted in the quorum present at the meeting. A Director, whose remuneration (including pension or other benefits) for himself is the subject of a resolution tabled at a meeting of our Board, shall not be entitled to vote on the resolution as he shall be taken to have a personal material interest in the matter and if he does vote his vote may not be counted nor shall such Director be counted in the quorum present at the meeting. Other Directors of our Company will not be prohibited by our Constitution from voting on that resolution so long as they do not have any direct or indirect personal material interest in the subject matter of the said resolution.

Remuneration (Rule 13.3)

Our Directors are to be paid out of the funds of our Company as remuneration for their services as Directors, such sum accruing from day to day as our Company in general meeting determines to be divided among them in such proportion and manner as they agree or in default of agreement equally. This rule does not limit the remuneration that may be paid to our Managing Director or Executive Directors.

Our Directors' remuneration for their services as Directors is by fixed sum and not a commission on or percentage of profits or turnover and may not be increased except at a general meeting where notice of the proposed increase has been given to the shareholders in the notice convening the meeting.

Borrowing Powers (Rule 19.1 and Rule 19.2)

The management and control of the business and affairs of our Company are vested in our Board, which (in addition to the powers and authorities conferred upon them by these rules) may exercise all powers and do all things as are within the power of our Company and are not by these rules or by the Corporations Act directed or required to be exercised or done by our Company in general meeting.

Subject to the Rule 19.1 above, our Directors may exercise all the powers of our Company to raise or borrow money, may guarantee the debts or obligations of any person and may enter into any other financing arrangement, in each case in the manner and on the terms it thinks fit.

Retirement Age Limit

There are no provisions relating to retirement of Directors upon reaching any age limit.

Shareholding Qualification

There shall be no shareholding qualification for Directors unless determined otherwise by Ordinary Resolution.

Share Rights and Restrictions

Our Company currently has only one class of Shares, which will be designated as ordinary shares.

Dividends (Rule 23)

Subject to the Corporations Act and/or the Listing Manual, our Directors may from time to time either determine or declare that a dividend is payable to our Shareholders and fix the amount of the dividend, the time for payment and the method of payment. The dividend is (subject to the rights of, or any restrictions on, the holders of shares created or raised under any special arrangement as to dividend) payable on all Shares pro rata to the total amount for the time being paid, but not credited as paid, in respect of the Shares as a proportion of the total of the amounts then paid and payable thereon, excluding amounts credited, and may be paid at a rate per annum in respect of a specified period provided that (for the purposes of this rule) no amount paid on a Share in advance of calls is to be treated as paid on that Share.

All unclaimed dividends may be invested or otherwise made use of by our Directors for the benefit of our Company until claimed or otherwise disposed of according to law. There is no time limit before our Company can dispose of such unclaimed dividends.

Call on Shares (Rule 5.1)

Subject to the terms upon which any shares may have been issued and the Listing Rules, our Directors may make calls from time to time upon the shareholders in respect of all moneys unpaid on their shares. Each Shareholder is liable to pay the amount of each call in the manner, at the time and at the place specified by our Directors. Calls may be made payable by instalments.

Redemption Provisions (Rule 3.8)

Subject to the Corporations Act, any preference shares may be issued on the terms that they are, or at the option of our Company, are liable, to be redeemed and otherwise on such terms and in such manner as our Board determines before the issue, provided that the rights attaching to Shares of a class other than ordinary shares shall be expressed in the special resolution creating the same or in the provisions of these rules.

Variation of Rights of Existing Shares or Classes of Shares (Rule 3.9)

If at any time the share capital is divided into different classes of shares, the rights attached to any class (unless otherwise provided by the terms of issue of shares of that class) may, whether or not our Company is being wound up, and subject to the Listing Rules and rules in the Constitution, be varied with the consent in writing of Shareholders with at least 75.0% of the votes in the class, or with the sanction of a special resolution passed at a separate meeting of the holders of the shares of that class.

The repayment of preference capital other than redeemable preference capital, or any alteration of preference shareholders' rights, may only be made pursuant to a special resolution of the preference shareholders concerned, provided always that where the necessary majority for such a special resolution is not obtained at the general meeting, consent in writing if obtained from holders of three-fourths of the preference shares concerned within two months of the general meeting, shall be as valid and effectual as a special resolution carried at the general meeting.

Changes in capital—Rule 3.11

Subject to any direction given by the Company in a general meeting or except as permitted under the Listing Rules, all new Shares must, before issue, be offered to such persons who as at the date of the offer are entitled to receive notices from the Company of general meetings in proportion to the amount of the existing Shares to which they are entitled.

The offer shall be made by notice specifying the number of Shares offered, and limiting a time within which the offer, if not accepted, will be deemed to be declined. After the expiration of that time, or on the notification from the person to whom the offer is made that he or she declines to accept the Shares offered, the Board may dispose of those Shares in such manner as they think most beneficial to the Company. The Board may likewise so dispose of any new Shares which (by reason of the ratio which the new shares bear to shares held by *persons entitled to an offer of new shares) cannot, in the opinion of the Board, be conveniently offered.*

See "Appendix B—Summary of Certain Provision of the Australia Corporations Law and the Constitution of our Company—Summary of Certain Provisions of the Corporations Act—Purchase of Shares by a Company" and "Appendix D—Description of our Shares—General Meeting of Shareholders" and for further details.

General Meetings (Rule 9.1)

See "Appendix D—Description of our Shares—General Meeting of Shareholders" for further details.

Voting Rights (Rule 10.8)

See "Appendix D—Description of our Shares—Voting Rights" for further details.

Share in surplus upon Winding Up (Rule 25)

In the event our Company is being wound up and the assets available for distribution among shareholders (the "surplus assets") are insufficient to repay the whole of the paid up capital, the surplus assets must be distributed as follows:

(a) the surplus assets must be applied first in repayment of the capital paid up on all shares that are not at the commencement of the winding up so that, if the surplus assets are insufficient to repay the whole of the capital paid up on those shares, the losses are borne by the holders of those shares, as nearly as may be, in proportion to the capital paid up or which ought to have been paid up at the commencement of the winding up on such of those shares as are held by them respectively; and

the remainder (if any) of the surplus assets must be applied in repayment of the capital paid up on all shares that are, at the commencement of the winding up, so that the losses are borne by the holders of those shares, as nearly as may be, in proportion to the capital paid up or which ought to have been paid up at the commencement of the winding up on such of those shares as are held by them respectively.

APPENDIX C—SUMMARY RULES OF THE PERFORMANCE RIGHTS PLAN

The object of the Plan is to:

(a) provide Participants with an incentive plan which recognises ongoing contribution to the achievement by the Company of long term strategic goals;

(b) establish an employee incentive scheme within the meaning of Class Order 03/184 issued by the Australian Securities and Investments Commission;

(c) align the interests of Participants with Security Holders through the sharing of a personal interest in the future growth and development of the Company as represented in the price of the Company's Securities; and

(d) provide a means of attracting and retaining skilled and experienced employees.

Eligibility

Under the Plan, the Board may grant rights to an employee or executive director of the Company or any wholly owned subsidiary or controlled entity of the Company whom the Board decides in its absolute discretion is eligible to be invited to receive a grant of Rights in the Plan from time-to-time and who is not prohibited from participating in the Plan under the terms and conditions of the Plan.

Awards

Mandatory vesting of Rights will occur when the specified conditions and performance measures are satisfied. Each Right, when vested, will automatically convert to one fully paid ordinary share in the Company.

Timing

The Rights are generally granted to vest in equal instalments over a period of between three and five years.

Special Provisions

The Company may acquire fully paid ordinary shares on market and transfer, or issue new shares, to holders on vesting of Rights. The Company will not apply for ASX quotation of any rights issued under the Plan. The Rights are not assignable.

Any shares issued or transferred as a result of the vesting of Rights issued under the Plan will rank equally with existing fully paid ordinary shares in the Company, in all respects including voting rights, entitlements to dividends and future entitlement issues.

Size and duration of Performance Rights Plan

The number or value of Rights to which an invitation relates is at the determination of the Linc Energy Chief Executive Officer.

In setting the number or value of Rights to which any specific invitation relates, the Linc Energy Chief Executive Officer will have regard to appropriate peer companies and to a percentage of base salary per employee pay band that reflects current market practice when making his/her determination of the Eligible Employee's entitlement.

If an Eligible Employee leaves before the Vesting Date of any tranche of Rights then any unvested Rights will lapse except in the following cases:

- Death and Total Permanent Disability: in this case current granted and unvested Rights entitlements will vest and there will be no further entitlements to future Rights awards;

- Redundancy: in this case the Chief Executive Officer will consider on a case by case base whether the current granted and unvested Rights entitlements will vest and how many, if any, vest.

Operation of Performance Rights Plan

The Board may from time to time invite an Eligible Employee to participate in the Plan and grant Rights to an Eligible Employee, as part of the Eligible Employee's remuneration.

Securities delivered under the Plan (upon conversion of Rights) will rank equally with all existing Securities on and from the Date of Registration in respect of all Security holder entitlements (including rights issues, bonus issues and dividends) which have a record date for determining entitlements on or after the Date of Registration.

Rights will not be quoted on the SGX or any other publicly traded exchange.

Adjustment events

In the event of any reconstruction (including consolidation, subdivision, reduction, capital return, buy back or cancellation) of the capital of the Company, the number of Securities that may be acquired by each Participant must be reconstructed accordingly, in a manner that does not result in any additional benefits being conferred on Participants that are not conferred on Security holders of the Company. However in all other respects, the Rights will remain unchanged.

If there is a Control Event, the Board may give written notice to Participants of the Control Event and convert all or any of the Participant's Rights to Securities whether or not the Performance Conditions have been met.

Modifications or alterations to the Performance Rights Plan

The terms and conditions of the Plan may be amended at any time and from time-to-time by the Board.

APPENDIX D—DESCRIPTION OF OUR SHARES

The following statements are brief summaries of certain rights and privileges of shareholders conferred by the Corporations Act and our Constitution. The description below is only a summary and is qualified in its entirety by reference to our Constitution and the Corporations Act.

Share Capital

As at the date of this document, we have 522,996,195 Shares on issue all of which are fully paid-up.

Under Australian law, there is no such thing as ''par value'' or ''authorised share capital''. In Australia a company increases its share capital by issuing additional shares.

Under the Corporations Act, the directors have the power to issue shares, or grant options in respect of further shares, on such terms and conditions as the Directors decide by resolution. This includes the power to issue:

(a) bonus shares (shares for whose issue no consideration is payable to the company);

(b) preference shares (including redeemable preference shares); and

(c) partly-paid shares.

Under Australian law, shareholder general authorisation (including a general mandate) is not required for the issue of further shares.

Under Australian law, the power of directors to issue shares in a company is subject to:

(a) the takeover provisions of the Corporations Act;

(b) any rights and restrictions attached to a class of shares expressed or implied in the constitution of the company;

(c) restrictions with respect to preference shares; and

(d) the provisions in the Corporations Act dealing with the issue of shares and other securities to related parties of the company.

A company may issue preference shares under the Corporations Act only if the rights attached to the preference shares are set out in the company's constitution or have been approved by way of a special resolution (75.0% approval) of the company's shareholders.

As an entity admitted to the official list of SGX-ST, the issue of further shares in the Company will be also be subject to, among others, the restrictions contained within the following:

(a) the SGX-ST; and

(b) the Singapore Take-Over code.

Any share issue which will fall within the above restrictions will be subject to the procedures contained in the Corporations Act and the Listing Rules, which shall include Shareholder approval in general meeting.

Purchase by our Company of our Shares

A company can either acquire its own shares pursuant to the terms on which they were issued (i.e. for redeemable preference shares) or pursuant to a regulated share buy-back under the Corporations Act.

The Corporations Act empowers a company to buy back its shares if the buy-back does not materially prejudice the company's ability to pay its creditors, and the company follows the procedures laid down in the Corporations Act.

A company buys back its shares when it acquires shares in itself from a shareholder under an agreement between the company and that shareholder. It is of the essence of a buy-back that any shareholder to whom the company makes an offer to buy back may decide whether or not to sell.

The Corporations Act regulates five types of buy-back:

(a) equal access schemes applicable only to ordinary shares—the company makes uniform offers to each shareholder to buy back a uniform percentage of each shareholder's ordinary shares;

(b) on-market buy-backs—a company listed on a securities exchange buys its shares in the ordinary course of trading on the stock exchange in compliance with the exchange's listing rules as well as the Corporations Act;

(c) minimum holding (odd-lot) buy-backs—a company listed on a securities exchange buys small parcels of shares which are not marketable parcels on the exchange;

(d) employee share scheme buy-backs—a company buys shares held by, or for the benefit of, current or former employees, including executive directors, under an existing employee share acquisition scheme that has been approved by the company in general meeting;

(e) selective buy-backs—the company buys back from a particular member, otherwise than in any of the first four modes.

A selective buy-back must be approved by a special resolution (75% approval) of the company in general meeting. That requirement is for protection of other shareholders who could be prejudiced by a buy-back which:

(a) unduly favours a particular shareholder who is bought out at an improper premium to market value; or

(b) would enable particular remaining shareholders to increase their control.

Other forms of buy-back do not require approval in a general meeting unless, in an employee share scheme buy-back, an on-market buy-back or an equal access scheme, the buy-back would exceed the limit on volume of "10% in 12 months". Approval by ordinary resolution is required for any such buy-back which exceeds the limit.

Shareholders

We maintain a register of members which contains the particulars required under the Corporations Act, and only recognise as shareholders of our Company such persons who are holders of Shares and who are registered on the register of members. The register of members must contain the address of a member for the purposes of determining whether they are a foreign shareholder.

As required by the Corporations Act, the principal register of members is contained in Australia. A local register of members is maintained in Singapore which mirrors the Australian register of members.

If any Share stands jointly in the names of two or more persons, the person first named in the register shall as regards service of notices and, subject to the provisions of the Constitution, all or any other matters connected with our Company, except with respect to the transfer of Shares, be deemed the sole holder of those Shares.

Subject to the terms and conditions of any application of Shares, we must allot Shares and despatch certificates within ten Market Days of the closing date for applications to subscribe for a new issue of securities (or such other period as may be approved by the SGX-ST).

We may close the register of shareholders for any time or times if we provide the SGX-ST with at least five clear Market Days' notice (excluding the date of announcement and the book closure date). However, the register may not be closed for more than 30 days in aggregate in any calendar year. We would typically close the register to determine shareholders' entitlement to receive dividends and other distributions.

Transfer of Shares

Subject to our Constitution, any shareholder may transfer all or any of their Shares by a duly signed instrument of transfer in the form acceptable to our Board provided always that our Company shall accept for registration an instrument of transfer in a form approved by the SGX-ST.

Save as provided in the:

(a) Constitution;

(b) the takeover provisions of the Corporations Act and the Singapore Take-Over code; and

(c) the provisions of the Foreign Acquisitions and Takeovers Act 1975 (FATA),

there will be no restriction on the transfer of fully paid up Shares (except where required by law or the rules or regulations of the SGX-ST).

For details on the takeover provisions of the Corporations Act and the Singapore Take-Over code, see "Appendix D—Description of Our Shares—Take-overs" of this offering document. For detail on ownership restrictions under the FATA, see "Appendix D—Description of Our Shares—Ownership Restrictions" of this offering document.

Our Board may decline to register a transfer of any Share which is not fully paid or on which our Company has a lien. Our Board may also decline to recognise any instrument of transfer unless, among other things, it is duly stamped and is presented for registration together with the share certificate and such other evidence as our Board may reasonably require, and a fee of such sum (not exceeding two Singapore dollar (S$2.00) or such other maximum sum as the SGX-ST may determine to be payable) as our Board may from time to time require is paid to our Company in respect thereof.

General Meeting of Shareholders

The Directors may convene a general meeting of Shareholders at their absolute discretion by giving not less than 21 days' notice in writing, excluding the day of posting of the notice and the day on which the general meeting is held, to each Shareholder for the passing of an ordinary or special resolution. The written notice must set out:

(a) the place, date and time of the meeting;

(b) the general nature of the meeting's business;

(c) the resolutions to be put to Shareholders for consideration and vote; and

(d) a proxy form stating that the Shareholder is entitled to appoint a proxy to attend the meeting and vote on the shareholder's behalf and at the shareholder's direction.

Under Australian law, the Company is required to present its accounts to Shareholders for approval at an annual general meeting not later than five months after the end of its financial year.

As the Company is incorporated in Australia, please note that the time requirements for the giving of notice of general meeting and for the presentation of accounts differ from a Singapore-incorporated company.

Shareholders are entitled to be present in person, or by proxy, attorney or representative to attend and vote at general meetings of the Company. A quorum of one Shareholder is required to be present at the general meeting before any business may be transacted.

A Shareholder/s who holds in excess of 5% of the votes that may be cast at the general meeting may requisition a general meeting of the Company in accordance with the provisions of the Corporations Act.

In accordance with Rule 12.3(e) of our Constitution, unless CDP specifies otherwise in a written notice to our Company, CDP shall be deemed to have appointed as CDP's proxies each of the Depositors (as defined in the Singapore Companies Act) who are individuals and whose names are shown in the records of CDP, as at a time not earlier than 48 hours prior to the time of the relevant general meeting, supplied by CDP to our Company. Therefore, Depositors who are individuals can attend and vote at the general meetings of our Company without the lodgement of any proxy form. Depositors who cannot attend a meeting personally may enable their nominees to attend as CDP's proxies. Depositors who are not individuals can only be represented at a general meeting of our Company if their nominees are appointed by CDP as CDP's proxies. Proxy forms appointing nominees of Depositors as proxies of CDP would need to be executed by CDP as member and must be deposited at the specified place and within the specified time frame to enable the nominees to attend and vote at the relevant general meeting of our Company.

Voting Instructions

Investors who hold Shares through CDP may instruct CDP to exercise the voting rights for the deposited Shares in accordance with the terms and conditions for the operation of Securities Accounts with CDP, as amended from time to time. However, as a matter of Australian law, CDP will be recognised as the only registered owner of these Shares and, accordingly, Depositors and Depository Agents on whose behalf CDP holds Shares will not be accorded the full rights of membership, such as voting rights, the right to appoint proxies, or the right to receive annual reports, notices of meeting and takeover documents. We will mail to Depositors any notice of shareholders' meeting and such other documents issued by us to our shareholders (including annual reports and circulars).

If a meeting of our Shareholders is convened, we will despatch to persons with Shares standing to the credit of their CDP Securities Account Voting Instructions Forms. Such persons will be required to return the Voting Instructions Forms on or before the date specified by CDP for that purpose (the "**Specified Date**"). The Voting Instructions Form will set out such details as the resolutions to be considered at the Shareholders' meeting. The Voting Instructions Form, duly completed, must be returned by such persons to CDP no later than the Specified Date. In the event that CDP does not receive the duly completed Voting Instructions Form from a person with Shares standing to the credit of a CDP securities account on or before the Specified Date, or if the Voting Instructions Form has not been duly completed or is invalid for any reason, CDP will not vote or take any action in respect of the Shares standing to the credit of this CDP securities account. CDP or any of its nominees may, at its absolute discretion and upon such terms and conditions as it may think fit, accept the written instructions of the person holding the CDP Securities Account to which the relevant Shares have been credited to vote, or appoint a proxy to vote, at any shareholders' meeting in respect of Shares standing to the credit of such CDP Securities Account.

However, except as provided in the foregoing, neither CDP nor any of its nominees will exercise any right to attend, speak or vote at any shareholders' meeting in respect of Shares deposited with CDP. The operation of a CDP securities account is subject to the terms and conditions for the operation of securities accounts with CDP, as amended from time to time.

Voting Rights

Subject to any special rights or restrictions as to voting for the time being attached to any shares by or in accordance with our Constitution, at any general meeting:

(a) on a show of hands—every shareholder present in person (or being a corporation, is present by a representative duly authorised under Rules 12.4 of the Constitution) or by proxy shall have one vote and the chairman of the meeting shall determine which proxy shall be entitled to vote where a shareholder (other than CDP) is represented by two proxies; and

(b) on a poll—every shareholder present in person or by proxy or, in the case of a shareholder being a corporation, by its duly authorised representative shall have one vote for every fully paid share of which they are the holder or which they represents and in respect of which all calls due to our Company have been paid, but so that no amount paid up or credited as paid up on a share in advance of calls or instalments is treated for the foregoing purposes as paid up on the share.

If the shareholder is CDP, CDP may appoint more than two proxies to attend and vote at the same general meeting and each proxy shall be entitled to exercise the same powers on behalf of CDP as CDP could exercise, including the right to vote individually on a show of hands.

Dividends

Subject to the Corporations Act, the Constitution and the terms or rights of any shares with special rights to dividends, our Board may from time to time resolve to pay dividends to Shareholders of the Company and fix the amount of the dividend, the time for determining entitlements to the dividend and the timing and method of payment.

Under the Corporations Act, our Board must not pay a dividend unless:

(a) our assets exceed our liabilities immediately before the dividend is declared and the excess is sufficient for the payment of the dividend;

(b) the payment of the dividend is fair and reasonable to our Shareholders as a whole; and

(c) the payment of the dividend does not materially prejudice our ability to pay our creditors.

For further information in respect of the Company's proposed dividend policy, see "Dividend Policy ".

Variation of share class rights

At present, the Company's only class of shares on issue is ordinary shares. Subject to the Corporations Act and the terms of issue of a class of shares, the rights attaching to any class of shares may be varied or cancelled:

(a) with the consent in writing of the holders of three-quarters of the issued shares included in that class; or

(b) by a special resolution passed at a separate meeting of the holders of those shares.

In either case, the holders of not less than 10% of the votes in the class of shares, the rights of which have been varied or cancelled, may apply to a court of competent jurisdiction to exercise its discretion to set aside such a variation or cancellation.

Take-overs

Singaporean takeover provisions

Under the Singapore Take-Over code

Our Company is subject to the Securities and Futures Act and the Singapore Take-Over Code notwithstanding that we are a corporation incorporated in Australia.

Under the Singapore Take-Over Code, issued by the Authority pursuant to Section 321 of the Securities and Futures Act, any person acquiring an interest, either on his own or together with parties acting in concert with him, in 30.0% or more of the voting Shares must extend a takeover offer for the remaining voting Shares in accordance with the provisions of the Singapore Take-Over Code. In addition, a mandatory takeover offer is also required to be made if a person holding, either on his own or together with parties acting in concert with him, between 30.0% and 50.0% of the voting shares acquires additional voting shares representing more than 1.0% of the voting shares in any six-month period. Under the Singapore Take-Over Code, the following individuals and companies will be presumed to be persons acting in concert with each other unless the contrary is established:

(a) the following companies:

- (i) a company;
- (ii) the parent company of (i);
- (iii) the subsidiaries of (i);
- (iv) the fellow subsidiaries of (i);
- (v) the associated companies of (i), (ii), (iii) or (iv); and
- (vi) companies whose associated companies include any of (i), (ii), (iii), (iv) or (v); and
- (vii) any person who has provided financial assistance (other than a bank in the ordinary course of business) to any of the above for the purchase of voting rights;

(b) a company with any of its directors (together with their close relatives, related trusts as well as companies controlled by any of the directors, their close relatives and related trusts);

(c) a company with any of its pension funds and employee share schemes;

(d) a person with any investment company, unit trust or other fund whose investment such person manages on a discretionary basis, but only in respect of the investment account which such person manages;

(e) a financial or other professional adviser, including a stockbroker, with its customer in respect of the shareholdings of:

- (i) the adviser and persons controlling, controlled by or under the same control as the adviser; and
- (ii) all the funds which the adviser manages on a discretionary basis, where the shareholdings of the adviser and any of those funds in the customer total 10.0 per cent. or more of the customer's equity share capital;

(f) directors of a company (together with their close relatives, related trusts and companies controlled by any of such directors, their close relatives and related trusts) which is subject to an offer or where the directors have reason to believe a bona fide offer for their company may be imminent;

(g) partners; and

(h) the following persons and entities:

  (i) an individual;

  (ii) the close relatives of (i);

  (iii) the related trusts of (i);

  (iv) any person who is accustomed to act in accordance with the instructions of (i);

  (v) companies controlled by any of (i), (ii), (iii) or (iv); and

  (vi) any person who has provided financial assistance (other than a bank in the ordinary course of business) to any of the above for the purchase of voting rights.

Under the Singapore Take-Over Code, a mandatory offer made with consideration other than cash must be accompanied by a cash alternative at not less than the highest price paid by the offeror or any person acting in concert within the preceding six months.

Australian takeover provisions

Under the takeover provisions of the Corporations Act, corporate takeovers are regulated by Chapter 6 of the Corporations Act. A takeover involves the acquisition by one company (bidder) of a sufficient number of shares in another company (target) to obtain control of the finances and operations of the target.

The Corporations Act prohibits an entity from acquiring an interest in voting shares in a company, where:

(a) the company is either a listed company, or an unlisted company with more than 50 members;

(b) the interest is acquired through a transaction in relation to securities entered into by or on behalf of the person who acquires the interest; and

(c) because of the transaction, that person's voting power in the company increases from 20% or below to more than 20%, or increases from a starting point that is above 20% and below 90%.

The Corporations Act provides a number of exceptions to this general prohibition including:

(a) acquisitions resulting from the acceptance of an offer under a takeover bid;

(b) an acquisition approved by shareholders;

(c) increased shareholding under a pro rata issue; and

(d) "creeping" provisions, which allows a person to acquire a relevant interest in excess of 20% of the voting shares in a company if (i) throughout the 6 months before the acquisition, that person had voting power of at least 19% in the company; and (ii) as a result of the acquisition, that person's voting power in the company does not increase by more than 3% from the voting power held by the person 6 months before the acquisition. However, for every 1% change, a substantial holding notice must be lodged with the company and the ASX.

A takeover may proceed by way of an off-market bid or an on-market bid. All offers to security holders in the bid class must be the same and the consideration offered must equal or exceed the maximum consideration that the bidder or an associate of the bidder provided for a security in the bid class in the four months prior to the announcement of the takeover bid.

A bidder making a takeover bid will be permitted to compulsorily acquire the remaining securities in the bid class if during or at the end of the offer period:

(a) the bidder and its associates have relevant interests in at least 90% (by number) of the securities in the bid class; and

(b) the bidder and its associates have acquired at least 75% (by number) of the securities that the bidder offered to acquire under the bid (other than securities in which the bidder had a relevant interest in at the start of the offer period).

Substantial Shareholders

The Securities and Futures Act requires our substantial shareholders to give notice to us of certain information as prescribed by the Authority, including particulars of their interest, within two business days of becoming aware of being our Substantial Shareholders, being aware of any change in the percentage level of their interest and being aware of ceasing to be a Substantial Shareholder. "Percentage level", in relation to a substantial shareholder, is the percentage figure ascertained by expressing the aggregate of the votes attached to all the voting shares in which the substantial shareholder has an interest (or interests) immediately before or (as the case may be) immediately after the relevant time as a percentage of the total votes attached to all of the voting shares, and if it is not a whole number, rounding that figure down to the next whole number. Under the Securities and Futures Act, a person has a substantial shareholding in us if he has an interest (or interests) in one or more of our voting shares and the total votes attached to those shares are not less than 5.0% of the aggregate of the total votes attached to all of our voting shares (excluding treasury shares).

Liquidation

If the Company is wound up, the liquidator may (with the sanction of a special resolution):

(a) distribute the whole or any part of the Company's assets in kind among some or all of the shareholders as the liquidator considers fair and can determine how the distribution is to be carried out as between different shareholders or different classes of shareholders; and

(b) vest the whole or any part of the Company's assets in trustees on such trusts for the benefit of some or all of the shareholders or some or all of any class of shareholders as are approved by the special resolution, but a shareholder may not be compelled to accept any shares in a body corporate or other securities in respect of which there is a liability.

Indemnity

The Company, to the extent permitted by law, may indemnify a current or former Director or officer against any liability incurred by that person as a Director or officer of the Company, and legal costs incurred by that person in defending an action for a liability of that person.

The Company, to the extent permitted by law, may pay, or agree to pay, a premium for a contract insuring a former or current Director or officer against any liability incurred by that person in that capacity, including liability for legal costs.

The Company, to the extent permitted by law, may enter into an agreement or deed with a person who is, or has been, a Director or officer of the Company in relation to the matters above. Such an agreement may include provisions relating to rights of access to the Company's books conferred by the Corporations Act or otherwise by law.

Ownership Restrictions

The acquisition of interests in our Company is regulated by the FATA.

Where a "foreign person" proposes acquiring certain interests in our Company (including Shares), the FATA gives the Treasurer of the Commonwealth of Australia (the "**Treasurer**") power to make a prohibition order or a divestment order in respect of such an acquisition, if as a consequence of that acquisition a single foreign person (alone or together with its associates) would have an interest in 15.0% or more of our Shares, votes or potential votes (including through interests in Shares such as notes and options) of our Company, or a number of foreign persons (alone or together with their respective associates) would have in aggregate an interest in 40.0% or more of our Shares, votes or potential votes of our Company (including through interests in Shares such as notes and options) and the Treasurer considers the proposal to be contrary to Australia's national interest. The FATA requires (with the sanction of penalties) that prior notice of the acquisition be given to the Treasurer by a foreign person (alone or together with its associates) that would have an interest in 15.0% or more of the Shares, votes or potential votes (including through interests in Shares such as notes and options) of our Company. In response to such notice the Treasurer may prohibit the proposal or state that there are no objections to the acquisition (with or without conditions) or a statutory period may expire without the Treasurer responding in which case the Treasurer's power to make orders lapses. The issue of a statement of no objections (with or without conditions) removes the Treasurer's ability to make orders in respect to the proposal.

The requirements and powers under FATA apply equally to acquisitions of interests through issuance or transfer of interests.

Investors requiring further information as to whether notification under FATA to the Treasurer (through the Foreign Investment and Review Board) is required in respect of a proposed investment or further investment in the Company should consult their professional advisor.

Investors that have foreign governments or their agencies in their ownership should also consult their professional adviser to ascertain whether notice under Australia's Foreign Investment Policy is required in addition to notice under FATA.

Minority Rights

The Corporations Act has various provisions allowing for application for a court order for oppressive conduct of a company's affairs, allowing for derivative actions and permitting the inspection of a company's books. A winding up may also be sought on just and equitable grounds.

Dividend Reinvestment Plan / Scrip Dividend Schemes

Our Constitution authorises our Directors, on any terms and at their discretion, to establish a dividend reinvestment plan (under which any member may elect that the dividends payable by us be reinvested by a subscription for securities).

Subject to the rules contained within the Listing Manual, our Company may also adopt a scrip dividend scheme entitling Shareholders to elect to receive Shares in lieu of cash amount in respect of any dividend paid.

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APPENDIX E—LIST OF PRESENT AND PAST DIRECTORSHIPS

The list of present and past principal directorships held by our Directors and Executive Officers in the last five years preceding the Latest Practicable Date is as follows:

DIRECTORS

Name	Present principal directorships	Past principal directorships
Mr. Kenneth Dark	*Group Companies* Linc Energy Ltd *Other Companies* Darton Aberdare Pty Ltd Darton Cessnock Pty Limited Darton International Pty. Ltd. Darton Salt Ash Pty Limited Darton Stanford Merthyr Pty Limited Darton Trucking Pty Limited Darton Weston Pty Limited Ken & Sandy Dark Pty Ltd Ken Dark Merchandising Pty Limited Salt Ash Australia Pty Ltd	*Group Companies* Nil *Other Companies* Darton Shortland Pty Limited
Mr. Peter Bond	*Group Companies* Diasu Holdings, LLC Diasu Oil & Gas, Inc. Linc Alaska Resources, LLC Linc Carbon Solutions Pty Ltd Linc Clean Energy, Inc. Linc Energy (Africa) Ltd Linc Energy (Africa) Pty Ltd Linc Energy (Alaska) Inc. Linc Energy (Europe) Ltd Linc Energy (Wyoming) Inc. Linc Energy Finance (USA) Inc. Linc Energy GP1 Pty Ltd Linc Energy GP2 Pty Ltd Linc Energy Ltd Linc Energy Operations Inc. Linc Energy (Operations) Ltd Linc Energy Operations Pty Ltd Linc Energy Operations (Africa) Proprietary Ltd Linc Energy Petroleum (Wyoming), Inc. Linc Energy Resources, Inc. Linc Gulf Coast Petroleum, Inc. Linc USA GP New Emerald Coal Ltd New Emerald Coal 1 Pty Ltd New Emerald Coal 2 Pty Ltd New Emerald Coal Operations Pty Ltd New Pentland Coal Pty Ltd SAPEX Limited Linc Energy Operations (Singapore) Pte. Ltd. *Other Companies* Auminco Mineral Processing Pty Ltd Bond Bros. Contracting Pty Ltd Bond Resources Pty Ltd	*Group Companies* Linc Energy (Montana) Inc. *Other Companies* Universal Trading Co. Pty Ltd

Name	Present principal directorships	Past principal directorships
	East Coast Tin Pty Ltd	
	Elu-Tech Solutions Pty Ltd	
	European-Australian Business Council Limited	
	Family Islands Group Pty Ltd	
	Family Islands Operations Pty Ltd	
	Hillgrove Investments Pty Ltd	
	ISNY Pty Limited	
	Kinetic Energy Australia Pty Ltd	
	Newtron Pty Ltd	
	Ore Pro Pty Ltd	
	Peter Bond Foundation Pty Ltd	
	Rhino Glass Pty Ltd	
	Rough Diamond Media Pty Ltd	
Mr. Craig Ricato	*Group Companies*	*Group Companies*
	Linc Alaska Resources, LLC	Linc Energy (Montana) Inc.
	Linc Carbon Solutions Pty Ltd	
	Linc Clean Energy, Inc.	
	Linc Energy (Africa) Ltd	
	Linc Energy (Africa) Pty Ltd	
	Linc Energy (Alaska) Inc.	
	Linc Energy (Europe) Ltd	
	Linc Energy (Wyoming) Inc.	
	Linc Energy GP1 Pty Ltd	
	Linc Energy GP2 Pty Ltd	
	Linc Energy Ltd	
	Linc Energy Operations Inc.	
	Linc Energy Operations Ltd	
	Linc Energy Operations Pty Ltd	
	Linc Energy Operations (Africa) Proprietary Ltd	
	Linc Energy Petroleum (Wyoming), Inc.	
	Linc Energy Resources, Inc.	
	Linc Gulf Coast Petroleum, Inc.	
	Linc USA GP	
	New Emerald Coal Ltd	
	New Emerald Coal 1 Ltd	
	New Emerald Coal 2 Ltd	
	New Emerald Coal Operations Pty Ltd	
	New Pentland Coal Pty Ltd	
	SAPEX Limited	
	Other Companies	*Other Companies*
	CWSC Pty Ltd	Everton Park Chipmunks Pty Ltd
	EMS (QLD) Pty Ltd	Springwood Chipmunks Pty Ltd
	Guthrie Entertainment Pty Ltd	
	TSC (QLD) Pty Ltd	
Mr. Lim Ah Doo	*Group Companies*	*Group Companies*
	Linc Energy Ltd	Nil
	Other Companies	*Other Companies*
	ARA-CWT Trust Management (Cache) Limited	BIO* ONE Capital Pte Ltd
	GP Industries Ltd	Chemoil Energy Limited
	Sateri Holdings Limited	EDB Investment Pte Ltd
	Sembcorp Marine Ltd	EDBI Pte Ltd
	SM Investments Corporation	PST Management Pte. Ltd.
	U Mobile Sdn Berhad	PT Indosat Tbk

Name	Present principal directorships	Past principal directorships
Mr. Jon Mathews	*Group Companies* Linc Energy Ltd New Emerald Coal 1 Pty Ltd New Emerald Coal 2 Pty Ltd Linc Energy Ltd	*Group Companies* Nil
	Other Companies Bradford Park Investments Pty. Ltd. Enviro Waste Management Pty. Ltd.	*Other Companies* Enviro Waste Holdings Pty Ltd
Mr. Koh Ban Heng	*Group Companies* Linc Energy Ltd	*Group Companies* Nil
	Other Companies Keppel Infrastructure Holdings Pte. Ltd. Singapore Petroleum Venture Private Limited Singapore Refining Company Private Limited Tipco Asphalt Company PLC Board of Chung Cheng High School Main Board of Chung Cheng High School Yishun Board of Nanyang Junior College	*Other Companies* Keppel Energy Pte. Ltd. Singapore Petroleum Company (Hong Kong) Limited Singapore Petroleum Company Limited Singapore Refining Company Private Limited SPC Shipping Pte. Ltd. (formerly known as "SPC Refining Company Pte. Ltd.")

EXECUTIVE OFFICERS

Executive Officers	Present principal directorships	Past principal directorships
Mr. Peter Bond	*Please see above.*	*Please see above.*
Mr. Stuart Jones	*Group Companies* Nil	*Group Companies* Nil
	Other Companies Port Corporate Advisors Pty Ltd Viking Field Development Solutions Pte Ltd	*Other Companies* Nil
Mr. John D. Anderson	*Group Companies* Nil	*Group Companies* Nil
	Other Companies DOSCO Ltd	*Other Companies* Nil
Mr. Scott Broussard	*Group Companies* Nil	*Group Companies* Nil
	Other Companies Nil	*Other Companies* Probe Resources Ltd.
Mr. Adam Bond	*Group Companies* AFC Energy plc	*Group Companies* Nil
	Other Companies Adam Bond Commercial Advisory Limited Curtin Court Pty. Ltd.	*Other Companies* Nil
Mr. Donald Schofield	*Group Companies* Nil	*Group Companies* Nil
	Other Companies Australian Oceanographics Pty. Ltd.	*Other Companies* Nil

Executive Officers	Present principal directorships	Past principal directorships
Mr. Michael Mapp	*Group Companies* New Emerald Coal Ltd New Emerald Coal 1 Pty Ltd New Emerald Coal 2 Pty Ltd *Other Companies* Grandview Produce Pty. Ltd.	*Group Companies* Nil *Other Companies* Bowen Central Coal Pty Ltd Broadlea Coal Management Pty Ltd Camberwell Coal Pty. Limited Carborough Downs Coal Management Pty Ltd Eagle Downs Coal Management Pty Ltd Ellensfield Coal Management Pty Ltd Glennies Creek Coal Management Pty Ltd Integra Coal Operations Pty Ltd Isaac Plains Coal Management Pty Ltd Maitland Main Collieries Pty Ltd Namoi Coal Pty Ltd Namoi Highwall Pty. Ltd. Namoi Hunter Pty Ltd Nebo Central Coal Pty Ltd NH2 Pty Ltd NSW Coal Resources Pty Ltd QLD Coal Holdings Pty Ltd Queensland Resources Council Ltd Rio Doce Australia Pty Ltd Vale Australia (CQ) Pty Ltd Vale Australia (EF) Pty Ltd Vale Australia (GC) Pty Ltd Vale Australia (IP) Pty Ltd Vale Australia Ellensfield Pty Ltd Vale Australia Holdings Pty Ltd Vale Australia Pty Ltd

Linc Energy Ltd
Financial Report

ABN 60 076 157 045

for the years ended 30 June 2013, 30 June 2012 and 30 June 2011

Linc Energy Ltd ABN 60 076 157 045
Financial Reports - 30 June 2013, 2012 and 2011

This financial report contains the consolidated financial statements for the consolidated entity consisting of Linc Energy Ltd and its subsidiaries (the Group) for the years ended 30 June 2013, 30 June 2012 and 30 June 2011.

The financial report is presented in Australian Dollars.

Linc Energy Ltd is a company limited by shares, incorporated and domiciled in Australia. Its registered office and principal place of business is 32 Edward Street, Brisbane, Qld 4000.

	Notes	2013 $'000	2012 $'000	2011 $'000
Continuing operations				
Revenue	2	124,370	57,060	3,199
Cost of sales	3	(59,381)	(31,680)	(2,992)
Gross profit		64,989	25,380	207
Gain on sale of coal tenement, net of costs	9	-	-	495,001
Gain on purchase of oil and gas assets	13, 29	628	-	6,027
Other income	2	143	1,075	971
Expenses:				
Administration and corporate		(64,410)	(72,902)	(57,550)
Site operating costs		(9,075)	(12,367)	(12,666)
Exploration and evaluation		(3,245)	(3,326)	(2,455)
Technology development		(11,139)	(18,063)	(18,997)
Other expenses		(33,322)	(1,841)	-
Results from operating activities		(55,431)	(82,044)	410,538
Finance income	4	41,446	3,578	22,181
Finance expenses	4	(72,001)	(11,231)	(413)
Net finance (expense) / income		(30,555)	(7,653)	21,768
Profit / (loss) before income tax		(85,986)	(89,697)	432,306
Income tax benefit / (expense)	5	22,161	27,804	(135,865)
Profit / (loss) for the year		(63,825)	(61,893)	296,441
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss:				
Net change in the fair value of available-for-sale financial assets, net of transaction costs, impairment and tax	4	6,596	(7,895)	5,726
Foreign currency translation differences for foreign operations		31,620	(597)	554
Total items that may be reclassified subsequently to profit or loss		38,216	(8,492)	6,280
Other comprehensive income / (loss) for the period, net of tax		38,216	(8,492)	6,280
Total comprehensive income / (loss) for the year		(25,609)	(70,385)	302,721
Profit / (loss) attributable to:				
Owners of Linc Energy Ltd		(63,805)	(61,891)	296.455
Non-controlling interest		(20)	(2)	(14)
Profit / (loss) for the year		(63,825)	(61,893)	296,441
Total comprehensive income / (loss) attributable to				
Owners of Linc Energy Ltd		(26,683)	(70,379)	302,757
Non-controlling interest		1,074	(6)	(36)
Total comprehensive income / (loss) for the year		(25,609)	(70,385)	302,721
Earnings per share attributable to the owners of Linc Energy Ltd:		Cents	Cents	Cents
Basic earnings / (loss) per share	24	(12.40)	(12.18)	59.27
Diluted earnings / (loss) per share	24	(12.40)	(12.18)	57.71

The above consolidated statements of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

	Notes	2013 $'000	2012 $'000	2011 $'000
ASSETS				
Cash and cash equivalents	6	**124,007**	25,680	310,343
Trade and other receivables	7	**50,526**	17,712	2,654
Inventories	8	**2,935**	2,773	936
Other financial assets	15	**958**	-	1,656
Assets held for sale	9	**-**	-	9,032
Other assets	10	**-**	-	14,158
Total current assets		**178,426**	46,165	338,779
Trade and other receivables	7	**28,100**	15,127	5,856
Intangibles	11	**271,294**	248,711	195,108
Property, plant and equipment	12	**17,806**	18,842	12,775
Oil and gas assets	13	**555,538**	384,581	25,288
Available-for-sale investments	14	**16,220**	13,652	23,128
Deferred tax assets	5	**1,077**	701	19
Other financial assets	15	**30**	-	-
Total non-current assets		**890,065**	681,614	262,174
Total assets		**1,068,491**	727,779	600,953
LIABILITIES				
Trade and other payables	16	**94,097**	38,851	14,927
Borrowings	17	**1,632**	185,678	2,786
Current tax liability		**-**	31	10,781
Provisions	18	**8,574**	3,702	2,894
Other financial liability	19	**2,691**	221	-
Total current liabilities		**106,994**	228,483	31,388
Trade and other payables	16	**1,281**	1,174	-
Borrowings	17	**477,423**	1,144	1,866
Deferred tax liability	5	**894**	18,922	48,331
Provisions	18	**37,052**	24,020	5,647
Other financial liability	19	**-**	162	-
Total non-current liabilities		**516,650**	45,422	55,844
Total liabilities		**623,644**	273,905	87,232
Net assets		**444,847**	453,874	513,721
EQUITY				
Share capital	20	**325,388**	310,606	309,493
Reserves	21	**70,459**	31,537	40,377
Retained earnings	23	**38,098**	101,903	163,794
Total equity attributable to owners of the company		**433,945**	444,046	513,664
Non-controlling interest		**10,902**	9,828	57
Total equity		**444,847**	453,874	513,721

The above consolidated statements of financial position should be read in conjunction with the accompanying notes.

in thousands of dollars	Attributable to equity holders of the company								
	Share capital	Foreign currency translation	Available-for sale reserve	Other reserves	Share-based payments	Retained earnings	Total	Non-controlling interest	Total equity
	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
Balance as at 01 July 2010	287,388	(102)	-	5,309	23,655	(83,018)	233,232	93	233,325
Total comprehensive income for the year									
Profit / (loss) for the year	-	-	-	-	-	296,455	296,455	(14)	296,441
Other comprehensive income									
Foreign currency translation differences for foreign operations	-	576	-	-	-	-	576	(22)	554
Net change in fair value of available-for-sale financial assets, net of transaction costs and tax	-	-	5,726	-	-	-	5,726	-	5,726
Total other comprehensive income	-	576	5,726	-	-	-	6,302	(22)	6,280
Total comprehensive income for the year	-	576	5,726	-	-	296,455	302,757	(36)	302,721
Transactions with owners, recorded directly in equity									
Contributions by and distributions to owners									
Contributions of equity, net of transaction costs	4,500	-	-	-	-	-	4,500	-	4,500
Share-based payment expense	-	-	-	-	15,232	-	15,232	-	15,232
Shares issued and transferred from share-based payment reserve on vesting of performance rights	2,574	-	-	-	(2,574)	-	-	-	-
Shares issued and transferred from share-based payment reserve on exercise of options	14,950	-	-	-	(7,445)	-	7,505	-	7,505
Shares issued as compensation for land access	81	-	-	-	-	-	81	-	81
Dividends to equity holders	-	-	-	-	-	(49,643)	(49,643)	-	(49,643)
Total contributions by and distribution to owners	22,105	-	-	-	5,213	(49,643)	(22,325)	-	(22,325)
Balance as at 30 June 2011	**309,493**	**474**	**5,726**	**5,309**	**28,868**	**163,794**	**513,664**	**57**	**513,721**

in thousands of dollars	Share capital $'000	Foreign currency translation $'000	Available-for sale reserve $'000	Other reserves $'000	Share-based payments $'000	Retained earnings $'000	Total $'000	Non-controlling interest $'000	Total equity $'000
	Attributable to equity holders of the company								
Balance as at 01 July 2011	309,493	474	5,726	5,309	28,868	163,794	513,664	57	513,721
Total comprehensive income for the year									
Profit / (loss) for the year	-	-	-	-	-	(61,891)	(61,891)	(2)	(61,893)
Other comprehensive income / (loss)									
Foreign currency translation differences for foreign operations	-	(593)	-	-	-	-	(593)	(4)	(597)
Net change in fair value of available-for-sale financial assets, net of transaction costs and tax	-	-	(7,895)	-	-	-	(7,895)	-	(7,895)
Total other comprehensive income / (loss)	-	(593)	(7,895)	-	-	-	(8,488)	(4)	(8,492)
Total comprehensive income / (loss) for the year	-	(593)	(7,895)	-	-	(61,891)	(70,379)	(6)	(70,385)
Transactions with owners, recorded directly in equity									
Contributions by and distributions to owners									
Share-based payment expense	-	-	-	-	10,721	-	10,721	-	10,721
Shares issued and transferred from share-based payment reserve on vesting of performance rights	9,571	-	-	-	(9,571)	-	-	-	-
Shares issued and transferred from share-based payment reserve on exercise of options	3,635	-	-	-	(1,502)	-	2,133	-	2,133
Shares purchased and cancelled via buy-back	(12,093)	-	-	-	-	-	(12,093)	-	(12,093)
Total contributions by and distribution to owners	1,113	-	-	-	(352)	-	761	-	761
Changes in ownership interests in subsidiaries									
Acquisition of non-controlling interests	-	-	-	-	-	-	-	9,777	9,777
Total transactions with owners	1,113	-	-	-	(352)	-	761	9,777	10,538
Balance as at 30 June 2012	**310,606**	**(119)**	**(2,169)**	**5,309**	**28,516**	**101,903**	**444,046**	**9,828**	**453,874**

in thousands of dollars	Attributable to equity holders of the company: Share capital	Foreign currency translation	Available-for-sale reserve	Other reserves	Share-based payments	Retained earnings	Total	Non-controlling interest	Total equity
	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
Balance as at 01 July 2012	310,606	(119)	(2,169)	5,309	28,516	101,903	444,046	9,828	453,874
Total comprehensive income for the year									
Profit / (loss) for the year	-	-	-	-	-	(63,805)	(63,805)	(20)	(63,825)
Other comprehensive income									
Foreign currency translation differences for foreign operations	-	30,526	-	-	-	-	30,526	1,094	31,620
Impairment of available-for-sale financial assets, net of tax	-	-	4,799	-	-	-	4,799	-	4,799
Net change in fair value of available-for-sale financial assets, net of transaction costs and tax	-	-	1,797	-	-	-	1,797	-	1,797
Total other comprehensive income	-	30,526	6,596	-	-	-	37,122	1,094	38,216
Total comprehensive income for the year	-	30,526	6,596	-	-	(63,805)	(26,683)	1,074	(25,609)
Transactions with owners, recorded directly in equity									
Contributions by and distributions to owners									
Share-based payment expense	-	-	-	-	13,363	-	13,363	-	13,363
Shares issued and transferred from share-based payment reserve on vesting of performance rights	5,226	-	-	-	(9,556)	-	(4,330)	-	(4,330)
Shares issued and transferred from share-based payment reserve on exercise of options	9,556	-	-	-	(1,992)	-	7,564	-	7,564
Cash settled share-based payments transferred from share-based payment reserve on vesting of performance rights	-	-	-	-	(15)	-	(15)	-	(15)
Total contributions by and distribution to owners	14,782	-	-	-	1,800	-	16,582	-	16,582
Changes in ownership interests in subsidiaries									
Total transactions with owners	14,782	-	-	-	1,800	-	16,582	-	16,582
Balance as at 30 June 2013	**325,388**	**30,407**	**4,427**	**5,309**	**30,316**	**38,098**	**433,945**	**10,902**	**444,847**

The above consolidated statements of changes in equity should be read in conjunction with the accompanying notes.

	Notes	2013 $'000	2012 $'000	2011 $'000
Cash flows from operating activities				
Receipts from customers and other debtors (inclusive of goods and services tax)		**121,998**	48,208	3,756
Payments to suppliers and employees (inclusive of goods and services tax)		**(102,612)**	(110,654)	(53,023)
Interest and borrowing costs paid		**(27,421)**	(10,186)	(413)
Receipts from Alaskan tax credits		**3,738**	-	-
Payments for commodity swaps		**(2,341)**	(3,634)	-
Income taxes refunded / (paid)		**987**	(9,651)	(30,802)
Net cash used in operating activities	6	**(5,651)**	(85,917)	(80,482)
Cash flows from investing activities				
Payments for property, plant and equipment		**(1,818)**	(6,716)	(4,192)
Proceeds from disposal of property, plant and equipment		**183**	23	88
Proceeds from sale of coal tenement		**-**	-	500,000
Payments for software		**(1,475)**	(1,929)	(410)
Payments for exploration and evaluation (including tenement acquisitions)		**(22,328)**	(35,169)	(34,041)
Payments for exploration and development of oil and gas assets and CTL assets		**(156,139)**	(32,550)	(8,807)
Payments for equity investments		**-**	(1,804)	(16,894)
Payments for acquisition of oil and gas assets		**(2,977)**	(254,697)	(18,268)
Payment for Umiat acquisition net of cash acquired	13	**-**	(44,660)	-
Loans to related parties	32	**(260)**	(250)	-
Proceeds from repayment of loans to related parties		**12**	-	-
Deposits paid on acquisition in progress		**-**	-	(14,158)
Interest received		**603**	3,623	20,175
Net cash transferred (to) / from term deposits held as security for guarantees and bonds or held as investments		**(12,156)**	(4,862)	(3,150)
Net cash from / (used) in investing activities		**(196,355)**	(378,991)	420,343
Cash flows from financing activities				
Proceeds from the exercise of share options		**3,234**	2,133	7,555
Proceeds from the extinguishment of convertible loan facility		**-**	-	5,018
Proceeds from borrowings		**103,397**	191,433	775
Proceeds from notes issues		**439,060**	-	-
Repayment of borrowings		**(257,047)**	(1,800)	-
Payments associated with financing activities		**(18,390)**	-	-
Repayment of finance lease liabilities		**(713)**	(1,274)	(1,104)
Dividends paid		**-**	-	(49,643)
Payments for share buy-backs net of costs		**-**	(12,093)	-
Net cash from / (used) in financing activities		**269,541**	178,399	(37,399)
Net increase / (decrease) in cash and cash equivalents		**67,535**	(286,509)	302,462
Cash and cash equivalents at 1 July		**25,680**	310,343	7,365
Effect of exchange rate fluctuations on cash held		**30,792**	1,846	516
Cash and cash equivalents at 30 June	6	**124,007**	25,680	310,343

The above consolidated cash flow statements should be read in conjunction with the accompanying notes.

1. Summary of significant accounting policies

The principal accounting policies adopted in the preparation of these consolidated financial statements are set out below. These policies have been consistently applied to all three years presented, unless otherwise stated. Linc Energy Ltd is a company limited by shares, incorporated and domiciled in Australia. Its registered office and principal place of business is 32 Edward Street, Brisbane, Qld 4000. The Group is a for-profit entity and is primarily involved in the exploration for, development and production of conventional oil and gas and coal resources and unconventional syngas through the utilisation of its unique underground coal gasification technology.

(a) Basis of preparation

Statement of Compliance

The consolidated financial statements have been prepared in accordance with Australian Accounting Standards (AASB's) as adopted by the Australian Accounting Standards Board (AASB). The consolidated financial statements comply with International Financial Reporting Standards (IFRS's) as issued by the International Accounting Standards Board (IASB).

The consolidated financial statements were authorised for issue by the Board of Directors on 24 September 2013

Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis, except for the following material items in the statement of financial position:

- Available-for-sale financial assets which are recognised at fair value.
- Oil and gas pipelines which are recognised at fair value on acquisition
- Financial assets which are initially recognised at fair value.
- Financial liabilities which are initially recognised at fair value.
- Derivatives which are recognised at fair value.

Functional and presentation currency

These consolidated financial statements are presented in Australian dollars, which is the Company's functional currency.

Covenant breach and reclassification of non-current liability – 30 June 2012

At 30 June 2012 the Group was technically in breach of the current ratio requirement of the loan covenant in respect of the Gulf Coast Reserve-Based Lending Facility (refer note 17). Under the terms of the credit agreement this technical breach allows the lenders, at their discretion, to declare the loan due and payable immediately. Although the breach was rectified as soon as it was identified and a waiver was subsequently received from the lenders, International Financial Reporting Standards mandate that the loan be classified as a current liability at the reporting date as the Group did not have an unconditional right to defer settlement of the liability for a period of greater than 12 months at the reporting date.

Had this liability not been classified as current, the Liabilities section of the Group's consolidated balance sheet would have looked as set out below:

	2013	2012	2011
	$'000	$'000	$'000
LIABILITIES			
Trade and other payables	**94,097**	38,851	14,927
Borrowings	**1,632**	59,654	2,786
Current tax liability	**8,574**	31	10,781
Provisions	**2,691**	3,702	2,894
Other financial liability	**-**	221	-
Total current liabilities	**106,994**	102, 459	31,388
Trade and other payables	**1,281**	1,174	-
Borrowings	**477,423**	127,168	1,866
Deferred tax liability	**894**	18,922	48,331
Provisions	**37,052**	24,020	5,647
Other financial liability	**-**	162	-
Total non-current liabilities	**516,650**	171,446	55,844
Total liabilities	**623,644**	273,905	87,232

1. Summary of significant accounting policies (continued)

Basis of preparation

The consolidated financial statements have been prepared on the going concern basis which assumes the continuity of normal business activities and the realisation of assets and the settlement of liabilities in the ordinary course of business.

The Directors are confident that there is significant flexibility and levers available to Linc management to ensure that cash balances will be maintained positively for at least 12 months. The flexibility to manage this position could be via one or a combination of the following, if necessary:-

- drawing on existing cash balances,
- partial use of cash flows from the Gulf Coast oil assets,
- ongoing commercial negotiations for the divestment of non-core assets,
- entry into joint venture arrangements for a combination of cash and/or carry of costs
- potential commercial UCG agreements,
- the potential capacity to raise further funds
- the ability of the Group to reduce discretionary project expenditure and overheads

In summary, the Directors are satisfied that the use of the going concern assumption is appropriate in the preparation of the consolidated financial statements at 30 June 2013, 30 June 2012 and 30 June 2011.

Should the above flexibility and levers not be subsequently available to the group, the use of the going concern assumption may not be appropriate, and material adjustments may be necessary to the carrying amount and/or classification of asset or liabilities within this financial report.

Rounding of amounts

Amounts in these consolidated financial statements have been rounded off to the nearest thousand dollars, or in certain cases, the nearest dollar.

Use of estimates and judgements

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimates are revised and in any future periods affected.

Information about critical judgements in applying accounting policies that have the most significant effect on the amounts recognised in the consolidated financial statements is included in the following notes:

- Note 5 - Income tax
- Note 11 – Intangibles, including carrying value of goodwill, coal-to-liquids technology development costs and exploration and evaluation costs
- Note 13 – Oil and gas assets, including classification of assets and recoverability of assets
- Note 17 – Borrowings, determination of fair value of embedded derivatives
- Note 18 – Provisions
- Note 28 – Contingent assets and liabilities

The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in note 1(bb).

Accounting policies

Presentation of transactions recognised in other comprehensive income

The Group has early adopted amendments to AASB 101 *Presentation of Financial Statements* outlined in AASB 2011-9 *Amendments to Australian Accounting Standards - Presentation of Items of Other Comprehensive Income / Amendments to IAS1 Presentation of Items of Other Comprehensive Income* from 1 July 2010. The change in accounting policy only relates to disclosures and has had no impact on consolidated earnings per share or net income. The changes have been applied retrospectively and require the Group to separately present these items of other comprehensive income that may be reclassified to profit or loss in the future from these that will never be reclassified to profit or loss. These changes are included in the statement of comprehensive income.

1. Summary of significant accounting policies (continued)

Basis of consolidation

Business combinations

Business combinations are accounted for using the acquisition method as at the acquisition date, which is the date on which control is transferred to the Group. Control is the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, the Group takes into consideration potential voting rights that currently are exercisable. The acquisition date is the date on which control is transferred to the acquirer. Judgement is applied in determining the acquisition date and determining whether control is transferred from one party to another.

The Group measures goodwill at acquisition date as the fair value of the consideration transferred including the recognised amount of any non-controlling interest in the acquiree, less the net recognised amount (generally fair value) of the identifiable assets acquired and liabilities assumed, all measured as of the acquisition date.

Consideration transferred includes the fair values of the assets transferred, liabilities incurred by the Group to the previous owners of the acquiree, and equity interests issued by the Group. Consideration transferred also includes the fair value of any contingent consideration and share-based payment awards of the acquiree that are replaced mandatorily in the business combination.

The Group recognises a bargain purchase gain in the statement of comprehensive income if the cost of an acquisition is less than the Group's share of the net fair value of the identifiable net assets acquired.

Transaction costs that the Group incurs in connection with a business combination, such as finder's fees, legal fees, due diligence fees, and other professional and consulting fees, are expensed as incurred.

A contingent liability of the acquiree is assumed in a business combination only if such a liability represents a present obligation and arises from a past event, and its fair value can be measured reliably.

Non-controlling interest

Acquisitions of non-controlling interests are accounted for as transactions with owners in their capacity as owners and therefore no goodwill is recognised. The Group measures any non-controlling interest at its proportionate interest in the identifiable net assets of the acquiree.

Subsidiaries

Subsidiaries are entities controlled by the Group. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases. The accounting policies of subsidiaries have been changed when necessary to align them with the policies adopted by the Group.

Transactions eliminated on consolidation

Intra-group balances and transactions, and any unrealised income and expenses arising from intra-group transactions with the exception of unrealised foreign exchange gains or losses on intercompany receivables and payables, are eliminated in preparing the consolidated financial statements.

(b) Revenue recognition

Revenue is measured at the fair value of the consideration received or receivable. Amounts disclosed as revenue are net of returns, trade allowances and amounts collected on behalf of third parties. Revenue is recognised for the major business activities as follows:

Gas sales revenue

The Group has entered into a gas sales contract with its customer containing a take or pay arrangement. Revenue from the sale of gas is recognised when the gas is delivered to the customer. If the contracted minimum volume of gas is not taken, the customer must pay for the minimum contracted volume.

Oil sales revenue

Revenue is recognised when the significant risks and rewards of ownership of the goods have passed to the buyer and can be measured reliably. Risks and rewards are considered passed to the buyer at the time of physical delivery of the goods to the customer. Revenue from oil sales is recognised on the basis of the Group's net interest in a producing field.

Consulting services revenue

Revenue from consulting services is recognised in the accounting period in which the services are rendered. For fixed price contracts, revenue is measured under the percentage of completion method, based on actual milestones met under the contract conditions as a proportion of the total services to be provided.

Rental income

Rental income from the lease of the Group's Coil Tubing Unit drilling rig is recognised in profit or loss on a straight line basis over the term of the lease.

1. Summary of significant accounting policies (continued)

(c) Finance income and finance expenses

Finance income comprises interest income on bank accounts and term deposit and gains on derivative financial instruments. Interest income is recognised as it accrues in profit and loss, using the effective interest method.

Finance expenses comprise of interest expense on borrowings, borrowing costs, losses on derivative financial instruments, impairment losses recognised on available-for-sale investments and unwinding of discounts. All borrowing costs are recognised in profit and loss using the effective interest method.

(d) Income tax

The income tax benefit/expense comprises current and deferred tax. Current and deferred tax is recognised in profit or loss except to the extent that it relates to a business combination, or items recognised directly in equity or in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years. Current tax payable also includes any tax liability arising from the declaration of dividends.

Deferred tax is recognised in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognised for the following temporary differences: the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss, differences relating to investments in subsidiaries and associates and jointly controlled entities to the extent that it is probable that they will not reverse in the foreseeable future and difference arising on the initial recognition of goodwill.

The measurement of deferred tax reflects the tax consequences that would follow the manner in which the Group expects, at the end of the reporting period, to recover or settle the carrying amount of its and assets and liabilities.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted at the reporting date.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realised simultaneously.

A deferred tax asset is recognised for unused tax losses, tax credits and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which they can be utilised. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

Additional income tax expenses that arise from the distribution of cash dividends are recognised at the same time that the liability to pay the related dividend is recognised. The Group does not distribute non-cash assets as dividends to its shareholders.

In determining the amount of current and deferred tax the group takes into account the impact of uncertain tax positions and whether additional taxes and interest may be due. The assessment relies on estimates and assumptions and may involve a series of judgements about future events. New information may become available that causes the Group to change its judgement regarding the adequacy of existing tax liabilities; such changes to tax liabilities will impact tax expense in the period that such a determination is made.

The Company and its wholly owned Australian resident entities are part of a tax consolidated group. As a consequence, all members of the tax consolidated group are treated as a single entity. The head entity within the tax-consolidated group is Linc Energy Ltd.

The Company, in conjunction with other members of the tax-consolidated group, has entered into a tax funding arrangement to set out the funding obligations of members of the tax-consolidated group in respect of tax amounts. The tax funding arrangements require payments to/from the head entity equal to the current tax liability/(asset) assumed by the head entity and any tax-loss deferred tax assets assumed by the head entity , resulting in the Company recognising an inter-entity payable / (receivable) equal in amount to the tax liability / (asset) assumed. The inter-entity payable / (receivable) is at call. Contributions to fund the current tax liabilities are payable as per the tax funding arrangement and reflect the timing of the head entity's obligation to make payment for tax liabilities to the relevant tax authorities.

The Company, in conjunction with other members of the tax-consolidated group, has also entered into a tax sharing agreement. The tax sharing agreement provides for the determination of the allocation of income tax liabilities between the entities should the head entity default on its tax payment obligations. No amounts have been recognised in the financial statements in respect of this agreement as payment of any amounts under the tax sharing agreement is considered remote.

1. Summary of significant accounting policies (continued)

(e) Earnings per share

Basic earnings per share

Basic earnings per share is calculated by dividing the profit attributable to equity holders of the Company by the weighted average number of ordinary shares outstanding during the financial year.

Diluted earnings per share

Diluted earnings per share adjusts the figures used in the determination of basic earnings per share to take into account the after income tax effect of interest and other financing costs associated with dilutive potential ordinary shares and the weighted average number of shares assumed to have been issued for no consideration in relation to dilutive potential ordinary shares.

(f) Cash and cash equivalents

Cash and cash equivalents includes cash on hand, deposits held at call with financial institutions and other short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

(g) Trade and other receivables

Trade and other receivables are recognised initially at fair value and subsequently measured at amortised cost, less provision for doubtful debts. Trade receivables are due for settlement generally within 30-90 day terms.

Collectability of trade receivables is reviewed on an ongoing basis. Debts which are known to be uncollectible are written off. A provision for doubtful receivables is established when there is objective evidence amounts will not be able to be collected according to the original terms of receivables. The amount of the provision is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate. Cash flows relating to short-term receivables are not discounted if the effect of discounting is immaterial. The amount of the provision is recognised in the statement of comprehensive income.

Government grants in relation to capital expenditures and investments are recognised initially as an adjustment to the cost of the assets when there is reasonable assurance that they will be received and that the Group will comply with the conditions associated with the grant.

(h) Inventories

Oil, raw materials and stores

Oil in tanks, raw materials and stores are stated at the lower of cost and net realisable value. The cost of inventories is based on the first-in first-out principle, and includes expenditure incurred in acquiring the inventories, production or conversion costs and other costs incurred in bringing them to their existing location and condition.

Net realisable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and selling expenses.

(i) Assets held for sale

Non-current assets are classified as held for sale if their carrying amount will be recovered principally through a sale transaction rather than through continuing use within the next twelve months. They are measured at the lower of their carrying amount and fair value less costs to sell. These assets are not depreciated but are tested annually for impairment or more frequently if events or changes in circumstances indicate that they might be impaired.

(j) Intangibles

Coal-to-liquids development costs

Costs incurred on coal-to-liquids development projects (relating to the design and testing of the Group's coal-to-liquids technology) are recognised as intangible assets when it is probable that the project will, after considering its commercial and technical feasibility, be completed and generate future economic benefits and its costs can be measured reliably. The expenditure capitalised comprises all directly attributable costs, including costs of materials, services, direct labour and an appropriate proportion of overheads. Other development expenditures that do not meet these criteria are recognised as an expense as incurred. Development costs previously recognised as an expense are not recognised as an asset in a subsequent period. Capitalised development costs are recorded as intangible assets and amortised from the point at which the asset is ready for use on a straight-line basis over its useful life.

The useful life of capitalised coal-to-liquids development costs for the year ended 30 June 2011 was between two and five years with an average of three years remaining on the majority of assets. Following the successful commissioning and operation of Gasifier 5, which is considered to be the basis of Linc's commercial UCG technology, and in conjunction with business development activities including commercial projects, a review of the coal-to-liquids intangible asset resulted in a reassessment of the components of the asset and an extension of their useful lives during the year ended 30 June 2012. The components of the coal-to-liquid intangible asset were been componentised into UCG technology with a 10 year useful life and the GTL technology which will be amortised once ready for use. The effect of this change resulted in a decrease in amortisation expense of $7,000,000 in the consolidated statement of comprehensive income during the year ended 30 June 2012.

1. Summary of significant accounting policies (continued)

(i) Intangibles (continued)

Exploration and evaluation

Exploration and evaluation expenditure incurred is either written off as incurred or accumulated in respect of each identifiable area of interest. Costs are only carried forward to the extent that they are expected to be recouped through the successful development of the area, sale of the respective areas of interest or where activities in the area have not yet reached a stage which permits reasonable assessment of the existence of economically recoverable reserves and the Group continues to hold the rights to the tenement.

Accumulated costs in relation to an abandoned area are written off in full to the statement of comprehensive income in the year in which the decision to abandon the area is made. When production commences, the accumulated costs for the relevant area of interest are tested for impairment and transferred to development costs or to oil and gas properties depending on the nature of the resource and amortised over the life of the area of interest according to the rate of depletion of the economically recoverable reserves.

A regular review is undertaken of each area of interest to determine the appropriateness of continuing to carry forward costs in relation to that area of interest. Restoration, rehabilitation and environmental costs necessitated by exploration and evaluation activities are expensed as incurred and treated as exploration and evaluation expenditure (see note 1(t)).

Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the Group's share of the net identifiable assets of the acquired subsidiary at the date of acquisition. Goodwill on acquisitions of subsidiaries is included in intangible assets. Goodwill is not amortised. Instead, goodwill is tested for impairment annually or more frequently if events or changes in circumstances indicate that it might be impaired and is carried at cost less accumulated impairment losses. Gains and losses on the disposal of an entity include the carrying amount of goodwill relating to the entity sold.

Goodwill is allocated to cash-generating units for the purpose of impairment testing. Each of those cash-generating units represents the Group's investment in each country of operation by each primary reporting segment.

(j) Research and development expenditure

The Group classifies the entire coal-to-liquids demonstration facility (pilot plant) and ongoing technology development at the site as research and development expenditure. Costs incurred in constructing the Group's coal-to-liquids demonstration facility have been capitalised and included within intangibles in the statement of financial position (refer note 1(j)). Costs that do not meet the recognition criteria of an intangible asset have been recognised in the statement of comprehensive income.

(k) Property, plant and equipment

Items of property, plant and equipment are stated at historical cost less accumulated depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items.

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. All other repairs and maintenance are charged to the statement of comprehensive income during the financial period in which they are incurred.

Land is not depreciated. Depreciation on other assets is calculated using the diminishing value method to allocate their cost or re-valued amounts, net of their residual values, over their estimated useful lives, as follows:

Buildings	40 years
Motor vehicles	5 years
Office equipment and furniture	2 to 5 years
Plant and equipment	5 years

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each reporting 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 (note 1(n)). Gains and losses on disposals are determined by comparing proceeds with carrying amount. These are included in the statement of comprehensive income.

1. Summary of significant accounting policies (continued)

(l) Oil and gas assets

Oil and gas assets include the initial cost of acquisition, together with the cost of construction, installation or completion of infrastructure facilities such as pipelines or processing plants, transferred exploration and evaluation costs, and the cost of development wells. 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. All other repairs and maintenance are charged to the statement of comprehensive income during the financial period in which they are incurred.

Oil and gas assets other than land are depreciated to their residual values on a unit of production basis over the economically recoverable proved and probable hydrocarbon reserves.

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each reporting 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 (note 1(n)). Gains and losses on disposals are determined by comparing proceeds with carrying amount. These are included in the statement of comprehensive income.

(m) Impairment of assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortisation but are tested annually for impairment or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets 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 value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). In relation to oil and gas assets, SAPEX, and coal segments, these are all assessed on an area of interest basis. The clean energy segment is assessed on a cash-generating basis. Non-financial assets other than goodwill that have previously suffered impairment are reviewed for possible reversal at each reporting date.

(n) Available-for-sale assets

Available-for-sale financial assets are non-derivative financial assets that are designated as available-for-sale. The Group's investments in equity securities are classified as available-for-sale financial assets and recognised at fair value which is determined by reference to the stock exchange closing share price at reporting date. Subsequent to initial recognition, changes in fair value, other than impairment losses, are recognised in other comprehensive income and presented within equity in the available-for-sale reserve. When an investment is disposed of or impaired, the cumulative gain or loss in equity is transferred to profit and loss.

(o) Trade and other payables

These amounts represent liabilities for goods and services provided to the Group prior to the end of financial year which are unpaid. The amounts are unsecured and are usually paid within 30 days of recognition.

(p) Borrowings

Borrowings are initially recognised at fair value, net of transaction costs incurred. Borrowings are subsequently measured at amortised cost. Any difference between the proceeds (net of transaction costs) and the redemption amount is recognised in the statement of comprehensive income over the period of the borrowings using the effective interest method. Fees paid on the establishment of loan facilities, which are incremental costs relating to the facility, are offset against the liability and amortised on an effective interest basis over the term of the facility.

(q) Compound financial instruments

Compound financial instruments issued by the Group comprise of convertible notes that can be converted to share capital at the option of the holder. The Group can settle the conversion by making a cash payment to the note holder or settle by the issue of shares. The liability component of the note is initially recognised at fair value and subsequently recognised at amortised cost using the effective interest rate method. The embedded derivative component is initially measured at fair value and subsequently measured at fair value through profit or loss at the end of each reporting period. Both the note liability and embedded derivative component are recognised as a part of borrowings in the statement of financial position.

(r) Derivative financial instruments

The Group uses derivative financial instruments to hedge its exposure to commodity price risk and foreign currency risk. The principal derivatives used are commodity oil price swap agreements and put and call options.

The Group records all derivative instruments as either assets or liabilities at fair value. The Group has not elected to designate its derivative instruments in a hedge relationship and, therefore, recognises all changes in fair value of its derivative financial instruments immediately through finance expenses in profit and loss.

1. Summary of significant accounting policies (continued)

(s) Provisions

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events and it is probable that an outflow of resources will be required to settle the obligation and the amount has been reliably estimated. 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.

If the effect is material, provisions are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognised as finance expense.

Site restoration and rehabilitation

In accordance with its environmental obligations the Group recognises a provision for the cost of decommissioning its coal-to-liquids demonstration facility, rehabilitating its exploration drill holes and decommissioning and rehabilitating its oil and gas wells, pipelines and processing infrastructure. A provision for decommissioning and/or restoration and the related expense is recognised when an area is disturbed as a result of the Group's activities. A provision for rehabilitation and the related expense is recognised when a drilling program is completed.

Increases in decommissioning and rehabilitation provisions in respect of oil and gas activities are capitalised to oil & gas assets and amortised using the units of production basis over the economically recoverable reserves in the relevant area.

(t) Leases

Leases in which the Group assumes substantially all the risks and rewards of ownership are classified as finance leases. Finance leases are capitalised at the lease's inception at the lower of the fair value and the present value of the minimum lease payments. The corresponding rental obligations, net of finance charges, are included in borrowings. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to the statement of comprehensive income over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period. The property, plant and equipment acquired under finance leases is depreciated over the shorter of the asset's useful life and the lease term.

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the statement of comprehensive income on a straight-line basis over the period of the lease.

(u) Employee benefits

Share-based payments

Share-based compensation benefits are provided to employees via the Group's Performance Rights Plan and the previous Employee Option Plan. Information relating to these schemes is set out in note 31.

The fair value of rights granted under the Performance Rights Plan and options granted under the Employee Option Plan are recognised as an employee benefit expense with a corresponding increase in equity. The fair value is measured at grant date and recognised over the period during which the employees become unconditionally entitled to the options (the "vesting period").

The fair value at grant date for performance rights is calculated based on the closing share price of Linc Energy Ltd on grant date. The fair value at grant date for options is independently determined using a Black-Scholes option pricing model that takes into account the exercise price, the term of the option, the impact of the dilution, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk free interest rate for the term of the option.

The fair value of the options granted excludes the impact of any non-market vesting conditions, as these are included in assumptions about the number of options that are expected to become exercisable. At each reporting date the entity revises its estimate of the number of options that are expected to become exercisable. The employee benefit expense recognised each period takes into account the most recent estimate.

Wages and salaries, annual leave and sick leave

Liabilities for wages and salaries, including non-monetary benefits, annual leave and accumulating sick leave expected to be settled within twelve months of the reporting date are recognised in other payables or provisions in respect of employees' services up to the reporting date and are measured at the amounts expected to be paid when the liabilities are settled.

1. Summary of significant accounting policies (continued)

(u) Employee benefits (continued)

Retirement benefit obligations

The Group contributes to defined contribution superannuation plans for all employees in accordance with relevant legislation. The Group makes fixed contributions at the current rate of nine per cent of gross salary and the Group's obligations are limited to these contributions. Contributions are recognised as an expense as they become payable.

Long service leave

The liability for long service leave is recognised in the provision for employee benefits and measured as the present value of expected future payments to be made in respect of services provided by employees up to the reporting date using the projected unit credit method. Consideration is given to future expected wage and salary levels, experience of employee departures and periods of service. Expected future payments are discounted using market yields at the reporting date on national government bonds with terms to maturity that match the estimated future cash outflows.

(v) Non-employee share based payments

The Group has granted shares and share options to suppliers as compensation for the provision of services and finance facilities or for access to private property for exploration drilling. Information relating to these grants is set out in note 31. The fair value of options granted to suppliers is recognised as an expense or, where appropriate, is capitalised in accordance with the Group's capitalisation policy with a corresponding increase in equity. The fair value is measured at grant date and recognised over the period during which the services are rendered or when the supplier becomes unconditionally entitled to the options (the "vesting period").

The fair value at grant date is determined using a Black-Scholes option pricing model that takes into account the exercise price, the term of the option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk free interest rate for the term of the option.

(w) Share capital

Ordinary shares are classified as equity. Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction.

When share capital recognised as equity is repurchased, the amount of consideration paid, including directly attributable costs, net of any tax effects is recognised as a deduction in equity.

Dividends are recognised as a liability in the period in which they are declared.

(x) Foreign currency translation

Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transaction. 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 are recognised in the statement of comprehensive income.

Foreign exchange gains and losses that relate to borrowings are presented in the profit or loss within finance costs. All other foreign exchange gains and losses are presented in the profit or loss on a net basis within other income or administration and corporate expenses.

Group companies

The results and financial position of all Group entities that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- Assets and liabilities are translated at the closing rate at the date of the Statement of Financial Position
- Income and expenses are translated at the exchange rate at the date of the transaction (or an average annual rate where not materially different), and
- All resulting exchange differences are recognised as a separate component of equity.

(y) Goods and Services Tax (GST)

Revenues, expenses and assets are recognised net of the amount of associated GST, unless the GST incurred is not recoverable from the taxation authority. In this case it is recognised as part of the cost of acquisition of the asset or as part of the expense.

Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included with other receivables or payables in the balance sheet.

Cash flows are presented on a gross basis. The GST components of cash flows arising from investing or financing activities which are recoverable from, or payable to the taxation authority, are presented as operating cash flows.

1. Summary of significant accounting policies (continued)

(z) Fair value estimation

The fair value of financial assets and financial liabilities must be estimated for recognition and measurement or for disclosure purposes. The fair value of financial instruments traded in active markets (such as available-for-sale securities and financial assets at fair value through profit and loss) is based on quoted market prices at the end of the reporting period. The quoted market price used for financial assets held by the Group is the current bid price, while the current ask price is used for financial liabilities. The nominal value less estimated credit adjustments of trade receivables and payables are assumed to approximate their fair values. Where applicable, information about the assumptions made in determining fair values is disclosed in the notes specific to that assets or liability.

(aa) Critical accounting estimates, judgements and assumptions

Estimates, judgements and assumptions are continually evaluated and are based on historical experience and other factors, including expectations of future events that may have a financial impact on the entity and that are believed to be reasonable under the circumstances. Actual results may differ from those estimates, judgements and assumptions.

The estimates, judgements 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.

Impairment of assets

In the absence of quoted market prices, estimates of the recoverable amounts of assets are based on the present value of future cash flows. For oil and gas assets, expected future cash flows are based on reserves, future production profiles, commodity prices and costs.

Exploration and evaluation

The Group currently capitalises exploration costs. The Group's policy for exploration and evaluation assets is set out in note 1(k) and requires certain estimates and assumptions as to future events and circumstances, particularly in relation to the assessments of whether economic quantities of reserves have been found. Estimates and assumptions may change as new information becomes available. If, after capitalising expenditure, management concludes that it is unlikely to recover expenditure through future exploitation or sale, then the relevant capitalised amount will be written off the statement of comprehensive income.

Income tax – research and development

The Group provides for the amount of tax payable on its estimated assessable income for the year. A significant component in determining the amount payable is the estimate of research and development expenditure deductible in respect of current and prior years.

Oil and gas assets – reserve estimation

The amount of proved and probable reserves is reassessed at each reporting date for the purposes of assessing possible impairment of assets and calculating depletion of acquired oil and gas assets and capitalised exploration, evaluation and development costs. Reserves are determined by independent third party reserve certification consultants and conform to guidelines issued by the Society of Petroleum Engineers. Estimated reserve quantities incorporate assumptions about future development and production costs and expected oil commodity prices. These estimates can change from period to period due to changes in these assumptions and as additional geological data is generated through drilling operations.

Provision for site restoration

The Group has provided for site restoration costs to allow for any necessary decommissioning and rehabilitation work at its coal-to-liquids technology development sites in Chinchilla and Wyoming, in the event of cessation of all activities at these sites. This provision is based on the Directors' best estimate of the costs of this work, which is consistent with estimates submitted to and approved by the relevant regulatory authorities in each jurisdiction.

The Group has also provided for the costs associated with rehabilitating disturbance caused by its exploration drilling in prior years. This provision is based on quotes received from third parties to undertake the required work. The Group has also provided for the costs associated with rehabilitation and decommissioning in respect of its US oil production activities. Increases in the provision are capitalised to Oil & Gas Assets and amortised over the life of the field using the units of production method based on economically recoverable reserves.

Business combinations

Acquired assets and liabilities are initially recognised at fair value. The fair value of acquired oil and gas assets is determined by independent third party reserve certification consultants and incorporates assumptions including the quantity of proved oil reserves, future development costs and expected oil prices.

1. Summary of significant accounting policies (continued)

(bb) Segment reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the CEO, who is the Group's chief operating decision maker.

An operating segment is a component of the Group that engages in business activities from which it may earn revenues and incur expenses, including revenues and expenses that relate to transactions with any of the Group's other components. All operating segments' operating results are regularly reviewed by the Group's CEO to make strategic decisions about resources to be allocated to the segment and assess its performance, and for which discrete financial information is available.

Segment capital expenditure is the total cost incurred during the period to acquire property, plant and equipment, and intangible assets other than goodwill.

(cc) New accounting standards and interpretations not yet adopted

A number of new standards, amendments to standards and interpretations are effective for annual reporting periods beginning on or after 1 July 2012. The amendments to AASB 10 'Presentation of Financial Statements' have been adopted in the current year.

AASB 2011-9 'Amendments to Australian Accounting Standards – Presentation of Items of Other Comprehensive Income' introduces new terminology for the statement of comprehensive income and income statement. Under the adoption of this amendment the statement of comprehensive income has been renamed as a statement of profit and loss and other comprehensive income. The amendment resulted in the grouping of items of other comprehensive income into two categories in the other comprehensive income section: (a) items that will not be reclassified subsequently to profit and loss and (b) items that may be reclassified subsequently to profit and loss when specific conditions are met. The amendments have been applied retrospectively however the nature of the items of other comprehensive income sees them all presented as items that may be classified subsequently to profit and loss and therefore the modification is not significant and does not result in any impact on profit or loss, other comprehensive income and total comprehensive income.

A number of Australia Accounting Standards and Interpretations are in issue but not effective for the current period financial statements. The Group does not plan to adopt any of the standards early. The following standards will be effective for the Group's 30 June 2014 financial statements.

- AASB 10 *Consolidated Financial Statements*;
- AASB 11 *Joint Arrangements*;
- AASB 12 *Disclosure of Interests in Other Entities*;
- AASB 13 *Fair Value Measurement;*
- AASB 127 *Separate Financial Statements;* and
- AASB 128 *Investments in Associates and Joint Ventures*.

It is not anticipated that these standards will have a significant impact on application as the Group currently consolidates all its subsidiaries and has no associates or joint arrangements. The main result of application will be the more extensive disclosures required around interest in subsidiaries and associates under AASB 12 and disclosures around fair value measurement under AASB 13.

AASB 9 *Financial Instruments* becomes mandatory for the Group's 2016 consolidated financial statements and will be adopted for that period. This amendment requires that all recognised financial assets that are within the scope of AASB 139 'Financial Instruments: Recognition and Measurement' to be subsequently measured at amortised cost or fair value.

The Group currently recognises a number of financial assets and liabilities. All of these except for the available-for-sale financial assets are currently recognised at fair value or amortised cost. However, all of the available-for-sale assets are listed equity securities which are currently recognised at their fair value based on the last trading price of the period. Any movement in the fair value of the available-for-sale-assets will be reflected in the profit and loss or other comprehensive income rather than the available-for-sale reserve. The impact of this may be significant depending on the change in value of these assets during future periods.

	2013 $'000	2012 $'000	2011 $'000

2. Revenue and other income

Revenue from continuing operations

	2013 $'000	2012 $'000	2011 $'000
Oil and gas sales revenue - USA	118,259	55,098	1,785
Clean Energy: Syngas sales revenue - Uzbekistan	2,267	1,962	1,414
Clean Energy: Consulting revenue	3,844	-	-
	124,370	57,060	3,199

	2013 $'000	2012 $'000	2011 $'000
Other income includes:			
Lease income	-	152	499
Sundry income	143	923	472
	143	1,075	971

3. Expenses

Profit before income tax includes the following specific expenses:

	2013 $'000	2012 $'000	2011 $'000
Cost of sales			
Oil and gas lease operating expenses	15,511	11,246	-
Other oil and gas production expenses	8	14	2,181
Royalties and production taxes	6,870	3,419	108
Work over expenses	5,884	3,946	373
Depletion and accretion expense of oil & gas assets	29,253	11,087	330
Production costs – Uzbekistan	1,855	1,968	-
Total cost of sales	59,381	31,680	2,992

	2013 $'000	2012 $'000	2011 $'000
Depreciation and amortisation			
Depreciation			
Buildings	12	12	12
Motor vehicles	455	365	198
Office equipment and furniture	1,039	801	262
Plant and equipment	1,328	885	580
Oil and gas field infrastructure, plant and equipment	1,344	1,015	-
Total depreciation	4,178	3,078	1,052
Amortisation			
Coal-to-liquids technology development	1,808	5,885	10,844
Software	475	424	223
Total amortisation	2,283	6,309	11,067
Total depreciation and amortisation	6,461	9,387	12,119

	2013	2012	2011
	$'000	$'000	$'000

3. Expenses (continued)

	2013	2012	2011
Employee benefits expenses			
Salaries and wages	32,016	33,439	20,807
Contributions to defined contribution superannuation plans	2,143	2,288	1,615
Other employee costs	3,329	4,568	519
Increase in provision for employee entitlements	436	532	222
Share-based payments	13,363	10,721	15,232
Total employee benefits expenses	51,287	51,548	38,395
Net foreign exchange (gains)/losses	(8,973)	4,630	7,707
Net loss/(gain) on disposal of non-current assets	196	121	(23)
Research and development expenditure	18,461	24,627	19,618
Other expenses			
Impairment expense – oil and gas assets	16,774	-	-
Impairment expense – available-for-sale assets	6,856	-	-
Impairment expense – other financial assets	-	1,841	-
Coal take-or-pay	9,692	-	-
Total other expenses	33,322	1,841	-

4. Finance income and finance expenses

	2013	2012	2011
Finance income recognised in profit and loss			
Interest income on cash and cash equivalents	632	3,564	22,181
Interest income on loans	44	14	-
Net gain on foreign currency options	958	-	-
Net change in fair value of embedded derivatives from convertible notes at fair value through profit or loss	39,812	-	-
Total finance income	41,446	3,578	22,181
Finance expenses recognised in profit and loss			
Interest and borrowing costs paid or payable	(45,378)	(7,220)	(413)
Net loss on commodity swaps	(4,329)	(4,011)	-
Unwind of discount on notes	(2,202)	-	-
Unrealised foreign exchange loss on convertible notes	(20,092)	-	-
Total finance expenses	(72,001)	(11,231)	(413)
Net finance expenses / (income)	(30,555)	(7,653)	21,768
Recognised in other comprehensive income			
Net change in the fair value of available-for-sale financial assets, net of transaction costs, impairment and tax	6,596	(7,895)	5,726

	2013 $'000	2012 $'000	2011 $'000

5. Income tax

(a) Income tax (benefit) / expense

The major components of income tax (benefit) / expense are:

	2013 $'000	2012 $'000	2011 $'000
Current income tax			
Current income tax charge	(34,379)	(23,790)	41,583
Adjustments in respect of current income tax of previous years	515	(1,772)	-
Deferred income tax			
Relating to origination and reversal of temporary differences	9,646	(2,242)	93,831
Adjustments in respect of deferred tax on previous years	2,057	-	451
Income tax (benefit) / expense reported in the statement of comprehensive income	(22,161)	(27,804)	135,865

(b) Amounts charged or credited directly to equity

Deferred income tax related to items charged / (credited) directly to equity:

	2013 $'000	2012 $'000	2011 $'000
Available-for-sale investment reserve	2,827	3,384	(2,454)
Income tax expense / (credit) reported in equity	2,827	3,384	(2,454)

(c) Numerical reconciliation between aggregate tax expense / (benefit) recognised in the statement of comprehensive income and income tax expense / (benefit) calculated per the statutory income tax rate

A reconciliation between tax expense / (benefit) and the product of accounting profit before income tax multiplied by the Group's applicable income tax rate is as follows:

	2013 $'000	2012 $'000	2011 $'000
Accounting (loss) / profit before tax	(85,986)	(89,697)	432,306
At the parent entity's statutory income tax rate of 30% (2012: 30%) (2011: 30%)	(25,796)	(26,909)	129,692
Amounts not deductible / (taxable) in calculating taxable income:			
Share-based payments (equity settled)	4,009	3,216	4,570
Under/over provision from prior years	4,552	(1,772)	(586)
Research and development	5,538	7,388	(1,471)
Foreign tax rate differential	(1,071)	(225)	(506)
Research and development tax incentive	(7,384)	(9,851)	-
Finance costs	(8,141)	-	-
Other	(1,275)	(7,369)	376
Tax losses (not previously) / not recognised			
Current year	7,407	7,718	4,241
Prior year	-	-	(451)
Income tax (benefit) / expense from continuing operations	(22,161)	(27,804)	135,865

5. Income tax (continued)

	2013 $'000	2012 $'000	2011 $'000
Deferred income tax at 30 June relates to the following:			
(i) Deferred tax assets			
Temporary differences attributable to:			
Share issue expenses	151	302	723
Provisions	1,563	1,542	1,597
Accruals	228	-	-
Property, plant and equipment	9,334	-	-
Borrowing costs	-	16	-
Other	5,733	862	407
Research and development tax offset	22,077	9,851	-
Tax losses	118,994	25,048	-
Total deferred tax assets	158,080	37,620	2,727
Set-off of deferred tax liabilities pursuant to set-off provisions	(157,003)	(36,919)	(2,708)
Net deferred tax assets	1,077	701	19
(ii) Deferred tax liabilities			
Temporary differences attributable to:			
Exploration capitalised	120,938	28,280	48,555
Accrued revenue	1	8	30
Investments	28,310	27,540	-
Finance costs	4,667	-	-
Unrealised foreign exchange	3,959	-	-
Other	22	13	2,454
Total deferred tax liabilities	157,897	55,841	51,039
Set-off of deferred tax liabilities pursuant to set-off provisions	(157,003)	(36,919)	(2,708)
Net deferred tax liabilities	894	18,922	48,331

(d) Tax losses

A deferred tax asset has been recognised in respect of tax losses, tax credits and deductible temporary differences, as it is probable that future taxable profits will be available against which they can be utilised. The deferred tax assets have been offset against the deferred tax liabilities to the extent that they relate to income taxes levied by the same tax authority.

(e) Unrecognised tax losses

At 30 June 2013, we do not recognise US tax losses of USD$13,800,000 (2012: USD$7,000,000) (2011: Nil). In Australia there are no temporary differences that have not been recognised. In particular, there are no unrecognised temporary differences associated with the Group's investments in subsidiaries, associates or joint ventures, as there were no undistributed earnings of Group subsidiaries, associates or joint ventures. (2012: Nil) (2011: Nil).

(f) Franking credits

At 30 June 2013 the Australian tax consolidated group has $18,190,166 (2012: $19,285,449) (2011: $9,526,061) imputation credits available for use in future periods resulting from payments of Australian federal income tax in 2012/13.

6. Cash and cash equivalents

	2013 $'000	2012 $'000	2011 $'000
Cash at bank and on hand	124,007	25,680	310,343
	124,007	25,680	310,343

Reconciliation of profit / (loss) after income tax to net cash outflow from operating activities

	2013 $'000	2012 $'000	2011 $'000
Profit / (loss) for the year	(63,825)	(61,893)	296,441
Finance income	(41,446)	(3,578)	(20,226)
Finance expense	20,229	(912)	413
Net (gain) or loss on sale of assets held for sale	-	-	(495,001)
Net (gain) or loss on settlement of financial instruments	1,988	377	(1,954)
Net (gain) or loss on sale of non-current assets	296	72	(23)
Net (gain) or loss on purchase of oil and gas assets	(628)	-	(6,027)
Net (gain) or loss on foreign exchange	(4,903)	(4,845)	3,312
Depreciation, amortisation, accretion and depletion	36,056	20,474	12,449
Bad debt expense	526	-	-
Non cash employee benefits (share-based payments)	13,348	10,721	15,232
Recognition of deferred tax on items directly in equity	(2,828)	3,384	(2,454)
Fair value loss on financial asset through profit and loss	-	1,841	90
Unrealised foreign exchange loss on convertible notes	20,092	-	-
Impairment on available-for-sale-financial assets	6,856	-	-
Impairment on oil and gas assets	16,774	-	-
Changes in operating assets			
Decrease / (increase) in receivables	(560)	(8,329)	(987)
Decrease / (increase) in prepayments	31	(232)	(640)
Decrease / (increase) in inventories	86	(1,816)	(458)
Increase / (decrease) in trade creditors	10,766	(708)	6,898
Increase / (decrease) in other payables	(434)	(10,474)	13,448
(Decrease) / increase in other provisions	329	91	2,269
(Increase) / decrease in deferred tax assets	(120,460)	(34,211)	99,293
(Decrease) / increase in deferred tax liabilities	102,056	4,121	(2,557)
Net cash outflow from operating activities	(5,651)	(85,917)	(80,482)

Non-cash investing and financing activities

	2013 $'000	2012 $'000	2011 $'000
Acquisition of assets by finance lease	-	950	161
Shares issued in repayment of convertible equity tranches	-	-	4,500
	-	950	4,661

7. Trade and other receivables

	2013 $'000	2012 $'000	2011 $'000
Current			
Trade receivables	**13,583**	13,998	119
Alaskan tax rebate (a)	**32,597**	-	-
Other receivables (b)	**1,817**	1,406	1,399
Prepayments	**717**	876	729
Deposits (c)	**1,812**	1,432	407
Total current trade and other receivables	**50,526**	17,712	2,654
Non-current			
Deposits (d)	**9,934**	9,319	1,442
Term deposits (e)	**17,020**	4,933	3,944
Loans to related parties (f)	**498**	250	-
Other receivable	**648**	625	470
Total non-current trade and other receivables	**28,100**	15,127	5,856

None of the trade and other receivables are impaired or past due but not impaired. Due to the short-term nature of current receivables, their carrying amount is assumed to approximate their fair value. The fair values of non-current receivables are consistent with their carrying amounts. The Group's exposure to risk is discussed in note 26.

(a) During the year ended 30 June 2013, the Company qualified for credits under Alaska Statutes. A receivable is recognised when the amount of the credit is reasonably estimable and receipts is probable. For expenditure and exploration based credits. The credit is recorded as a reduction to the related assets.
(b) Current other receivables are amounts generally arising from Business Activity Statement refunds, accrued interest on deposits and amounts receivable from employees.
(c) Current deposits relate to normal trade deposits for example rental bonds on property leases. Included in current deposits at 30 June 2013 was an amount of $1,812,000 placed in escrow to secure access to equipment required for the upcoming Umiat winter drilling activities. (2012: $1,432,000) (2011: 407,000).
(d) Non-current deposits relate to security held in relation to mining tenements. These deposits are returned on relinquishment of a tenement subject to satisfactory compliance with environmental and other regulatory requirements.
(e) Term deposits are held by banking institutions as security against guarantees and credit card facilities of the Group. These funds are not available for general use as working capital.
(f) Loans made to related parties are detailed in note 32.

8. Inventories

	2013 $'000	2012 $'000	2011 $'000
Raw materials and stores – at cost	**2,935**	2,773	936
	2,935	2,773	936

9. Assets held for sale

	2013 $'000	2012 $'000	2011 $'000
Intangible assets			
Exploration and evaluation – at cost	-	-	9,032
	-	-	9,032

Given the significant increase in development activity at the Teresa mine and the length of time that both the Teresa (Bowen Basin) and Pentland (Galilee Basin) tenements had been classified as 'held for sale' these assets totalling $9,032,000 were reclassified back to Exploration and Evaluation Intangible Assets in 2012.

On 3 August 2010 Linc Energy announced that it had entered into a contract with Adani Mining Pty Ltd ("Adani"), a subsidiary of Adani Enterprises of India, to sell the non-core Galilee coal tenement for $500,000,000. The Company also entered into an agreement with Adani entitling it to receive A$2.00 per tonne, indexed to inflation, for the first 20 years of production from the tenement.

The sale was completed on 10 August 2010 and $500,000,000 was received. No amount has been recognised in the financial statements in respect of the contingent royalty asset (see note 28). The net gain on disposal of the tenement is calculated as follows:

	2013 $'000	2012 $'000	2011 $'000
Proceeds from sale of tenement	-	-	500,000
Less carrying value of Galilee tenement	-	-	(4,831)
Less costs of sale	-	-	(168)
Net gain on disposal of tenement	**-**	**-**	**495,001**

10. Other assets

	2013 $'000	2012 $'000	2011 $'000
Deposits on acquisitions	-	-	14,158

On 6 June 2011, Linc Energy entered into an agreement to acquire oil fields in Texas and Louisiana, USA, from ERG Resources LLC ("ERG"), at a purchase price of USD$236,000,000. The acquisition included 14 Oil fields consisting of 156 leases covering approximately 13,400 acres. A deposit was paid to ERG to the value of USD$10,000,000 ($9,439,000).

On 16 June 2011, Linc Energy entered into an agreement to acquire a controlling interest in the 'Umiat' Oil Field in Alaska, USA, via the purchase of an 84.5% interest in Renaissance Umiat LLC (which owns a 100% working interest and 80% net revenue interest in the Umiat Project) for USD$50,000,000 plus working capital adjustments. A deposit was paid to Renaissance Umiat LLC of USD$5,000,000 ($4,719,000).

11. Intangibles

	Coal-to-liquids technology development (c)	Exploration and evaluation (b)	Software (c)	Goodwill	Technology licences	Total
	$'000	$'000	$'000	$'000	$'000	$'000
Year ended 30 June 2013						
Cost						
Opening balance	85,053	210,349	3,629	1,292	197	300,520
Additions (at cost)	-	19,251	819	-	-	20,070
Disposals	-	-	(710)	-	-	(710)
Exchange rate movements	-	5,470	45	-	-	5,515
Closing balance	85,053	235,070	3,783	1,292	197	325,395
Amortisation and impairment losses						
Opening balance	(50,644)	-	(968)	-	(197)	(51,809)
Amortisation	(1,808)	-	(475)	-	-	(2,283)
Exchange rate movements	-	-	(9)	-	-	(9)
Closing balance	(52,452)	-	(1,452)	-	(197)	(54,101)
Closing net book amount	32,601	235,070	2,331	1,292	-	271,294
Year ended 30 June 2012						
Cost						
Opening balance	79,505	158,339	1,076	1,292	199	240,411
Additions (at cost)	12,609	34,192	2,553	-	-	49,354
Transfer between intangible assets (a)	(7,364)	7,364	-	-	-	-
Transfer from assets classified as held for sale	-	9,032	-	-	-	9,032
Exchange rate movements	303	1,422	-	-	(2)	1,723
Closing balance	85,053	210,349	3,629	1,292	197	300,520
Amortisation and impairment losses						
Opening balance	(44,759)	-	(544)	-	-	(45,303)
Amortisation	(5,885)	-	(424)	-	-	(6,309)
Impairment loss	-	-	-	-	(197)	(197)
Closing balance	(50,644)	-	(968)	-	(197)	(51,809)
Closing net book amount	34,409	210,349	2,661	1,292	-	248,711

11. Intangibles (continued)

	Coal-to-liquids technology development (c)	Exploration and evaluation (b)	Software (c)	Goodwill	Technology licences	Total
	$'000	$'000	$'000	$'000	$'000	$'000
Year ended 30 June 2011						
Cost						
Opening balance	70,026	144,245	636	1,292	-	216,199
Additions (at cost)	9,479	19,981	440	-	199	30,099
Exchange rate movements	-	(5,887)	-	-	-	(5,887)
Closing balance	79,505	158,339	1,076	1,292	199	240,411
Amortisation and impairment losses						
Opening balance	(33,915)	-	(321)	-	-	(34,236)
Amortisation	(10,844)	-	(223)	-	-	(11,067)
Impairment loss	-	-	-	-	-	-
Closing balance	(44,759)	-	(544)	-	-	(45,303)
Closing net book amount	34,746	158,339	532	1,292	199	195,108

(a) During 2012 amounts capitalised in respect of the Gasifier 6 project being constructed in Wyoming were transferred to exploration and evaluation intangible asset.

(b) The recoverability of the carrying amount of the exploration and evaluation assets is dependent on the successful development and commercial exploitation or sale of the respective areas of interest. Costs are transferred to oil and gas assets or to other development assets once oil or coal reserves are certified and the Group commences development of the resource.

(c) Amortisation of the coal-to-liquids technology development and intangible software costs are included within administration and corporate expenses in the statement of comprehensive income.

Impairment tests for goodwill

Goodwill is allocated to the Group's cash-generating units identified according to reportable business segment and region of operation:

	2013	2012	2011
	$000	$000	$000
Asia			
Syngas	**1,292**	1,292	1,292
Total	**1,292**	1,292	1,292

Recoverable amount of Goodwill with an indefinite life

The recoverable amount of Goodwill is determined based on fair value less costs to sell. Fair value is determined as the amount for which the underlying asset (equity securities of JSPC Yerostigaz) could be exchanged between willing parties in an arm's length transaction.

UCG technology and know-how has become increasingly sought after by Governments and corporations around the world during recent years. This is demonstrated by the recent commercial agreement with Exxaro Resources in South Africa of which $3,000,000 has already been received and $20,000,00 is due upon successful completion of the specified conditions and further UCG project opportunities being investigated and planned in the USA, UK, Vietnam, China, India, Canada, Poland, Hungary and Russia. As UCG becomes more accepted as an economically and environmentally viable production process for energy and petroleum products, the value of companies and their personnel with UCG technology and experience is increasing.

The investment in Yerostigaz represents a controlling stake in the only commercially operating UCG business in the world. The controlling stake provides access to a pool of UCG technical specialists and to 50 years of accumulated knowledge and UCG intellectual property of Yerostigaz. It also restricts competitors of the Group from accessing the technology, providing the Group with both a valuable competitive advantage and a valuable product in itself in terms of the ability to generate revenue through consulting and other commercial avenues which further supports a fair value in excess of the carrying value of the goodwill.

The Directors' believe that the recoverable amount of Yerostigaz exceeds the carrying value of goodwill.

12. Property, plant and equipment

	Land and buildings $'000	Motor vehicles $'000	Office equip and furniture $'000	Plant and equipment $'000	Total $'000
Year ended 30 June 2013					
Cost					
Opening balance	4,759	2,892	4,784	11,854	24,289
Additions	-	383	348	886	1,597
Disposals	-	(287)	(298)	(45)	(630)
Exchange rate movements	14	138	390	379	921
Closing balance	4,773	3,126	5,223	13,054	26,176
Accumulated depreciation					
Opening balance	(67)	(1,022)	(1,374)	(2,984)	(5,447)
Depreciation charge	(12)	(455)	(1,039)	(1,328)	(2,834)
Exchange rate movements	-	(21)	(47)	(20)	(88)
Closing balance	(79)	(1,498)	(2,460)	(4,332)	(8,369)
Closing net book amount	4,694	1,628	2,763	8,721	17,806
Year ended 30 June 2012					
Cost					
Opening balance	4,754	1,932	2,441	7,023	16,150
Additions	-	845	2,395	4,845	8,085
Acquisitions	-	106	147	-	253
Disposals	-	-	(172)	-	(172)
Exchange rate movements	5	9	(27)	(14)	(27)
Closing Balance	4,759	2,892	4,784	11,854	24,289
Accumulated depreciation					
Opening balance	(55)	(656)	(632)	(2,032)	(3,375)
Depreciation charge	(12)	(366)	(801)	(885)	(2,064)
Exchange rate movements			59	(67)	(8)
Closing balance	(67)	(1,022)	(1,374)	(2,984)	(5,447)
Closing net book amount	4,692	1,870	3,410	8,870	18,842
Year ended 30 June 2011					
Cost					
Opening balance	4,080	1,416	794	5,432	11,722
Additions	702	557	1,605	1,751	4,615
Acquisitions		26	51	13	90
Disposals		(93)	(5)		(98)
Exchange rate movements	(28)	26	(4)	(173)	(179)
Closing Balance	4,754	1,932	2,441	7,023	16,150
Accumulated depreciation					
Opening balance	(43)	(458)	(370)	(1,452)	(2,323)
Depreciation charge	(12)	(198)	(262)	(580)	(1,052)
Closing balance	(55)	(656)	(632)	(2,032)	(3,375)
Closing net book amount	4,699	1,276	1,809	4,991	12,775

Assets held under finance leases have a net book value of $1,747,000 (2012: $2,352,000) (2011: $2,713,000).

13. Oil and gas assets

	Undeveloped	In development	Producing	Field infrastructure, plant and equipment	Total
	$'000	$'000	$'000	$'000	$'000
Year ended 30 June 2013					
Cost					
Opening balance	67,975	2,973	308,136	17,047	396,131
Additions	9,028	57,186	103,202	-	169,416
Acquisitions	-	-	-	-	-
Transfers	(158)	7,032	(6,874)	-	-
Provision for closure costs	-	-	15,168	-	15,168
Disposals	(9)	-	(3,561)	-	(3,570)
Exchange rate movements	7,637	334	34,650	1,916	44,537
Closing balance	84,473	67,525	450,721	18,963	621,682
Accumulated depreciation, depletion					
Opening balance	-	-	(10,535)	(1,015)	(11,550)
Accumulated depreciation, depletion	-	-	(29,253)	(1,344)	(30,597)
Impairment	-	-	(16,774)	-	(16,774)
Exchange rate movements	-	-	(6,942)	(281)	(7,223)
Closing balance	-	-	(63,504)	(2,640)	(66,144)
Closing net book amount	84,473	67,525	387,217	16,323	555,538
Year ended 30 June 2012					
Cost					
Opening balance	7,768	-	17,520	-	25,288
Additions	1,137	3,974	30,850	-	35,961
Acquisitions	55,560	-	261,132	17,509	334,201
Transfers	-	(1,001)	1,001	-	-
Provision for closure costs	-	-	3,345	-	3,345
Exchange rate movements	3,510	-	(5,712)	(462)	(2,663)
Closing balance	67,975	2,973	308,136	17,047	396,131
Accumulated depreciation, depletion					
Opening balance	-	-	(330)	-	(330)
Accumulated depreciation, depletion	-	-	(10,205)	(1,015)	(11,220)
Closing balance	-	-	(10,535)	(1,015)	(11,550)
Closing net book amount	67,975	2,973	297,601	16,032	384,581

13. Oil and gas assets (continued)

Year ended 30 June 2011	Undeveloped	In development	Producing	Field infrastructure, plant and equipment	Total
	$'000	$'000	$'000	$'000	$'000
Cost					
Opening balance	-	-	-	-	-
Additions	9	-	-	-	9
Acquisitions	8,250	-	16,176	-	24,426
Transfers					
Provision for closure costs	-	-	2,616	-	2,616
Exchange rate movements	(491)	-	(942)	-	(1,433)
Closing balance	7,768	-	17,850	-	25,618
Accumulated depreciation, depletion					
Opening balance	-	-	-	-	-
Accumulated depreciation, depletion	-	-	(330)	-	(330)
Closing balance	-	-	(330)	-	(330)
Closing net book amount	7,768	-	17,520	-	25,288

The ultimate recoupment of costs carried forward for oil & gas assets is dependent on the successful development and commercial exploitation or sale of the respective areas. Undeveloped oil & gas assets represent the costs associated with the Umiat oil field. Oil & gas assets in development represent costs associated with the CO_2 enhanced oil recovery project in Wyoming. All exploration and evaluation costs carried forward in respect of tenements prospective for oil & gas are disclosed separately in note 13. These costs are transferred to oil & gas assets only once proven or probable reserves have been certified.

Gasrock Acquisition

On 18 July 2012 Linc Energy USA Inc. purchased the Gasrock Net Profit Interest (NPI) of 10% in exchange for a 0.5% Over Riding Royalty Interest (ORRI) for $2,977,000 (USD$3,060,000). The net profit interest covers selected leases in the Group's Glenrock field in Wyoming. The net worth of the Gasrock NPI was estimated at $3,605,000 (USD$3,706,000) based on an economic reserve analysis report. As the estimated value of the 10% NPI received was in excess of the cash consideration paid, the difference resulted in a bargain purchase gain of $628,000 (USD$646,000).

Umiat Acquisition (asset acquisition)

On 8 July 2011, Linc Energy acquired a 100% interest in Linc Alaska resources, LLC (formerly Renaissance Alaska, LLC) which holds an 84.5% membership and voting interest in Renaissance Umiat. Total consideration for the acquisition was $52,529,000 (USD$56,416,000) of which $44,660,000 net of cash acquired (USD$47,965,000) was paid during 2012 to complete the acquisition (following working capital adjustments at closing). Renaissance Umiat holds 19,358 undeveloped acres leased in the Umiat Oil Field, which is located in the National Petroleum Reserve, Alaska. Renaissance Umiat owns a 100% working interest and 80% net revenue interest in the Umiat lease position.

The acquisition was treated as an asset acquisition as the acquired entities did not meet the definition of a business as described by the relevant accounting standard (AASB 3 *Business Combinations*). Linc Energy recorded the fair value of the 15.5% non-controlling interest in Renaissance Umiat on the date of close of $9,038,000 (USD$9,707,000).

There are no known contingent assets or liabilities and no further contingent consideration is payable to the seller. The Group does not expect any material changes to the amounts disclosed in the table on the next page.

13. Oil and gas assets (continued)

Assets acquired	Carrying amount	Fair value adjustments	Fair value
	$'000	$'000	$'000
Cash	4,383	-	4,383
Accounts receivable (net of allowance)	261	-	261
Unproved oil and gas properties	55,560	-	55,560
Equipment inventory	954	-	954
Property, plant, and equipment	31	-	31
Bonds	498	-	498
Other assets	41		41
Liabilities (accounts payable)	(161)	-	(161)
Net identifiable assets	61,567		61,567
Purchase consideration paid in cash			(52,529)
Non-controlling interest			(9,038)

14. Available-for-sale investments

	2013	2012	2011
	$'000	$'000	$'000
Listed securities			
Equity securities	16,220	13,652	23,128
	16,220	13,652	23,128

The carrying amount of listed securities is equal to their fair value. The fair value of listed securities has been calculated using prices quoted on the Australian Securities Exchange and AIM London Stock Exchange at balance date or the last trading date during the period. The Group's exposure to risk is discussed in note 26.

At 30 June 2013, two of the listed securities are considered impaired as their fair values have declined significantly below their acquisition cost. An impairment of $6,857,000 was reclassified from equity within the available-for-sale reserve to the statement of profit or loss and other comprehensive income and is included as part of other expenses.

15. Other financial assets

	2013	2012	2011
	$'000	$'000	$'000
Current			
Foreign currency options	958	-	-
Option ot acquire shares (a)	-	-	1,656
	958	-	1,656
Non-current			
Commodity swap contracts (oil hedges)	30	-	-
	30	-	-

(a) On 11 March 2011, Linc Energy announced the purchase of a ten percent interest in Powerhouse Energy Plc for USD$6,000,000. The purchase price also included options to acquire an additional USD$6,000,000 of shares in the future at a discount to the market price. These options were recognised as financial assets and re-valued at each reporting date with gains and losses being recognised in the statement of comprehensive income. At 30 June 2012 the value of the option to acquire additional shares in Powerhouse was written down to nil.

16. Trade and other payables

	2013	2012	2011
	$'000	$'000	$'000
Current			
Trade payables	**82,504**	34,795	13,278
Accrued employee related costs	**142**	121	312
Accrued taxes	**1,577**	2,035	-
Accrued interest payable	**9,455**	-	-
Other payables	**419**	1,900	1,337
	94,097	38,851	14,927
Non-current			
Other payables	**1,281**	1,174	-
	1,281	1,174	-

17. Borrowings

	2013	2012	2011
	$'000	$'000	$'000
Current			
Secured			
Line of credit facility (refer to note A below)	**-**	58,299	-
Reserve based lending facility (refer to note B below)	**-**	126,025	-
Bank loan	**-**	-	1,800
Finance lease liabilities	**537**	1,354	986
Total secured current borrowings	**537**	185,678	2,786
Unsecured			
Credit Suisse option (refer to note E below)	**1,095**	-	-
Total unsecured current borrowings	**1,095**	-	-
Total current borrowings	**1,632**	185,678	2,786
Non-current			
Secured			
Asset based lending facility (refer to note C below)	**37,645**	-	-
Senior secured notes (refer to note D below)	**268,917**	-	-
Finance lease liabilities	**734**	445	1,196
Total secured non-current borrowings	**307,296**	445	1,196
Unsecured			
Convertible notes (refer to note E below)			
- convertible note component	**155,115**	-	-
- embedded derivative component	**14,234**	-	-
Equipment funding loan	**778**	699	670
Total unsecured non-current borrowings	**170,127**	699	670
Total non-current borrowings	**477,423**	1,144	1,866
Total borrowings	**479,055**	186,822	4,652

17. Borrowings (continued)

Terms and debt repayment schedule

Terms and conditions of outstanding liabilities were as follows:

In thousands of dollars	Currency	Cash interest rate at 30 June 2013	Year of maturity	Face value 2013	Carrying amount 2013	Face value 2012	Carrying amount 2012	Face value 2011	Carrying amount 2011
Reserve based lending facility	USD	-	-	-	-	126,025	126,025	-	-
Line of credit facility	AUD	-	-	-	-	58,299	58,299	-	-
Secured finance lease liabilities	AUD	7.01%	2015-2016	792	736	1,205	1,129	2,265	2,050
Secured finance lease liabilities	USD	6.92%	2013-2015	579	535	733	670	151	132
Secured bank loan	AUD	6.4%	2012	-	-	-	-	1,800	1,800
Asset based lending facility	USD	4.25%	2016	38,323	37,645	-	-	-	-
Senior secured notes	USD	12.50%	2017	290,157	268,917	-	-	-	-
Unsecured convertible notes	USD	7.00%	2018	218,986	155,115	-	-	-	-
Credit Suisse option	USD	-	2014	1,095	1,095	-	-	811	670
Convertible notes - embedded derivative component	USD	-	2018	14,234	14,234	-	-	-	-
Equipment funding loan	USD	12.00%	2016	941	778	811	699	-	-
Total interest bearing liabilities				565,107	479,055	187,073	186,822	5,027	4,652

The fair values of current and non-current borrowings approximate their carrying amounts, except for the Senior Secured Notes which had a fair value at 30 June 2013 of $316,996,000 (USD$289,513,000) and the Unsecured Convertible Notes which had a fair value of $177,138,000 (USD$161,780,000). Lease liabilities are finance leases for the purchase of plant, equipment and motor vehicles. The Group's exposure to interest rate risk is discussed in note 26.

A. Line of credit facility

On 6 September 2012, the Group announced it had reached agreement with an affiliate of Fortress Investment Group, LLC to extend the line of credit facility until 24 July 2015. Following receipt of proceeds from the Group's Senior Secured Notes $67,000,000 of the line of credit facility was repaid and the facility limit was reduced to $90,000,000. After further drawings during the period, the balance of the facility was repaid in full upon the receipt of proceeds from the Group's convertible notes in April 2013 and the facility was closed. The agreement with Fortress also granted a warrant allowing them to subscribe for 5,112,991 shares adjusted in accordance with the issued share capital of Linc Energy Ltd at a total cost of $1 at any time until 24 July 2015. The warrant is still available upon closure of the facility and had not been exercised at the end of the reporting period. However, subsequent to the end of the period a settlement was reached to terminate the warrants. Refer to note 35, for further details. Interest was calculated monthly on the drawn amount at a rate of approximately 7 per cent over the 1 month BBSY rate and was payable in arrears. A line fee of 2 per cent per annum was also payable on any undrawn amount of the facility and was calculated monthly in arrears.

The facility contained minimum production covenants. In February 2013 the required minimum production covenant was not met. However, on 8 March 2013 the Group obtained a waiver and was no longer in breach.

A summary of the movements in the facility is below:	2013	2012	2011
	$000	$000	$000
Opening balance at 1 July	58,299	-	-
Proceeds from draw downs	65,000	60,000	-
Repayment of borrowings	(125,000)	-	-
Establishment and extension fees	(2,400)	(3,000)	-
Amortisation of fees	4,101	1,299	-
Carrying amount at 30 June	-	58,299	-

17. Borrowings (continued)

B. Reserve based lending facility

To partially finance the ERG Resources, LLC acquisition and to provide working capital to develop the assets, Linc Gulf Coast Petroleum, Inc. entered into a USD$300,000,000 non-recourse credit agreement with BNP Paribas in 2012. This facility was administrated by Wells Fargo following its purchase from BNP Paribas. The credit facility provided for a maximum borrowing of up to USD$300,000,000, with an initial borrowing base of USD$130,000,000. The credit facility has a five year term and the borrowing base will be re-determined semi-annually. The determination of the borrowing base is made by the lenders, taking into consideration the estimated value of Linc Gulf Coast's oil and gas properties incorporating the level of production and proved reserves. The facility is secured by Linc Gulf Coast Petroleum, Inc. assets which include the Wyoming, Texas, and Louisiana oil and gas assets.

Borrowings under the credit facility currently bear interest at approximately 3.75%, with the rate dependant on a number of factors including borrowing base utilisation. At 30 June 2012 the Group was in breach of one of the financial covenants in respect of the current ratio of the sub-group of entities that comprise the Group's producing US oil & gas assets. Under the terms of the facility agreement, the lenders have the right to declare the outstanding balance of the facility immediately due and payable. However, subsequent to 30 June 2012 the Group received a waiver in respect of the breach and the breach condition was remedied.

Although the breach has been rectified and a waiver received from the lender, accounting standards mandate that the loan be classified as a current liability at the reporting date as the Group did not have an unconditional right to defer repayment of the liability at that date for a period of 12 months.

Debt issuance costs are offset against the borrowing on the statement of financial position and amortised over the period of the borrowings on an effective interest basis.

On 12 October 2012, the Group repaid the outstanding balance of the facility of $126,669,000 (USD$130,000,000) with funds received from the issuance of the Senior Secured Notes. On repayment the facility was cancelled and has been replaced by an asset based lending facility. Refer to note C for further information.

A summary of the movements in the facility is below:

	2013	2012	2011
	$'000	$'000	$'000
Opening balance at 1 July	**126,025**	-	-
Proceeds from draw downs	**-**	131,433	-
Repayment of borrowings	**(126,669)**	-	-
Establishment fee	**-**	(2,323)	-
Amortisation of fees	**1,858**	382	-
Effects of movement in exchange rates	**(1,214)**	(3,467)	-
Carrying amount at 30 June	**-**	126,025	-

C. Asset based lending facility

On 12 October 2012, Linc Energy Resources, Inc (Linc Resources) entered into an asset based lending facility with Wells Fargo. The borrowing base under the facility was originally USD$50,000,000 but was reduced to USD$35,000,000 during the period. Redetermination of the borrowing base occurs semi-annually, on 1 April and 1 October with majority lenders having the right to conduct up to two unscheduled redeterminations. The credit facility matures on 12 October 2016.

Any borrowings under the credit facility are secured by Linc Energy Resources, Inc oil and gas producing properties, personal property and equity interests. Linc Energy Resources, Inc has entered into crude oil hedging transactions with Wells Fargo with their obligations under the hedging contracts secured by this facility.

Interest on the facility is based on the adjusted LIBOR rate for Eurodollar loans plus an additional percentage that can vary on a daily basis and is based on the daily unused portion of the facility. This additional percentage is based on a sliding scale of 2.75% to 3.25%, depending on the borrowing base usage. Additionally, the new credit facility provides for a borrowing base fee of 0.375% to 0.5%, depending on borrowing base usage.

The credit facility contains representations, warranties, covenants and conditions customary for transactions of this type.

Fees of $669,000 (USD$640,000) were incurred in establishing the facility and is recognised as an offset against the outstanding liability in the consolidated statement of financial position. The fees are then being amortised over the term of the facility using the effective interest rate method.

At 30 June 2013, the facility has been fully drawn.

17. Borrowings (continued)

A summary of the movements of the facility is below:

	2013 $'000	2012 $'000	2011 $'000
Proceeds from facility	38,397	-	-
Repayment of borrowings	(5,379)		-
Establishment fees	(669)	-	-
Amortisation of fees	117	-	-
Effects of movements in exchange rates	5,179	-	-
Carrying amount	37,645	-	-

The facility contains financial and operational covenants, one of which is a minimum production covenant. At 30 November 2012 the Group would have been in breach of one of the operational covenants with respect to minimum monthly production for the US oil and gas assets. Under the terms of the facility agreement, the lenders had the right to declare the outstanding balance of the facility immediately due and payable. However, there was no balance on the debt facility and subsequently, on 21 January 2013, the Group entered into an amendment to the facility agreement which modified the terms of the covenant such that the Group was not in breach with the respective operational covenant.

In June 2013, the required minimum production covenant was not met. However, on 28 June 2013, the Group and Wells Fargo entered into a Second Amendment to the Credit Agreement which revised the requirement of the minimum production covenant and a waiver was obtained. With that revision, the Group was no longer in breach of the covenant.

D. Senior Secured Notes

On 12 October 2012, Linc USA GP and Linc Energy Finance (USA), Inc. wholly owned subsidiaries of the parent entity Linc Energy Ltd, issued $258,209,000 (USD$265,000,000) of 12.5% Senior Secured Notes due 31 October 2017. The Notes were issued at 96.402% of their face amount, resulting in net proceeds of $248,918,000 (USD$255,500,000) before discounts and fees. The net proceeds were used to repay $67,000,000 of the line of credit facility and $126,669,000 (USD$130,000,000) to repay the reserve based lending facility. Remaining proceeds will be used to fund capital expenditures and for general corporate purposes.

The interest on the Notes is payable on 30 April and 31 October of each year, beginning on 30 April 2013. The Notes contain covenants, representations and warranties including limitations on distributions to the Group's non US entities.

The Notes are redeemable by the Group at any time on or after 30 April 2015, at the redemption prices set forth in the Notes indenture.

Notes issue fees of $11,812,000 (USD$12,152,000) were paid in cash and are recognised as an offset against the outstanding liability in the consolidated statement of financial position. The discount of $9,285,000 (USD$9,535,000) is also offset against the liability in the statement of financial position. The fees and discount are then amortised over the period of the term of the facility on an effective interest basis.

A summary of the movements of the facility is below:

	2013 $'000	2012 $'000	2011 $'000
Proceeds from notes issue	248,918	-	-
Notes issue fees	(11,812)	-	-
Amortisation of discount	978	-	-
Amortisation of fees	1,250	-	-
Effects of movements in exchange rates	29,583	-	-
Carrying amount	268,917	-	-

17. Borrowings (continued)

E. Convertible Notes

On 10 April 2013, Linc Energy Ltd raised $190,142,000 (USD$200,000,000) through the issue of Unsecured Convertible Notes due 10 April 2018. A portion of the proceeds were used to repay the Fortress Line of Credit Facility.

The Notes are convertible into ordinary shares of Linc Energy Ltd at the election of note holders at any time on or after 21 May 2013 and ten days prior to 10 April 2018 and are non-callable by the Group for a period of two years. From 21 May 2013 to 21 May 2015, Linc can only settle the conversion of the notes by issuing ordinary shares. After 21 May 2015, Linc can settle the conversion of the notes by issuing ordinary shares or making cash payment as prescribed by a predefined formula.

The Notes bear cash interest at 7% per annum, payable semi-annually in arrears on 10 April and 10 October of each year beginning on 10 October 2013.

Linc has also granted Credit Suisse (Hong Kong) Limited an upsize option to purchase up to an additional $54,747,000 (USD$50,000,000) in principal amount of the Notes, on or before 10 May 2014. The option has been valued at inception using a Monte-Carlo valuation tool at a fair value of $6,655,000 (USD$7,000,000) and forms part of current borrowings. The offset has been recognised as a transaction cost and is offset against the convertible note. The option is subsequently re-valued each reporting period to fair value with any change recognised as part of finance income in profit and loss. At 30 June 2013, the options has been valued at $1,095,000 (USD$1,000,000).

Notes issue fees of $12,136,000 (USD$12,757,000) which include the Credit Suisse capitalised fees are recognised as an offset against the outstanding liability in the consolidated statement of financial position. The fees are amortised over the period of the term of the facility on an effective interest basis.

A summary of the movements of the convertibles notes facility is below:

	2013 $'000	2012 $'000	2011 $'000
Proceeds from note issue	190,142	-	-
Notes issue fees	(12,136)	-	-
Recognise embedded derivative	(48,486)	-	-
Unwind of notes	1,856	-	-
Amortisation of fees	3,646	-	-
Difference relating to exchange rate fluctuations	20,093	-	-
Carrying amount	155,115	-	-

The convertible notes can be converted to share capital at the option of the holder and the Group can settle the conversion by making either a cash payment to the note holder or settle by the issue of shares. This is known as an embedded derivative and on inception of the note, a Monte-Carlo valuation was performed to determine the note liability component and embedded derivative component.

The liability component of the note is initially recognised at fair value and subsequently recognised at amortised cost using the effective interest rate method. The embedded derivative component is initially measured at fair value and subsequently measured at fair value through profit or loss at the end of each reporting period.

The embedded derivative component was recognised on inception at a fair value of $48,486,000 (USD$51,000,000) and re-valued at the end of the reporting period to fair value of $14,234,000 (USD$13,000,000) using the Monte-Carlo valuation model. The decrease in fair value of $34,252,000 (USD$38,000,000) has been recognised as part of finance income in profit and loss.

A summary of the movements of the embedded derivative liabilities is below:

	Notes derivative $'000	Credit Suisse option derivative $'000
Embedded derivative recognised on inception	48,486	6,655
Fair value through profit and loss adjustment (excluding tax)	(34,252)	(5,560)
Closing fair value balance	14,234	1,095

17. Borrowings (continued)

Finance lease liabilities

Finance lease liabilities of the Group are payable as follows:

	Future minimum lease payments 2013 $'000	Interest 2013 $'000	Present Value of minimum lease payments 2013 $'000	Future minimum lease payments 2012 $'000	Interest 2012 $'000	Present Value of minimum lease payments 2012 $'000	Future minimum lease payments 2011 $'000	Interest 2011 $'000	Present Value of minimum lease payments 2011 $'000
Less than one year	768	73	695	1,457	102	1,355	1,139	153	986
Between one and five years	604	27	577	481	36	445	1,277	81	1,196
	1,372	100	1,272	1,938	138	1,800	2,416	234	2,182

18. Provisions

	Site rehabilitation - drilling activities	Decommissioning and site restoration	Oil & gas rehabilitation	Employee entitlements	Total
	$'000	$'000	$'000	$'000	$'000
Balance at 1 July 2010	585	1,826	-	1,229	3,640
Provisions utilised during the period	(572)	-	-	-	(572)
Provisions recognised during the period	142	1,786	2,617	928	5,473
Effect of exchange rate movements	-	-	-	-	-
Balance at 30 June 2011	155	3,612	2,617	2,157	8,541
Balance at 1 July 2011	155	3,612	2,617	2,157	8,541
Provisions utilised during the period	(15)	(412)	19,077	-	18,650
Provisions recognised during the period	100	-	(81)	532	551
Provision no longer required	(141)	-	-	-	(141)
Exchange rate movement	1	-	111	9	121
Balance at 1 July 2012	100	3,200	21,724	2,698	27,722
Balance at 1 July 2012	100	3,200	21,724	2,698	27,722
Provisions utilised during the period	-	-	(1,447)	-	(1,447)
Provisions recognised during the period	-	(189)	16,615	436	16,862
Effect of exchange rate movements	-	-	2,441	48	2,489
Balance at 30 June 2013	100	3,011	39,333	3,182	45,626
		-			
Current	100	-	5,853	2,621	8,574
Non-current	-	3,011	33,480	561	37,052

Exploration drilling rehabilitation

The current site rehabilitation provision relates to rehabilitation work at the Group's exploration drilling sites in the Eromanga Basin in North Queensland during the year.

Decommissioning and site restoration

The non-current site restoration provision allows for the decommissioning and restoration of the Group's coal-to-liquids technology development facility at Chinchilla on cessation of all activity at that site.

Oil and gas rehabilitation

The provision relates to the cost of rehabilitating and decommissioning oil field assets and infrastructure such as wells, pipelines and processing facilities.

Employee entitlements

The current employee entitlements provision relates to accrued wages at 30 June 2013 and accrued annual leave and sick leave entitlements. The non-current provision relates to long service leave entitlements.

19. Other financial liabilities

	2013 $'000	2012 $'000	2011 $'000
Current			
Commodity swap contracts (oil hedges)	**2,691**	221	-
Non-current			
Commodity swap contracts (oil hedges)	**-**	162	-
Total other financial liabilities	**2,691**	383	-

20. Share Capital

	2013 Number	2012 Number	2011 Number	2013 $'000	2012 $'000	2011 $'000
Share capital						
Ordinary shares – fully paid	**519,468,416**	509,952,685	506,809,613	**325,388**	310,606	309,493
Movements:						
Ordinary shares						
Opening Balance	**509,952,685**	506,809,613	489,674,970	**310,606**	309,493	287,388
Shares issued on exercise of options (a)	**3,266,797**	3,923,167	10,679,337	**5,226**	3,635	14,950
Shares issued on vesting of performance rights (b)	**6,248,934**	6,304,905	1,997,044	**9,556**	9,571	2,574
Shares issued as compensation for drilling activities (c)	**-**	-	30,000	**-**	-	81
Shares issued in repayment of convertible equity tranches (d)	**-**	-	4,428,262	**-**	-	4,500
Cancellation of shares from share buy-back (e)	**-**	(7,085,000)	-	**-**	(12,093)	-
Closing Balance	**519,468,416**	509,952,685	506,809,613	**325,388**	310,606	309,493

(a) Information relating to the Linc Energy Ltd Employee Option Plan, including details of options issued, exercised and lapsed during the financial year and options outstanding at the end of the financial year, is set out in note 31.

(b) Information relating to the Linc Energy Ltd Performance Rights Plan, including details of rights granted, vested and lapsed during the financial year and rights outstanding at the end of the financial year, is set out in note 31.

(c) In 2011, the Group issued shares to landowners as compensation for drilling activities.

(d) The Group entered into a convertible equity facility during the 2010 year. Under the facility, tranches were drawn down and repaid in shares 31 days later based on the average of the five lowest daily VWAP's during the tranche period. The final tranche was repaid on the 27 July 2010 via the issue of 4,428,262 shares. The facility was terminated in October 2010 with no tranche outstanding.

(e) On 12 September 2011, Linc Energy Ltd announced its intention to conduct an on-market buy-back of up to five per cent of the Company's fully paid ordinary shares as part of its capital management strategy due to the opportunity presented by the Company's share price at the time. The buy-back commenced on 26 September 2011 and concluded on 26 September 2012. 7,085,000 shares were bought back and cancelled during the 2012 financial year for a total consideration of $12,093,000. No further shares were bought back during the 2013 financial year.

Ordinary shares

Ordinary shares entitle the holder to participate in dividends and then proceeds on winding up of the Company in proportion to the number of and amounts paid on the shares held. On a show of hands every holder of ordinary shares present at a meeting in person or by proxy, is entitled to one vote, and upon a poll each share is entitled to one vote. The Company does not have authorised capital and ordinary shares have no par value.

20. Share Capital (continued)

Capital risk management

The Group's objectives when managing its ordinary share capital are to ensure its ability to continue as a going concern and to maintain an optimal capital structure and cost of capital appropriate to the stage of development of the Group's business. The Group is currently seeking to raise additional debt finance and to dispose of part or all of its interests in certain non-core assets to provide for its future funding requirements.

There are no externally imposed capital requirements on Linc Energy Ltd, however the Company's subsidiary located in Uzbekistan, JSPC Yerostigaz is intermittently subject to government mandated recapitalisation programs for foreign controlled companies. Linc Energy fully participates in these recapitalisations to ensure it maintains or increases its ownership interest in the company. There were no recapitalisations this reporting period (2012: Nil) (2011: Nil).

Shares issued on exercise of options

3,266,797 shares were issued during the year as a result of the exercise of options (2012: 3,923,167) (2011: 10,679,337). The total cash received by the Group from the exercise of options was $3,234,316 (2012: $2,133,058) (2011: $7,555,145). Since the end of the financial year no shares have been issued as a result of the exercise of options.

Shares issued on vesting of performance rights

6,248,934 shares were issued during the year as a result of vested performance rights (2012: 6,304,905) (2011: 1,997,044). No consideration was received. Since the end of the financial year 2,825,725 shares have been issued as a result of the vesting of performance rights.

	2013 $'000	2012 $'000	2011 $'000
21. Reserves			
Share-based payments reserve	**30,316**	28,516	28,868
Other reserves	**5,309**	5,309	5,309
Available-for-sale reserve	**4,427**	(2,169)	5,726
Foreign currency translation reserve	**30,407**	(119)	474
	70,459	31,537	40,377

Nature and purpose of reserves

Share-based payments reserve

The share-based payment reserve is used to recognise the fair value of options granted to employees and suppliers. It also recognises the fair value of performance rights issued to employees but not yet vested.

Other reserves

The other reserve represents amounts recognised directly in equity in respect of transactions with other shareholders in Group companies. In 2010, Linc Energy Ltd increased its interest in subsidiary JSPC Yerostigaz from 73% to 91.6% through the purchase of new shares with a total cost of $521,601. The transactions with other shareholders amount in the other reserve balance represents the relative transfer of value to / from the non-controlling interest as a result of the transaction.

The other reserve account also contains the remaining balance transferred from the convertible note reserve following the termination of the convertible note facility and the redemption of all outstanding notes. This amount will remain in other reserves indefinitely.

Available-for-sale reserve

The available-for-sale reserve represents changes in the fair value and exchange differences arising on translation of investments, such as equities, classified as available-for-sale financial assets. The amounts will only be recognised in profit and loss when the associated assets are sold or impaired.

Foreign currency translation

Exchange differences arising on translation of the foreign controlled entity are taken to the foreign currency translation reserve, as described in note 1(x). The reserve is recognised in profit and loss when the net investment is disposed of.

22. Dividends

No dividends were declared or paid in the reporting period. (2012: No dividend declared or paid) (2011: The special dividend was fully franked at a rate of 30% at 10 cents per share. The total amount of $49,642,674 was paid on 8 October 2010. No dividends were paid by the Company in the prior year.)

23. Retained earnings

Movements in retained earnings were as follows:

	2013 $'000	2012 $'000	2011 $'000
Balance at start of the year	101,903	163,794	(83,018)
Dividends paid	-	-	(49,643)
Net profit / (loss) for the year	(63,805)	(61,891)	296,455
Balance at the end of the year	38,098	101,903	163,794

24. Earnings per share

	2013 Cents	2012 Cents	2011 Cents
Basic earnings per share			
Profit (loss) attributable to the ordinary equity holders of the Company	(12.40)	(12.18)	59.27
Diluted earnings per share			
Profit (loss) attributable to the ordinary equity holders of the Company	(12.40)	(12.18)	57.71

	Number	Number	Number
Weighted average number of ordinary shares			
Issued shares at 1 July	509,952,685	506,809,613	489,674,970
Effect of shares issued during the period	4,759,783	1,333,519	10,529,277
Weighted average number of ordinary shares at 30 June	514,712,468	508,143,132	500,204,247
Weighted average number of ordinary shares (diluted)			
Weighted average number of ordinary shares at 30 June	514,712,468	508,143,132	500,204,247
Effect of conversion of share options on issue	-	-	6,127,776
Effect of conversion of share rights on issue	-	-	7,385,508
Weighted average number of ordinary shares (diluted) at 30 June	514,712,468	508,143,132	513,717,531

	2013 $'000	2012 $'000	2011 $'000
Profit / (loss) from continuing operations attributable to ordinary shareholders (basic)	(63,805)	(61,891)	296,455
Profit / (loss) from continuing operations attributable to ordinary shareholders (diluted)	(63,805)	(61,891)	296,455

Impact of transactions subsequent to year end

Subsequent to the end of each financial year, the Company issued 2,825,725 shares (2012: 1,495,966) (2011: 1,678,058) from the vesting of performance rights. The Company also granted a further 510,921 (2012: 1,782,079) (2011: 1,772,821) rights under the Performance Rights Plan to new and existing employees of the Group. These ordinary share transactions and potential ordinary share transactions would have changed the number of ordinary shares and potential ordinary shares outstanding at the end of the financial year if those transactions had occurred before the end of the reporting period each year.

25. Commitments and operating leases

Capital expenditure

Capital commitments of $5,319,000 (2012: $5,728,000) (2011: $15,403,000) are payable within one year of balance date and relate to contractual expenditure for exploration and evaluation or coal-to-liquids technology development committed but not yet incurred. In addition, the Group has certain obligations to conduct exploration activities in its coal and petroleum tenements (see below).

Operating lease commitments as lessee

Lease commitments contracted but not recognised as liabilities are for non-cancellable operating leases of office premises and office equipment. All finance leases have been recognised in both Current and Non-Current Liabilities. Refer to note 16 for further details.

Commitments in relation to operating leases contracted for at the reporting date but not recognised as liabilities payable:

	2013	2012	2011
	$'000	$'000	$'000
Within one year	1,369	1,977	1,918
Later than one year but not later than five years	1,171	3,117	4,504
Later than five years	686	746	-
	3,226	5,840	6,422

The Group leases a number of office premises under operating leases. Leases typically run for between two and six years with an option to renew for a similar term. The leases generally provide for additional rental payments that are based on CPI or market reviews with minimum escalation rates.

Tenement commitments

Tenement commitments relate to the rental and expenditure components of the agreements.

	2013	2012	2011
	$'000	$'000	$'000
Within one year	3,614	4,196	4,492
Later than one year but not later than five years	26,025	24,849	10,189
Later than five years	386	592	296
	30,025	29,637	14,977

Tenement commitments are not contractual obligations and may be subject to negotiation, deferment or modification. Failure to meet tenement activity or spending commitments within permitted timeframes may result in the relinquishment of parts of, or all of, a tenement.

Port commitments

Port commitments that relate to the take or pay arrangement with Gladstone Port Corporation contracted for at the reporting date but not recognised as liabilities and payable:

	2013	2012	2011
	$'000	$'000	$'000
Within one year	14,537	-	-
Later than one year but not later than five years	53,875	-	-
Later than five years	115,447	-	-
	183,859	-	-

26. Financial instruments

Overview

Overall responsibility for financial risk management rests with the Audit and Risk Management Committee of the Board of Directors. This committee has responsibility for ensuring the effectiveness of the organisation's financial risk management system, including the approval of associated policies. The Finance group is responsible for the development of policy and the implementation of practices and processes for the management of financial risk.

Credit risk

Credit risk arises mainly from cash and cash equivalents, deposits with banks and financial institutions and trade and other receivables. This risk is managed by depositing funds with credible and independently rated institutions with a minimum S&P credit rating of AA and maximum thresholds for the proportion of investable funds to be held with any one institution. None of the trade and other receivables or other financial assets are deemed to be impaired.

Exposure to credit risk

The carrying amount of financial assets represents the maximum credit exposure. The maximum exposure to credit risk at the reporting date was:

		Carrying amount		
		2013	2012	2011
	Note	$'000	$'000	$'000
Cash and cash equivalents	6	124,007	25,680	310,343
Trade and other receivables	7	78,626	32,839	8,510
Other financial assets	15	988	-	1,656
		203,621	58,519	320,509

The maximum exposure to credit risk for cash and cash equivalents at the reporting date held by geographic region was:

	Carrying amount		
	2013	2012	2011
	$'000	$'000	$'000
Australia	118,330	18,956	199,815
USA	5,293	6,583	110,236
Europe	348	91	271
Asia	36	50	21
Total cash and cash equivalents	124,007	25,680	310,343

The majority of cash and cash equivalents (2013: $118,314,000) (2012: $18,953,000) (2011: $199,808,000) is being held by two of the Big Four Banks in Australia who have AA credit ratings.

The maximum exposure to credit risk for trade and other receivables at the reporting date held by geographic region was:

		Carrying amount	
	2013	2012	2011
	$'000	$'000	$'000
Australia	19,049	6,038	5,610
USA	58,889	26,420	2,394
Europe	384	239	226
Asia	304	142	280
Total trade and other receivables	78,626	32,839	8,510

Trade and other receivables is predominately comprised of US receivables of $58,900,000 of which $32,597,000 is due from the Alaskan Government for tax credits arising from the winter Umiat drilling program. The remaining balance of US receivables is primarily from oil and gas revenue which is paid in the following month after delivery.

There are no known significant past due or impaired assets as at 30 June 2013 (2012: Nil) (2011: Nil).

26. Financial instruments (continued)

Market risk

Foreign currency risk
Foreign currency risk is associated with international procurement and operational activities. This risk arises when future commercial transactions and recognised assets and liabilities are denominated in a currency that is not the entity's functional currency. The establishment and settlement of foreign exchange transactions require senior finance management approval to minimise exposures to currency fluctuations.

At 30 June 2013 the Group held a material amount of cash and cash equivalents. The distribution of this cash, by currency, is set out in the table below:

	Carrying amount		
	2013	2012	2011
	$'000	$'000	$'000
Australian Dollar	**19,741**	18,956	199,743
US Dollar	**103,877**	6,583	110,310
Pounds Sterling	**314**	84	271
Uzbekistan Soms	**36**	50	19
Polish Zloty	**39**	7	-
Total cash and cash equivalents	**124,007**	25,680	310,343

Following the convertible note issue and repayment of the Fortress Facility, Linc held a balance of approximately USD$111,000,000. On 29 May 2013, Linc Energy entered into a series of hedge contracts to convert a known amount of USD to AUD each month. For each of the months of June 2013 to December 2013, 2 put options were sold and the proceeds were used to buy 1 call option. The combination of the 3 contracts for each month provided a collar structure with a maximum sell conversion price of the USD to AUD whilst still allowing Linc to participate in the reduction of the USD/AUD exchange rate seen in recent months. This structure has allowed Linc to benefit from its known profile of cash requirements in order to give certainty to the exchange rate exposure over the period covered while benefiting from a reduction in the USD/AUD exchange rate.

The Group recognised unrealised gains of $925,000 (2012: Nil) (2011: Nil) in profit and loss.

A portion of the Group's available-for-sale assets are also exposed to foreign currency risk. $14,803,000 (2012: $11,669,000) (2011: $21,000,000) of the balance represents investments in companies listed on the London Stock Exchange AIM which are denominated in Pounds Sterling.

26. Financial instruments (continued)

The Group holds a material amount of borrowings taken out in currency other than functional currency which is subject to foreign currency risk. The convertible notes issued in April 2013 are denominated in USD whereas the functional currency is AUD.

At 30 June 2013, a 10% change in the USD foreign currency rates would have increased/(decreased) the convertible notes, embedded derivatives, foreign currency options and profit and loss by the amounts shown below, assuming all other variables remain constant:

	Profit or loss	
	10%	10%
All amounts in thousands	Increase	Decrease
2013		
Borrowings - convertible note component	15,512	(15,512)
Borrowings - embedded derivatives	1,752	(1,861)
Foreign currency options	5,627	(1,421)
Net sensitivity	22,891	(18,794)
2012		
Borrowings - convertible note component	-	-
Borrowings - embedded derivatives	-	-
Foreign currency options	-	-
Net sensitivity	-	-
2011		
Borrowings - convertible note component	-	-
Borrowings - embedded derivatives	-	-
Foreign currency options	-	-
Net sensitivity	-	-

Movement of a 10% increase / decrease in foreign currency exchange rates would have no impact on equity (2012: Nil) (2011: Nil).

Equity price risk

The Group is exposed to equity securities price risk. This arises from the investments in listed companies held by the Group and classified on the statement of financial position as available-for-sale assets. To manage its price risk arising from investments in equity securities, the Group only invests in equity securities approved by the Board of Directors and where the investment provides a strategic advantage to the Group.

At 30 June 2013 the Group held equity securities in a number of listed companies. Changes in the value of these securities are recognised in the available-for-sale reserve in equity. A 5% increase in the value of the investments would have the effect of increasing the available-for-sale reserve in equity by $353,000 (2012: $478,000) (2011: $1,156,000). A 5% decrease in the value of the investments would have the effect of reducing profit and loss by $64,000 (2012: Nil) (2011: Nil).

Commodity price risk

The Group periodically enters into derivative instruments such as swap agreements in an attempt to moderate the effects of fluctuations in commodity prices on the Group's cash flow and to manage exposure to commodity price risk. The Group's commodity derivative instruments generally serve as effective economic hedges of commodity price exposure; however, the Group has elected not to designate its derivatives as hedging instruments. As such, the Group recognises all changes in fair values of its derivative instruments as unrealised gains or losses in profit and loss.

	2013 Oil (NYMEX WTI)		2012 Oil (NYMEX WTI)	
Commodity swaps	**Barrels**	**Weighted Avg Hedged price per barrel (USD)**	**Barrels**	**Weighted Avg Hedged price per barrel (USD)**
Financial year 2013	-	-	426,588	86.49
Financial year 2014	487,724	88.95	326,724	86.96
Financial year 2015	265,734	86.73	265,734	87.28
Financial year 2016	120,492	87.01	120,492	87.55

The Group did not have any derivative instruments at 30 June 2011.

26. Financial instruments (continued)

The table below summarises the location and fair value amounts of the Group's derivative instruments reported as assets and liabilities in the consolidated statement of financial position.

United States	2013 $'000	2012 $'000	2011 $'000
Current			
Other financial asset	30	-	-
Other financial liability	-	(221)	-
Non-current			
Other financial liability	(2,691)	(162)	-
Total	(2,661)	(383)	-

The Group recognised realised losses of $2,341,000 (USD$2,404,000) (2012: $3,634,0000) (USD$3,751,000) and unrealised losses of $1,988,000 (USD$2,042,000) (2012: $377,000) (USD $389,000) in profit and loss.

Interest rate risk

Interest rate risk occurs with respect to cash and deposits and borrowings to the extent they are subject to movements in floating interest rates. Cash is usually placed on deposit at fixed interest rates for periods of between 30 and 180 days. At 30 June 2013, the majority of cash held by the Group was held at floating interest rates but $10,000,000 was held on a fixed term deposit maturing at 3.92% maturing 8 July 2013. At 30 June 2012 and 2011 the cash held by the Group was held at floating interest rates.

At 30 June 2013, a change in interest rates would have increased/(decreased) financial assets and liabilities and profit and loss by the amounts shown below, assuming all other variables remain constant:

	Profit or loss	
All amounts in thousands	100bp Increase	100bp Decrease
2013		
Financial assets	653	(653)
Financial liabilities	(376)	376
Borrowings - embedded derivatives	876	(766)
Net cash flow sensitivity	1,153	(1,043)
2012		
Financial assets	199	(199)
Financial liabilities	(1,843)	1,843
Borrowings -embedded derivatives	-	-
Net cash flow sensitivity	(1,644)	1,644
2011		
Financial assets	3,103	(3,103)
Financial liabilities	(18)	18
Net cash flow sensitivity	(3,085)	3,085

Movement of 100 basis points would have no impact on equity at 30 June 2013, 30 June 2012 or 30 June 2011.

26. Financial instruments (continued)

Interest rate risk exposure

The following table sets out the Group's exposure to interest rate risk and the effective weighted average interest rates at the end of the reporting period:

	Weighted average effective interest rate	Floating interest rate	Fixed interest rate	Non-interest bearing	Total
	per cent	$'000	$'000	$'000	$'000
2013					
Financial Assets					
Cash and cash equivalents	0.66%	64,093	54,195	5,719	124,007
Trade and other receivables	0.92%	1,191	22,266	55,169	78,626
	0.76%	**65,284**	**76,461**	**60,888**	**202,633**
Financial Liabilities					
Trade and other payables	-	-	-	95,378	95,378
Lease liabilities	6.97%	-	1,272	-	1,272
Unsecured equipment funding loan	12.00%	-	778	-	778
Asset based lending facility	4.25%	37,645	-	-	37,645
Senior secured notes	14.86%	-	268,917	-	268,917
Unsecured convertible notes	13.19%	-	155,115	-	155,115
	11.13%	**37,645**	**426,082**	**95,378**	**559,105**
2012					
Financial Assets					
Cash and cash equivalents	2.93%	18,944	-	6,736	25,680
Trade and other receivables	0.75%	919	9,634	22,286	32,839
	1.71%	**19,863**	**9,634**	**29,022**	**58,519**
Financial Liabilities					
Trade and other payables	-	-	-	40,025	40,025
Lease liabilities	8.17%	-	1,799	-	1,799
Unsecured equipment funding loan	12.00%	-	699	-	699
Reserve based lending facility	3.75%	126,025	-	-	126,025
Line of credit facility	10.64%	58,299	-	-	58,299
	4.92%	**184,324**	**2,498**	**40,025**	**226,847**
2011					
Financial Assets					
Cash and cash equivalents	3.32%	310,343	-	-	310,343
Trade and other receivables	2.53%	-	4,019	4,491	8,510
	3.41%	310,343	4,019	4,491	318,853
Financial Liabilities					
Trade and other payables	-	-	-	14,927	14,927
Lease liabilities	8.97%	-	2,182	-	2,182
Unsecured equipment funding loan	12.00%	-	670	-	670
Reserve based lending facility					
Bank loan	6.4%	1,800	-	-	1,800
Line of credit facility	**-**	**-**	**-**	**-**	**-**
	1.98%	**1,800**	**2,852**	**14,927**	**19,579**

26. Financial instruments (continued)

Liquidity risk

Liquidity risk exists with respect to the ability of the organisation to meet obligations associated with its financial liabilities that are settled by cash. Treasury management including regular monitoring of cash and expenditure levels is undertaken to minimise funding issues.

Maturities of financial liabilities

The tables below analyse the contractual maturities of the Group's financial liabilities (including estimated interest payments) at the reporting date.

	Carrying amount	Contractual cash flows	< 1 year	1 to 2 years	2 to 3 years	> 3 years
	$'000	$'000	$'000	$'000	$'000	$'000
2013						
Trade and other payables	95,378	95,378	94,097	1,281	-	-
Lease liabilities	1,272	1,372	768	599	5	-
Unsecured equipment funding loan	778	941	188	188	188	377
Asset based lending facility	37,645	43,674	1,629	1,629	1,629	38,787
Senior secured note	268,917	453,619	36,270	36,270	36,369	344,710
Convertible note	155,115	295,631[1]	15,329	234,315[2]	15,329	30,658
Other financial liabilities	2,691	2,691	2,691	-	-	-
	561,796	**893,306**	**150,972**	**274,282**	**53,520**	**414,532**
2012						
Trade and other payables	40,025	40,025	38,851	86	98	990
Lease liabilities	1,799	1,938	1,457	481	-	-
Unsecured equipment funding loan	699	860	172	172	172	344
Reserve based lending facility [3]	126,025	143,650	4,799	4,799	4,799	129,253
Line of credit facility	58,299	64,301	64,301	-	-	-
Other financial liabilities	383	383	221	162	-	-
	227,230	**251,157**	**109,801**	**5,700**	**5,069**	**130,587**
2011						
Trade and other payables	14,927	14,927	14,927	-	-	-
Lease liabilities	2,182	2,416	1,139	1,277	-	-
Unsecured equipment funding loan	670	811	122	162	162	365
Reserve based lending facility	-	-	-	-	-	-
Line of credit facility	-	-	-	-	-	-
Other financial liabilities	-	-	-	-	-	-
Secured bank loan	1,800	1,810	1,810	-	-	-
	19,579	**19,964**	**17,998**	**1,439**	**162**	**365**

As disclosed in note 16, the Group has a secured asset-based lending facility which contains a debt covenant. A future breach of covenant may require the Group to repay the loan earlier than indicated in the above table.

[1] The contractual cash flows contain the embedded derivative
[2] From May 2015 the convertible notes can be settled in either cash or shares
[3] At 30 June 2012 as a result of the technical breach of a debt covenant the Reserve based lending facility was reclassified as a current liability – refer note 16 Borrowings for further detail. Had the Group not received a waiver and the lender had declared the debt due and payable immediately then the contractual cash flows would have been limited to the principal amount of $127,965,000 (USD$130,000,000). Interest of $15,685,000 payable over the term of the loan would not be incurred.

26. Financial instruments (continued)

Fair Value Hierarchy

The fair value of financial assets and liabilities approximate their carrying values. The table below analyses financial instruments carried at fair value, by valuation method. The different levels have been defined as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets and liabilities
- Level 2: inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices)
- Level 3: inputs for the asset of liability that are not based on observable market data (unobservable inputs).

In thousands of dollars	Level 1 $000	Level 2 $000	Level 3 $000	Total $000
2013				
Available-for-sale investments	16,220	-	-	16,220
Other financial assets	-	988	-	988
Other financial liabilities	-	(2,691)	-	(2,691)
Borrowings – embedded derivatives	-	-	(15,329)	(15,329)
	16,220	(1,703)	(15,329)	(812)
2012				
Available-for-sale investments	9,231	4,421	-	13,652
Other financial assets	-	-	-	-
Other financial liabilities	-	(383)	-	(383)
Borrowings – embedded derivatives	-	-	-	-
	9,231	4,038	-	13,269
2011				
Available-for-sale investments	23,128	-	-	23,128
Other financial assets	-	-	-	-
Other financial liabilities	-	-	-	-
Borrowings – embedded derivatives	-	-	-	-
	23,128	-	-	23,128

There has been a transfer from Level 2 to Level 1 in the available-for-sale investments in 2013 due to one of the listed investments being suspended from trade at the end of 2012 with the last available share price being used as fair value. At 30 June 2013, all listed investments were actively traded and classified as Level 1.

The Group has embedded derivatives as part of the convertible notes issued in April 2013. In order to determine the fair value of the embedded derivatives, management used a Monte-Carlo valuation model. Key assumptions adopted for the valuation included: a coupon rate of 7%, initial conversion price of $3.40, initial conversion price USD as a fixed ratio of 1.0463 times the AUD conversion price, volatility of Linc assets (USD) at 85%, risk free interest rate (USD) of 0.74%, and share price and foreign exchange spot rate inputs.

The following table shows a reconciliation from the beginning balances to the ending balances for the fair value measurements in Level 3 of the fair value hierarchy:

All amounts in thousands	Notes embedded derivative	Credit Suisse embedded derivatives
2013		
Opening balance	-	-
Balance recognised on inception	48,486	6,655
Total gains recognised in profit and loss	(34,252)	(5,560)
Balance at 30 June 2013	14,234	1,095

27. Operating segments

Reportable segments

The Group's operating segments were restructured in 2012 to provide better strategic focus going forward. This restructure resulted in four reportable segments, each being led by a divisional president.

The Group's has four reportable segments, each being led by a divisional president. The reportable segments are:

- Oil and Gas – exploration, development and production of traditional oil and gas assets in North America.
- Coal – acquisition, exploration and development of the Group's significant coal resources.
- Clean Energy – development and commercialisation of Coal-to-Liquids (CTL) processes through the combined utilisation of Underground Coal Gasification (UCG) and Gas to Liquids (GTL) technologies.
- SAPEX – exploration of the Group's petroleum exploration tenements in South Australia.

The divisional presidents are accountable for their division's financial performance and maintain regular contact with the chief operating decision maker (CODM). The Group's Chief Executive Officer who is the chief operating decision maker reviews internally generated management reports on at least a monthly basis.

Information regarding the results of each reportable segment is included in the table on the following page.

27. Operating segments (continued)

	Oil & Gas			Coal			Clean Energy			SAPEX			Corporate/unallocated			Total		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
	$000	$000	$000	**$000**	$000	$000	**$000**	$000	$000	**$000**	$000	$000	**$000**	$000	$000	**$000**	$000	$000
External revenues	**118,259**	55,098	1,785	**-**	-	-	**6,111**	1,962	1,414	**-**	-	-	**-**	-	-	**124,370**	57,060	3,199
Interest revenue	**14**	-		**-**	-		**-**	-		**10**	-		**652**	3,578	20,208	**676**	3,578	22,181
Interest and borrowing expenses	**(3,821)**	(3,387)	-	**-**	-	-	**-**	-	-	**-**	-	-	**(41,557)**	(3,833)	(386)	**(45,378)**	(7,220)	(413)
Depreciation, amortisation & depletion	**(30,983)**	(11,777)	(356)	**-**	-	-	**(3,049)**	(7,051)	(11,515)	**(2)**	(9)	(12)	**(1,680)**	(1,631)	(566)	**(35,714)**	(20,474)	(12,449)
Reportable segment profit / (loss) before income tax	**20,679**	7,186	3,878	**(13,600)**	-	495,001	**(20,430)**	(24,447)	(26,774)	**(1,485)**	(3)	(7)	**(51,058)**	(72,433)	(39,792)	**(65,894)**	(89,697)	(432,306)
Material items of income or expense:																		
Gain on disposal of coal tenement	**-**	-	-	**-**	-	495,001	**-**	-	-	**-**	-	-	**-**	-	-	**-**	-	495,001
Material non-cash items of income or expense:																		
Bargain purchase gain on acquisition of oil & gas assets	**628**	-	6,027	**-**	-	-	**-**	-	-	**-**	-	-	**-**	-	-	**628**	-	6,027
Share-based payment expense	**-**	-	-	**-**	-	-	**-**	-	-	**-**	-		**(13,363)**	(10,721)	15,232	**(13,363)**	(10,721)	15,232
Impairment expense	**(16,774)**	-	-	**-**	-	-	**-**	-	-	**-**	-	-	**(6,856)**	(1,841)	-	**(23,630)**	(1,841)	-
Reportable segment non-current assets	**563,342**	393,737	26,170	**40,518**	26,934	3,755	**107,883**	92,354	75,344	**135,479**	135,290	121,927	**42,843**	33,299	34,978	**890,065**	681,614	262,174
Total reportable segment assets	**619,980**	413,588	50,812	**41,487**	26,934	12,787	**109,615**	97,753	76,324	**135,516**	135,290	121,927	**164,893**	54,214	339,103	**1,068,491**	727,779	600,953
Goodwill	**-**	-		**-**	-		**1,292**	1,292	1,292	**-**	-	-	**-**	-	-	**1,292**	1,292	1,292
Capex	**169,416**	375,304	26,035	**13,141**	14,147	1,338	**5,518**	23,702	14,189	**399**	13,372	10,834	**563**	5,943	6,843	**189,037**	432,468	59,239

27. Operating segments (continued)

Geographical Segments

The worldwide operations of the Group are managed from the Brisbane head office, but the group's operations are located in four principal locations: Australia, North America, Asia and Europe. In Australia, the Group operates in Queensland and South Australia. In North America the Group operates in Colorado, Wyoming, Montana, Texas and Alaska. In Asia, the operations are at Yerostigaz in Angren, Uzbekistan. In Europe the Group operates from a regional base in London, with subsidiaries established in Poland and Hungary.

In presenting information on the basis of geographical segments, segment revenue is based on the geographical location of customers. Segment assets are based on the geographical location of the assets.

	2013		2012		2011	
	Revenues	Non-Current Assets	Revenues	Non-Current Assets	Revenues	Non-Current Assets
	$'000	$'000	$'000	$'000	$'000	$'000
Australia	-	252,253	-	226,952	-	191,328
USA	118,259	632,816	55,098	450,975	1,785	68,135
Asia	2,459	2,251	1,962	2,364	1,414	2,350
Europe	153	2,745	-	1,323	-	360
South Africa	3,274	-	-	-	-	-
Canada	225	-	-	-	-	-
	124,370	890,065	57,060	681,614	3,199	262,173

In the USA, all oil produced from the Glenrock fields in Wyoming is currently delivered to and sold to a third party refiner. On the Gulf Coast (Texas and Louisiana) oil is sold to two third party refineries. In Asia, all syngas produced at Yerostigaz is currently sold to the Angren power station which is a State-owned utility company.

28. Contingent assets and liabilities

Contingent assets

Adani Royalty

On 3 August 2010, Linc Energy announced that it had entered into a contract with Adani Mining Pty Ltd ("Adani"), a subsidiary of Adani Enterprises of India, to sell the non-core Galilee coal exploration tenement for $500,000,000. As part of this transaction Linc is also entitled to receive $2.00 per tonne, indexed to inflation from the date of sale, for the first 20 years of production from the tenement.

As the receipt of income from the royalty is dependent on future production from a mine in the tenement, it currently does not meet the criteria for recognition as an asset in the financial statements. Given the inherent uncertainty in estimating the ultimate quantum and timing of production from a mine in the tenement, it is not practicable to quantify the present value of the contingent asset.

Contingent liabilities

Acquisition of Powder River Basin coal leases from Gastech Inc.

On 24 December 2009 the Group announced that it had acquired an additional 81,268 acres of Powder River Basin (Wyoming) and Williston Basin (Montana) coal lease tenements from Gastech Inc. and Wold Oil Properties Inc respectively. Gastech Inc. retains a royalty interest in an amount equal to one quarter of the coal production royalties payable to the State of Wyoming under the Wyoming leases, but not greater than 2%. Wold Oil Properties Inc retains a royalty interest of 2% of the market value of the coal mined and sold from the Montana leases.

28. Contingent assets and liabilities (continued)

Acquisition of Alaskan oil and gas leases from GeoPetro Alaska LLC

On 2 March 2010 the Group acquired 123,000 acres of oil & gas leases in the Cook Inlet Basin in Alaska from GeoPetro Alaska LLC. An additional $3,937,000 (USD$4,000,000) will be payable from the proceeds of any successful production from the acquired leases. Following payment GeoPetro will also be entitled to an overriding royalty of between 7 to 10 per cent of the value of commercial production from the leases.

Legal claims and other assets or liabilities

As at 30 June 2013 there was one legal claim pending against the Group in relation to the assets acquired from ERG Resources LLC ("ERG"). ERG alleges certain breaches of the acquisition agreement. Linc Energy has filed a counterclaim. Linc Energy considers that the legal claim will not result in a material liability to the Group.

The directors are not aware of any other contingent assets or liabilities. As at 30 June 2013, the maximum amount quantifiable in relation to litigation and associated legal fees that had not already been provided or accrued for in the financial statements was $Nil (2012: $Nil) (2011: $Nil).

29. Business combinations

Rancher Energy Corp

On 15 March 2011, Linc Energy Petroleum (Wyoming), Inc, a wholly owned subsidiary of Linc Energy Ltd, acquired three producing oil fields along with certain employees and related assets from Rancher Energy Corp, securing immediate oil production. The total consideration for the acquisition was US$18,203,000 ($18,268,000) while the fair value of the net identifiable assets acquired was US$24,208,000 ($24,295,000). This resulted in a bargain purchase gain of US$6,005,461 ($6,027,000). This gain resulted from the fair value of unproved oil & gas properties previously written off by the vendor who was in bankruptcy. The fair value of proved oil & gas properties was based on an independent third party reserve analysis prepared by Ryder Scott Company, while unproved reserves were valued per acre based on comparable transactions in Wyoming in 2011.

2011 Assets acquired	Carrying amount $'000s	Fair value adjustments $'000s	Fair value $'000
Inventory	746	(328)	418
Property, plant and equipment	83	-	83
Oil and gas plant and equipment	13	-	13
Oil and gas assets	15,808	8,618	24,426
Liabilities (Rehabilitation provision, other payables)	(394)	(251)	(645)
Net identifiable assets	16,256	8,039	24,295
Purchase consideration paid in cash			(18,268)
Bargain purchase gain			(6,027)

Had the assets been acquired at 1 July 2010 and held for the full year to 30 June 2011, the estimated impact on the Group's revenue from oil sales would have been an increase of $3,700,000, with a resulting increase in operating profit of $1,400,000. Linc incurred transaction costs of $334,784 which have been recognised in profit and loss in accordance with AASB 3 *Business Combinations*.

ERG Resources LLC

On 11 October 2011, Linc Gulf Coast Petroleum, Inc. a wholly owned subsidiary of Linc Energy USA, acquired thirteen oil and gas fields in Texas and Louisiana along with related assets and certain employees from ERG Resources LLC, securing immediate oil production. The effective date of the purchase was 1 October 2011.

Total consideration for the acquisition was $264,230,000 (USD$261,350,000) of which $254,697,000 (USD$251,920,000) was paid during the current period to complete the acquisition. The fair value of the proved oil and gas properties was based on comparable Gulf Coast transactions and a risk adjusted third party reserve report prepared by Haas Petroleum Engineering Services, Inc. The fair value of the related oil and gas assets such as compression, transportation, and processing facilities was based on a third party valuation analysis prepared by WCG Consulting, LLC.

The Group has accrued $217,954 (USD$221,419) for potential claims associated with unpaid vendors who performed services prior to the acquisition date on behalf of ERG Resources, LLC. While the Group has been indemnified against all such claims and judgments by the seller, it may be required to settle future claims for continued operational purposes. Also, in accordance with the purchase and sale agreement, Linc Gulf Coast Petroleum, Inc. is required to reimburse ERG Resources, LLC for costs related to the Higgins #18 well which was drilled and completed by ERG Resources, LLC prior to the close date on behalf of Linc Gulf Coast Petroleum, Inc. The Group accrued $1,445,383 (USD$1,468,365) for the expected costs at 30 June 2012.

29. Business combinations (continued)

2012 Assets acquired	Carrying amount $'000s	Fair value adjustments $'000s	Fair value $'000
Property, plant and equipment	222	-	222
Oil and gas plant and equipment	17,509	-	17,509
Oil and gas assets (producing)	261,132	-	261,132
Other assets	3,883	-	3,883
Liabilities	(2,443)	-	(2,443)
Asset retirement obligation	(16,073)	-	(16,073)
Net identifiable assets	264,230	-	264,230
Purchase consideration paid in cash		-	(264,230)

Had the assets been acquired at 1 July 2011, the estimated impact on the Group's revenue for 2012 from oil sales would have been an increase of $12,593,238, with a resulting increase in net profit of $9,202,751. Transaction costs of $1,948,924 (USD$2,011,874) were incurred which have been recognised in profit and loss in accordance with AASB 3 *Business Combinations*.

No acquisitions occurred during the year ended 30 June 2013.

30. Subsidiaries

The consolidated financial statements incorporate the assets, liabilities and results of the following subsidiaries:

Entity	Balance Date	Country of incorporation	Class of shares	2013 %	2012 %	2011 %
JSPC Yerostigaz	31 December[1]	Uzbekistan	Ordinary	91.6	91.6	91.6
Better Air LLC	31 December[1]	Uzbekistan	Ordinary	100	100	100
SAPEX Limited	30 June	Australia	Ordinary	100	100	100
Linc Carbon Solutions Pty Ltd	30 June	Australia	Ordinary	100	100	100
Linc Energy Operations Pty Ltd	30 June	Australia	Ordinary	100	100	100
New Emerald Coal Ltd (formerly Teresa Coal Pty Ltd)	30 June	Australia	Ordinary	100	100	100
New Emerald Coal Operations Pty Ltd	30 June	Australia	Ordinary	100	100	-
New Pentland Coal Pty Ltd	30 June	Australia	Ordinary	100	100	-
Linc Energy (Africa) Pty Ltd (formerly Linc Energy Property Pty Ltd)	30 June	Australia	Ordinary	100	100	-
Linc Energy GP1 Pty Ltd	30 June	Australia	Ordinary	100	-	-
Linc Energy GP2 Pty Ltd	30 June	Australia	Ordinary	100	-	-
Linc Energy Operations (Africa) Proprietary Limited	28 Feb	Africa	Ordinary	100	-	-
Linc USA Inc.	30 June	USA	Ordinary	-	100	100
Linc USA GP	30 June	USA	Ordinary	100	-	-
Linc Energy Finance (USA), Inc	30 June	USA	Ordinary	100	-	-
Linc Energy Resources, Inc	30 June	USA	Ordinary	100	100	-
Linc Clean Energy, Inc	30 June	USA	Ordinary	100	100	100
Linc Energy (Wyoming), Inc	30 June	USA	Ordinary	100	100	100
Linc Energy (Montana), Inc	30 June	USA	Ordinary	100	100	100
Linc Energy (Alaska), Inc	30 June	USA	Ordinary	100	100	100
Linc Energy Operations Inc.	30 June	USA	Ordinary	100	100	100
Linc Energy Petroleum (Wyoming), Inc	30 June	USA	Ordinary	100	100	100
Linc Gulf Coast Petroleum, Inc	30 June	USA	Ordinary	100	100	100
Pean Insula, LLC	30 June	USA	Ordinary	100	100	-
Diasu Holdings, LLC	30 June	USA	Ordinary	100	100	-
Diasu Oil & Gas, Inc	30 June	USA	Ordinary	100	100	-
Linc Energy Petroleum Lousiana, LLC	30 June	USA	Ordinary	100	100	-
Linc Energy Lousiana, LLC	30 June	USA	Ordinary	100	100	-
Linc Alaska Resources, LLC (formerly Renaissance Alaska, LLC)#	30 June	USA	Ordinary	100	100	-
Renaissance Umiat, LLC	30 June	USA	Ordinary	84.5	84.5	-
Linc Energy (Europe) Ltd	30 June	United Kingdom	Ordinary	100	100	100
Linc Energy Operations Ltd	30 June	United Kingdom	Ordinary	100	100	100
Linc Energy (Africa) Ltd (formerly Linc Energy (UK) Ltd)	30 June	United Kingdom	Ordinary	100	100	100
Linc Energy (Poland) (sp.z.o.o.)	30 June	Poland	Ordinary	100	100	100
Linc Energy (Asia) Pte Ltd	30 June	Singapore	Ordinary	100	100	100
Linc Energy (Asia) 2 Pte Ltd	30 June	Singapore	Ordinary	100	100	100

[1] Companies incorporated in Uzbekistan must have a balance date of 31 December.
(formerly Renaissance Alaska, LLC)

31. Share-based payments

Employee option plan

The establishment of the Linc Energy Ltd Employee Option Plan was approved by Shareholders at the 2005 Annual General Meeting. This plan was replaced by the Performance Rights Plan with effect from the 2009 Annual General Meeting. However the option plan continues to operate until all outstanding options have vested. Options were granted at the discretion of the Board in accordance with the rules of the plan and all staff employed by the Company or its subsidiaries were eligible to participate in the plan.

As determined by the Board, a minimum continuous period of employment (usually twelve months) with the Company or any of its subsidiaries must be served prior to the first exercise date, which falls on 31st December annually. The option exercise price is set at the discretion of the Board, but is generally the ten day volume weighted average price (VWAP) of Linc Energy Ltd shares traded on the ASX following commencement of employment with the Group. Subject to ongoing employment by the Company or any of its subsidiaries, options are exercisable over three consecutive years from the initial exercise date, with one-third of the total options awarded exercisable each year.

Options granted under the plan carry no dividend or voting rights. When exercisable, each option is convertible into one ordinary share.

The assessed fair value at grant date was independently determined using a Black-Scholes option pricing model that took into account the exercise price, the term of the option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk free interest rate for the term of the option.

No options were granted during the reporting period.

Financial year of grant	Expiry date	Exercise price range	Balance at start of year	Granted	Exercised or transferred	Forfeited[1]	Balance at end of year	Exercisable at end of the year
2013		**$**	**Number**	**Number**	**Number**	**Number**	**Number**	**Number**
30 Jun 2010	31 Dec 14	1.45 to 1.79	2,672,164	-	(163,333)	(1,935,500)	573,331	573,331
30 Jun 2009	31 Dec 14	0.59 to 3.16	3,564,662	-	(777,133)	(1,668,335)	1,119,194	1,119,194
30 Jun 2008	31 Dec 13	0.60 to 2.55	2,663,331	-	(2,046,333)	(129,999)	486,999	486,999
30 Jun 2007	31 Dec 12	0.25 to 0.60	279,998	-	(279,998)	-	-	-
Total			**9,180,155**	**-**	**(3,266,797)**	**(3,733,834)**	**2,179,524**	**2,179,524**
Weighted average exercise price $			1.52	0.00	0.99	1.79	1.86	1.86

[1]Forfeited includes options that have lapsed or cancelled due to termination

Financial year of grant	Expiry date	Exercise price range	Balance at start of year	Granted	Exercised or transferred	Forfeited[1]	Balance at end of year	Exercisable at end of the year
2012		**$**	**Number**	**Number**	**Number**	**Number**	**Number**	**Number**
30 Jun 2010	31 Dec 14	1.45 to 1.79	6,540,497	-	(205,000)	(3,663,333)	2,672,164	1,625,501
30 Jun 2009	31 Dec 14	0.59 to 3.16	8,267,999	-	(255,000)	(4,448,337)	3,564,662	3,385,996
30 Jun 2008	31 Dec 13	0.60 to 2.55	3,803,333	-	(1,133,334)	(6,668)	2,663,331	2,663,331
30 Jun 2007	31 Dec 12	0.25 to 0.60	2,609,831	-	(2,329,833)	-	279,998	279,998
Total			**21,221,660**	**-**	**(3,923,167)**	**(8,118,338)**	**9,180,155**	**7,954,826**
Weighted average exercise price $			1.66	0.00	0.53	2.35	1.53	1.53

[1]Forfeited includes options that have lapsed or cancelled due to termination.

31. Share-based payments (continued)

Financial year of grant	Expiry date	Exercise price range	Balance at start of year	Granted	Exercised or transferred	Forfeited[1]	Balance at end of year	Exercisable at end of the year
2011		**$**	**Number**	**Number**	**Number**	**Number**	**Number**	**Number**
30 Jun 2011	27 May 13	0.25	-	500,000	(500,000)	-	-	-
30 Jun 2010	31 Dec 15	0.66 to 1.95	8,348,365	-	(1,056,171)	(751,697)	6,540,497	3,873,836
30 Jun 2009	31 Dec 14	0.25 to 3.16	11,514,668	-	(1,948,336)	(1,298,333)	8,267,999	5,960,674
30 Jun 2008	31 Dec 13	0.60 to 2.55	6,601,666	-	(2,771,667)	(26,666)	3,803,333	3,150,001
30 Jun 2007	31 Dec 12	0.25 to 0.60	7,012,996	-	(4,403,163)	(2)	2,609,831	2,609,831
Total			**33,477,695**	**500,000**	**(10,679,337)**	**(2,076,698)**	**21,221,660**	**15,594,342**
Weighted average exercise price $			0.96	0.25	0.69	1.89	1.66	1.62

[1]Forfeited includes options that have lapsed or cancelled due to termination.

During 2013 3,266,797 (2012: 3,923,167) (2011: 10,679,337) options were exercised. The weighted average share price at the dates of exercise was $0.99 (2012: $0.53) (2011: $0.69).

On 6 September 2012, FCCD (Australia) Pty Limited were granted 5,112,991 warrants as part of changes to the terms of the Fortress Line of Credit Facility. The fair value of the warrants on this day, totalling $3,016,663.69, has been recognised as an expense.

During the year ended 30 June 2011, in addition to options granted to employees under the Employee Option Plan, the following share based payment transactions occurred during the reporting period:

Shares issued as compensation for drilling activities

The Group negotiates access to landholders' property in accordance with government guidelines on the payment of compensation to land owners for disturbance. Linc Energy offers land owners a choice as to how they receive their compensation - either $1,000 cash or Linc Energy shares to the value of $2,000. The number of shares issued is based on the market price on the date of completion of drilling. 30,000 (2010: 2,063) shares with a fair value of $81,000 (2010: $4,000) were issued to landowners during the year.

Performance Rights Plan

The establishment of the Linc Energy Employee Performance Rights Plan was approved by Shareholders at the 2009 Annual General Meeting. Under the Plan, the Board may from time to time invite a full time employee or executive director of the Company or any wholly owned subsidiary or controlled entity of the Company whom the Board decides in its absolute discretion is eligible to be invited to receive a grant of Rights in the Plan, to participate in the Plan and grant the eligible employee a right to acquire fully paid ordinary shares in the Company on conversion of the right as part of the eligible employee's remuneration.

Rights typically vest in either three or four equal tranches over a period of three and half to four and half years with the first tranche vesting twelve months from the successful completion of an employee's six month probation period. The number of Rights granted to an employee is determined at the discretion of the Board and is generally based on a formula taking into account an employee's base salary and the Company's share price at the time of grant. Rights are granted to employees at no cost but may include non-market-based performance conditions. Rights automatically convert to shares on the vesting dates provided all vesting conditions have been met.

The fair value of the rights is determined based on Linc's closing share price at the date of grant.

Rights granted under the plan carry no dividend or voting rights until they convert to ordinary shares. 9,123,603 Performance Rights were granted during the period (2012: 6,543,756) (2011: 13,790,899).

Share rights were issued to a fixed term contractor during the financial year, with the option to be settled via equity or cash, dependent upon the employment status at the time of vesting. The first tranche vested during the period and were cash settled due to the individual's employment status remaining as a contractor. The employment status has now changed to permanent employee and the remaining two tranches will be equity settled.

31. Share-based payments (continued)

Performance rights granted
Set out below is a summary of performance rights granted during the year:

Financial year of grant	Financial year of vesting date	Balance at start of year	Granted	Vested and converted into equity	Vested and paid in cash	Forfeited[1]	Balance at end of year
		Number	Number	Number	Number	Number	Number
2013							
30 June 2013	30 June 2013	-	1,130,936	(1,095,010)	(8,392)	-	27,534
	30 June 2014	-	2,207,659	-	-	(33,308)	2,174,351
	30 June 2015	-	1,885,063	-	-	(37,740)	1,847,323
	30 June 2016	-	1,709,495	-	-	(37,740)	1,671,755
	30 June 2017	-	1,462,809	-	-	(37,740)	1,425,069
	30 June 2018	-	717,404	-	-	(4,432)	712,972
30 June 2012	30 June 2012	50,000	-	(50,000)	-	-	-
	30 June 2013	989,561	10,237	(744,009)	-	(128,812)	126,977
	30 June 2014	1,458,225	-	(6,757)	-	(237,786)	1,213,682
	30 June 2015	1,108,216	-	(6,756)	-	(237,780)	863,680
	30 June 2016	828,040	-	-	-	(139,319)	688,721
	30 June 2017	374,459	-	-	-	(106,355)	268,104
30 Jun 2011	30 June 2012	100,000	-	(100,000)	-	-	-
	30 June 2013	3,008,140	-	(2,791,617)	-	(112,582)	103,941
	30 June 2014	1,741,066	-	-	-	(153,196)	1,587,870
	30 June 2015	671,036	-	-	-	(95,181)	575,855
30 Jun 2010	30 June 2013	1,468,543	-	(1,454,785)	-	(13,758)	-
	30 June 2014	216,104	-	-	-	(63,969)	152,135
Total		**12,013,390**	**9,123,603**	**(6,248,934)**	**(8,392)**	**(1,439,698)**	**13,439,969**

[1]Forfeited rights are due to employees ceasing employment.

Financial year of grant	Financial year of vesting date	Balance at start of year	Granted	Vested and converted into equity	Vested and paid in cash	Forfeited	Balance at end of year
2012							
30 June 2012	30 June 2012	-	1,066,333	(1,016,333)	-	-	50,000
	30 June 2013	-	1,178,221	-	-	(190,433)	987,788
	30 June 2014	-	1,651,858	-	-	(193,633)	1,458,225
	30 June 2015	-	1,301,844	-	-	(193,628)	1,108,216
	30 June 2016	-	936,067	-	-	(108,027)	828,040
	30 June 2017	-	409,433	-	-	(33,201)	376,232
30 Jun 2011	30 June 2012	4,324,524	-	(3,977,481)	-	(247,043)	100,000
	30 June 2013	4,117,871	-	(10,811)	-	(1,098,920)	3,008,140
	30 June 2014	2,850,797	-	-	-	(1,109,731)	1,741,066
	30 June 2015	1,170,354	-	-	-	(499,318)	671,036
30 Jun 2010	30 June 2012	1,458,379	-	(1,279,605)	-	(178,774)	-
	30 June 2013	1,708,372	-	(20,675)	-	(219,154)	1,468,543
	30 June 2014	453,401	-	-	-	(237,297)	216,104
Total		**16,083,698**	**6,543,756**	**(6,304,905)**	**-**	**(4,309,159)**	**12,013,390**

31. Share-based payments (continued)

Financial year of grant	Financial year of vesting date	Balance at start of year	Granted	Vested and converted	Vested and paid in cash	Forfeited[1]	Balance at end of year
2011							
30 June 2011	30 June 2011	-	992,075	(992,075)	-	-	-
	30 June 2012	-	4,444,290	-	-	(119,766)	4,324,524
	30 June 2013	-	4,224,631	-	-	(106,759)	4,117,872
	30 June 2014	-	2,957,631	-	-	(106,759)	2,850,872
	30 June 2015	-	1,172,348	-	-	(1,993)	1,170,355
30 Jun 2010	30 June 2011	1,019,969	-	(1,004,969)	-	(15,000)	-
	30 June 2012	1,934,606	-	-	-	(476,227)	1,458,379
	30 June 2013	2,184,599	-	-	-	(476,227)	1,708,372
	30 June 2014	914,627	-	-	-	(461,226)	453,401
Total		**6,053,801**	**13,790,975**	**(1,997,044)**	**-**	**(1,763,957)**	**16,083,775**

Expenses arising from share-based payment transactions

Expenses arising from share-based payment transactions recognised during the period totalled $13,363,000 (2012: $10,721,270) (2011: $15,232,470).

32. Related party transactions

	2013	2012	2011
	$	$	$
Key management personnel compensation			
Short-term employee benefits	**4,581,905**	4,135,460	2,738,776
Post-employment benefits	**365,509**	314,709	217,861
Long-term benefits	**19,091**	30,390	13,102
Share-based payments	**3,496,786**	5,000,008	5,881,202
	8,463,291	9,480,567	8,850,941

Loans to key management personnel

On 16 December 2011, a loan of $250,000 was provided to Ken Dark, a Non-Executive Independent Director, for the purposes of exercising options granted under the Employee Share Plan. The loan was provided on commercial terms, with interest calculated monthly at a current rate of 10.08 per cent. The loan is repayable no later than four years from the date of the loan and is secured by a holding lock over the shares. As at 30 June 2013 the outstanding balance of the loan is $238,220 (2012: $250,000) (2011: $Nil).

On 22 August 2012, an agreement was entered into to provide a loan of up to $249,917 (£150,000) to Hillgrove Pty Ltd, a company controlled by Managing Director Peter Bond, for the purposes of providing short term funding to Powerhouse Energy Plc. During the reporting period an amendment was made to the original contract, extending the amount of the loan by an additional $16,661 (£10,000). The loan was provided on commercial terms, with interest calculated monthly at a current rate of 10.08 per cent. The loan is repayable no later than four years from the date of the loan. Linc Energy retains the right to take over this loan from Hillgrove Pty Ltd. At the end of the reporting period the outstanding balance of the loan including interest is $284,708 (£170,882).

Transactions with key management personnel and directors

Directors, Mr P. Bond, Mr C Ricato, and Mr K. Dark, and Key Management Personnel Mr D. Smith, hold positions in other entities that result in them having control or significant influence over the financial and operating policies of those entities. These entities have transacted with the Group in the reporting period. The terms and conditions of the transactions with these entities were no more favourable than those available, or which might reasonably be expected to be available, on similar transactions to non-key management personnel related entities on an arm's length basis.

The aggregate value of transactions and outstanding balances relating to key management personnel and entities over which they have control of significant influence were as follows:

32. Related party transactions (continued)

Payable transactions with key management personnel and directors

Key Management Person	Related party entity	Transaction	Transactions value year ended 30 June 2013 $	2012 $	2011 $	Balance outstanding as at 30 June 2013 $	2012 $	2011 $
Peter Bond	Bond Bros Contracting Pty Ltd	Executive services	**1,008,333**	824,633	583,000	**-**	-	-
	Bond Air Charters Pty Ltd	Chartered flights	**173,201**	480,188	259,140	**2,067**	42,895	2,584
	Rough Diamond Media Pty Ltd	Documentary film	**2,913**	67,897	50,000	**-**	-	50,000
	Australian Syngas Association	Membership	**44,000**	11,000	11,000	**-**	-	-
Craig Ricato	Executive Management Services Discretionary Trust	Executive services	**633,072**	555,940	297,713	**-**	-	-
Brian Johnson	Ferrous Metals Pty Ltd	Directors fees	**-**	-	4,167	**-**	-	-
	Ferrous Metals Pty Ltd	Reimbursement of expenses	**-**	-	763	**-**	-	-
Ken Dark	KE & SL Dark	Executive services	**166,440**	129,809	-	**14,238**	65,681	-
	KE & SL Dark	Reimbursement of expenses	**-**	12,369	-	**-**	-	-
David Smith	Dame Consulting	Executive services	**412,500**	378,125	-	**34,375**	34,375	-

* All Values are GST Inclusive

Receivable transactions with key management personnel and directors

Key Management Person	Related party entity	Transaction	2013 $	2012 $	2011 $	2013 $	2012 $	2011 $
Peter Bond	Peter Bond	Reimbursement of expenses	**61,931**	32,408	**33,447**	-	76,681	44,273
	Bond Bros Contracting Pty Ltd	Reimbursement of expenses	**-**	-	**-**	**3,200**	3,200	3,200
Ken Dark	KE & SL Dark	Loan	**-**	250,000	**-**	**238,220**	250,000	-
Don Schofield	Don Schofield	Reimbursement of expenses	**24,337**	-		**26,056**	1,719	
Peter Bond	Hillgrove Pty Ltd	Loan	**284,708**	-	**-**	**284,708**	-	-

* All Values are GST Inclusive

32. Related party transactions (continued)

Options over equity instruments

The movement during the reporting period in the number of options over ordinary shares in Linc Energy Ltd held, directly, indirectly or beneficially, by each key management person, including their related parties, is as follows:

Name	Expiry date [1]	Exercise price	Balance at start of year[3]	Granted	Exercised	Disposed [2]	Forfeited/ expired	Balance at end of year[4]
		$	Number	Number	Number	Number	Number	Number
2013								
C. Ricato	31 Dec 2012	0.70	500,000	-	(500,000)	-	-	-
A. Rohner	31 Dec 2014	1.53	1,533,333	-	-	-	(1,533,333)	-
K. Terblanche	31 Dec 2013	1.91	1,333,333	-	(360,000)	(150,000)	(666,667)	156,666
D. Smith	31 Dec 2013	2.98	400,000	-	-	-	(200,000)	200,000
D. Schofield	31 Dec 2014	0.76	666,666	-	-	(666,666)	-	-
J. Van de Velde	31 Dec 2012	0.60	200,000	-	-	(200,000)	-	-
J. Van de Velde	31 Dec 2013	3.16	100,000	-	-	-	-	100,000
			4,733,332	**-**	**(860,000)**	**(1,016,666)**	**(2,400,000)**	**456,666**
Weighted average exercise price $			1.58	-	1.21	0.90	1.76	2.65
2012								
K. Dark	31 Dec 2011	0.25	1,000,000	-	(1,000,000)	-	-	-
C. Ricato	31 Dec 2012	0.70	500,000	-	-	-	-	500,000
A. Rohner	31 Dec 2014	1.53	1,733,333	-	-	(200,000)	-	1,533,333
K. Terblanche	31 Dec 2013	1.91	1,700,000	-	-	-	(366,667)	1,333,333
D. Smith	31 Dec 2013	2.98	600,000	-	-	-	(200,000)	400,000
D. Schofield	31 Dec 2014	0.76	1,150,000	-	-	(483,334)	-	666,666
J. Van de Velde	31 Dec 2011	0.25	193,166	-	(125,500)	(67,600)	-	-
J. Van de Velde	31 Dec 2012	0.60	400,000	-	-	(200,000)	-	200,000
J. Van de Velde	31 Dec 2013	3.16	100,000	-	-	-	-	100,000
			7,376,499	**-**	**(1,125,500)**	**(950,934)**	**(566,667)**	**4,607,332**
Weighted average exercise price $			1.32	0.00	0.25	0.85	2.29	1.56

32. Related party transactions (continued)

Name	Expiry date [1]	Exercise price	Balance at start of year[3]	Granted	Exercised	Disposed [2]	Forfeited/ expired	Balance at end of year[4]
		$	Number	Number	Number	Number	Number	Number
2011								
K. Dark	31 Dec 2011	0.25	2,000,000	-	(1,000,000)	-	-	1,000,000
C. Ricato	31 Dec 2012	0.70	1,500,000	-	-	(1,000,000)	-	500,000
A. Rohner	31 Dec 2014	1.53	2,000,000	-	-	(266,667)	-	1,733,333
K. Terblanche	31 Dec 2013	1.91	2,000,000	-	-	(300,000)	-	1,700,000
D. Smith	31 Dec 2013	2.98	600,000	-	-	-	-	600,000
D. Schofield	31 Dec 2014	0.76	1,800,000	-	-	(650,000)	-	1,150,000
			9,900,000	**-**	**(1,000,000)**	**(2,216,667)**	**-**	**6,683,333**
Weighted average exercise price $			1.17	0.00	0.25	0.98	0.00	1.48

[1] Options vest and are exercisable over three consecutive years from the initial exercise date, with one-third of the total options awarded vesting and exercisable at 31 December each year following completion of a minimum service period, usually twelve months. The expiry date disclosed is the expiry date of the third and final tranche of options. Where an employee has been employed for greater than three years, an additional award of options may be granted at the discretion of the Board in the employee's fourth or later year.

[2] In accordance with a resolution of the Board, directors and employees may dispose of their vested options to a third party. The third party remains subject to the employee option plan rules in respect of options held and have exercised these options during the period.

[3] Or date commenced as a key management person.

[4] Or date ceased as a key management person.

Rights over equity instruments

The movement during the reporting period in the number of rights to ordinary shares in Linc Energy Ltd held, directly, indirectly or beneficially, by each key management person, including their related parties, is as follows:

Name	Balance at start of year[1]	Number of rights granted as compensation during year	Vested during the year	Unvested balance at end of the year[2]
	Number	Number	Number	Number
2013				
P. Bond[3]	-	11,824	-	11,824
J. Mathews	375,000	-	(125,000)	250,000
C. Ricato	750,000	354,700	(1,104,700)	-
K. Terblanche	666,666	-	(666,666)	-
D. Smith	1,000,000	-	(500,000)	500,000
J. Van de Velde	50,000	-	(50,000)	-
S. Broussard	400,000	600,000	(100,000)	900,000
A. Bond	400,000	600,000	(100,000)	900,000
M, Mapp	1,000,000	-	-	1,000,000
S. Jones	-	800,000	-	800,000
	4,641,666	**2,366,524**	**(2,646,366)**	**4,361,824**
2012				
J. Mathews	500,000	-	(125,000)	375,000
C. Ricato	1,250,000	396,861	(896,861)	750,000
O. Yates	1,000,000	-	(250,000)	750,000
K. Terblanche	1,333,333	-	(666,667)	666,666
D. Smith	1,500,000	-	(500,000)	1,000,000
D. Schofield	-	500,000	(500,000)	-
J. Van de Velde	225,000	53,851	(228,851)	50,000
S. Broussard	-	400,000	-	400,000
A. Bond	-	400,000	-	400,000
M. Mapp	-	1,000,000	-	1,000,000
	5,808,333	**2,750,712**	**(3,167,379)**	**5,391,666**

32. Related party transactions (continued)

Name	Balance at start of year[1]	Number of rights granted as compensation during year	Vested during the year	Unvested balance at end of the year[2]
	Number	Number	Number	Number
2011				
J. Mathews	-	500,000	-	500,000
C. Ricato	1,750,000	-	(500,000)	1,250,000
O. Yates	-	1,000,000	-	1,000,000
K. Terblanche	-	2,000,000	(666,667)	1,333,333
D. Smith	-	1,500,000	-	1,500,000
	1,750,000	5,000,000	(1,166,667)	5,583,333

[1] Or date commenced as a key management person. [2] Or date ceased to be a key management person [3] Mr Bond's shares are held by related parties.

Movements in shares

The movement during the reporting period in the number of ordinary shares in Linc Energy Ltd held, directly, indirectly or beneficially, by each key management person, including their related parties, is as follows:

Name	Balance at the start of the year[4]	Additions	Disposals	Balance at the end of the year[5]
	Number	Number	Number	Number
Ordinary shares				
2013				
K. Dark [1]	2,079,250	-	-	2,079,250
P. Bond [2]	202,121,028	500,000	-	202,621,028
J. Mathews	125,000	125,000	-	250,000
C. Ricato	1,396,861	1,104,700	-	2,501,561
K. Terblanche	766,668	866,666	(1,446,893)	186,441
D. Smith[3]	500,000	500,000	(786,535)	213,465
D. Schofield	500,000	666,666	(836,666)	330,000
J. Van de Velde	145,673	76,190	(37,000)	184,863
S. Broussard	-	100,000	-	100,000
A. Bond	-	100,000	-	100,000
	207,634,480	4,039,222	(3,107,094)	208,566,608
2012				
K. Dark	1,079,250	1,000,000	-	2,079,250
P. Bond [2]	202,121,028	-	-	202,121,028
J. Mathews	-	125,000	-	125,000
C. Ricato	500,000	896,861	-	1,396,861
O. Yates	1,000,000	-	(250,000)	750,000
K. Terblanche	315,001	666,667	(215,000)	766,668
D. Smith[3]	18,143	500,000	(18,143)	500,000
D. Schofield	-	500,000	-	500,000
J. Van de Velde	365,000	354,351	(573,678)	145,673
	205,398,422	4,042,879	(1,056,821)	208,384,480
2011				
B. Johnson[6]	1,000,000	-	(1,000,000)	-
P. Bond[2]	200,923,904	1,197,124	-	202,121,028
K. Dark	597,503	1,000,000	(580,503)	1,079,250
O. Yates	-	278,551	-	278,551
C. Ricato	-	500,000	-	500,000
K. Terblanche	-	666,667	(351,666)	315,001
D. Smith[3]	28,143	-	(10,000)	18,143
D. Schofield	-	750,000	(750,000)	-
	202,549,550	4,392,342	(2,692,169)	204,311,973

[1] A portion of Mr Dark's shares are held by related parties.
[2] Mr Bond's shares are held via Newtron Pty Ltd or its nominees.
[3] Mr Smith's shares are held via a related party.
[4] Or date commenced being a key management person
[5] Or date ceased to be a key management person
[6] Mr Johnson's shares are held via Moon Star Investments Pty Ltd atf The Pemberley Trust

32. Related party transactions (continued)

Other related party interests

Hillgrove Pty Ltd, a company controlled by Managing Director, Peter Bond owns a 7.03 per cent interest in Powerhouse Energy Group plc, an entity Linc Energy Ltd also holds a 9.96 per cent interest in. Mr P. Bond is not involved in discussions or board decisions relating to the Company's investment in Powerhouse Energy.

On 6 November 2012, an agreement was entered into with Powerhouse Energy Group plc, granting a license to occupy office space in Linc Energy's London Office. The loan was provided on the basis of PowerHouse being entitled to occupy one desk, for up to ten days per month, along with reasonable access during that period to Linc Energy's photocopying, printing and other administrative facilities. The monthly rent payment of £1,000 will compensate Linc Energy for the provision of such office space and other administrative facilities. Linc Energy will accrue the monthly rent payment until such time as PowerHouse is capitalised in the amount of £2,000,000 or higher, upon which all rent payments incurred will become due and payable. If any charges outside of the above mentioned are incurred by Linc Energy on behalf of PowerHouse, these charges are invoiced on a monthly basis. At the end of the reporting period the total rent accrued is $13,329 (£8,000).

33. Parent entity disclosures

As at and throughout the financial year ended 30 June 2013 the parent entity of the Group was Linc Energy Ltd:

	Company		
	2013	2012	2011
	$'000	$'000	$'000
Result of the parent entity			
Profit/(loss) for the period	**(32,502)**	(55,630)	307,119
Other comprehensive income	**6,596**	(7,895)	5,726
Total comprehensive income / (loss) for the period	**(25,906)**	(63,525)	312,845
Financial position of the parent entity at year end			
Current assets	**120,586**	20,411	201,189
Total assets	**705,015**	545,138	604,691
Current liabilities	**22,180**	70,563	23,310
Total liabilities	**250,426**	81,226	79,110
Total equity of the parent entity comprising of:			
Share capital	**325,388**	310,606	309,493
Share-based payment reserve	**30,316**	28,516	28,868
Available-for-sale reserve	**4,427**	(2,169)	5,726
Other reserves	**5,274**	5,274	5,274
Retained earnings	**89,184**	121,685	176,220
Total Equity	**454,589**	463,912	525,581

Parent entity contingencies

As at the balance sheet date there are no legal claims pending against the parent and the Directors are not aware of any other contingent liabilities other than as set out in note 26.

Parent entity capital commitments for the acquisition of intangible assets or property, plant and equipment

As at the balance sheet date the parent entity had capital commitments totalling $1,034,000 (2012: $4,310,000) (2011: $12,386,000) for the acquisition of tangible and intangible assets.

Parent entity guarantees in respect of debts of its subsidiaries

The parent entity does not guarantee the debts of its subsidiaries (30 June 2012: Nil). The Parent entity has provided a letter of financial support to the Directors of SAPEX Limited, New Emerald Coal and Linc's US subsidiaries.

34. Remuneration of auditors

During the year the following fees were paid or payable for services provided by the auditor of the Group.

	Consolidated		
	2013	2012	2011
	$	$	$
Audit services			
KPMG Australia	**370,900**	326,650	293,000
Overseas KPMG firms	**382,678**	233,701	121,853
	753,578	560,351	414,853
Services other than statutory audit:			
KPMG Australia:			
Taxation advisory services	**-**	-	49,900
IT advisory services	**11,135**	180,491	54,797
Forensic advisory services	**-**	39,000	-
Other assurance services	**20,000**	-	-
	31,135	219,491	104,697

35. Subsequent events

Matters subsequent to the end of the financial year were as follows:

- *Fortress Warrants Termination* - On 25 July 2013, the Group and FCCD (Australia) Pty Limited agreed to terminate the Warrant Deed entered into on 6 September 2012 for a cash settlement of $9,790,586. On 26 July 2013, the amount was paid by the Group and the warrants were immediately cancelled.
- *Alaskan Tax credit rebate sale* - On 20 August 2013, the Group sold its rights to certain oil and gas tax credits to Apollo Investment Corporation for USD$24,740,122 with net proceeds received of $USD24,560,122. The proceeds have been applied against US oil and gas costs including Alaska and the Gulf Coast.

In the Directors' opinion:

1. The financial report projects presents fairly the state of affairs and the results of the group;

2. There are reasonable grounds to believe that the group will be able to pay its debts as and when they fall due;

3. The company and its controlled entities have kept such accounting records to correctly record and explain their transactions and financial position;

4. The company and its controlled entities have kept accounting records so that a true and fair financial report of the group can be prepared from time to time; and

5. The directors draw attention to Note 1(a) to the consolidated financial statements, which includes a statement of compliance with International Financial Reporting Standards.

This declaration is made in accordance with a resolution of the Directors.

Peter Bond
Managing Director
Brisbane
25 September 2013

The Board of Directors
Linc Energy Ltd
Smellie & Co. Building
32 Edward Street
Brisbane Qld 4000

Independent auditor's report to the Board of Directors of Linc Energy Ltd on the Consolidated Financial Statements

We have audited the accompanying financial report of Linc Energy Ltd (the Company), which comprises the consolidated statements of financial position as at 30 June 2013, 30 June 2012 and 30 June 2011, and consolidated statements of profit and loss and other comprehensive income, consolidated statements of changes in equity and consolidated statements of cash flows for the years ended on those dates, notes 1 to 35 comprising a summary of significant accounting policies and other explanatory information of the Group comprising the Company and the entities it controlled at the year's end or from time to time during the financial years ("Consolidated Financial Statements").

The Consolidated Financial Statements have been prepared in accordance with the requirements of Rule 246(9) of the Singapore Exchange Securities Trading Limited ("SGX-ST') Listing Manual and in connection with the proposed listing of the Company on the SGX-ST. This report has been prepared for the Board of Directors of the Company for inclusion in the Offering Document of the Company in connection with the initial public offering of the shares of the Company.

Directors' responsibility for the financial report

The directors of the Company are responsible for the preparation and fair presentation of the Consolidated Financial Report in accordance with Australian Accounting Standards and for such internal control as the directors determine is necessary to enable the preparation of the financial report that is free from material misstatement whether due to fraud or error. In Note 1, the directors also state, in accordance with Australian Accounting Standard AASB 101 *Presentation of Financial Statements*, that the financial statements of the Group comply with International Financial Reporting Standards.

Auditors' responsibility

Our responsibility is to express an opinion on the Consolidated Financial Report based on our audits. We conducted our audits in accordance with International Standards on Auditing. These Auditing Standards require that we comply with relevant ethical requirements relating to audit engagements and plan and perform the audit to obtain reasonable assurance whether the financial report is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial report. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial report, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial report in order to design audit procedures that are appropriate in 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 accounting policies used and the reasonableness of accounting estimates made by the directors, as well as evaluating the overall presentation of the financial report.

We performed the procedures to assess whether in all material respects the Consolidated Financial Report is presented fairly in accordance with Australian Accounting Standards, so as to present a view which is consistent with our understanding of the Group's financial position, and of its performance and cash flows.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Independence

In conducting our audits, we have complied with the independence requirements of the International Ethics Standards Board for Accountants' Code of Ethics for Professional Accountants (IESBA Code).

Auditor's opinion

In our opinion:

(a) the Consolidated Financial Report presents fairly, in all material respects, the financial position of Linc Energy Ltd and its controlled entities as of 30 June 2013, 30 June 2012 and 30 June 2011 and of its financial performance and its cash flows for each of the years then ended in accordance with the Australian Accounting Standards; and

(b) the Consolidated Financial Report also complies with International Financial Reporting Standards as disclosed in Note 1.

Other matter

Linc Energy Ltd has prepared a separate financial report for each of the years ended 30 June 2013, 30 June 2012 and 30 June 2011 in accordance with the *Corporations Act 2001*, Australian Accounting Standards and the *Corporations Regulations 2001* on which we issued separate auditor's reports conducted in accordance with the *Corporations Act 2001* and Australian Auditing Standards to the members of Linc Energy Ltd, dated 24 September 2013, 28 September 2012 and 27 September 2011 respectively.

No audited financial statements of the Company or its controlled entities have been prepared for any period subsequent to 30 June 2013.

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KPMG

Brisbane
25 September 2013

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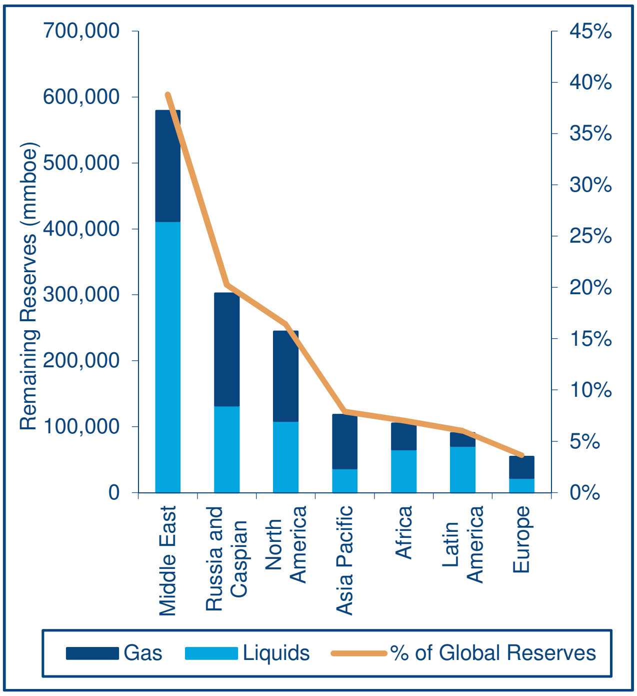
Market overview

Executive Summary

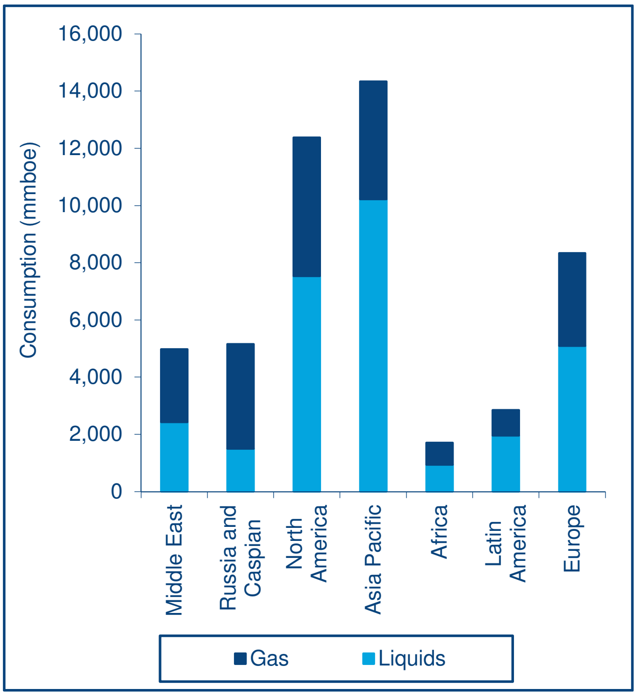
Total global commercial oil and gas reserves are estimated to be approximately 1,492 billion boe (as of 1 January 2013A), with the Middle East region accounting for 39% of the total, followed by the Russia and Caspian region (20%), North America (16%), and Asia-Pacific (8%).

Commercial oil and gas reserves by region



Source: Wood Mackenzie

Oil and gas consumption by region (2013)

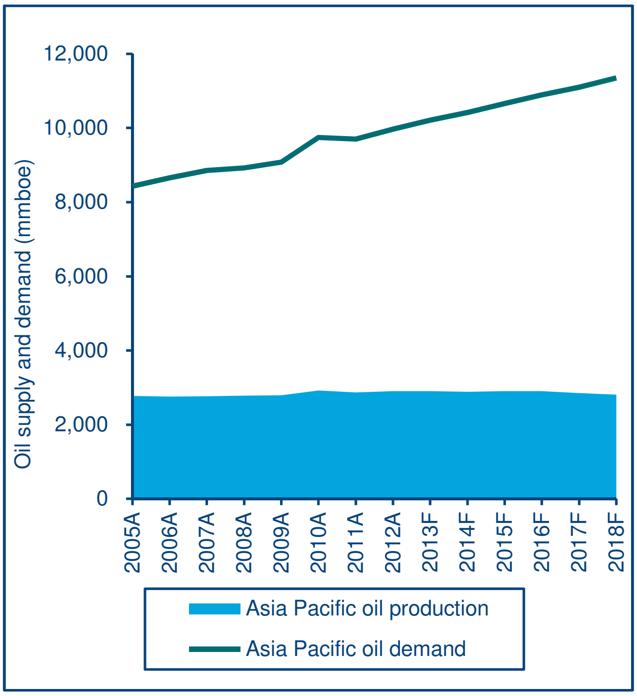


Source: Wood Mackenzie

In contrast to where oil and gas reserves are located, Asia Pacific is the largest consumer (29%), followed by North America (25%) and Europe (17%). Growth in demand over the next 5 years is also expected to be faster in Asia Pacific than in any other region except the Middle East, with overall demand for oil and gas growing at 3.5% p.a. to reach 17,050 mmboe (in 2018).

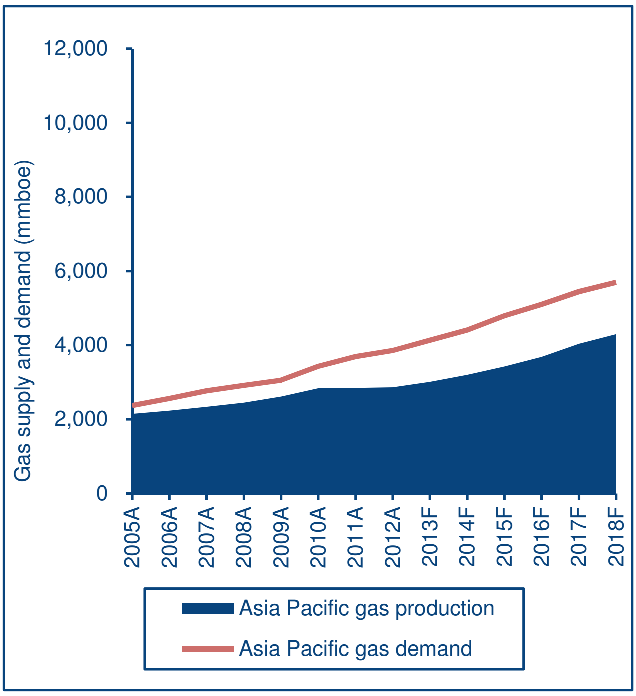
The Asia-Pacific region is therefore a significant net importer of both oil and gas. Production of oil is expected to remain essentially flat, which will result in net imports continuing to increase from 7,309 mmboe in 2013 to 8,542 mmboe in 2018. Over the same period, imports of gas (either by pipeline or LNG) are expected to increase from 1,116 mmboe to 1,401 mmboe.

Asia-Pacific crude oil supply/demand (2005A-2018F)



Source: Wood Mackenzie

Asia-Pacific gas supply/demand (2005A-2018F)



Source: Wood Mackenzie

Although there is a general deficit of both oil and gas across the region as a whole, the situation is not the same for all countries within the region.

Australian oil supply and demand are both flat, with the country expected to remain a net importer of oil. Production of gas is however expected to grow significantly in the next few years as the ramp-up of several LNG projects sees Australia becoming the world's largest exporter of LNG (by 2018).

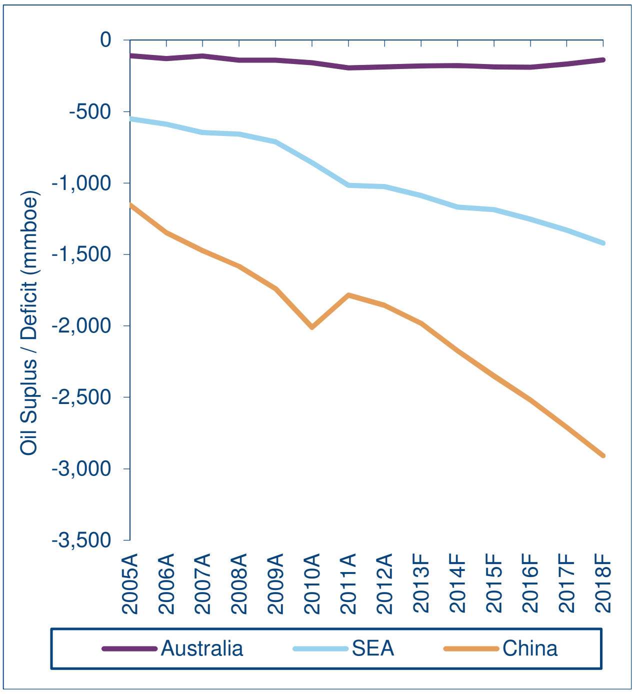
In contrast to Australia, oil demand in Southeast Asia (SEA) will grow strongly, whilst oil production is expected to decline (Malaysia is the region's only major oil producing country forecast to increase oil output in the period to 2018). This will lead to increasing imports being required. Indonesia is the largest market for oil in South East Asia, although Vietnam will be the fastest growing oil consumer through 2018F, followed by Cambodia and Myanmar.

SEA gas demand too, will grow strongly and, although the region as a whole will remain a net exporter of gas, market dynamics vary between countries and even between regions within the same country. Hence, while Malaysia, Indonesia and Brunei Darussalam are expected to remain LNG exporters, imports of LNG into specific countries are expected to grow strongly. Thailand and Indonesia commenced LNG imports in 2011 and 2012, respectively, while Malaysia and Singapore commenced LNG imports in 2013. SEA LNG imports are expected to grow to more than three times 2013F levels by 2018F.

China is by far the largest oil producer in Asia, producing more than four times the amount of oil that Indonesia produced in 2012. But existing fields are maturing and despite enhanced oil recovery techniques being used, and extensive exploration, Chinese oil production is expected to fall slightly over the next five years. China is already the world's second largest oil importer after the U.S. and with continued demand growth, combined with declining domestic production, is forecast to see China overtake the U.S. as the world's largest importer by 2018.

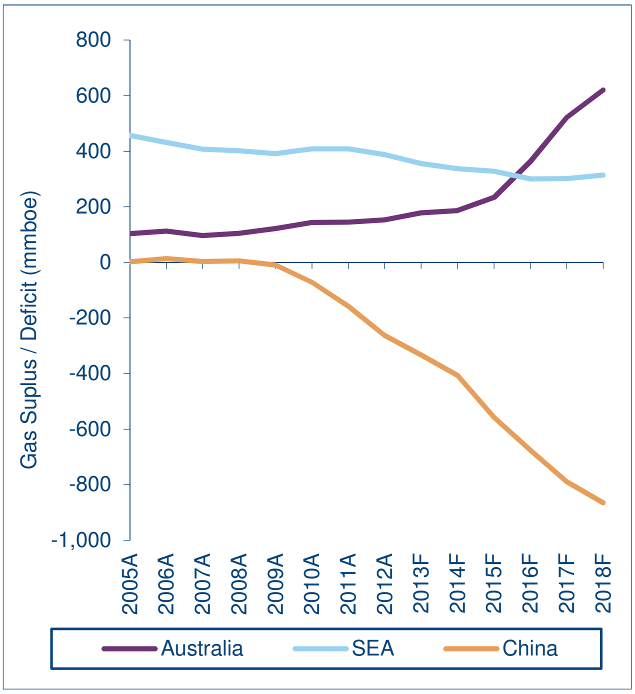
China's gas production, primarily from conventional sources, is increasing rapidly but, with demand growing even faster than production, imports are expected to continue to increase, with over one third of gas demand met by imports by 2018.

Asia-Pacific intra-regional crude oil surplus/deficit (2005A-2018F)



Source: Wood Mackenzie

Asia-Pacific intra-regional gas surplus/deficit (2005A-2018F)



Source: Wood Mackenzie

The general deficit of oil and gas is the Asia-Pacific region could provide a potential market for the development of Underground Coal Gasification (UCG). More specifically, localised deficits within the region could be opportunities for UCG development where it can be developed at a lower cost than the imported alternatives.

While not yet a commercial established technology, UCG is a possible alternative source of both unconventional liquids and gas. UCG is the process of gasifying coal in-situ (i.e. within the coal seam, without the need to mine the coal and process it above ground) to produce syngas, which comprises primarily H_2 and CO. Syngas is a highly versatile product that can be used directly for power generation, converted into a synthetic crude oil ('syncrude') and then refined into a variety of liquid fuels, reformed into synthetic natural gas (SNG), or used as a chemical feedstock to produce a variety of value-added products.

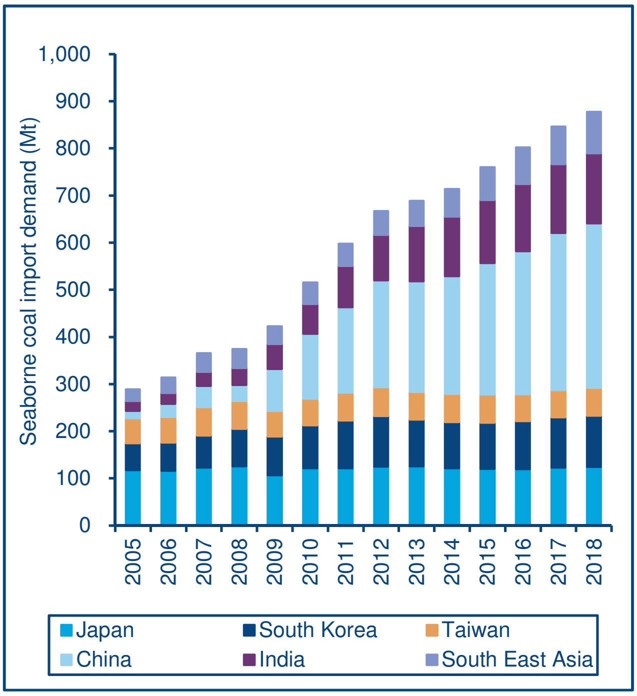
One of the main attractions of UCG is its potential to monetise otherwise 'stranded' coal resources. Coal is a widely distributed natural resource but a large proportion of the world's known coal resources are 'unmineable' using conventional surface or underground mining techniques – for economic, environmental, technical or safety reasons.

The last few years has seen renewed interest in UCG in most coal producing regions of the world, with a number of commercial and pilot-scale operations and trials commencing operation, and many more exploration and planning activities underway.

However, despite growth in oil and gas demand in Asia-Pacific, and the search for alternative unconventional sources of oil and gas, coal remains the major source of primary energy in the region and is far and away the largest source of electricity. Rising energy demand, allied with lack of domestic resources or the inability of domestic supply to keep pace with demand, has led to the growth of the seaborne market for thermal coal, especially in Asia.

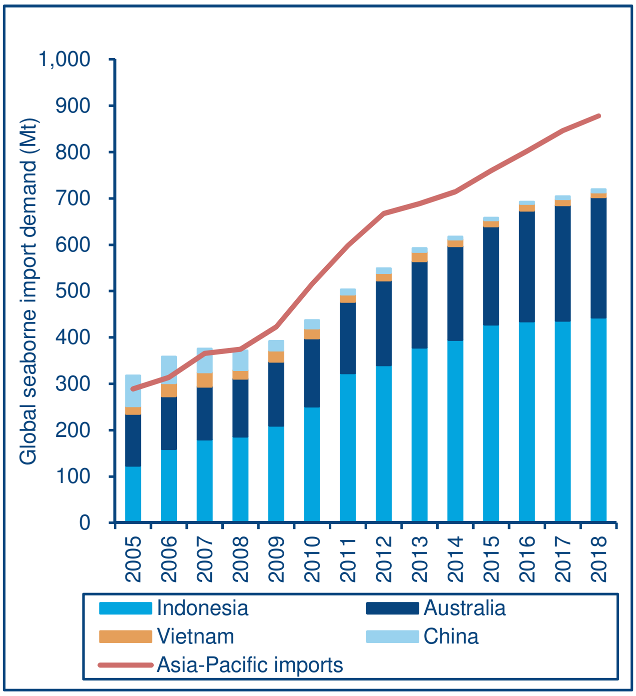
Almost all growth in demand for seaborne coal between 2005 and 2012 was from Asia-Pacific, where strong economic growth, and resultant increase in coal demand, has led to demand outstripping domestic supply. Demand growth has been strongest in large developing economies, such as China and India, with strong, albeit less volumetrically substantial, growth in smaller developing economies in Southeast Asia. China and India will continue to lead global seaborne demand growth, accounting for 85% of global import demand growth between 2013 and 2018. Despite both having large coal reserves, production (which is generally located inland at some distance from coastal demand centres) will be insufficient to meet demand.

Asia-Pacific thermal coal imports by country (2005-2018)



Source: Wood Mackenzie

Asia-Pacific thermal coal exports and imports(2005-2018)



Source: Wood Mackenzie

Supply of coal to the seaborne market has traditionally been dominated by six countries: Australia, Indonesia, South Africa, China, Colombia and Russia. However, rapid economic growth in China has seen Chinese demand outstrip domestic supply, and China became a net importer of coal in 2009. Traditional Pacific Basin suppliers, Indonesia and Australia, will continue to supply the majority of the seaborne market. However, strong growth in Pacific Basin demand will result in the deficit in Asia-Pacific continue to grow, which will encourage other producers to increase exports to Asia, particularly South Africa and Colombia.

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Nomenclature

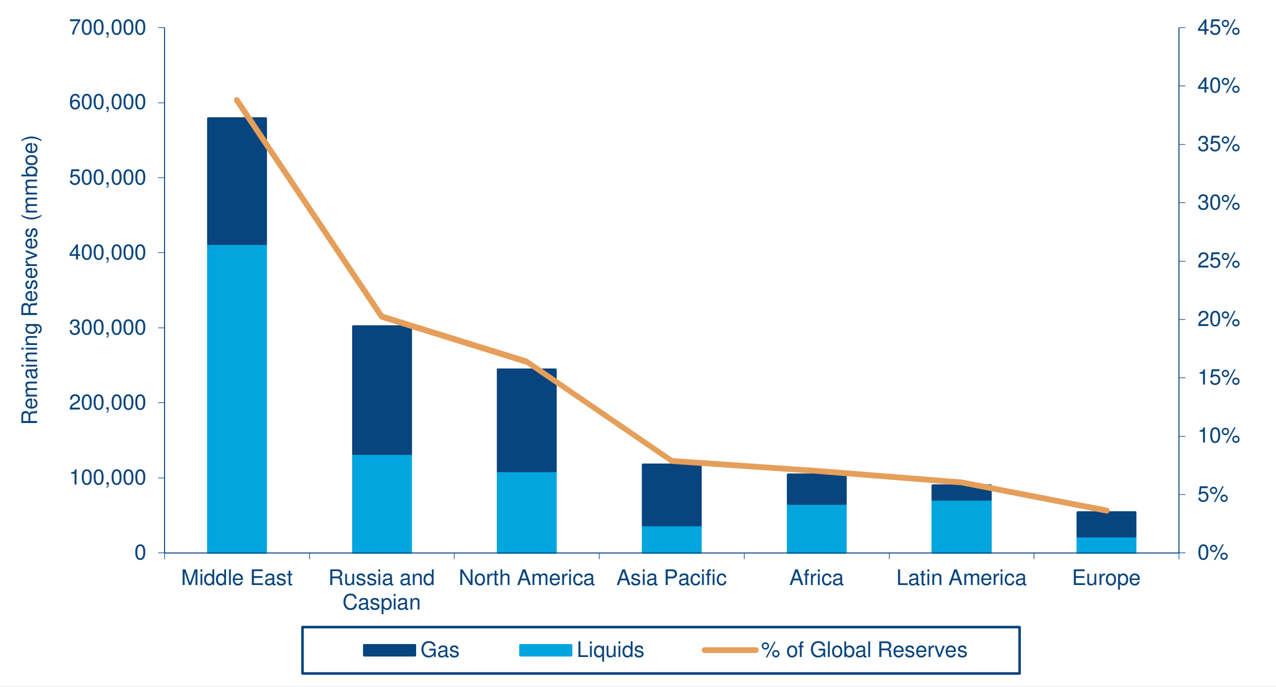
A	Actual
ACG	Aboveground coal gasification
API	American Petroleum Institute
APLNG	Australia Pacific LNG
b/d	Barrels per day
bbl	Barrel
bnboe	Billion barrels of oil equivalent
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
Bt	Billion tonnes
CAGR	Compound annual growth rate
CBM	Coal bed methane
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CPI	Consumer price index
CRIP	Controlled retracting injection point
CSG	Coal seam gas
CTG	Coal-to-gas
CTL	Coal-to-liquids
DMO	Domestic Market Obligation
ECBM	Enhanced coal bed methane
EIA	The U.S. Energy Information Administration
EOR	Enhanced oil recovery
F	Forecast
FLNG	Floating LNG
FOB	Free-on-board
FSU	Former Soviet Union
FT	Fischer-Tropsch
GAR	Gross as received
GDP	Gross domestic product
GHG	Greenhouse gas
GLNG	Gladstone LNG
GSA	Gas sales agreement
GTL	Gas-to-liquids
GW	Gigawatt
H_2	Hydrogen
H_2S	Hydrogen sulphide
HBA	Harga Batubara Acuan
HH	Henry Hub
HSFO	High sulphur fuel oil
IGCC	Integrated gasification combined cycle
JFY	Japanese Financial Year
JORC	Joint Ore Reserves Committee
JPU	Japanese Power Utilities
kcal	Kilocalories
kg	Kilogram
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MCC	Microbial coal conversion
mmboe	Million barrels of oil equivalent
MRRT	Minerals Resource Rent Tax
Mt	Million tonnes
MWh	Megawatt hour
NAR	Net as received
NBP	National Balancing Point
NDRC	National Development and Reform Commission
NGL	Natural gas liquids
NO_X	Nitrogen oxides
NSW	New South Wales
OPEC	Organization of Petroleum Exporting Countries
PCI	Pulverised coal injection
PF	Pulverised fuel
PRB	Powder River Basin
QCLNG	Queensland Curtis LNG
QLD	Queensland
RoW	Rest of World
SEA	South East Asia
SNG	Synthetic (or substitute) natural gas
SO_X	Sulphur oxides
t	Tonne
tcf	Trillion cubic feet
U.S.	United States
UCG	Underground coal gasification
UMPP	Ultra Mega Power Project
WGS	Water-gas-shift
WM	Wood Mackenzie
WTI	West Texas Intermediate
YTF	Yet-to-find

1 Oil and gas market review

1.1 Global and regional oil & gas reserves

Wood Mackenzie estimates total global commercial oil and gas reserves[1] at approximately 1,492 billion boe[2] (as of 1 January 2013A), with the Middle East region accounting for 39% of the total, followed by the Russia and Caspian region (20%), North America (16%), and Asia-Pacific (8%).

Figure 1.1 Commercial oil and gas reserves by region



Source: Wood Mackenzie

1.2 Global oil and gas demand

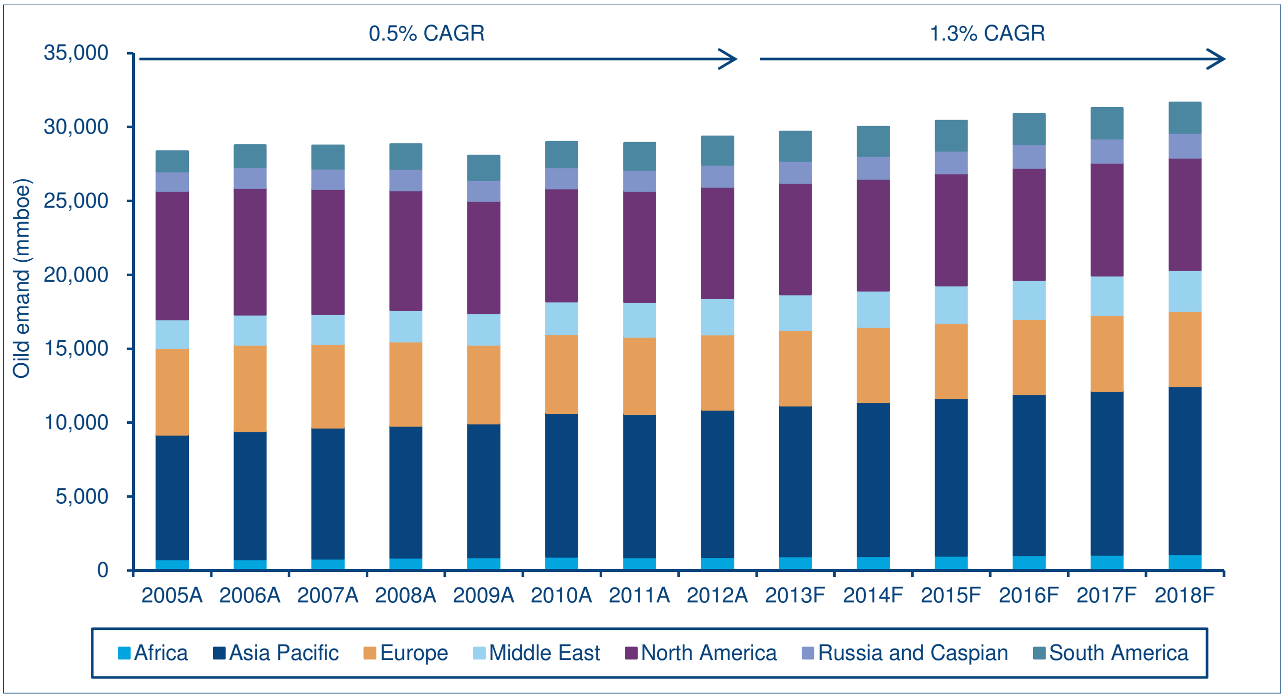
1.2.1 Crude oil demand by region

Global oil demand has risen since 2009A, with Wood Mackenzie projecting oil demand to continue increasing from 29,674 mmboe in 2013F to 31,662 mmboe in 2018F, equating to a 1.3% average annual growth rate. Economic development in the rest of the world looks set to drive this overall growth in global oil demand despite negligible demand growth in Europe and North America. In particular, Wood Mackenzie expects that the growth in demand for oil in Asia-Pacific will surpass the total increase in demand from the rest of the regions, with 1,139 mmboe of additional demand expected from 2013F to 2018F, equivalent to an average annual growth rate of 2.1%.

[1] *Using Wood Mackenzie's methodology, commercial reserves are broadly equivalent to proven and probable reserves. In particular, Wood Mackenzie considers commercial reserves to be fields which are currently in production, under development or regarded as probable developments. Fields under development are fields where the development plan has been approved by the government authorities and the field participants have made the final investment decision for the project to proceed. Probable developments are discoveries where reserve estimates have been sufficiently proved-up and any development plan would be economically viable. Wood Mackenzie would expect probable developments to be either on-stream or under development within a five-year timescale.*

[2] *This includes both conventional and unconventional commercial reserves such as shale gas, tight oil, and oil sands.*

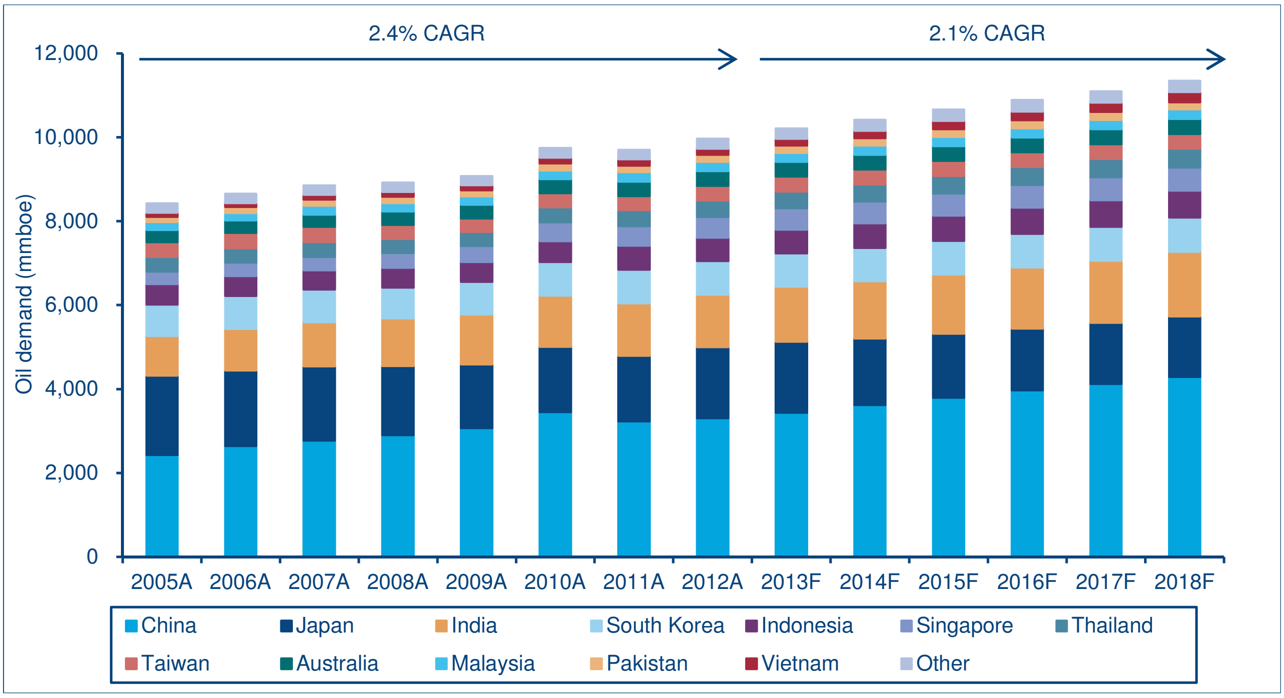
Figure 1.2 Crude oil consumption by region (2005A – 2018F)



Source: Wood Mackenzie

China and Japan are currently the two largest oil demand centres in Asia. However, this is set to change as India is projected to overtake Japan as second largest oil market in Asia by 2017F. China and India are expected to account for the majority of the growth through 2018F, driven by growth from their transport sectors. Strong demand growth is also expected in other smaller oil markets, including Indonesia, Singapore and Vietnam.

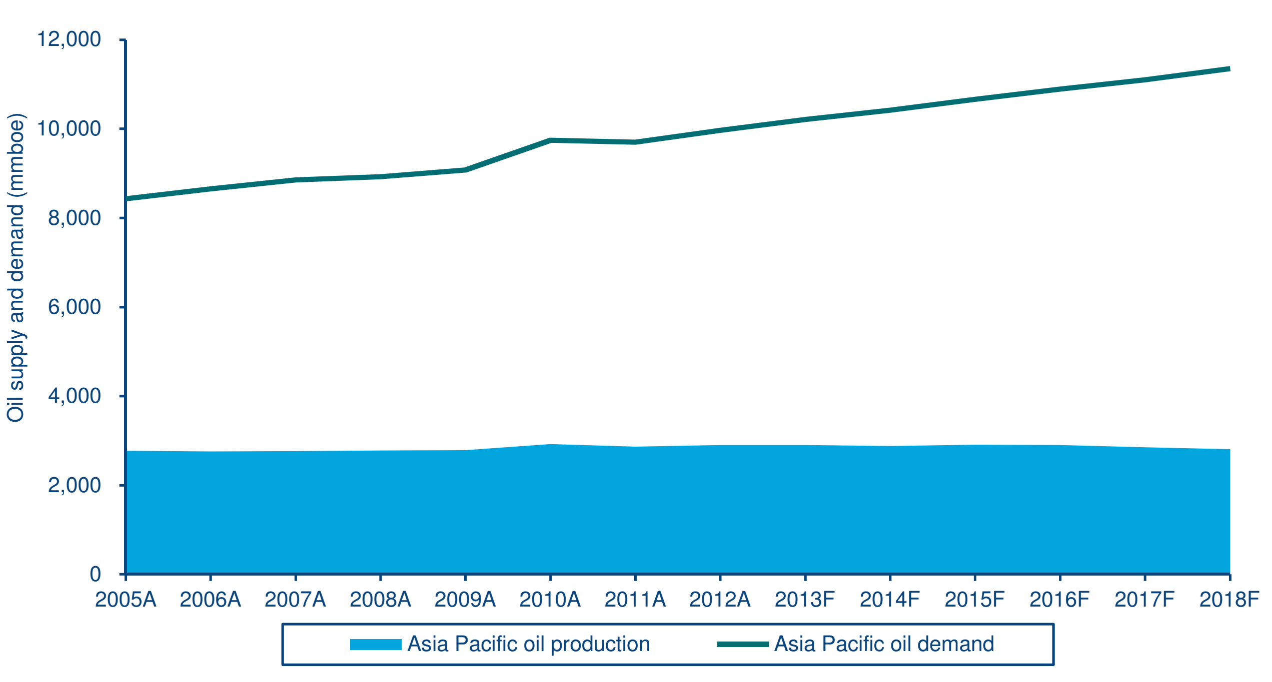
Figure 1.3 Asia-Pacific crude oil consumption by country (2005A – 2018F)



Source: Wood Mackenzie

The Asia-Pacific region has a major deficit in terms of crude oil supply/demand. The region will require greater imports of oil over time as oil demand in the region continues to grow strongly but production is expected to remain essentially flat.

Figure 1.4 Asia-Pacific crude oil supply/demand (2005A – 2018F)

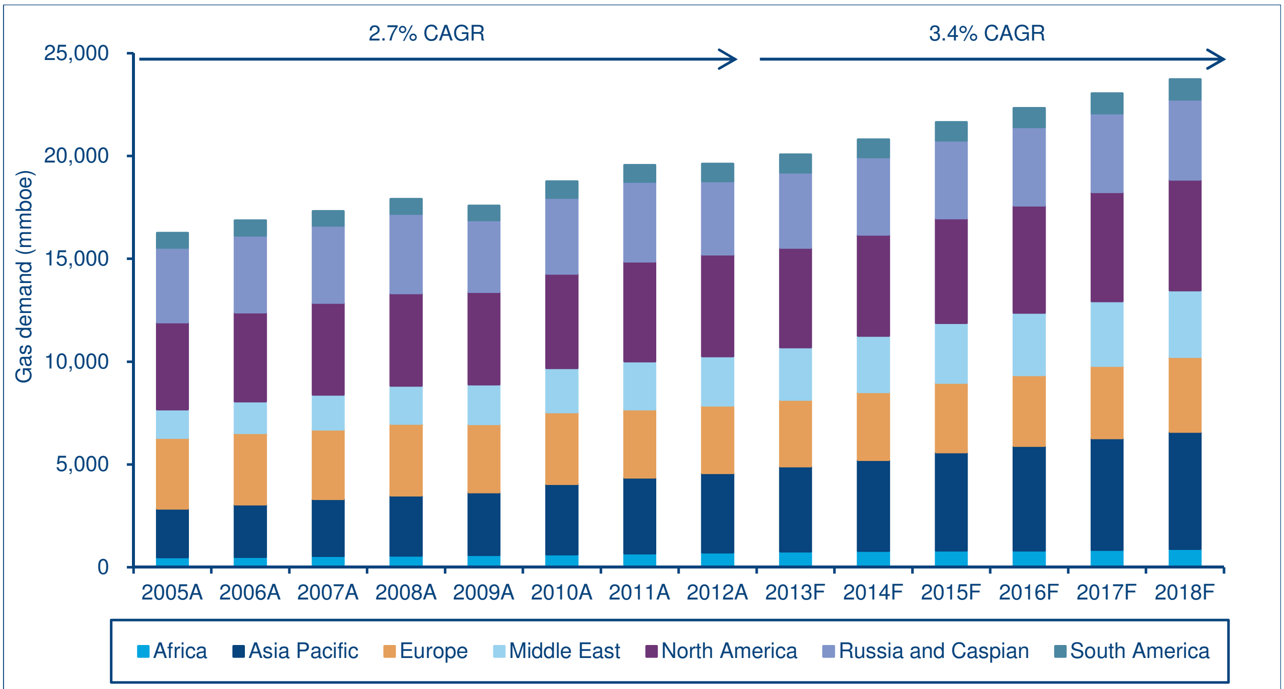


Source: Wood Mackenzie

1.2.2 Gas demand by region

In Wood Mackenzie's view, gas will play a greater role in the global energy mix of the future. Oil and coal will continue to domninate the energy mix but gas's share of the mix will increase through households switching from traditional fuels and growing industrial demand (particularly petrochemicals). Gas will maintain its share of the generation fuel mix within the context of strong overall growth in electricty demand. Gas demand is expected to increase steadily, from 20,083 mmboe in 2013F to 23,737 mmboe in 2018F, equating to an average annual growth rate of 3.4%. The main regions that contribute to this rise are Asia-Pacific, the Middle East, and North America, with Asia-Pacific gas demand growing the quickest, at an average of 6.7% per year between 2013F and 2018F.

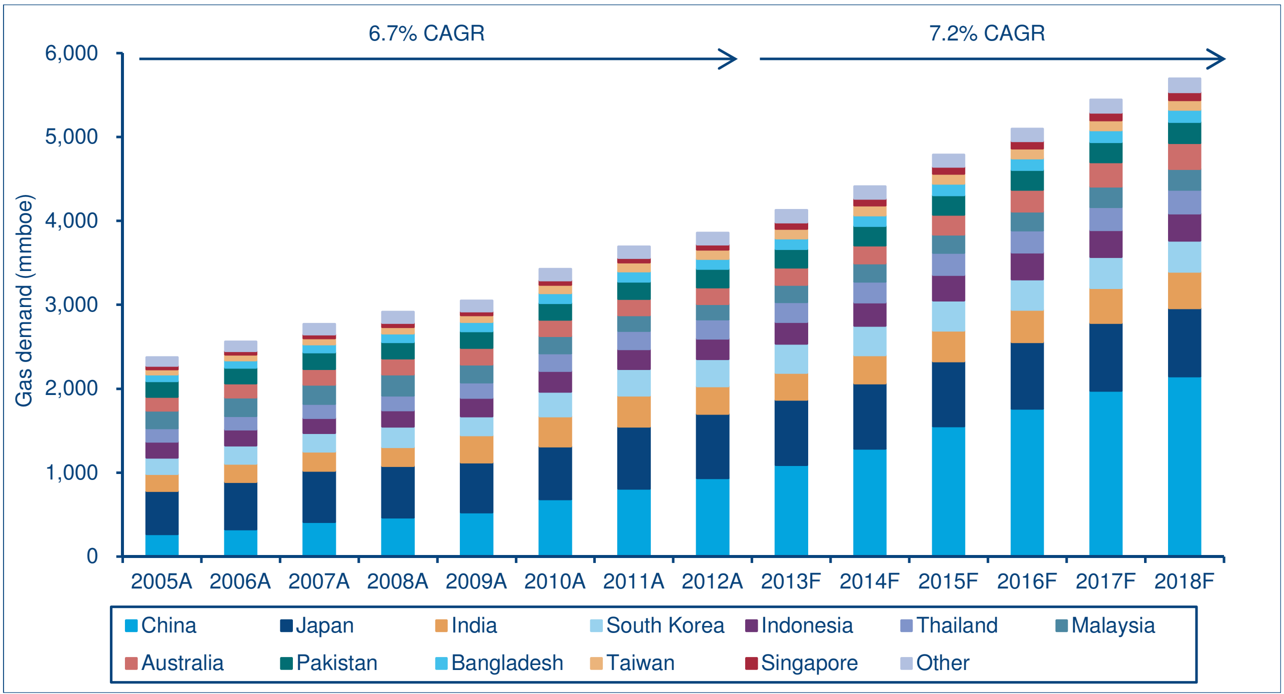
Figure 1.5 Gas consumption by region (2005A – 2018F)



Source: Wood Mackenzie

China is the largest gas market in Asia and the fastest growth centre in the region through the 2013F to 2018F period. Chinese gas consumption is expected to grow from 1,089 mmboe in 2013F to 2,148 mmboe in 2018F, equivalent to a growth rate of 14.6%. India, although slightly behind Japan and South Korea in terms of current demand, is estimated to grow at an average 6.1% per year through to 2018F, over taking South Korea as the third largest gas market in Asia by 2015. Strong growth is also expected in other smaller Asian markets including Indonesia, Malaysia and Vietnam.

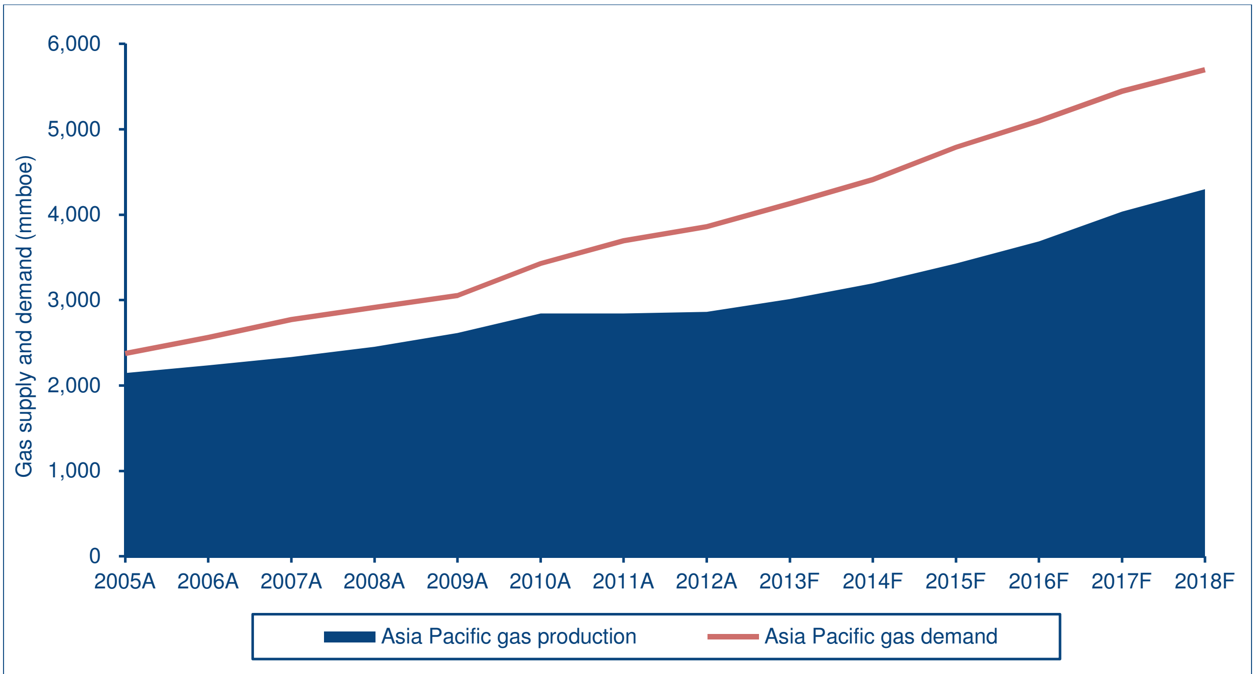
Figure 1.6 Asia-Pacific gas consumption by country (2005A – 2018F)



Source: Wood Mackenzie

The Asia-Pacific region is a net importer of gas. Gas imports from outside of the region are delivered by LNG or pipeline gas. China is the main importer of piped gas in the region with its supply coming from Central Asia (Turkmenistan and Uzbekistan).

Figure 1.7 Asia-Pacific gas supply/demand (2005A – 2018F)



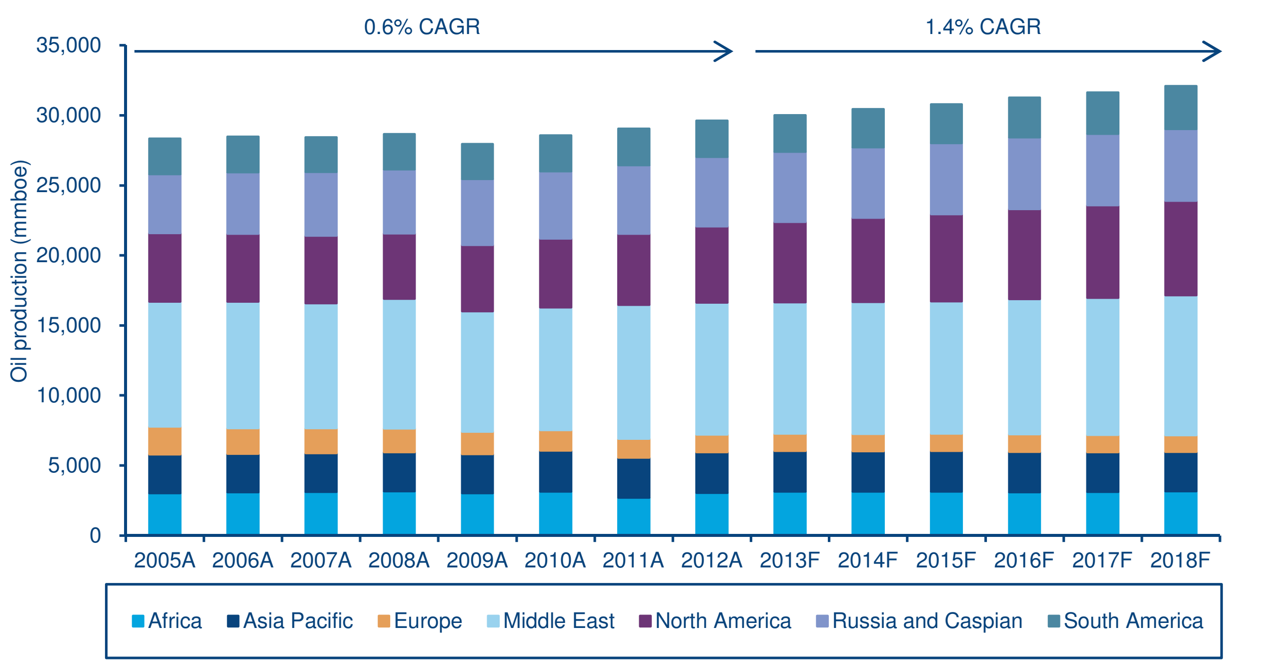
Source: Wood Mackenzie

1.3 Global oil and gas production

1.3.1 Crude oil production by region

Based on Wood Mackenzie estimates, global oil production is set to rise from 30,023 mmboe in 2013F to 32,105 mmboe in 2018F, at an average annual growth rate of 1.4%. This is led by a projected growth in production in North America, the Middle East and South America.

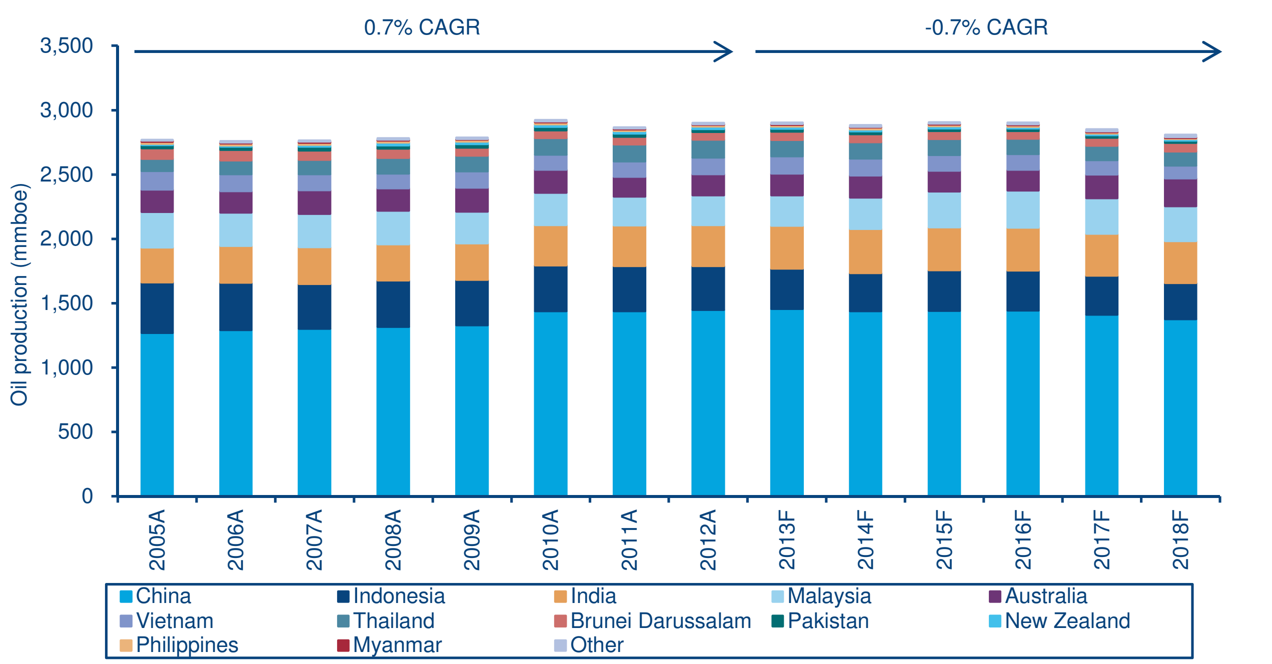
Figure 1.8 Crude oil production by region (2005A – 2018F)



Source: Wood Mackenzie

The impact of unconventional oil production will be felt acutely in North America. Tight oil (crude held within very low permeability reservoir horizons) production in the United States is expected to increase from 2.6 million b/d in 2013F to 4.5 million b/d in 2018F. Tight oil production is also expected to increase in Canada from around 276,000 b/d in 2013F to 420,000 b/d in 2018F. Wood Mackenzie expects a level of tight oil production of only 132,000 b/d by 2018F outside of North America.

Figure 1.9 Asia-Pacific crude oil production by country (2005A – 2018F)



Source: Wood Mackenzie

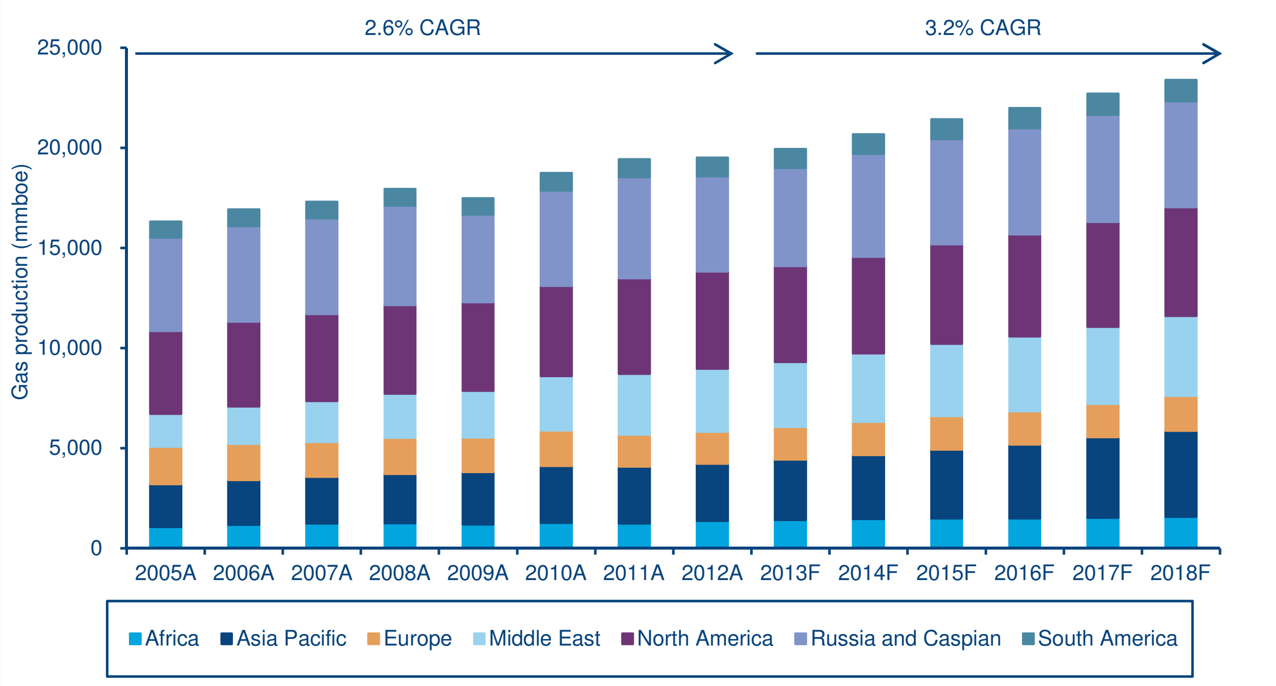
In the Asia-Pacific region, oil production between 2013F and 2018F is set to fall slightly, from 2,904 mmboe in 2013F to 2,810 in 2018F. Oil production in the Asia-Pacific region is dominated by China, India, Indonesia and Malaysia, which together account for 80% of the region's production. China is currently the region's largest oil producer, however, production is expected to gradually decline over the medium term, falling from 1,454 mmboe in 2013F to 1,375 mmboe in 2018F.

Asia-Pacific has a reserves to production ratio of 11.1 years (based on 2012A) for oil.

1.3.2 Gas production by region

Wood Mackenzie expects a 3.2% average annual increase in global gas production, from 19,949 mmboe (113 tcf) in 2013F to 23,400 mmboe (133 tcf) in 2018F. While the regions of North America and Russia & Caspian are expected to continue maintaining their positions as the leading producers of gas globally, Asia-Pacific is expected to grow its gas production at an annual average rate of 7.4% between 2013F and 2018F, outperforming other regions.

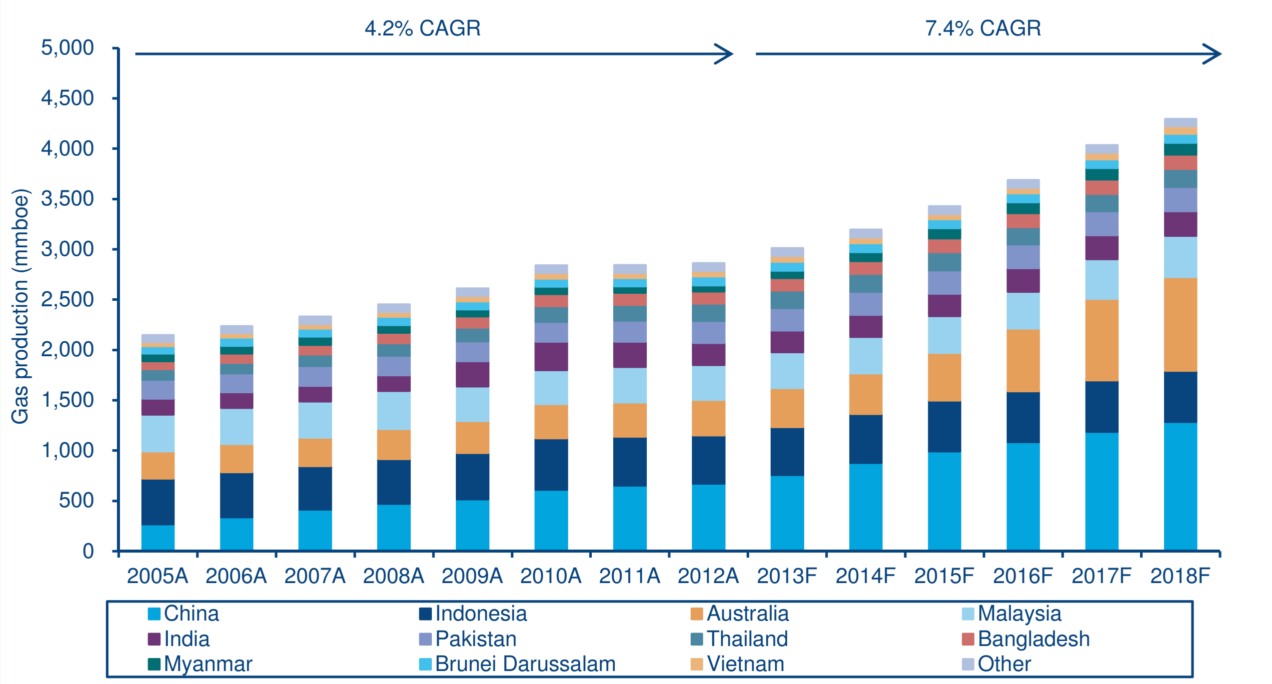
Figure 1.10 Gas production by region (2005A – 2018F)



Source: Wood Mackenzie

Asia-Pacific gas production is expected to grow rapidly, from 3,014 mmboe (17 tcf) in 2013F to 4,298 mmboe (24 tcf) in 2018F. Gas production in the Asia-Pacific region is dominated by China, Indonesia, Australia and Malaysia, which together account for two thirds of the region's production. China is currently the region's largest gas producer and is expected to increase gas production at an average annual rate of 11.1% over the next five years, from 756 mmboe in 2013F to 1,283 mmboe in 2018F. Within the Asia-Pacific region, gas production is expected to grow fastest in Australia, increasing from 386 mmboe in 2013F to 931 mmboe in 2018F. This growth is driven by a dramatic increase in Australia's LNG export capacity, and will see Australia overtake Indonesia as the region's second largest gas producer in 2016.

Figure 1.11 Asia-Pacific gas production by country (2005A – 2018F)



Source: Wood Mackenzie

Asia-Pacific has a reserves to production ratio of 24.3 years (based on 2012A) for gas.

While the advancements in hydraulic fracturing and horizontal drilling have revolutionized North American energy by enabling commercial production of tight and shale gas, it will take time for other regions to enjoy similar success. Issues such as the absence of a supportive regulatory regime, early geological understanding, low local pricing, lack of infrastructure access and low service sector capability are throttling the pace of growth. Consequently Wood Mackenzie does not anticipate that shale gas growth in other regions will make a material impact on either supply or pricing, until after at least 2018F.

2 Crude oil and natural gas pricing

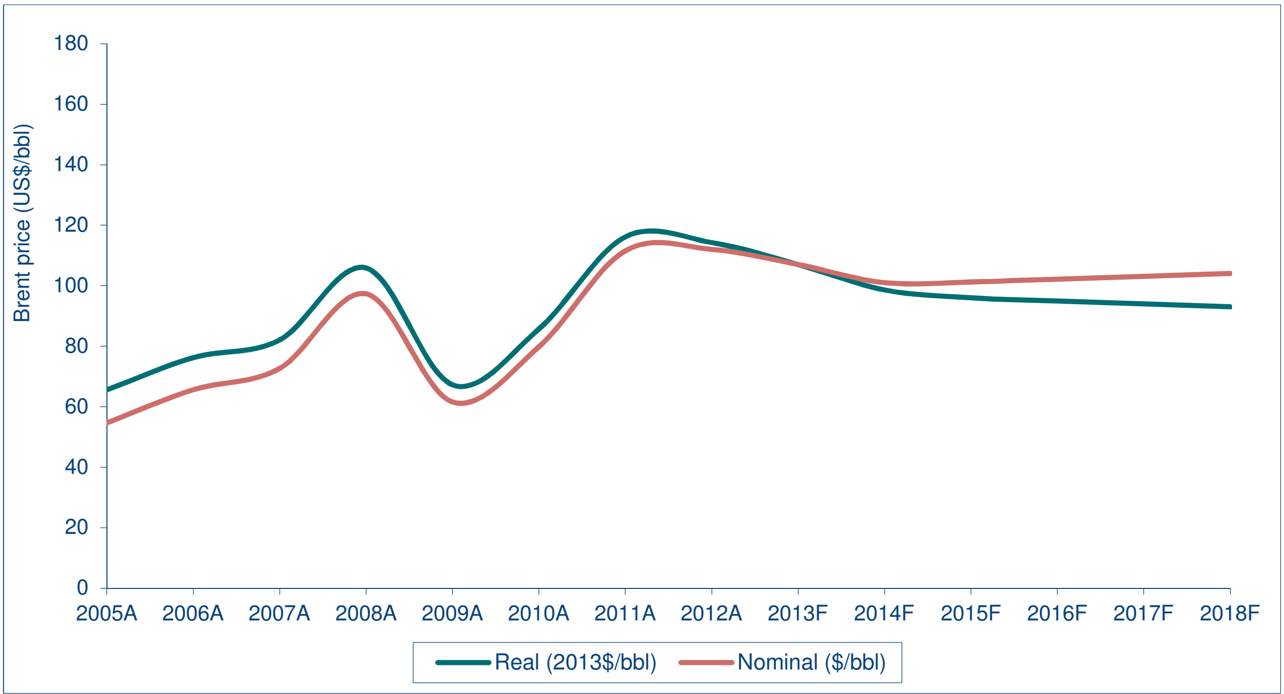
2.1 Crude oil pricing

2.1.1 Key global benchmarks

From 2013F to 2018F, the growth in non-Organization of Petroleum Exporting Countries ("OPEC") production is projected to keep OPEC spare crude oil productive capacity between five and seven million barrels/day. Prices are lower in 2018F on a real basis than projected for 2013F. Wood Mackenzie expects a widening in OPEC spare capacity (Wood Mackenzie forecasts OPEC spare capacity will rise from 5.29 mmbbl/d in 2013F to 6.22 mmbbl/d in 2018F) through much of the decade will cause oil prices to decline on an annual average basis, with Brent falling to a low for 2018F of US$93.00 per barrel real, or US$104.09 per barrel on a nominal basis.

In the period to 2018F, Wood Mackenzie estimates oil will have a protected market share because of the reliance on oil in the transport and the petrochemical sectors. Policies and technologies under development at present to reduce oil use are reflected in the demand forecast but are not expected to have a significant impact over the forecast period (while efficiency improvements and the use of natural gas in transport have been factored into the forecast to some degree, they are not yet strong enough to counter the underlying upward trend in transport caused by a rising middle class and robust GDP growth in the developing parts of the world).

Figure 2.1 Brent crude price (2005A – 2018F)



Source: 2005A-2012A historical data--Thomson Datastream[3]; 2013F-2018F forecast--Wood Mackenzie

Brent-West Texas Intermediate ("WTI") Differential

From late 2010A, the historical differential between Brent and WTI has undergone a major shift, with WTI pricing at a steep discount to Brent – a remarkable shift, given that Brent traditionally traded at a slight discount (approximately US$1.50 per barrel) to WTI, based on Brent being of slightly inferior quality to WTI.

The shift in the relationship between these two marker crude oils is structural, with landlocked U.S. domestic light sweet crude growing in volume and experiencing challenges placing itself in a demand constrained domestic refining system, while waterborne light sweet Brent-linked grades are able to trade more freely in international markets.

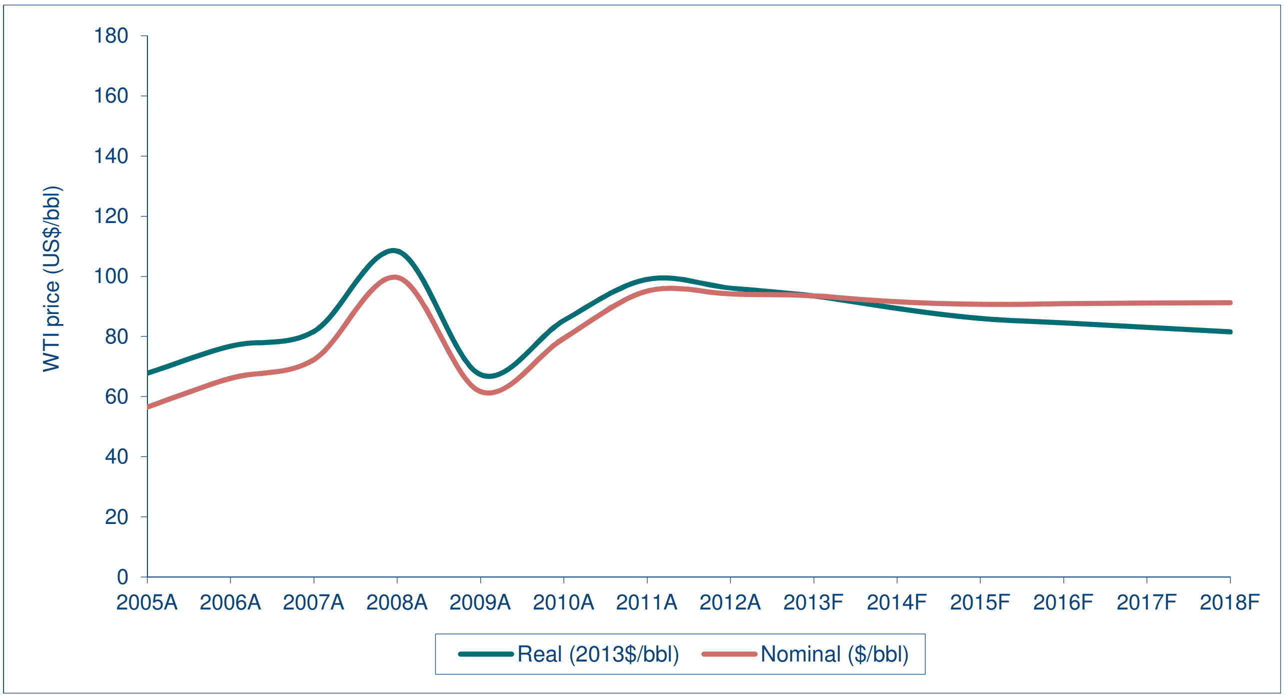
[3] *Thomson Datastream has not provided its consent, for the purposes of Section 249 of the Securities and Futures Act, to the inclusion of the information cited and attributed to it, in this report prepared by Wood Mackenzie and is thereby not liable for such information under Sections 253 and 254 of the Securities and Futures Act. As this report has been prepared by Wood Mackenzie for the purposes of incorporation in an offering document, the company, the vendor and the joint book runners and joint lead managers have relied upon Wood Mackenzie to ensure that the relevant information from the relevant source has been reproduced in its proper form and context. Neither Wood Mackenzie, the company, the joint book runners and joint lead managers nor any other party has conducted an independent review or verified the accuracy or completeness of the relevant information.*

Wood Mackenzie sees the evolution of the Brent-WTI differential as largely driven by three critical factors:

- Refinery demand for light crude oil
- Logistics
- Competition between growing volumes of domestic light crude and waterborne crude imports.

A surge in pipeline capacity additions in 2013F and 2014F could alleviate pipeline bottlenecks to refineries on the Gulf Coast, causing the differential to narrow. However, surging production is expected to result in a period in which the WTI discount to Brent may widen from 2015F to 2020F. Wood Mackenzie expects the differential will start to narrow only after 2020, driven by a flattening of the domestic crude oil production profile, continued additions to pipeline capacity and through growing volumes of domestic light sweet production entering markets on the east and west coasts. Wood Mackenzie does not foresee the differential returning to its historical relationship.

Figure 2.2 WTI crude price (2005A – 2018F)



Source: 2005A-2012A historical data--Thomson Datastream[4]; 2013F-2018F forecast--Wood Mackenzie

Brent-Dubai differential

The availability of light sweet crude increased during 2012A as growing domestic supply in the U.S. reduced demand for U.S. crude imports from West Africa. The resumption of crude exports from Libya has also resulted in increased supply of light sweet crude. This has contributed to narrower price premiums for light sweet crudes versus heavier, more sour, crudes. This has been reflected in the discount for Dubai crude versus Brent which narrowed significantly in 2012A after having been very wide in 2011A. The value of heavier more sour crudes has been supported by sanctions against Iran and Syria which have forced many refiners to look for alternative sources for replacement grades of similar quality.

Wood Mackenzie forecasts that the global crude slate will get lighter through 2017F. As a result Wood Mackenzie expects the price premium for light sweet crudes such as Brent to narrow. Over the same period, investments are being made to increase coking capacity at refineries. This will increase demand for heavier crudes similar to Dubai and their value is expected to increase relative to lighter sweet crudes. Wood Mackenzie estimates that the Brent-Dubai differential will narrow through 2017A, from $3.25 in 2013F to $2.56 (real) in 2018F. After this time, the proportion of

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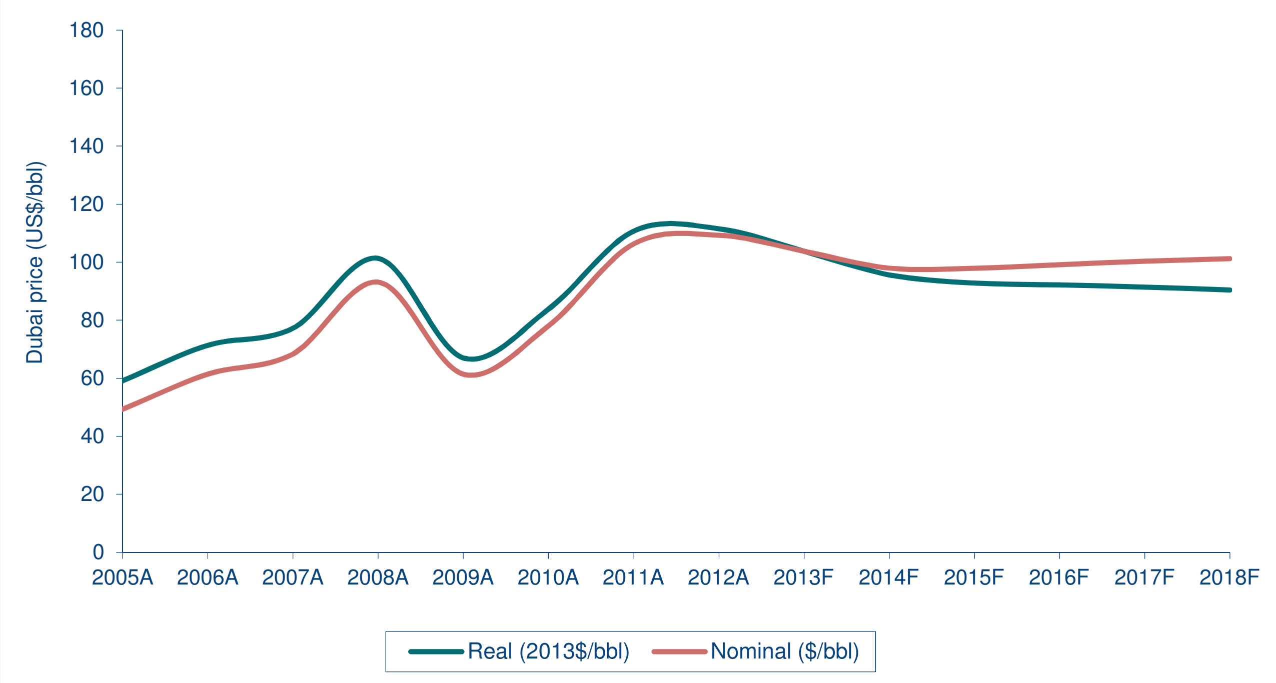
heavy crude in the global crude slate starts to grow and, together with increasing outright prices, this leads Wood Mackenzie to forecast that the Brent-Dubai differential will widen again.

Figure 2.3 Dubai crude price (2005A – 2018F)



Source: 2005A-2012A historical data--Thomson Datastream[5]; 2013F-2018F forecast--Wood Mackenzie

The key light sweet benchmark crudes in the Asia-Pacific region are Minas and Tapis. Both of these crudes traded at 4% to 5% premium to Brent in 2012A.

Landed diesel and Jet A-1 pricing in various Asian markets

As a major trading hub, Singapore plays a critical role in price discovery of regional diesel and jet prices. Prices in Singapore are driven by crude oil prices as well as product specific supply and demand dynamics. Singapore prices directly influence landed prices across the Asia-Pacific Region, with the landed price in many markets equivalent to the Singapore price plus a freight differential. This is the case in markets such as Australia, Indonesia, and Thailand where pricing is equivalent to the traded Singapore adjusted for freight. Ex-refinery prices of diesel and jet in China are set by the government in a way that broadly reflects the Singapore price but is set at a lower level. Prices in India tend to be based off Arab Gulf prices.

2.2 Natural gas pricing

2.2.1 Overview of regional pricing dynamics

Regional gas market dynamics results in different pricing points for gas across the globe. Three of the key pricng points analysed by Wood Mackenzie are;

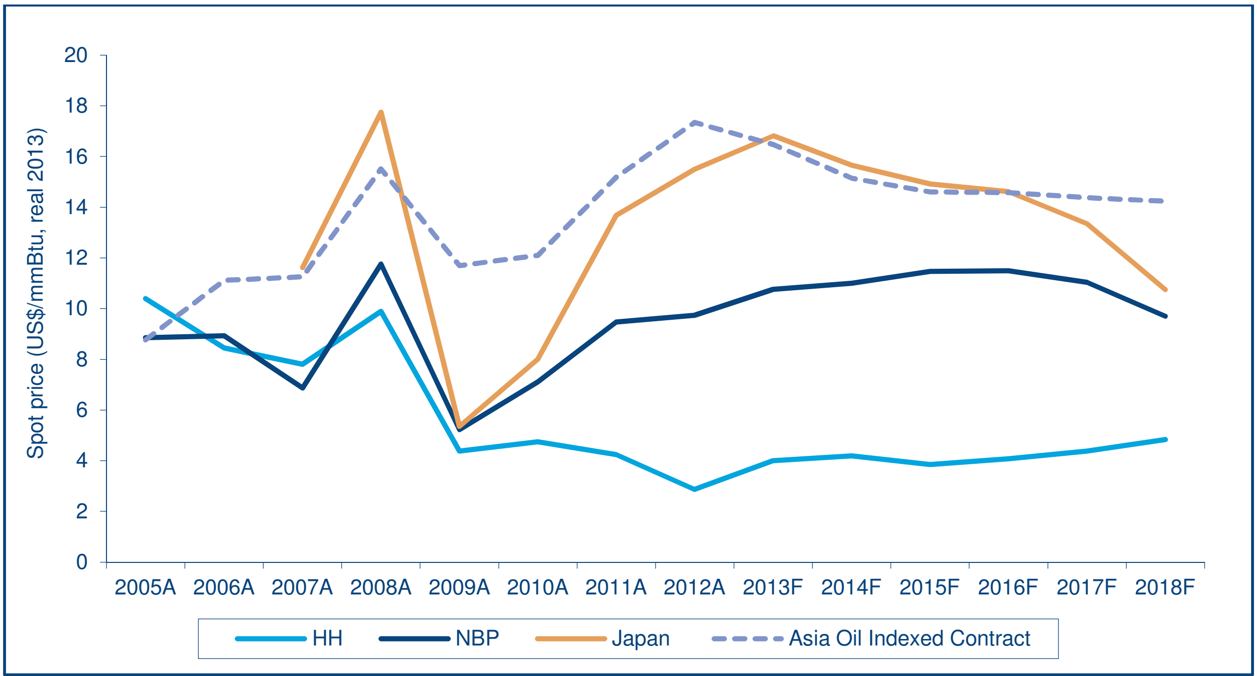
- Henry Hub (HH) – The main pricing point in the U.S. gas market. It is a pipeline interchange near Erath in Louisiana, close to the U.S.'s main production centre on the Gulf Coast. Prices in most locations in the U.S. are indexed at an expressed differential to the Henry Hub.
- National Balancing Point (NBP) - It is generally recognised that the UK has the most liquid traded gas market in Europe, with the NBP growing in popularity as a gas trading hub. Prices in European long term contracts were

[5] Thomson Datastream has not provided its consent, for the purposes of Section 249 of the Securities and Futures Act, to the inclusion of the information cited and attributed to it, in this report prepared by Wood Mackenzie and is thereby not liable for such information under Sections 253 and 254 of the Securities and Futures Act. As this report has been prepared by Wood Mackenzie for the purposes of incorporation in an offering document, the company, the vendor and the joint book runners and joint lead managers have relied upon Wood Mackenzie to ensure that the relevant information from the relevant source has been reproduced in its proper form and context. Neither Wood Mackenzie, the company, the joint book runners and joint lead managers nor any other party has conducted an independent review or verified the accuracy or completeness of the relevant information.

formed on a market value principle, reflecting the competing fuels in individual sectors specific to individual national markets. This was principally defined using oil product indices to ensure that gas retained its competitive advantage in displacing oil demand, although coal, electricity and inflationary indices also feature as indices in some contracts. The UK gas market pricing mechanism is dominated by a virtual trading hub – NBP – where operators balance their portfolio position at the marginal clearing price. The market fundamentals of supply and demand define the pricing dynamics.

- Japan – There is no equivalent trading hub for gas in Asia. Crude oil has generally been used as an index in long term contracts. While this has reflected fuel competition, it has also served as a liquid and transparent reference familiar to both buyers and sellers for the purposes of negotiating an acceptable outcome. Most LNG delivered into Asia is supplied under long term contracts indexed to oil. Spot trading of LNG cargos exists with cargos sometimes trading above oil parity. However, the spot sales accounts for a relatively minor proportion of supply. The prevailing premium that LNG suppliers enjoy in Asian markets is a consequence of the lack of proximate supply to meet demand, requiring LNG from suppliers as far away as Norway and Trinidad & Tobago to meet demand. Wood Mackenzie therefore uses the uncontracted price for gas into Japan as an indicative spot price point for gas.

Figure 2.4 Global gas spot prices (2005A – 2018F, 2013 US$ real)



Source: 2005A-2012A Oil Indices--Thomson Datastream[6], 2005A-2012A NBP--Argus, Others and all forecast 2013F-2018F—Wood Mackenzie

While HH prices in the U.S. have averaged around US$3.75/mmbtu for the last three years Wood Mackenzie expects prices to rise through the medium term to encourage new supply into the market for growing demand to be met. Growing demand will come from the industrial renaissance in the U.S., from fuel displacement in power, residential and transport and from LNG exports. Wood Mackenzie estimates LNG exports from the U.S. will start in 2016, from the Sabine Pass liquefaction facility on the U.S. Gulf Coast. Wood Mackenzie forecasts Henry Hub prices to increase to $5.37 in 2018F (equivalent to $4.70 real).

In the European gas market, the oversupply that has existed since 2008, aggravated by new global LNG capacity coming online, caused a prolonged disconnect between spot prices and oil indexed price levels typical in long term European contracts. Since then the collapse in carbon prices has left gas losing market share to coal in the power sector. But while demand has not fully recovered, a combination of restraint by some major pipe suppliers and a reduction in LNG imports into Europe since 2011 have helped lift spot prices, assisted on occasion by weather effects.

[6] *Thomson Datastream has not provided its consent, for the purposes of Section 249 of the Securities and Futures Act, to the inclusion of the information cited and attributed to it, in this report prepared by Wood Mackenzie and is thereby not liable for such information under Sections 253 and 254 of the Securities and Futures Act. As this report has been prepared by Wood Mackenzie for the purposes of incorporation in an offering document, the company, the vendor and the joint book runners and joint lead managers have relied upon Wood Mackenzie to ensure that the relevant information from the relevant source has been reproduced in its proper form and context. Neither Wood Mackenzie, the company, the joint book runners and joint lead managers nor any other party has conducted an independent review or verified the accuracy or completeness of the relevant information.*

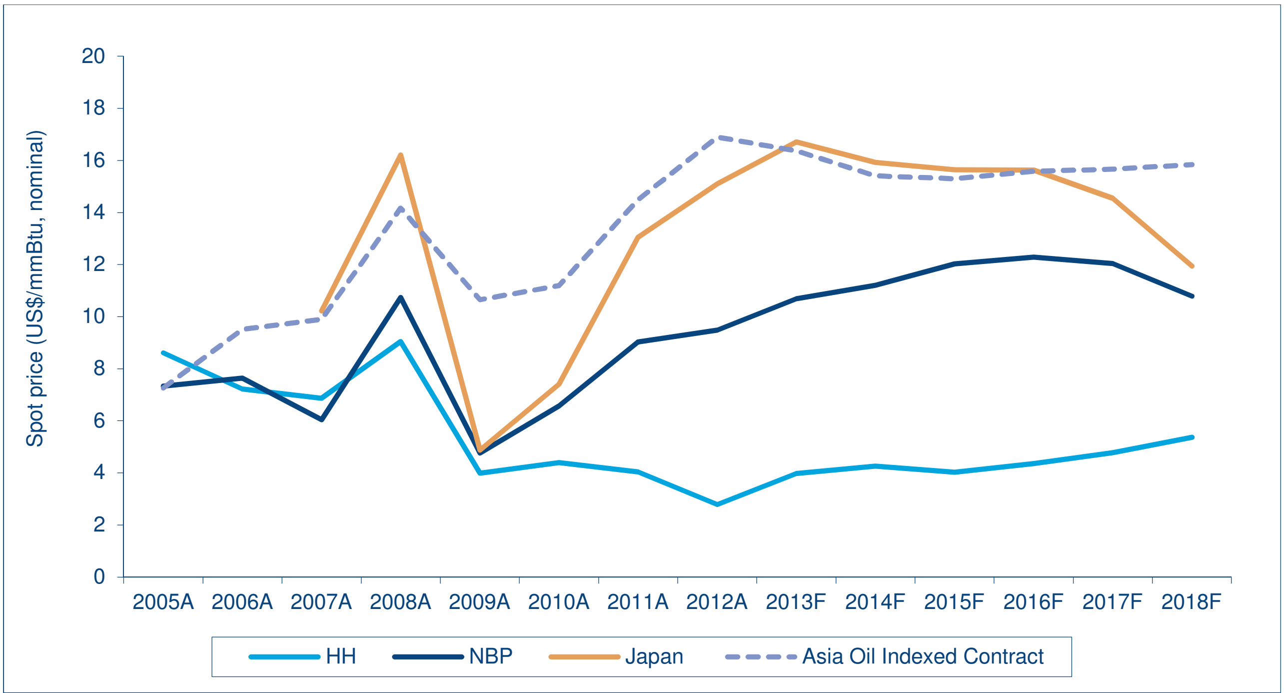
Nevertheless, high oil prices and high corresponding oil indexed contract prices have meant that the disconnect between European spot prices and oil indexed prices has persisted. Global LNG has been diverted to meet the deficit in the Asia-Pacific region and will result in a continued decline in European LNG imports, with incremental gas above annualised contractual offtake obligations and/or flexible LNG imports required to meet demand in the mid-term.

Through to 2017 we expect the delivered price of LNG in Asia-Pacific to be established by the price of fuel oil in the tight Asia-Pacific LNG market. Through this period LNG from Qatar, diverted from Europe, and Atlantic portfolio players remains essential to balance the market. The need to attract Atlantic LNG to balance the market has ensured that Asia-Pacific prices retain a premium over Atlantic prices. And the limited number of sellers has driven prices up to the price of alternative options in the medium term, with oil a key price marker.

Post-2016 the tightness in the Asia-Pacific market diminishes as new LNG supply from Australia and the U.S. comes onstream, providing additional liquidity in the market. Even as the tightness in the market subsides, Asia-Pacific spot prices are expected to retain a premium over Atlantic spot prices through the forecast period due to a lack of sufficient proximate supply options.

High cost gas requiring high indexation term – the high breakeven costs of new greenfield LNG projects, most recently from Australia, means these projects require contract pricing with relatively high oil indexation terms to ensure commerciality. Developers are typically using oil prices of around US$80/bbl for economic hurdles. The corresponding indexation levels required at these oil prices is in excess of 13%. While some term LNG supply has been agreed on a HH basis, oil indexation is likely to remain key to price formation of LNG in Asia for some time, and certainly through 2018F.

Figure 2.5 Global gas spot prices (2005A – 2018F, US$ nominal)



Source: 2005A-2012A Oil Indices--Thomson Datastream[6], 2005A-2012A NBP--Argus, Others and all forecast 2013F-2018F--Wood Mackenzie

Pricing of indigenous gas in Asian markets is priced under a variety of pricing mechanisms. Prices may be linked to a range indices, including High or Medium Sulphur Fuel Oil, local crude benchmarks or ammonia prices. In Thailand a wholesale gas index exists which is also commonly referenced in sales agreement. In general, there has been an increasing convergence of local gas prices and regional LNG prices in recent years.

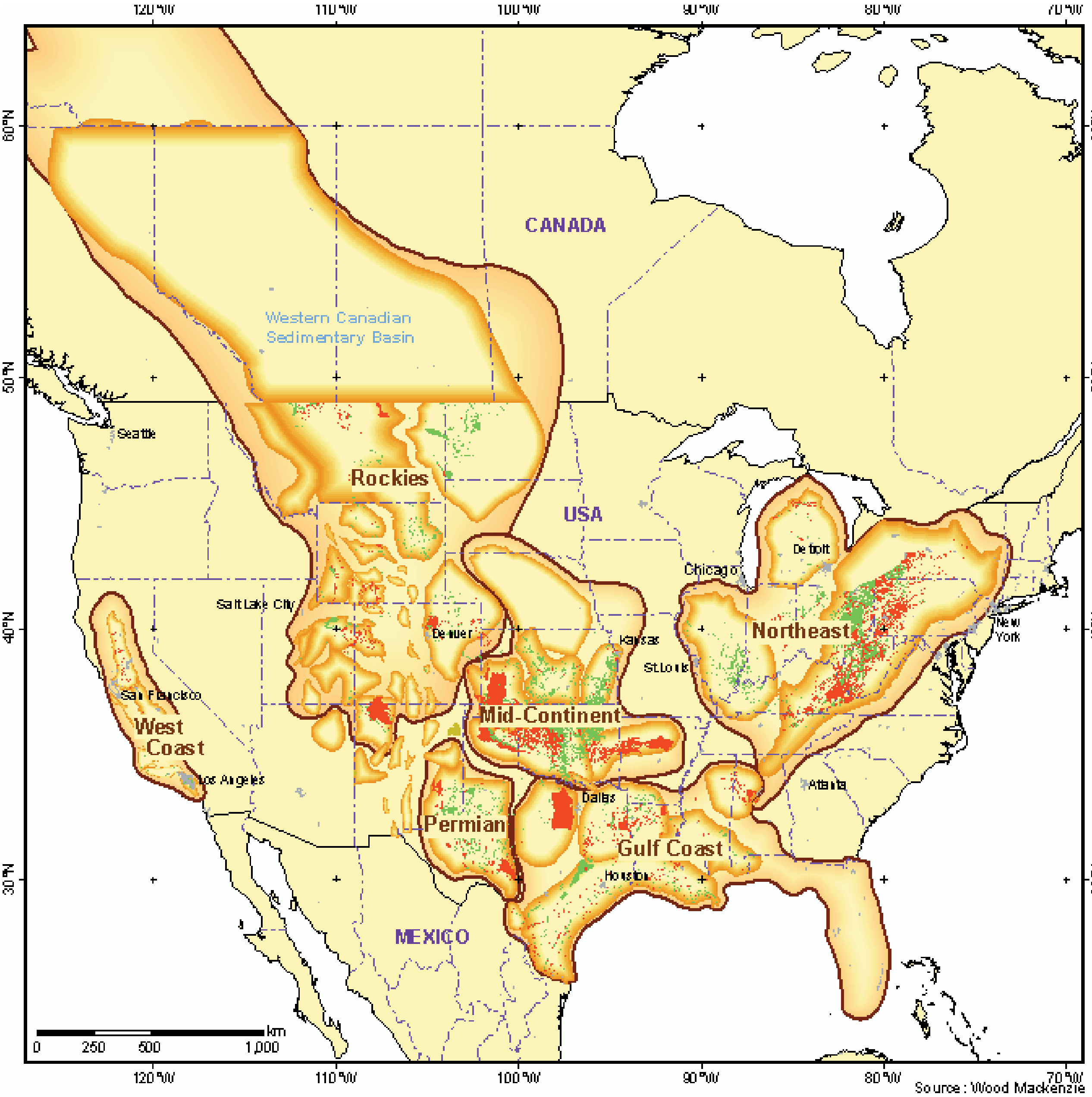
3 Overview of Key Countries' Oil and Gas Industry

3.1 United States of America ("U.S.")

3.1.1 Overview

U.S. energy production has been revolutionised by advances in drilling and hydraulic fracturing technology. The rapid development of the unconventional oil and gas sectors reversed a trend of steadily declining oil production and an outlook for increasing energy imports, including imports of LNG. Instead, liquids production in 2018 is expected to be nearly double that of 2008 and the U.S. is set to become a major LNG exporter.

Figure 3.1 U.S. (and southern Canadian) oil & gas basins map

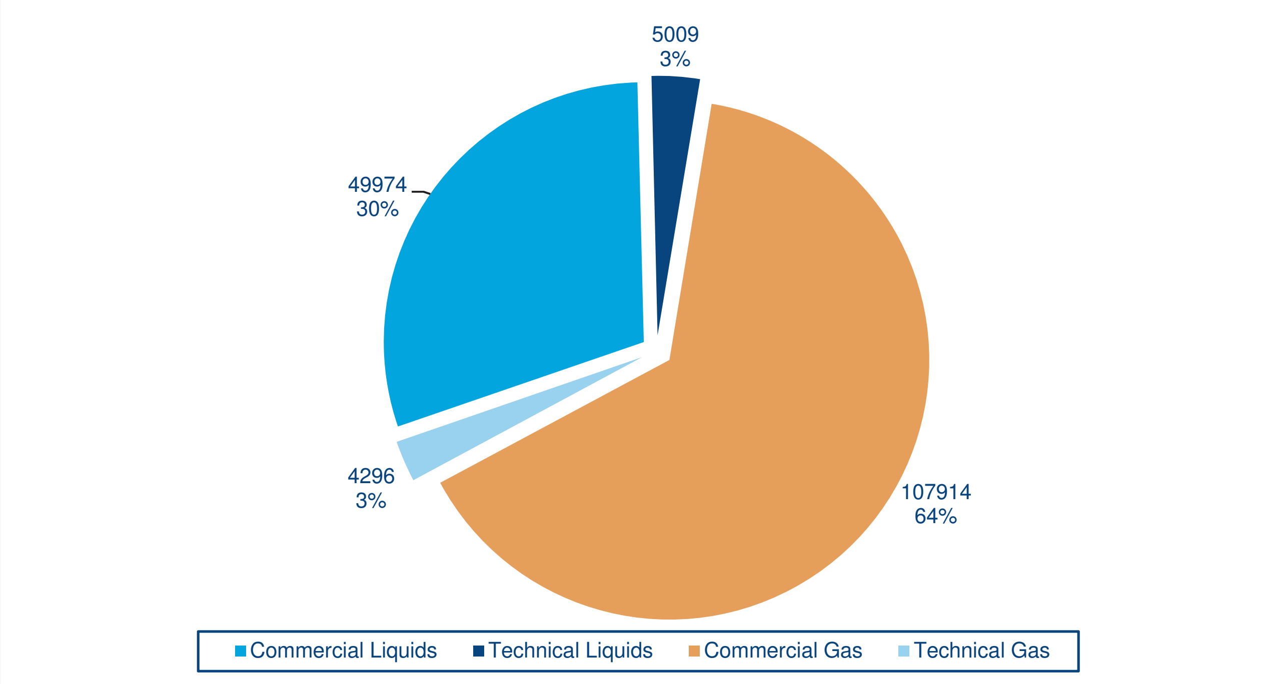


Source: Wood Mackenzie

3.1.2 Oil and gas reserves/resources

The U.S. has 167,193 mmboe of remaining commercial and technical oil and gas reserves. Gas dominates the U.S.'s petroleum reserves, contributing 68% on a commercial and technical basis, and 67% on a commercial basis only. Tight plays dominate liquids reserves while shale plays account for the majority of gas reserves.

Figure 3.2 U.S. commercial and technical oil and gas reserves (mmboe, 2012A)

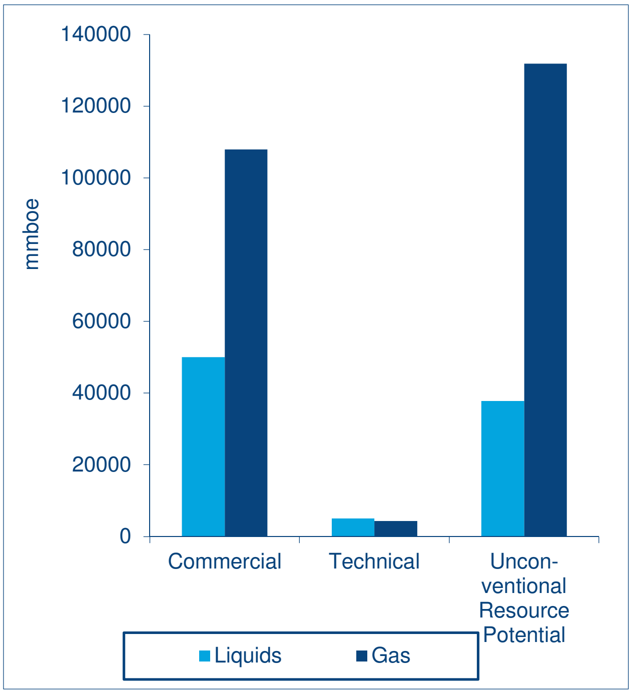


Source: Wood Mackenzie

3.1.3 Unconventional oil and gas reserves/resources

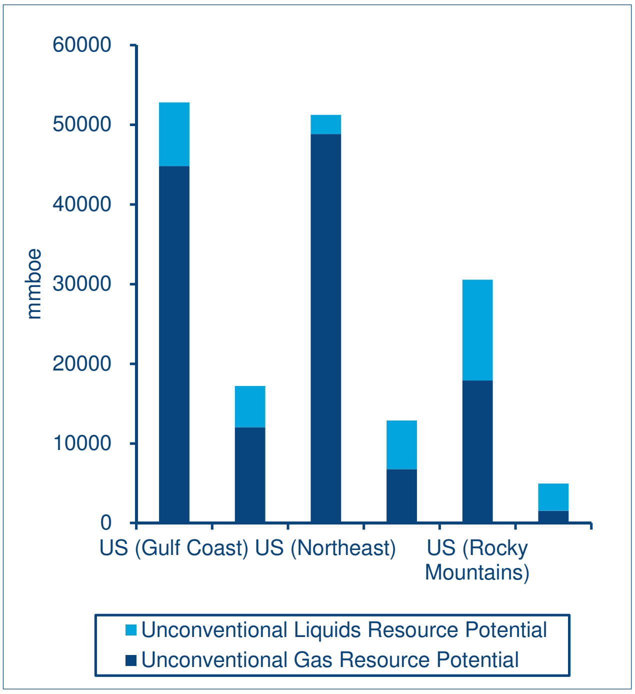
Unconventionals account for 67% of U.S. commercial liquids reserves and over 90% of commercial gas reserves. Additionally, the U.S. has significant further unconventional potential, estimated by Wood Mackenzie at 76% of existing commercial liquids reserves and 122% of existing commercial gas reserves.

Figure 3.3 Reserves and unconventional resource potential



Source: Wood Mackenzie

Figure 3.4 Unconventional resource potential by region

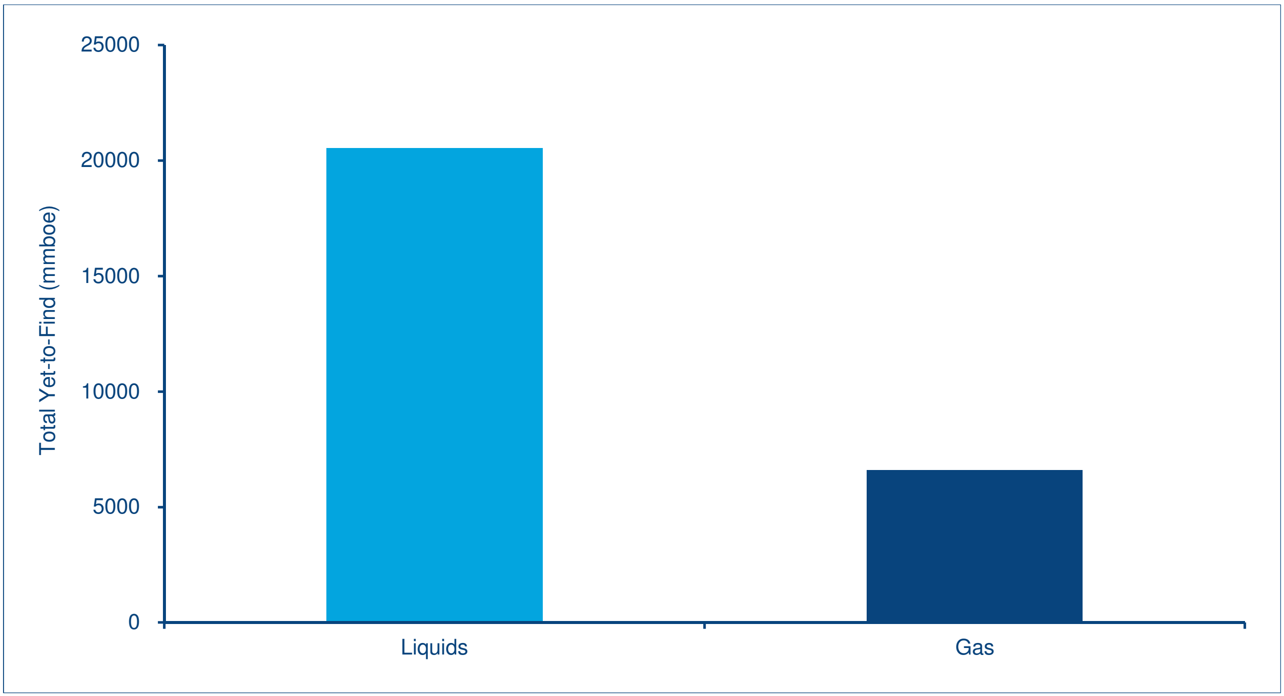


Source: Wood Mackenzie

The growth of unconventionals in the U.S. has resulted in a tremendous diversity of reserves and resources, spread right across the country. Gas reserves are concentrated in the Gulf Coast (home to the Barnett, Haynesville and Eagle Ford plays) and Northeast (home to the prolific Marcellus play) regions. The regions with the largest liquids reserves include the Rocky Mountains (dominated by the Bakken tight oil play), Gulf Coast (in particular, the Eagle Ford play) and Permian (West Texas and southeastern New Mexico).

3.1.4 Prospectivity and recent discoveries

Figure 3.5 U.S. yet-to-find and technical reserve volumes



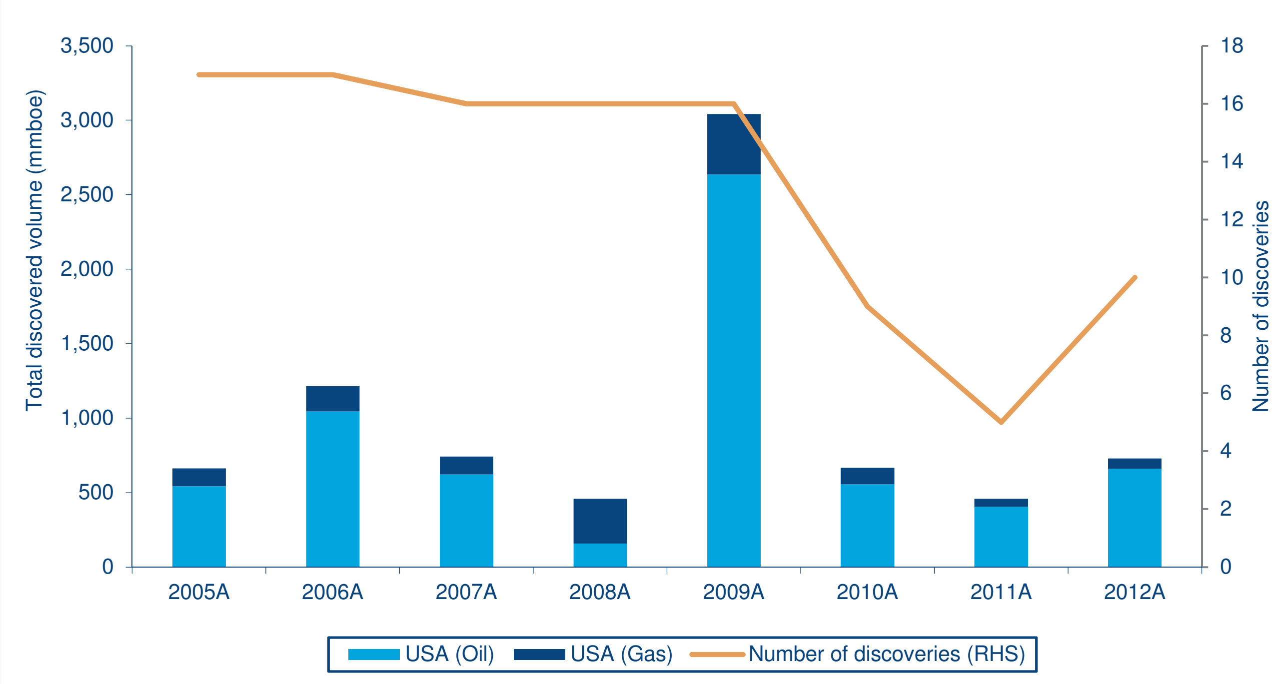
Source: Wood Mackenzie

While the recent focus of the oil and gas industry has been on the unconventional sector, the U.S. also has significant conventional prospectivity. Wood Mackenzie estimates 27,142 mmboe of remaining YTF[7] and technical oil and gas reserves, concentrated in the Gulf of Mexico and offshore Alaska (no technical reserves have been modeled for unconventional plays). Technical reserves in these basins reflect challenging operating environments; extreme environmental conditions in Alaska and depths at the limit of current technology in the Gulf of Mexico. Oil accounts for around 75% of the U.S.'s technical and YTF conventional reserves.

In recent years, the country has seen ~10 oil fields and ~5 gas fields discovered per year, however since 2009, the number of gas discoveries has fallen markedly. The fall in discoveries since 2009 is primarily as a result of lower exploration drilling activity in the Gulf of Mexico in response to the Macondo drilling disaster (in 2010). The volumes discovered each year has varied considerably, with 2009A seeing a high of 3,041 mmboe added (mainly from the Gulf of Mexico). Overall, there has been 7,972 mmboe of discovered volumes from 2005A-2012A.

[7] *Wood Mackenzie bases its YTF resource on the potential from the discovery of conventional oil and gas new fields. Unconventional resource potential is excluded from the scope of reporting, as is the potential from upgrades and extensions on existing discoveries. Wood Mackenzie uses a projected creaming curve to derive the assumption of YTF potential in a basin. The curve is generated using best fit of a hyperbolic trend to historic data on cumulative reserves by cumulative exploration wells. The curve's trajectory is also an assumption of reserves that will be discovered per exploration well. The overall basin YTF assumption is constrained by Wood Mackenzie's forecast of exploration well numbers to 2030F. This YTF assumption is intended to be a broadly realistic input to Wood Mackenzie's future economics evaluation, and is not a substitute for a geologically-constrained resource assessment.*

Figure 3.6 U.S. recent discoveries (2005A – 2012A)

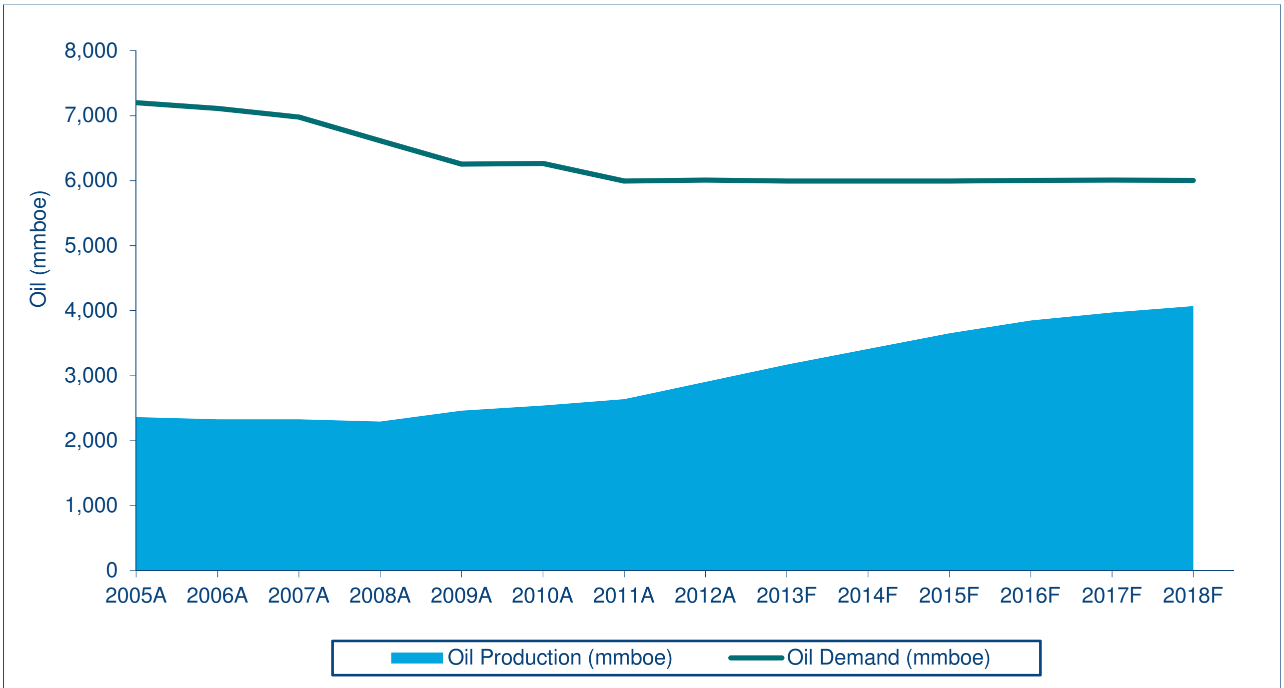


Source: Wood Mackenzie

3.1.5 Historical and forecast oil and gas demand and production

U.S. oil production had been in decline since 1985A, with production of 2,294 mmboe in 2008A, almost 1,000 mmboe less than in 1985A. This decline was halted by the emergence of the unconventional (shale and tight) sector, enabled by technological improvements relating to hydraulic fracturing and horizontal drilling. Since 2008A, U.S. oil production has increased sharply, and is expected to reach 3,171 mmboe in 2013F and 4,069 mmboe in 2018F.

Figure 3.7 U.S. oil supply-demand (2005A – 2018F)



Source: Wood Mackenzie

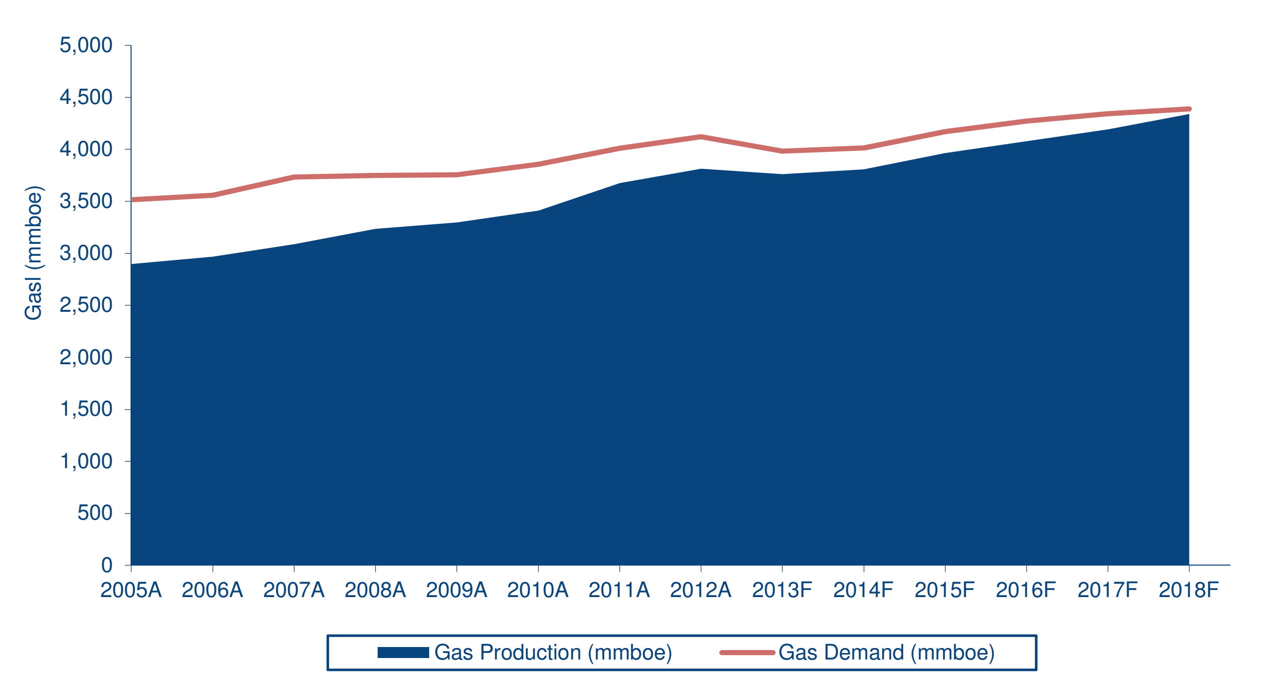
In contrast, U.S. oil demand fell from 2005A to 2011A and is expected to remain flat through to 2018F. A positive economic outlook and a renaissance in the petrochemical industry will be offset by improvements in vehicle fuel efficiency as well as inter-fuel substitution, resulting in the flat demand profile.

As a consequence of the divergent trends in oil demand and supply, the U.S. will become significantly less reliant on imports. In 2005A, the gap between oil demand and supply was 4,833 mmboe and is expected to fall to 1,935 mmboe by 2018F.

U.S. gas supply has increased steadily since 2005, driven by the emergence of the unconventional sector exploiting gas in shale and tight reservoirs. Gas production increased from 2,899 mmboe in 2005A to 3,815 mmboe in 2012A, equivalent to a growth rate of 3.5% per year. Gas production is expected to remain slightly below 2012A levels until 2015F, as drilling activity has shifted away from gas plays towards the higher returns offered by liquids-rich developments. From 2015, gas production is expected to increase again, reaching 4,339 mmboe by 2018F.

The increase in U.S. gas production has led to a significant fall in the gas price. The reduced cost of gas and increased availability has seen demand rise from 3,516 mmboe in 2005A to 4,123 mmboe in 2012A. Falling gas prices and air pollution regulation has resulted in a significant increase in gas demand from the power sector at the expense of coal. Gas demand in 2013F is expected to remain below 2012A levels, as a higher gas price reduces the competitiveness of gas and the implementation of energy efficiency regulation impacts demand growth. Demand growth will resume from 2014F bolstered by new gas-intensive industrial capacity, the continued retirement of coal-fired power plants, the commencement of LNG exports and strengthening power demand from the residential and commercial sectors. Gas demand is expected to reach 4,389 mmboe in 2018F.

Figure 3.8 U.S. gas supply-demand (2005A – 2018F)



Source: Wood Mackenzie

3.1.6 Indicative crude oil and natural gas pricing

Liquids Pricing

The primary oil benchmark in the U.S. is the West Texas Intermediate (WTI), a light, sweet crude. The price settlement point for WTI is Cushing, Oklahoma, an important trans-shipment point with many intersecting pipelines and storage facilities. Arbitrage ensures that pricing from other pricing hubs around the country does not diverge too far from WTI. However, when infrastructure constraints limit arbitrage, differentials can widen with refineries facing constraints paying a higher price.

Natural Gas Pricing

The primary gas benchmark in the U.S. is the Henry Hub price. The Henry Hub is an important pipeline interconnection point near Erath, Louisiana. Henry Hub is the pricing point for natural gas futures on the NYMEX. Arbitrage ensures that prices in other pricing hubs around the country does not diverge too far from Henry Hub, however pricing is sensitive to changes in supply and demand, particularly at less liquid pricing hubs.

3.2 Australia

3.2.1 Overview

Australia has emerged as a major international gas player over the last few years. Already an LNG exporter through the North West Shelf, Darwin and Pluto projects, Australia's global market share is set to soar as seven new greenfield LNG projects come onstream over the coming decade. With this remarkable run of LNG projects, Australia is set to overtake Qatar as the world's largest supplier of LNG by 2018. New LNG capacity is concentrated in two regions; on Australia's northwest coast, supplied by offshore conventional fields and at Gladstone, Queensland, supplied by CBM (coal bed methane, known locally as coal seam gas or CSG) from the Surat and Bowen basins.

Competition for resources and tightening environmental legislation, has resulted in an environment of escalating costs that threatens additional proposed LNG capacity in Australia. However, exploration and appraisal activity is buoyant as operators look for the gas to underpin developments with enhanced economics, such as brownfield expansions and floating LNG (FLNG) projects. Additionally, some smaller operators are now exploring the shale oil and gas potential in numerous basins across Australia and have already attracted farm-ins from Chevron, BG, ConocoPhillips, Hess, Mitsubishi and Statoil.

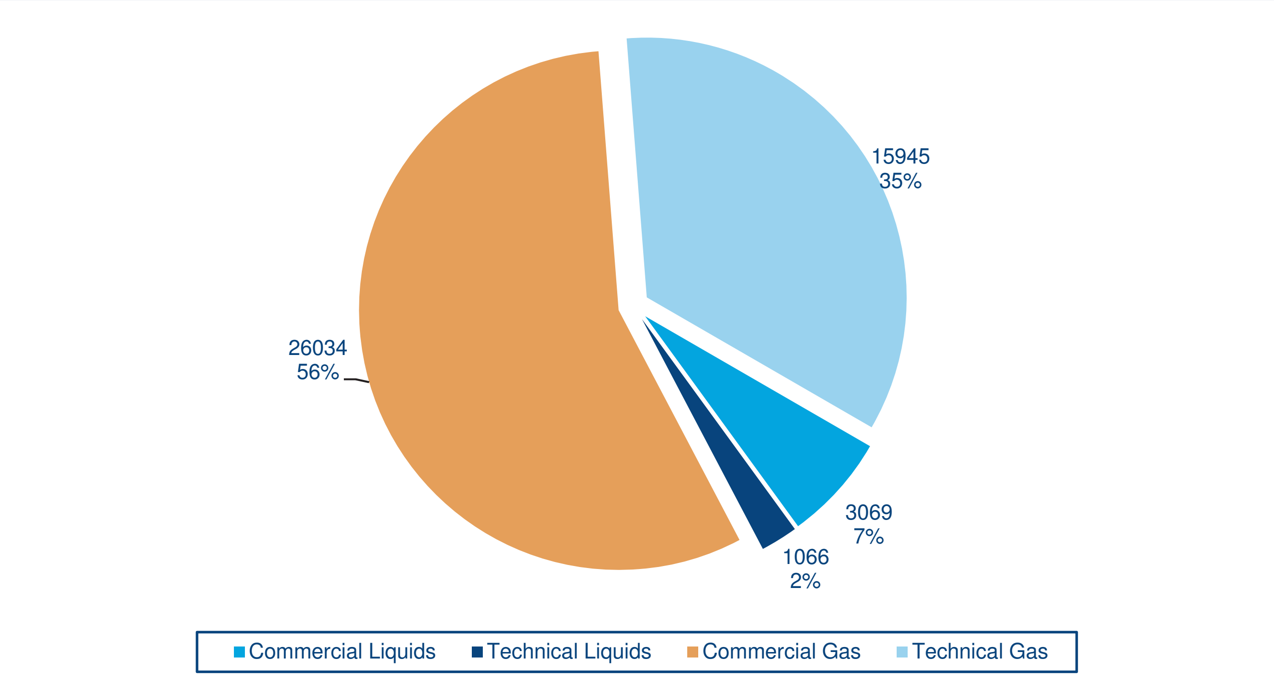
Figure 3.8 Australia oil & gas basins infrastructure map

Source: Wood Mackenzie

3.2.2 Oil and gas reserves/resources

Australia has 46,114 mmboe of remaining commercial and technical oil and gas reserves. Gas accounts for a significant portion of Australia's reserves, contributing 91% on a commercial and technical basis, and 89% on a commercial basis only. The largest gas reserves in Australia are those associated with LNG export projects in Queensland, Western Australia and the Northern Territory. Similarly, the vast majority of Australia's oil/liquids reserves are associated with LNG export projects in Western Australia and the Northern Territory.

Figure 3.9 Australia commercial and technical oil and gas reserves (mmboe, 2012A)



Source: Wood Mackenzie

3.2.3 Unconventional oil and gas reserves/resources

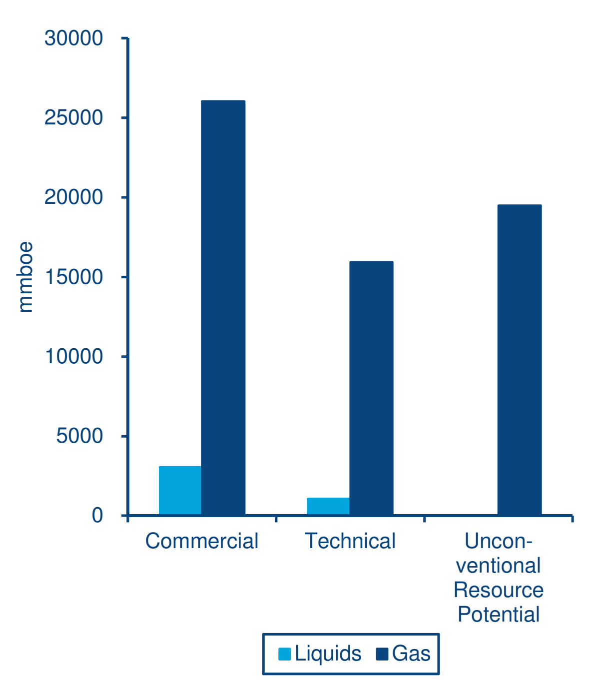
The revolutionary impact of shale gas on the U.S. market (accounting for ~40% of U.S. gas production in 2013F) prompted the search for unconventional oil and gas resources in numerous basins across Australia. Australia is considered highly prospective for unconventional resources, with the EIA estimating that Australia has the seventh largest technically recoverable shale gas resources (437 tcf or 77,130 mmboe), and sixth largest shale oil resources (18 bnboe), in the world.

Wood Mackenzie takes a more conservative estimate as to the unconventional potential in Australia, estimating potential gas resources of 80 tcf (14,120 mmboe) across the Canning, Cooper and Perth basins. Wood Mackenzie estimates another 30 tcf (5,295 mmboe) of potential CBM resources in NSW and QLD, excluding resources already classified as commercial or technical. Exploration and appraisal of unconventional resources is being pursued in many other basins in Australia, however, due to the embryonic state of the industry in these basins, no estimate of resource potential has been compiled. Similarly, despite the indications of significant unconventional liquids potential in Australia, such as the report released by Linc Energy on the Arckaringa basin[8], no estimate of liquids resource potential has been compiled due to the immaturity of the sector.

Australia's unconventional potential has caught the attention of the industry, as evidenced by the number of farm-in deals in recent years. Mitsubishi, Hess, ConocoPhillips and PetroChina have entered into the Canning Basin, BG and Chevron have entered into the Cooper Basin while Santos, Statoil and Total have entered into basins in the Northern Territory. The funds committed under these deals will be critical to the development of the sector and are a positive sign for the sector.

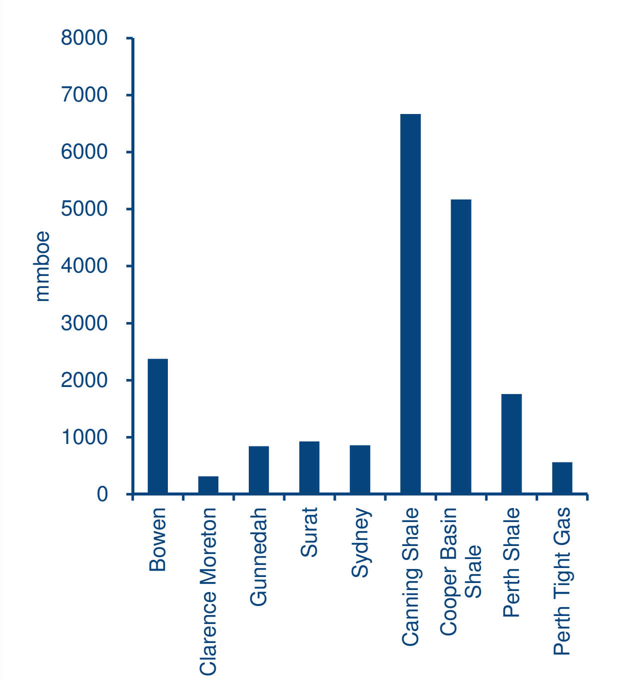
[8] http://www.lincenergy.com/data/asxpdf/ASX-LNC-458.pdf

Figure 3.10 Reserves and unconventional resource potential



Source: Wood Mackenzie

Figure 3.11 Unconventional resource potential by region



Source: Wood Mackenzie

Despite these activities, commercial production of shale gas remains some way off. Different basins face specific challenges, but the entire country is a high cost environment with limited supply chain support. Detailed knowledge of the target shales is limited and will take time to develop. A key enabler for shale gas production is the availability of gas infrastructure, with basins proximate to infrastructure, such as the Cooper and Perth basins, expected to achieve commercial production first. Another key enabler for shale gas production is the presence of liquids. While liquids rich shales are being targeted in a number of basins around Australia, it is too early to estimate their unconventional liquids resource potential.

Comparison to Eagle Ford and Bakken

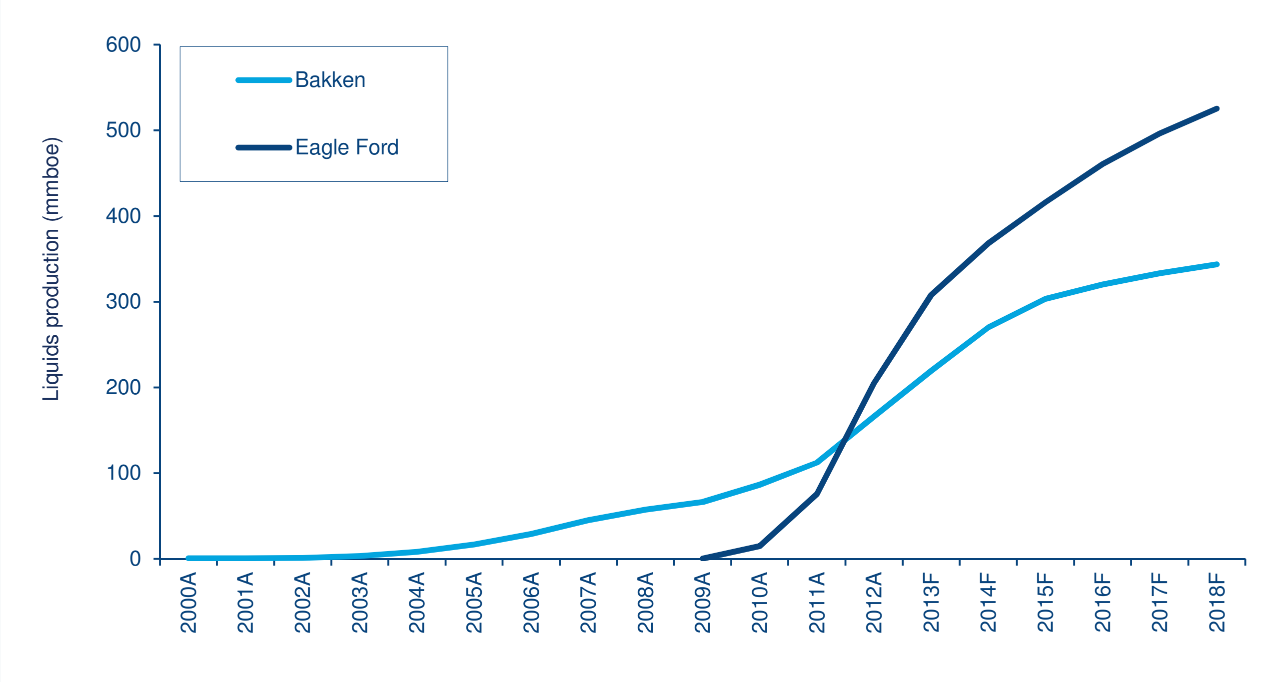
The Eagle Ford and Bakken are leading unconventional plays in the U.S. The Bakken is a world-class tight oil play in the Rocky Mountains (North Dakota and Montana) region, located in the Williston Basin, which also contains the underlying Three Forks formation. The Eagle Ford is a shale play in the Gulf Coast Basin, South Texas. Production from Bakken wells is roughly 80% oil, with the balance split between gas and natural gas liquids. Production from the Eagle Ford varies significantly across the play, varying from dry gas to heavier oil (25° – 40° API), with a gas-condensate (40°+ API) window in between.

The Bakken was one of the country's first commercial tight oil plays with the beginning of the current phase in the play's history often dated to Lyco Energy's entry in 2000. Early success, with the discovery of the Elm Coulee field, attracted new entrants to the play. Not only did the these entrants increase the number of wells drilled, they drove significant innovation in well design, drilling techniques, fracturing technologies and well spacing. Over time, as these parameters were optimised for different sections of the play, well productivity and production rose significantly. Production increased by at least 25% per year, in every year from 2001A to 2013F, except 2009 (in which the rig count significantly decreased). In many years, the increase in production exceeded 50% and even exceeded 100% in 2003, 2004 and 2005.

In comparison, the growth of liquids production from the Eagle Ford was explosive, as technologies and learning were transferred from other plays. Apache drilled its first wells in the Eagle Ford in early 2008, and began testing different drilling and fracturing techniques. By mid-2010, the rig count exceeded 70, with drilling innovation, including the use of batch drilling, continuing. Crude and condensate production from the Eagle Ford is approaching 600,000 boe/d. Wood Mackenzie predicts total liquids production from the play will exceed 1,000,000 boe/d in 2015.

While companies have leased large amounts of land across all hydrocarbon windows (dry gas, gas-condensate, oil) of the Eagle Ford, the economics associated with each distinct window vary greatly. Currently, producers are focused mainly on developing the gas-condensate window which offers the most attractive economics. In contrast, the dry gas window does not produce positive returns at current gas prices with many operators allowing leased acreage to expire in this window.

Figure 3.12 Production profile development curve (mmboe)



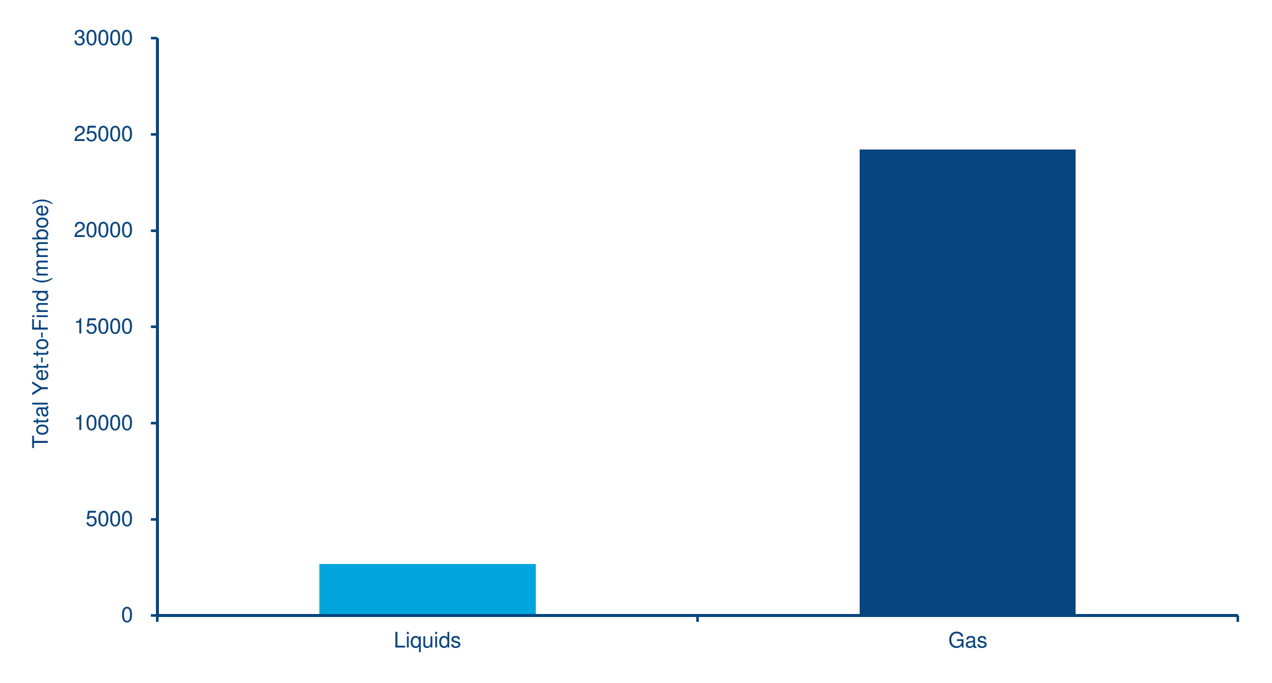
Source: Wood Mackenzie

In comparison to the Bakken and Eagle Ford, all tight and shale plays in Australia are in their infancy. To date, the largest unconventional spend has occurred in the Cooper Basin, where gas, rather than liquids, is the target of exploration activities. Shale plays in which liquids are a primary target, have seen even less drilling. The Arrowsmith-2 well in the Perth Basin recovered oil from shale in March 2013, the first well in Australia to do so. The oil window of the Goldwyer shale in the Canning Basin, has been drilled once, while the various plays being proposed in the Northern Territory are yet to have any wells drilled at all.

Significant exploration and drilling activity will be required to determine the viability of Australia's shale and tight plays, with much further activity required to determine sweet spots in the play and the optimal drilling and fracturing techniques for the different sections of each play. The funds committed under the recent spate of farm-ins into unconventional acreage will be critical to the initial assessment of the viability of these plays. The results of these initial drilling programs will be a key influence on speed of the development of these plays. However, Australia's high cost environment, lack of service sector support, the remoteness of many of the most prospective plays and other challenges such as native title agreements and a wet season that reduces available drilling time, all add to the cost and time required for development. Consequently, while the ability to transfer technology and learnings should result in a more compressed learning curve than in the Bakken, Australia-specific challenges faced make an Eagle Ford style growth in production unlikely.

3.2.4 Prospectivity and recent discoveries

Figure 3.13 Australia yet-to-find and technical reserve volumes



Source: Wood Mackenzie

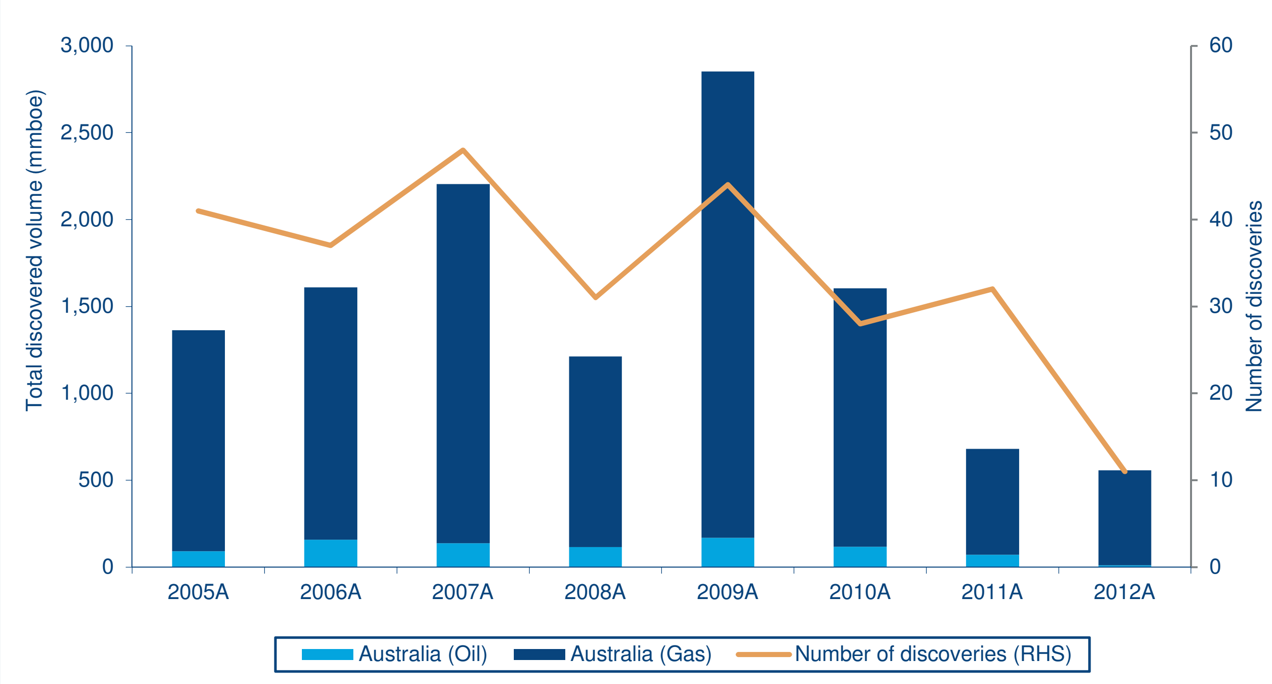
Australia is viewed as having considerable remaining oil and gas potential, with Wood Mackenzie estimating 26,886 mmboe of total technical reserves and YTF[9] volumes. Technical reserves include both conventional reserves and CBM reserves in Queensland and New South Wales. The Browse, Carnarvon and Bonaparte basins off Australia's north western coast dominate Australia's technical reserves and YTF volumes. These basins are remote, necessitating large-scale developments, far beyond what the domestic market can absorb. However, the logistics and economics of developing fields in these basins will be improved by the infrastructure associated with the current wave of LNG projects and maturing FLNG technology, thus driving increased exploration and the development of reserves currently classified as technical.

Additionally, Wood Mackenzie estimates significant technical CBM reserves, in Eastern Australia. In Queensland, the development of additional LNG capacity, beyond the three projects currently under construction could drive the monetisation of these technical reserves. New South Wales also has material technical reserves, however to date, regulation has hindered the development of the CBM industry in this state.

In recent years, 10-20 oil fields and 20-30 gas fields have been discovered per year. However as operators have moved towards the development of these fields, the number of discoveries has trended downwards. Between 2005A and 2010A, over 1,000 mmboe was added each year, with 2009A seeing a high of 2,853 mmboe added (mainly from the North Carnarvon and Browse basins). Overall, there have been 12,085 mmboe of discovered volumes from 2005A-2012A.

[9] *Wood Mackenzie bases its YTF resource on the potential from the discovery of conventional oil and gas new fields. Unconventional resource potential is excluded from the scope of reporting, as is the potential from upgrades and extensions on existing discoveries. Wood Mackenzie uses a projected creaming curve to derive the assumption of YTF potential in a basin. The curve is generated using best fit of a hyperbolic trend to historic data on cumulative reserves by cumulative exploration wells. The curve's trajectory is also an assumption of reserves that will be discovered per exploration well. The overall basin YTF assumption is constrained by Wood Mackenzie's forecast of exploration well numbers to 2030F. This YTF assumption is intended to be a broadly realistic input to Wood Mackenzie's future economics evaluation, and is not a substitute for a geologically-constrained resource assessment.*

Figure 3.14 Australia recent discoveries (2005A – 2012A)

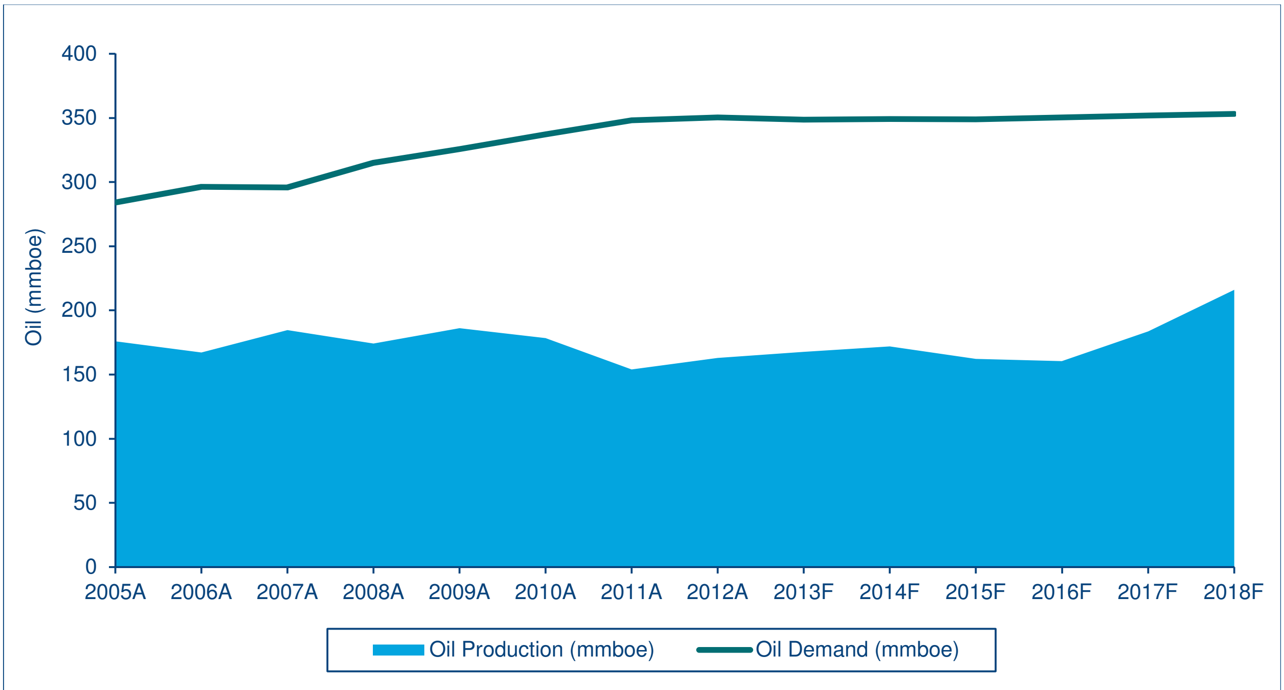


Source: Wood Mackenzie

3.2.5 Historical and forecast oil and gas demand and production

Australia's oil demand increased from 284 mmboe in 2005A to 350 mmboe in 2012A, equivalent to an annual rate of 3.0%. This increase was driven by growth from the mining and transport sectors. However, oil demand is expected to remain flat from 2013F to 2018F. This lack of growth will occur as demand increases from economic growth and vehicle ownership growth are offset by engine efficiency, fuel switching in the power generation and industrial sectors and lower oil losses driven by reduced oil refining capacity.

Figure 3.15 Australia oil supply-demand (2005A – 2018F)



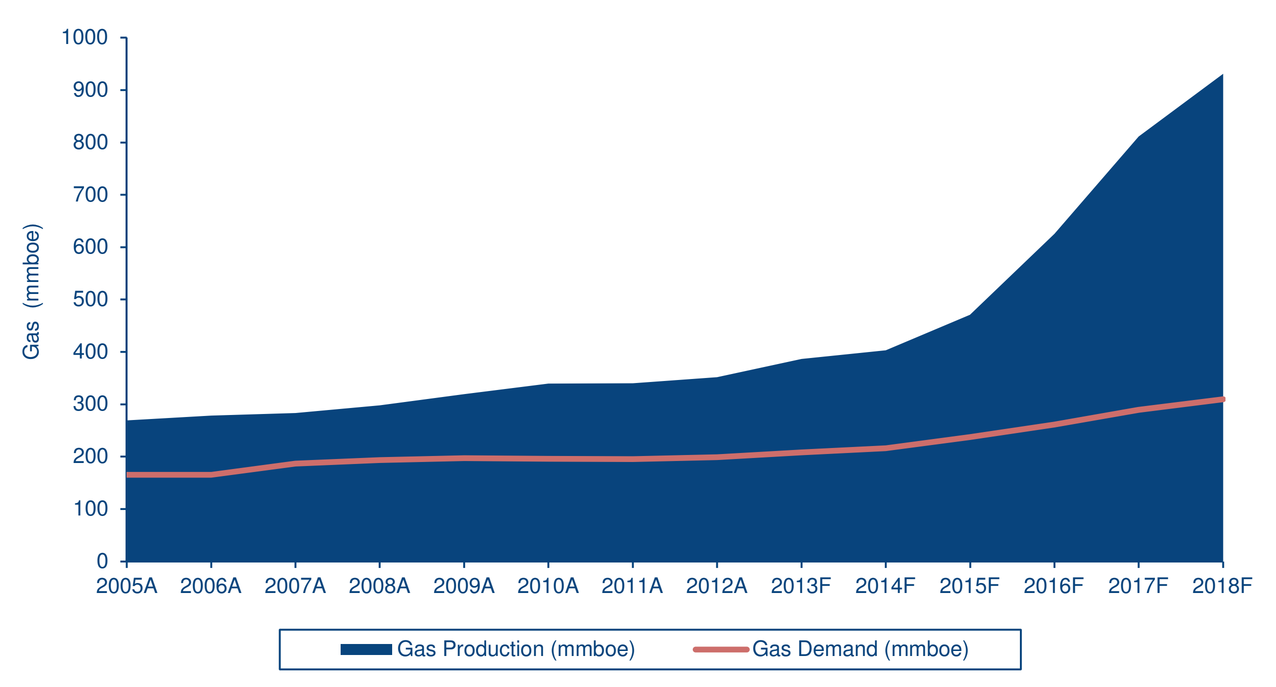
Source: Wood Mackenzie

Australian oil production has been in gradual decline as smaller new oil developments have struggled to replace output from larger, mature fields such as the Bass Strait. This decline trend is set to be halted and, from 2017F, reversed, by the ramp-up of condensate production from major gas/LNG projects, such as Ichthys and Gorgon.

Australian gas supply is expected to increase from 386 mmboe in 2013F to 931 mmboe in 2018F, equivalent to an annual growth rate of nearly 20%. This dramatic growth is driven by an increase in LNG exports, which will see Australia become the world's largest exporter of LNG. Projects commencing or ramping-up between 2013F and 2018F include Pluto, Gorgon and Wheatstone in Western Australia, QCLNG, APLNG and GLNG in Queensland, Ichthys in the Northern Territory and the Prelude FLNG project.

Australia's gas consumption is expected to grow from 208 mmboe in 2013F to 310 mmboe in 2018F. However, this growth is largely driven by losses/consumption from LNG liquefaction plants which is expected to account for over a third of Australian gas consumption by 2018F. Excluding losses/consumption from LNG liquefaction plants, Australian gas demand is expected to remain largely flat, reflecting lower power demand, increased competition from renewables and a demand response to higher gas prices.

Figure 3.16 Australia gas supply-demand (2005A – 2018F)



Source: Wood Mackenzie

3.2.6 Indicative crude oil and natural gas pricing

Liquids Pricing

Oil is sold at a price referenced to local crudes (e.g. Tapis) or baskets of crude (e.g. Brent, Tapis and Minas). Condensate pricing is based on a similar selection of reference crudes, plus a discount or premium of typically less than 5%.

Natural Gas Pricing

Eastern Australia, Western Australia and the Northern Territory operate as separate gas markets with no interconnectivity between them. Market dynamics and prices vary between each market. Each of the Australian gas markets is characterised by long-term bilateral contracts between wholesale gas buyers and producers, with shorter term trades primarily used for balancing, portfolio optimisation and to procure emergency supply during supply interruptions.

Historically, prices across Australia were far below global levels, reflecting a cost-based pricing structure. In Eastern Australia, the development of the CBM to LNG plants has resulted in a transition of domestic prices towards LNG netback levels (LNG price received minus shipping minus liquefaction costs). This transition is expected to continue, with contracts increasingly containing a linkage to oil prices (as is standard with LNG pricing). In Western Australia, strong demand and increasing costs have resulted in dramatically increased gas prices, which were in some cases higher than LNG netback levels. Here too, a number of contracts are now linked to oil prices rather than the traditional fixed price with CPI escalation. Gas pricing in the Northern Territory remains on a fixed price basis, however, incremental demand from mine sites is expected to be linked to oil prices or High Sulphur Fuel Oil.

3.3 South East Asia (SEA)

3.3.1 Overview

With developing economies achieving strong levels of economic growth, South East Asian energy demand is expected to experience robust growth over the forecast period. The region's liquids production is quite mature, and will be unable to keep pace with demand, increasing the region's reliance on crude imports.

Gas demand growth will also outpace production. Although the region has historically been a major exporter of LNG, imports of LNG will grow rapidly over the forecast period, driven by Thailand, Indonesia, Malaysia and Singapore. In order to incentivise further exploration and the development of higher cost technical reserves, governments around the region have been raising domestic gas prices. Significant technical reserves exist in Indonesia and Malaysia but will take time to be developed, despite gas price reform.

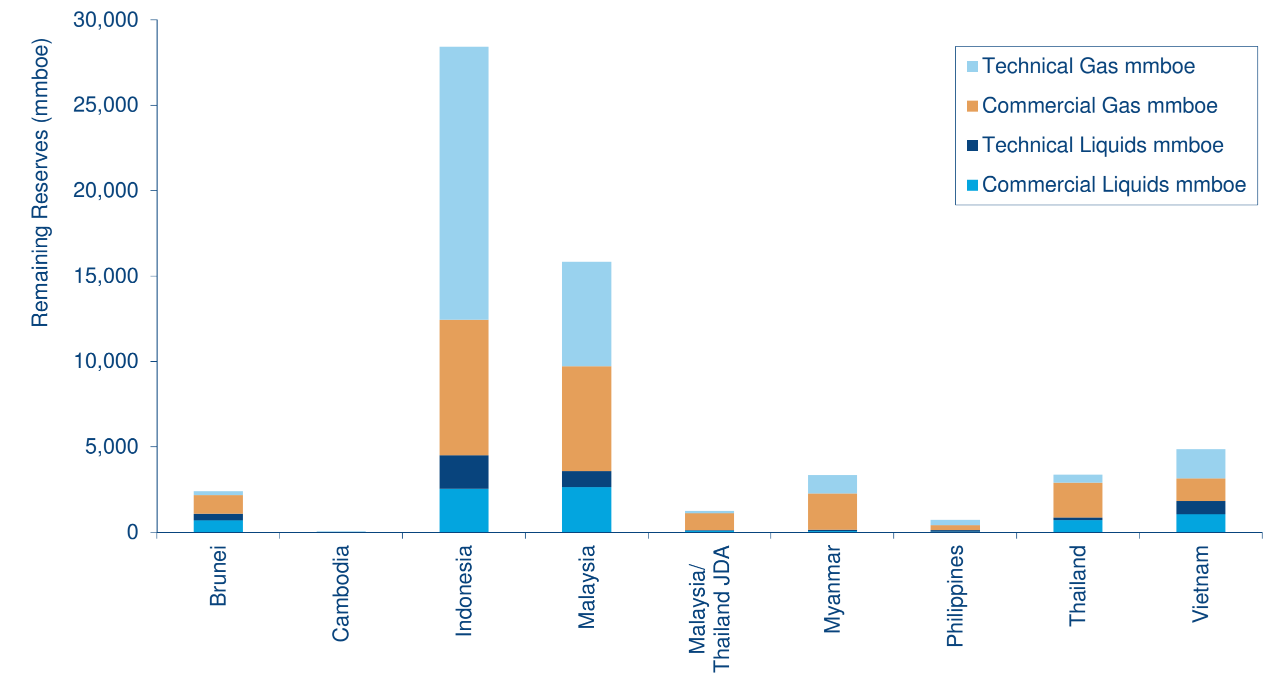
Figure 3.16 South East Asia oil & gas basins map

Source: Wood Mackenzie

3.3.2 Oil and gas reserves/resources

South East Asia has 60,310 mmboe of remaining commercial and technical oil and gas reserves. The bulk of the reserves are located in Indonesia and Malaysia, which contribute 28,432 mmboe (47%) and 15,852 mmboe (26%) to the regional total, respectively. In South East Asia, 80% of commercial and technical reserves are gas, demonstrating the strong regional bias toward gas.

Figure 3.17 SEA commercial and technical oil and gas reserves (mmboe, 2012A)



Source: Wood Mackenzie

3.3.3 Unconventional oil and gas reserves/resources

No unconventional oil and gas reserves have been booked in South East Asia. Indonesia has the most promising geology for unconventional gas production, prospective for both coal bed methane (CBM) and shale gas. Additionally, the country's declining conventional gas supply has increased the potential role of unconventional gas in Indonesia's future energy mix.

CBM is being evaluated in the Barito, South Sumatra and Kutei basins. The Indonesian government has recognised CBM as a viable alternative to conventional resources, and has adjusted fiscal terms to encourage investments. Some of the CBM resources in Indonesia are considered to be world class and have attracted large producers to conduct exploration activities. Thus, despite facing a number of challenges, CBM could be commercially produced, both as LNG feedgas and as supply to the domestic market. In contrast, production from Indonesia's shales are long-dated. The Indonesian government has drafted shale gas regulations, but has yet to sign them into law. This legal framework is the necessary first step in the lengthy process of evaluating the commercial potential of Indonesia's shale gas resources.

Based on Wood Mackenzie's projections, the total yet-to-find ("YTF") volume in South East Asia is 14,433 mmboe, of which 4,916 mmboe is liquids and 9,517 mmboe is gas.[10] Indonesia, Malaysia and Myanmar are highly prospective for gas reserves, while Vietnam's YTF liquids volume is the highest in the region at 1,821 mmboe.

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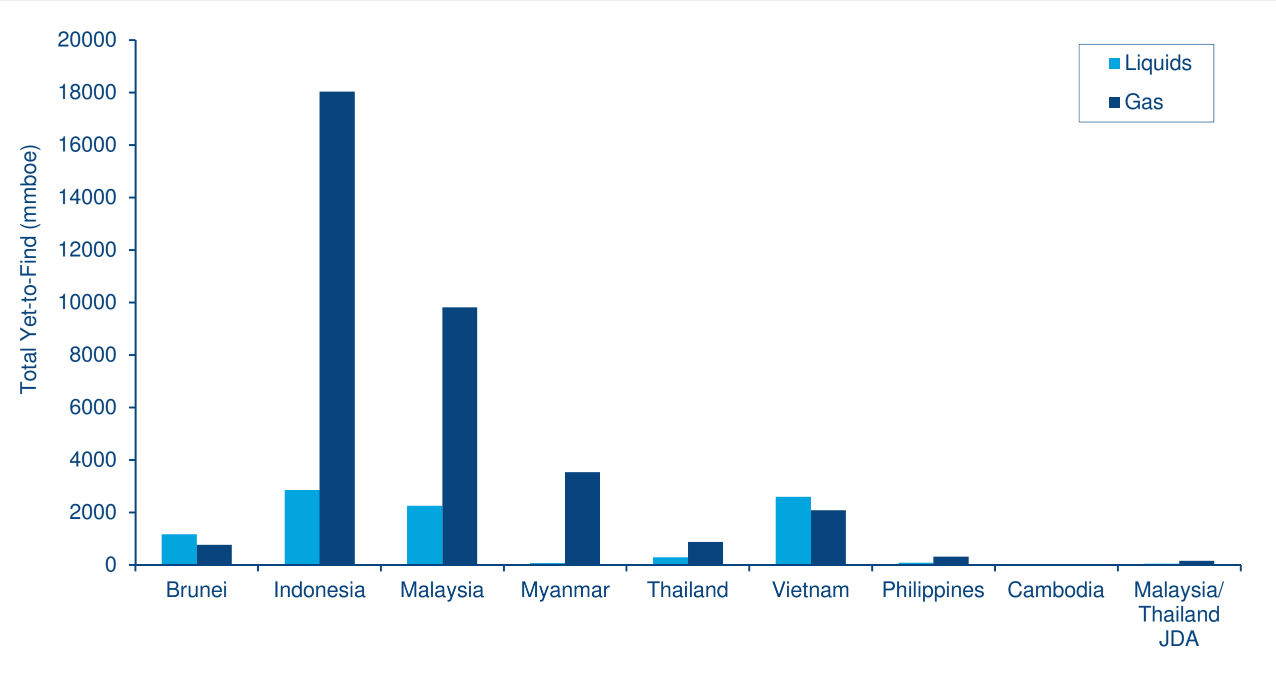
[10] *Wood Mackenzie bases its YTF resource on the potential from the discovery of conventional oil and gas new fields. Unconventional resource potential is excluded from the scope of reporting, as is the potential from upgrades and extensions on existing discoveries. Wood Mackenzie uses a projected creaming curve to derive the assumption of YTF potential in a basin. The curve is generated using best fit of a hyperbolic trend to historic data on cumulative reserves by cumulative exploration wells. The curve's trajectory is also an assumption of reserves that will be discovered per exploration well. The overall basin YTF assumption is constrained by Wood Mackenzie's forecast of exploration well numbers to 2030F. This YTF assumption is intended to be a broadly realistic input to Wood Mackenzie's future economics evaluation, and is not a substitute for a geologically-constrained resource assessment. Basin coverage excludes Cambodia and the Philippines.*

3.3.4 Prospectivity and recent discoveries

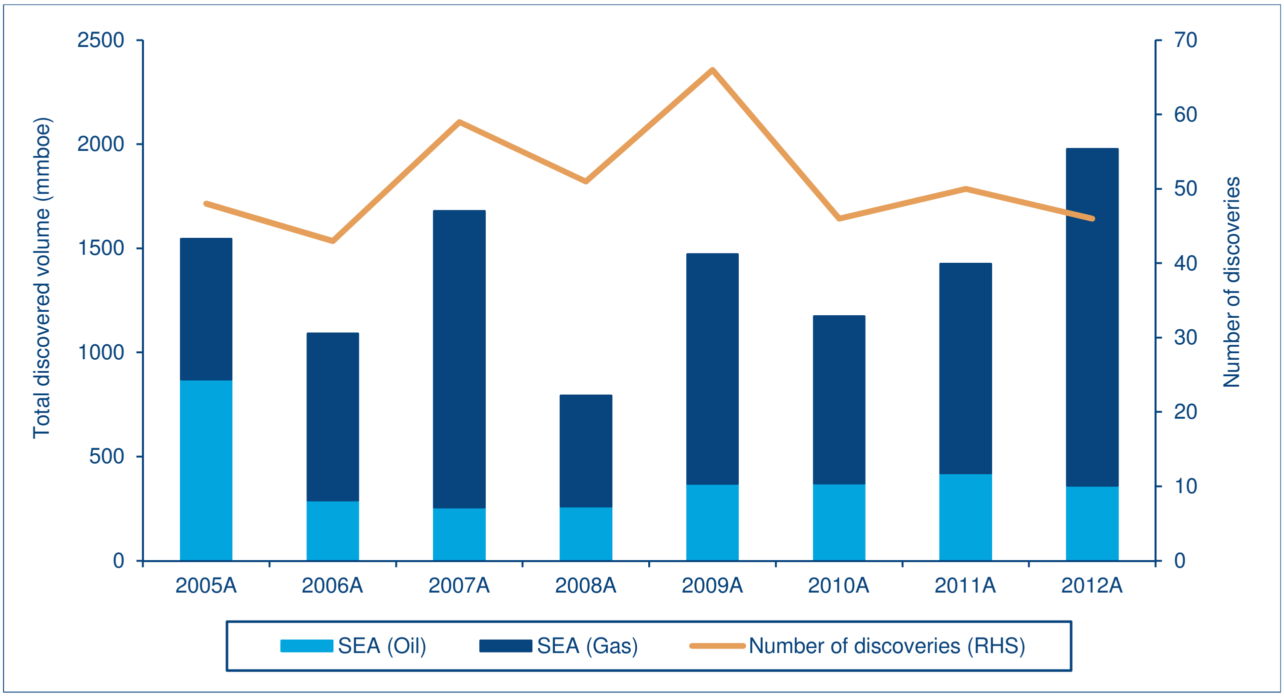
Figure 3.18 SEA yet-to-find and technical reserve volumes



Source: Wood Mackenzie

In recent years, 40-60 discoveries have been made per year, split relatively evenly between gas and liquids. However, discovered volumes between 2005A-2012A have been weighted towards gas, with total discovered gas of 7,966 mmboe compared to 3,195 mmboe of liquids. Vietnam accounts for the largest share of discovered liquids, followed by Malaysia, Indonesia and Brunei. Malaysia dominates discovered gas, accounting for nearly half of all volumes discovered in South East Asia.

Figure 3.19 SEA recent discoveries (2005A – 2012A)



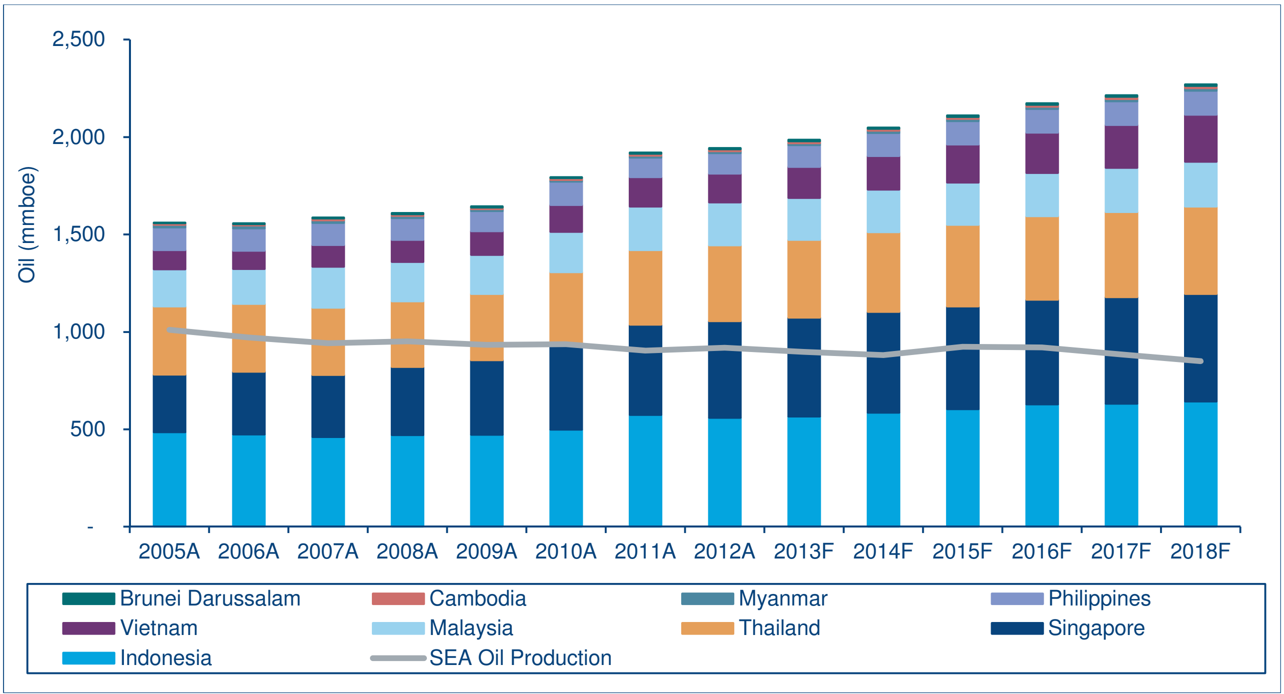
Source: Wood Mackenzie

3.3.5 Historical and forecast oil and gas demand and production

South East Asia's oil demand increased from 1,561 mmboe in 2005A to 1,944 mmboe in 2012A, equivalent to an annual rate of 3.2%. South East Asian oil demand is expected to continue to grow strongly, at an average annual rate of 2.7%, reaching 2,270 mmboe by 2018F. Indonesia is the largest market for oil in South East Asia, driven by transport requirements, although Vietnam will be the fastest growing oil consumer through 2018F, with an average annual 8.7% growth rate, followed by Cambodia and Myanmar at 3.6% and 3.3%, respectively.

Wood Mackenzie projects oil production in South East Asia to decline slightly between 2013F and 2018F, from 897 mmboe to 849 mmboe. The largest decrease in production comes from Vietnam, while Malaysia is the only major oil producing country in South East Asia expected to increase production over the period to 2018. Other countries in the region are also expected to see a drop in oil production, including Indonesia, Thailand and Vietnam.

Figure 3.20 SEA oil supply-demand (2005A – 2018F)



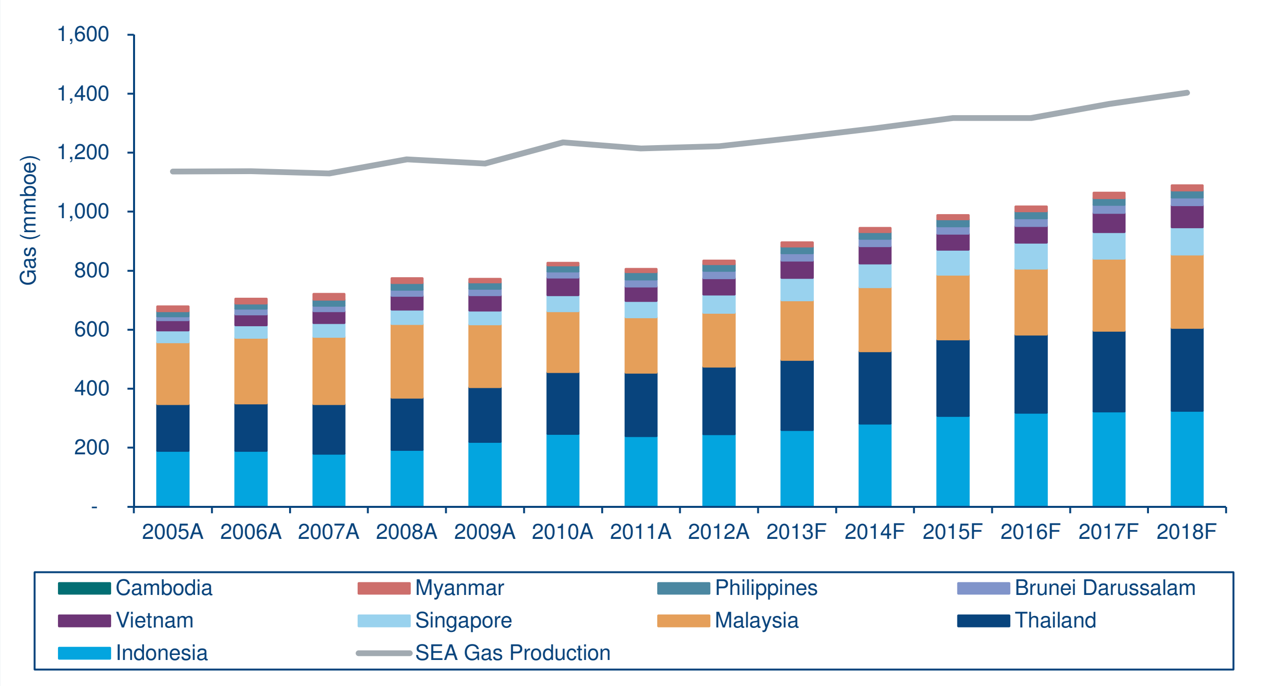
Source: Wood Mackenzie

Gas looks set to take on greater importance for South East Asia in the coming years, as Wood Mackenzie expects the region to see an average 4.0% annual increase in gas demand from 896 mmboe in 2013F to 1,089 mmboe in 2018F. Indonesia, Malaysia and Thailand are the top three drivers of this gas demand, together accounting for 80% of the region's increase in gas demand growth. Vietnam is the fastest growing gas demand centre through 2018F with a 5.1% average annual growth rate.

Gas production in South East Asia is expected to rise from 1,251 mmboe in 2013F to 1,403 mmboe in 2018F. Myanmar and Vietnam are both projected to significantly increase their gas production rates from 2013F to 2018F, with average annual growth rates of 9.5% and 5.1%, respectively. Regionally, gas production will increase at an average annual rate of 2.5% through 2018F, with the largest producers, Indonesia and Malaysia, growing at an average annual rate of 1.3% and 2.9% respectively.

While the region is a net exporter of gas, market dynamics vary between different countries and even between regions in the same country. Hence, while Malaysia, Indonesia and Brunei Darussalam are expected to remain LNG exporters, the region is expected to experience rapid growth in LNG import demand. Thailand and Indonesia commenced LNG imports in 2011 and 2012, respectively, while Malaysia and Singapore commenced LNG imports in 2013. South East Asian LNG imports are expected to grow to more than three times 2013F levels by 2018F.

Figure 3.21 SEA gas supply-demand (2005A – 2018F)



Source: Wood Mackenzie

3.3.6 Indicative crude oil and natural gas pricing

Liquids Pricing

Liquids pricing in South East Asia is generally based off local benchmarks crudes or a basket of crudes. The benchmark crudes often referenced include Tapis and Minas, as well as more globally significant benchmarks, such as Dubai, Oman and Brent crudes.

Natural Gas Pricing

Indigenous gas in Asian markets is priced under a variety of pricing mechanisms. Prices may be linked to a range of indices, including High or Medium Sulphur Fuel Oil, local crude benchmarks or ammonia prices. Index linked prices are common when gas is exported or when large gas consumers negotiate gas sales agreements (GSAs) directly with producers. In contrast, gas sold into the domestic market has utilised prices fixed for the duration of the contract (i.e. flat in nominal terms), with prices often set by the host country government. In recent years, the domestic gas price in key markets, such as Indonesia and Malaysia has been trending upwards and increasingly incorporating indices for price escalation.

3.4 China

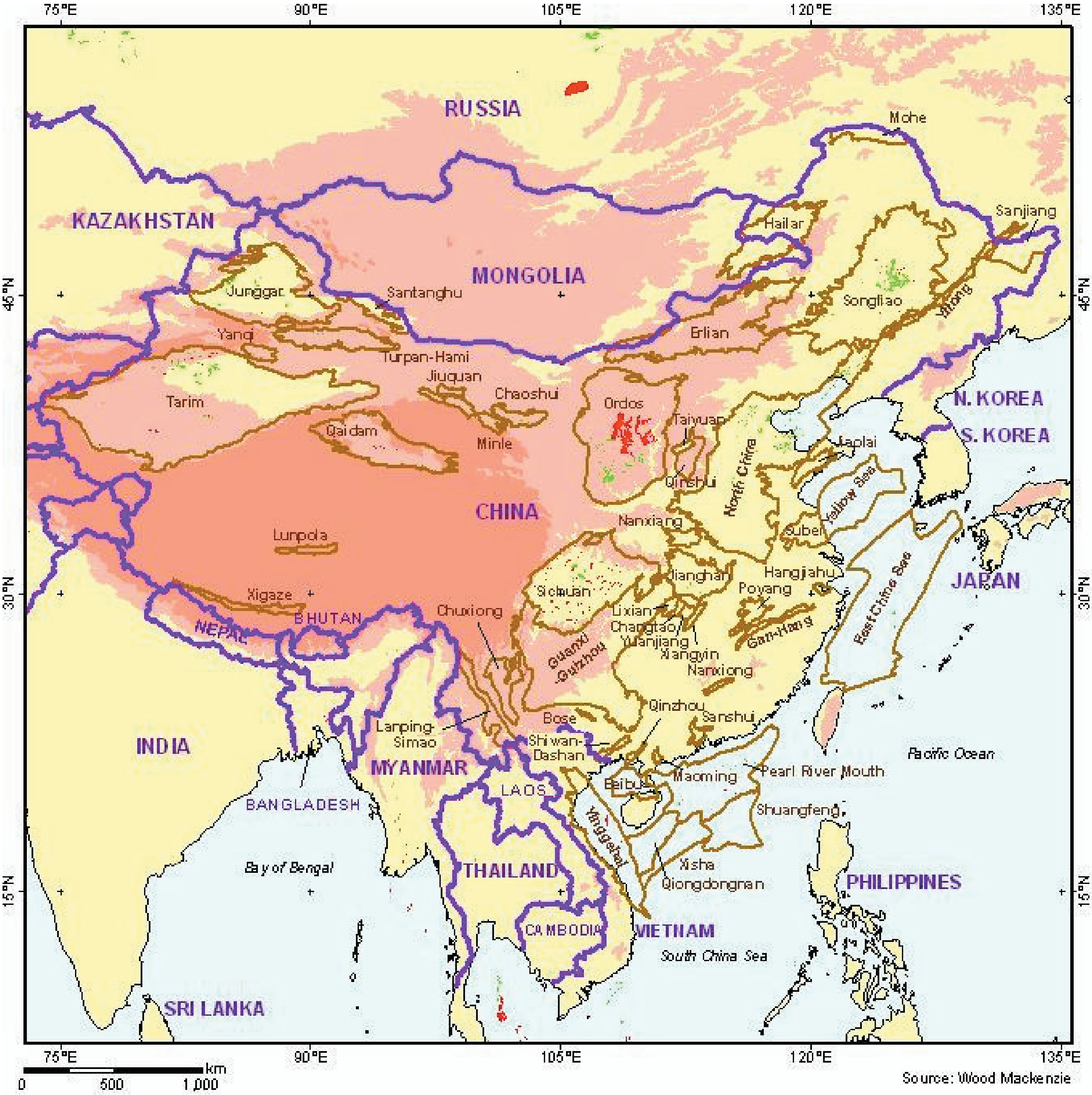
3.4.1 Overview

China's oil and gas production is unable to keep pace with demand growth, resulting in an increasing reliance on imports. China's oil sector is relatively mature, with production expected to peak in 2013F. In the short-term, the performance of secondary and tertiary oil recovery projects at major mature fields will determine the level of Chinese liquids production. However, in the longer term, the level of production will depend upon the success of exploration efforts in the frontier basins, located in the northwest of the country and in the deep waters of the South China Sea.

In contrast, the gas sector is relatively immature and is expected to experience rapid growth. This growth is expected to come primarily from onshore conventional production over the forecast period (i.e. before 2018), with material shale gas production unlikely during this period.

Despite this rapid growth in production, China will become increasingly reliant on energy imports. China is expected to overtake the U.S. as the world's largest importer of crude by around 2017 and will also become increasingly reliant on gas imports, consisting of piped gas from Central Asia and LNG.

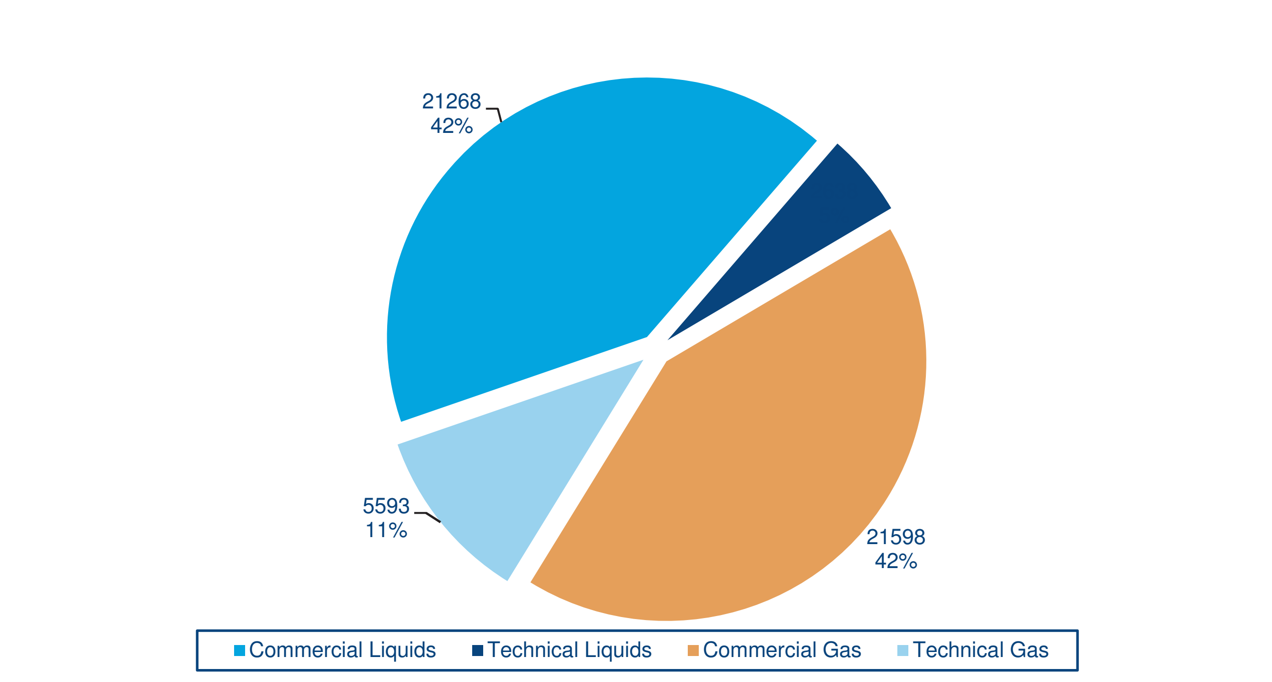
Figure 3.22 Chinese oil & gas basins map



3.4.2 Oil and gas reserves/resources

China has 51,097 mmboe of remaining commercial and technical oil and gas reserves. China's reserves are evenly split between liquids and gas. The majority of China's commercial reserves are situated onshore, in conventional reservoirs. The majority of China's gas reserves are located the Sichuan, Ordos and Tarim basins. China's liquids reserves are concentrated in the Ordos, North China, Songliao and Junggar basins.

Figure 3.23 China commercial and technical oil and gas reserves (mmboe, 2012A)



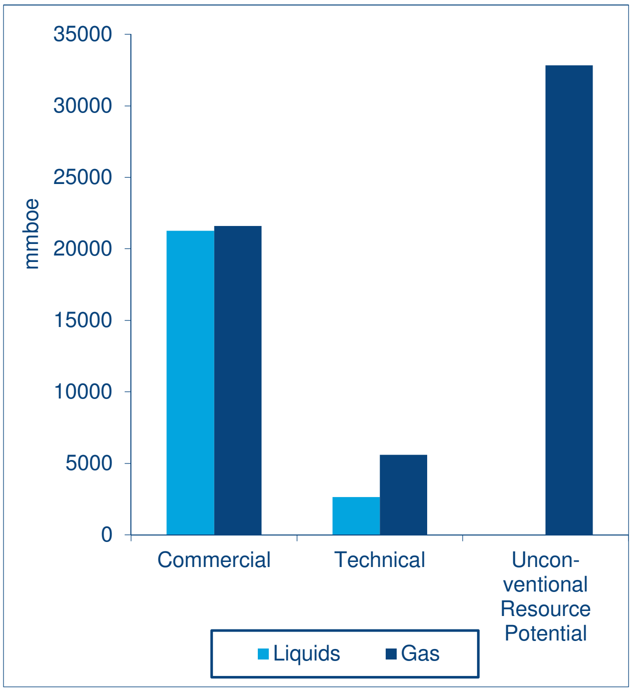
Source: Wood Mackenzie

3.4.3 Unconventional oil and gas reserves/resources

China is considered highly prospective for unconventional resources, with the EIA estimating that China has the largest technically recoverable shale gas resources (1,115 tcf or 196,798 mmboe), and third largest shale oil resources (32 bnboe), in the world. Wood Mackenzie takes a more conservative estimate as to the unconventional potential in China (and calculates reserves of a less comprehensive list of plays), estimating potential gas resources of 93 tcf (16,285 mmboe) across the the Sichuan and Tarim shales. Wood Mackenzie estimates another 79 tcf (13,944 mmboe) of potential CBM resources in the Junggar, Ordos, and Qinshui plays, in addition to 15 tcf (2,588 mmboe) of tight gas potential in the Ordos and Sichuan basins.

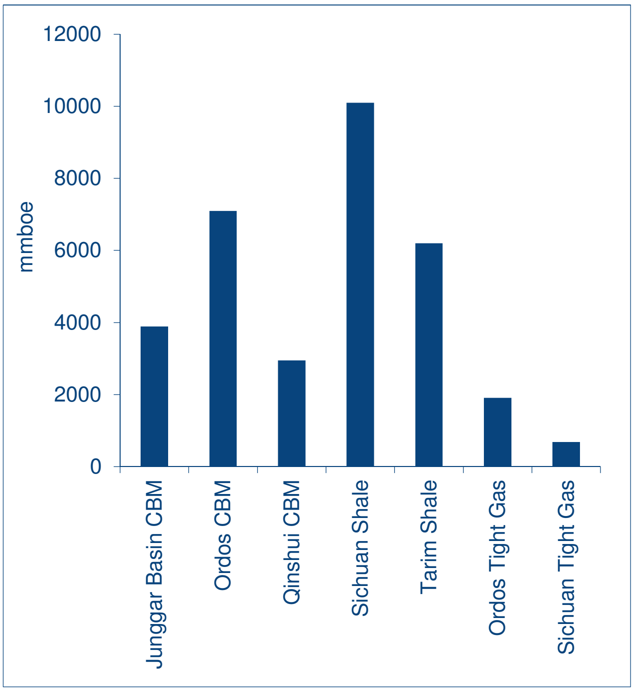
Tight gas has an established position in the domestic gas supply mix, with significant production from the Ordos and Sichuan basins. In contrast, the shale and CBM sectors are relatively immature. CBM production is expected to exceed shale gas production throughout the forecast period, with shale gas growing strongly during the next decade.

Figure 3.24 China reserves and unconventional resource potential



Source: Wood Mackenzie

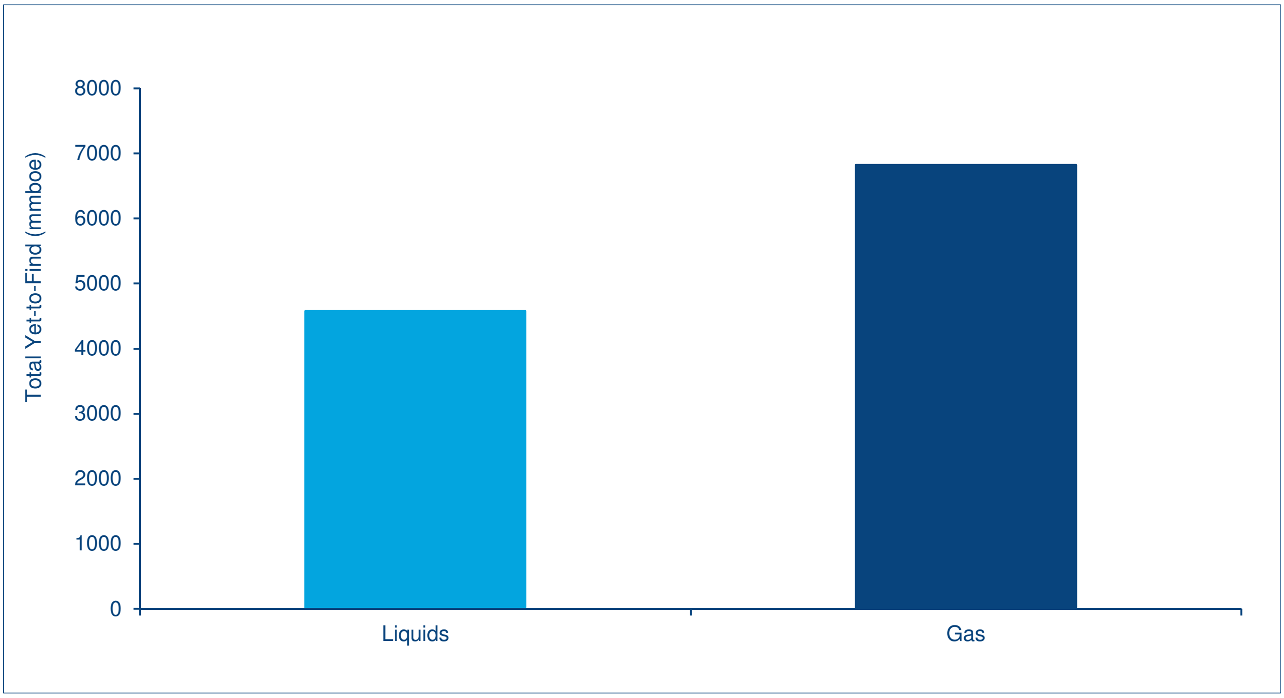
Figure 3.25 Unconventional resource potential by region



Source: Wood Mackenzie

3.4.4 Prospectivity and recent discoveries

Figure 3.26 China yet-to-find and technical reserve volumes



Source: Wood Mackenzie

China is viewed as having considerable remaining oil and gas potential, with Wood Mackenzie estimating about 49,866 mmboe of total technical reserves and YTF[11] volumes. China's drive for oil self-sufficiency over the past thirty years led

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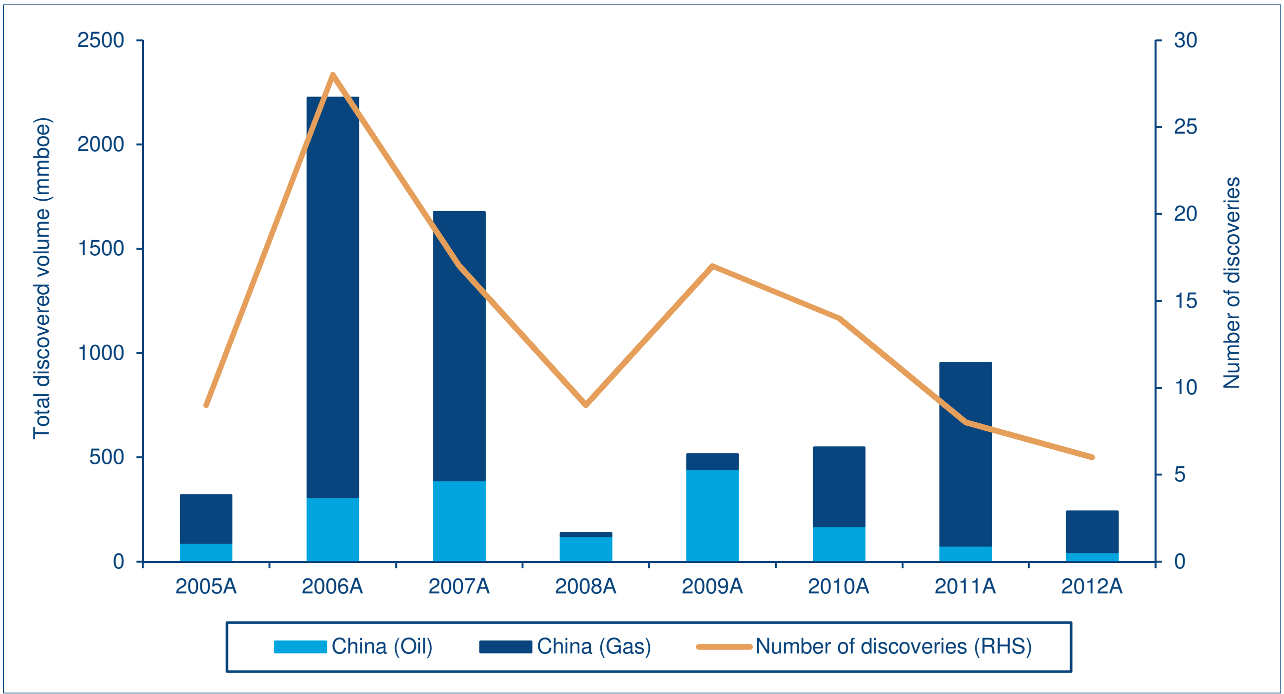
[11] *Wood Mackenzie bases its YTF resource on the potential from the discovery of conventional oil and gas new fields. Unconventional resource potential is excluded from the scope of reporting, as is the potential from upgrades and extensions on existing discoveries. Wood Mackenzie uses a projected*

to the country's lack of emphasis on gas exploration. Consequently, China’s technical reserves and YTF volumes are weighted towards gas, accounting for over 60% of total volumes. The offshore Pearl River Mouth Basin, with significantly underexplored deepwater acreage, dominates China’s YTF volumes. Technical reserves are primarily onshore, conventional reserves, concentrated in the Sichuan, Ordos and North China basins. The expansion of the country's gas pipeline network will facilitate the commercial development of these reserves.

In recent years, there have generally been 10-20 discoveries per year, the majority being oil. Despite this, the majority of discovered volumes have been gas, reflecting the relative immaturity of gas exploration and regional geology. Discovered volumes varied significantly between 2005A and 2010A, with 2,225 mmboe added in 2006 compared to just 138 mmboe in 2008. In total, 6,615 mmboe were discovered betweed 2005A-2012A, dominated by the Sichuan, Tarim and North China basins.

Figure 3.27 China recent discoveries (2005A – 2012A)



Source: Wood Mackenzie

3.4.5 Historical and forecast oil and gas demand and production

China’s oil demand increased from 2,422 mmboe in 2005A to 3,304 mmboe in 2012A, equivalent to an annual rate of 4.5%. This increase was largely driven by increased diesel and LPG demand from the transport and industrial sectors, which offset dramatically falling use of oil in the power generation sector. Looking forward, China’s oil demand is expected to increase from 3,435 mmboe in 2013F to 4,284 mmboe in 2018F, equivalent to a growth rate of 4.5%.

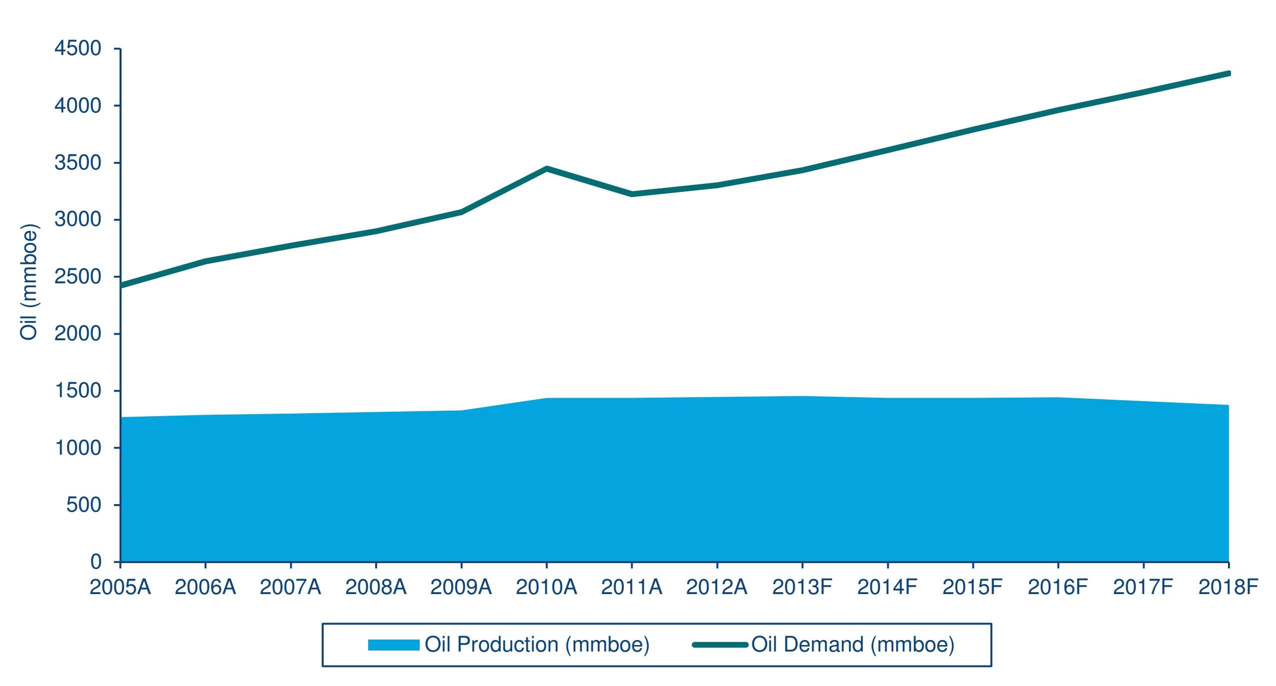
The transport sector will be responsible for much of the growth in China’s oil demand as the private motoring sector continues to expand. As of 2012A, China's vehicle penetration only totalled 64 cars per thousand people, as compared to 465 per thousand in Japan and 300 per thousand in South Korea. Wood Mackenzie’s forecast is for the car ownership rates to reach 126 per thousand people by 2020F. Demand will also be driven by the petrochemical industry as China’s economy grows and investment in chemical manufacturing capacity continues.

China is by far the largest oil producer in Asia, producing 1,447 mmboe in 2012A (more than four times the amount of oil that Indonesia produced). The largest oil producing areas are in Northeast China (Daqing, Shengli, Liaohe) and the Ordos Basin. These fields are maturing, however, and Chinese companies have to employ enhanced oil recovery techniques in order to keep production up. Continued exploration and development in the western provinces, as well as additional offshore oil discoveries in the Bohai Bay have helped to keep production increasing. Given the maturity of current supply, Chinese oil production is expected to fall slightly over the next five years, to 1,375 mmboe in 2018F.

creaming curve to derive the assumption of YTF potential in a basin. The curve is generated using best fit of a hyperbolic trend to historic data on cumulative reserves by cumulative exploration wells. The curve’s trajectory is also an assumption of reserves that will be discovered per exploration well. The overall basin YTF assumption is constrained by Wood Mackenzie's forecast of exploration well numbers to 2030F. This YTF assumption is intended to be a broadly realistic input to Wood Mackenzie's future economics evaluation, and is not a substitute for a geologically-constrained resource assessment.

China became a net importer of crude and oil products in the early 1990s. With demand rising rapidly, China's oil import position has grown to become the second largest in the world, behind the United States. Indeed, by around 2017F, Wood Mackenzie expects China to surpass the Unites States as the largest oil importer in the world.

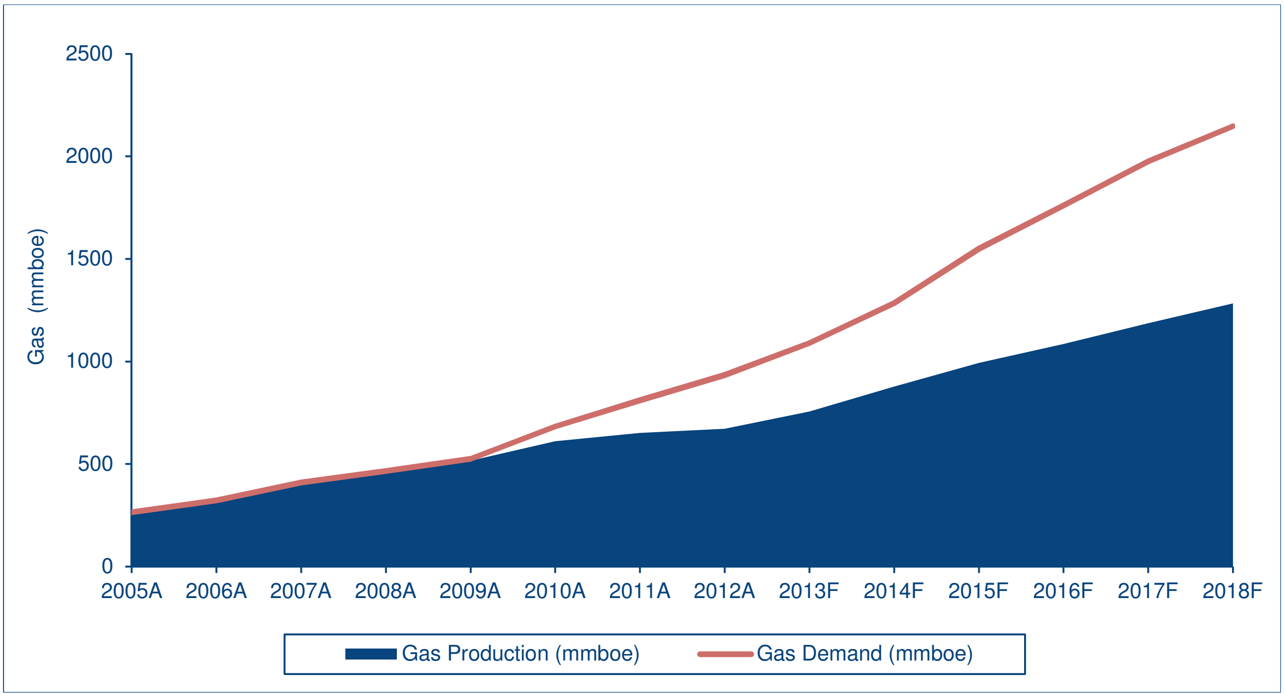
Figure 3.28 China oil supply-demand (2005A – 2018F)



Source: Wood Mackenzie

China's gas demand has risen rapidly in recent years, from 265 mmboe in 2005A to 934 mmboe in 2012A, equivalent to an annual growth rate of 19.7%. Despite the rapid growth in the past decade, the outlook for China's gas demand is extremely strong. China's gas demand is expected to grow at 14.6% per year, from 1,089 mmboe in 2013F to 2,184 mmboe in 2018F.

Figure 3.29 China gas supply-demand (2005A – 2018F)



Source: Wood Mackenzie

While industrial demand has traditionally been the dominant gas-consuming sector, Wood Mackenzie's demand growth forecast is not solely dependent the strength of the Chinese economy. With only 14% of China's 1.35 billion population having access to piped gas, significant latent demand exists. As gas infrastructure is developed, access to gas, and therefore gas demand, will increase, displacing oil products.

China's gas output is also increasing rapidly. Production is forecast to increase from 756 mmboe in 2013F to 1,283 mmboe in 2018F, an average increase of 14.1% per year. The majority of China's gas production comes from the Sichuan, Ordos and Tarim basins, with the gas routed via long-distance cross-country pipelines to the main economic centres along the eastern coast. Conventional production is expected to continue to dominate production over the forecast period.

China became a gas importer in 2006, with its first LNG regasification terminal constructed to help meet demand in South China and Hong Kong. China also imports piped gas from Central Asia through the Trans-Asia pipeline, commissioned in late 2009. China's reliance on gas imports is expected to increase over the forecast period, and will import over one-third of its gas requirements by 2018F.

3.4.6 Indicative crude oil and natural gas pricing

Liquids Pricing

Oil produced in China is typically sold at prices linked to Dubai or Duri benchmark prices.

Natural Gas Pricing

From 10 July, 2013, a new gas pricing structure became effective in China. Reflecting cost of supply increases and the growing volumes of oil-linked imports, the reforms will raise gas prices for all sectors excluding residential and will create a two-tier pricing structure across China.

The National Development and Reform Commission (NDRC), the country's macroeconomic management agency, will set city gate prices based on the oil-indexed formula but will retain the authority to adapt the pricing index and to assess the timing and scale of the rollout of incremental pricing across the country. Under the new pricing structure, the NDRC will set gas prices nationwide at the city gate instead of at the wellhead, which will shift China away from the historical cost-plus system for onshore gas prices to a net-back mechanism. Two city-gate prices will be set; one for existing supply and one for incremental supply. Existing supply, defined as China's 2012 onshore and piped import gas consumption of 112 bcm, will receive the lower of the published prices. Incremental supply above 2012 contracted volumes will link to imported LPG/HSFO prices. The government aims to unify city gate prices for existing and incremental supply by the end of 2015.

4 Underground coal gasification

4.1 UCG technology overview

4.1.1 UCG process fundamentals

Gasification is the conversion of coal (or other carbon based feedstocks such as biomass) to a combustible product gas called synthesis gas ('syngas') consisting primarily of hydrogen (H_2) and carbon monoxide (CO). Gasification involves a series of controlled reactions involving heat, pressure, oxygen, coal and water.

Coal gasification technology has a long history, and wide application in creating fuels or feedstock for power generation or industry. Traditionally, aboveground coal gasification (ACG) has involved mining the coal using conventional mining techniques, and then gasifying it in a reactor on the surface. ACG gasifiers can be classified by reactor configuration and the method of contacting the solid (i.e. coal) and gaseous (i.e. oxidant) phases, with common commercial technologies including fixed or moving bed, fluidized bed, and entrained flow reactors. Each technology has its own advantages and disadvantages, and choice of technology will depend on the quality of the coal feedstock, as well as on the intended downstream processing route for the syngas produced.

Underground coal gasification (UCG) is the process of gasifying coal *in situ*, i.e. within the coal seam, without the need to mine the coal and process it aboveground. The life-cycle of a UCG operation can be broken down into four main steps (illustrated in Figure 4.1):

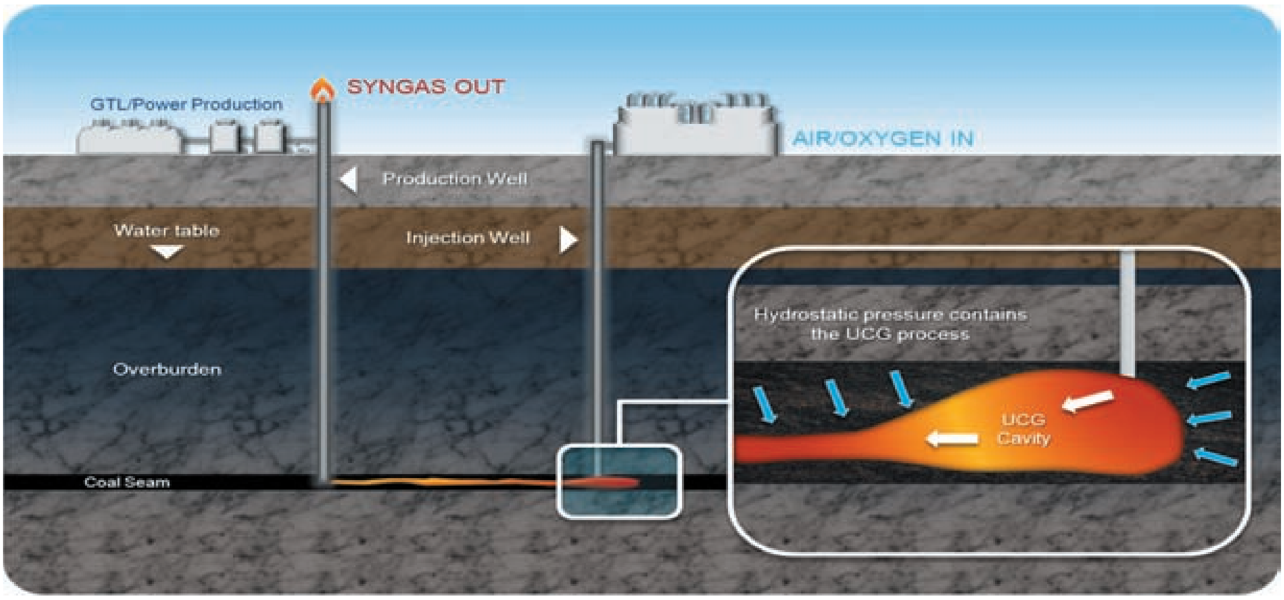
Well construction and linkage Wells are drilled into the coal to allow for oxidant injection and product gas extraction. The wells are linked or extended to form an in-seam channel to facilitate oxidant injection, cavity development and syngas flow.

Ignition The coal seam is dried and then ignited.

Gas production Syngas is produced through combustion and gasification reactions. The oxidant (either air or a mixture of oxygen and steam) is pumped into the injection well, and combustion produces heat, carbon dioxide (CO_2) and some syngas (through partial combustion). Gasification reactions then take place – involving heat and CO_2 from the combustion process, pressure, steam, and carbon from the coal – to produce syngas. The syngas flows from the gasification zone, through constructed or formed horizontal channels, to a gas production well where it flows to the surface for treatment. The surrounding hydrostatic pressure contains the UCG process, and the UCG reactions are managed by controlling the rate of oxidant that is injected into the coal seam through the injection well. Expansion of the gas production process is achieved via the addition and linkage of further injection and production wells.

Decommissioning The UCG process can be halted by stopping the injection of the oxidant. After all the available coal is converted to syngas in a particular location, the remaining cavity (which will contain the leftover ash or slag from the coal) is depressurised, and may be flooded with saline water and the wells capped.

Figure 4.1 Overview of the UCG process



Source: Linc Energy

4.1.2 UCG operational issues & site selection

Whilst the basic UCG process is conceptually simple, establishing a commercially viable long term operation is technologically more complex and challenging.

Key process parameters that influence basic gasification behaviour include the gasifier temperature and gas residence time; operating pressure; oxygen/coal ratio; and water/coal ratio. For UCG operations, these process parameters are governed by site specific geological and hydrogeological properties. A thorough understanding of these relationships is necessary to allow the UCG process to be controlled from the surface to achieve the desired gas production rate and syngas composition, as well as to maximise resource recovery efficiency, predict environmental effects, and mitigate risk.

The design of the UCG operation and the operating methodology are important, especially choice of oxidant and gasifier design. Ultimately, though, the environmental, operational and economic performance of UCG is determined by the characteristics of the site chosen. Key site specific characteristics are coal seam geology, hydrogeology, and coal characteristics.

Coal seam geology

A number of properties of the coal seam are important including:

- ***Depth*** The depth of the coal seam influences the maximum operating pressure of the process (a constant hydrostatic head being required for long term operation) and groundwater availability. Operating in deeper seams also reduces the risk of subsidence at the surface. Depths of 100–600 metres are generally suitable, with >300 metres considered preferable. That said, most of the long running commercial UCG operations in the Former Soviet Union (FSU), as well as more recent trials in Australia (see Section 4.3.2), have used shallower seams, which reduces drilling costs.

- ***Thickness*** This is primarily an economic consideration (thicker coal seams means more coal per well drilled), but coal seam thickness can also affect operational efficiency and syngas composition. Seams thicker than five metres are preferred. On the downside, operating in thicker seams increases the risk of subsidence.

- ***Dip*** Steeply dipping seams operate differently and tend to have higher efficiencies.

- ***Permeability*** Some natural permeability of the coal seam is required to allow for initial gas flow between the injection and production wells. The permeability of the surrounding rock strata is also important, with a low permeability preferred to reduce water influx rates and minimise gas leakage.

- ***Continuity*** Seam structures with minimal discontinuities are preferred, as disturbed geology makes construction and operation more challenging and expensive.

Hydrogeology

The groundwater pressure and flow around the gasifier are crucial to successful UCG operation for a number of reasons:

- Hydrostatic pressure confines the gasification process to the desired space;

- Supplies of water are required for the gasification reactions; and

- Groundwater influx creates a 'steam jacket' around the operating cavity, reducing heat losses.

It is also preferable to avoid operating in the vicinity of good quality water aquifers to minimise the risk of groundwater contamination as a result of undetected geological structures or unforeseen operational problems.

Coal characteristics

Coal rank and chemical composition is not a major consideration for UCG, however very high moisture or ash contents will reduce the efficiency of the process.

Oxidant

Either air, or a mixture of oxygen and steam, can be used as the oxidant. The choice of oxidant will depend on the design of the site and the required composition of the syngas. The oxygen/water ratio also affects the thermochemical efficiency of the gasification process, whilst the oxidant flow rate will directly affect the rate of gasification and hence of syngas production.

Gasifier design

The spatial arrangement of the gasifier is important in controlling gas velocities and mixing efficiencies. A number of different UCG configurations are possible.

4.1.3 UCG technologies & techniques

The fundamental principles of UCG are the same as for other coal gasification technologies. However, the use of geological strata to contain the gasification reactions has resulted in a wide variety of gasifier configurations and construction methods, which have relevance to particular types of site. Possible UCG designs include:

Linked vertical wells As illustrated by Figure 4.1, blocks of coal for gasification are delineated by conventionally drilled wells that are linked in the coal seam by natural permeability, hydro-fracturing and/or directionally drilled wells. A pair of wells can potentially last for as long as fifteen years. This approach has been used widely in the FSU and some recent commercial demonstrations, but is mostly suited to relatively shallow coal seams.

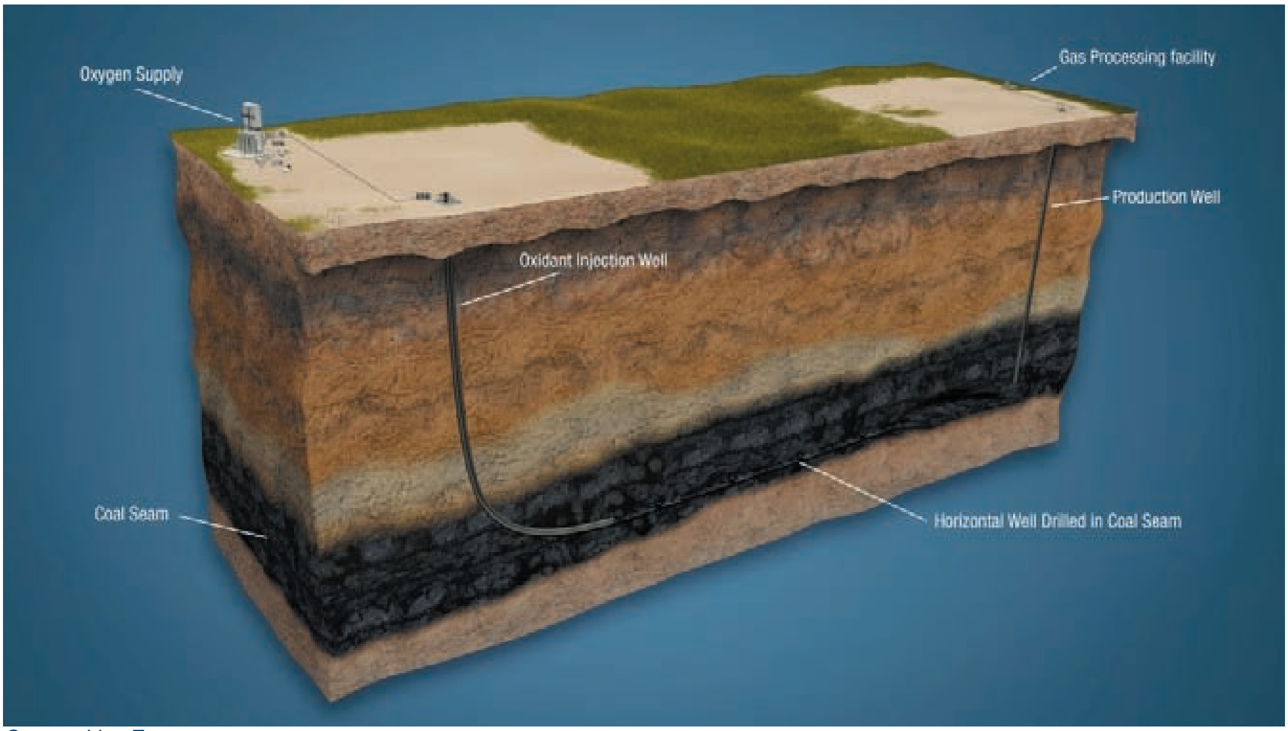
Steeply dipping bed This method is necessary for coal seams that are angled significantly from the horizontal and uses combinations of vertical and angled wells. The gasification process is slightly different in this case, due to coal falling into the reaction zone as the cavity grows upwards.

Blindhole This technique uses a single well to inject the oxidant, with the product gas being extracted via the permeable zone around the well. An enhancement of this technique that involves progressive shortening of the well may make this attractive in some situations.

Tunnel Mined tunnels can be used to define the block of coal to be gasified, and ignition systems installed. This technology has been extensively trialled in China but has not been generally commercially accepted.

Controlled retracting injection point (CRIP) This is a more recent development that uses directionally drilled wells to potentially access large quantities of coal-per-well by in-seam drilling. An example of a basic CRIP setup is illustrated by Figure 4.2. The injection well is shortened progressively to expose new coal to reaction, meaning that fewer wells are required. Whilst more complex than linked vertical wells, this technique may be more economical for deeper coal seams that would incur high drilling costs.

Figure 4.2 Example of the CRIP technique

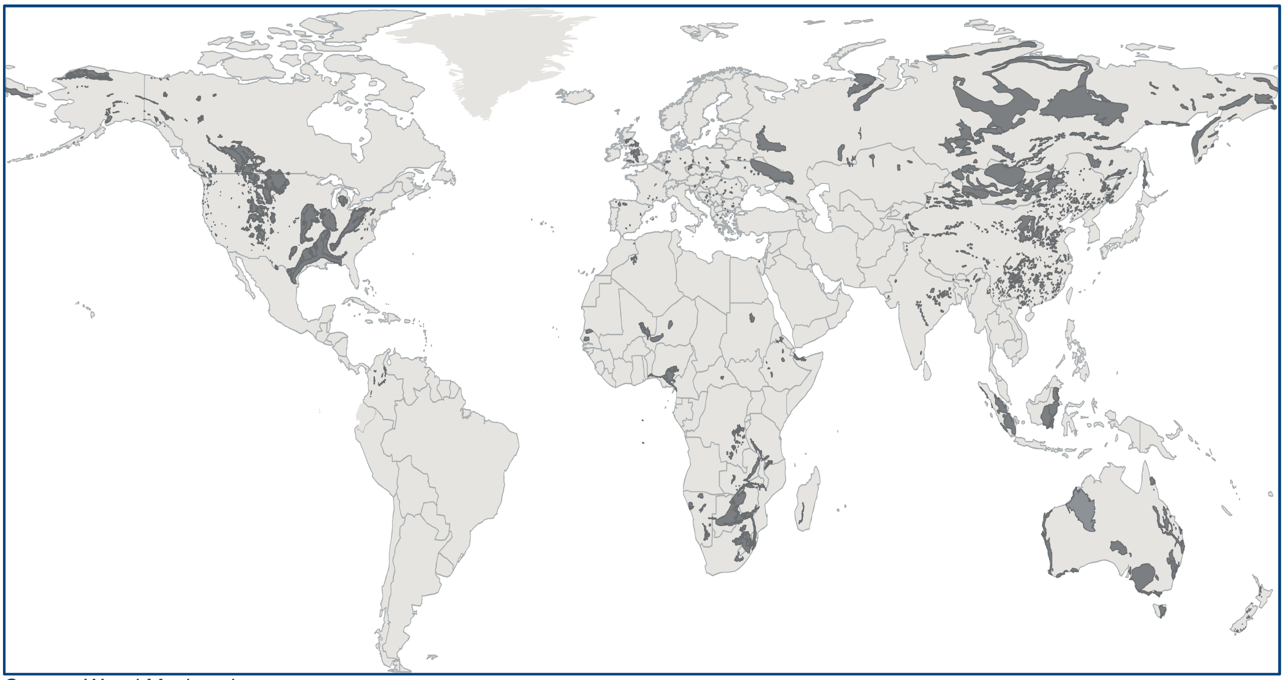


Source: Linc Energy

4.1.4 Coal resources suitable for UCG

Coal is a widely distributed natural resource, as illustrated by Map 4.1, but a large proportion of the world's known coal resources are 'unmineable' using conventional surface or underground mining techniques – for economic, environmental, technical or safety reasons. One of the major benefits of UCG is that it can potentially access a portion of this otherwise 'stranded' coal resource.

Map 4.1 Global coal basins



Source: Wood Mackenzie

UCG has the ability to utilise coal that is poor quality (e.g. lignite), inaccessible (e.g. deep or offshore coal seams), or otherwise difficult to mine (e.g. coal seams with unfavourable geology). In targeting such inaccessible or poor quality coal, UCG could serve to substantially increase global energy reserves. There have been several attempts to establish criteria for categorising coal reserves according to suitability for UCG operations. However, whilst the potential certainly appears to be there, the precise extent to which UCG could increase accessible reserves has not, as yet, been determined[12].

Trials to date have indicated that UCG appears to be a relatively versatile technique. Coal deposits with obstacles to mining such as high fault frequency, volcanic intrusions and other complex depositional and tectonic features, potentially form a part of the UCG resource base. That said, there are some preferred resource requirements, and site selection is key to establishing a commercially viable operation. A number of coal seams may not be suitable for UCG because of geologic or hydrologic conditions, particularly at relatively shallow depths.

In some locations, UCG could in theory access the same coal resources that could alternatively be mined using conventional underground mining techniques, such as longwall or bord-and-pillar. To date, the small scale of the UCG industry, and the targeting of low quality coals by UCG companies, has tended to minimise competition with traditional miners, as these resources tend not to be targets for conventional mining due to poor financial returns. This may change in future, however, if the UCG sector expands or underground mining techniques develop.

[12] The most cited assessment to-date is that from the 2007 Survey of Energy Resources by the World Energy Council (http://www.worldenergy.org/documents/ser2007_final_online_version_1.pdf), which suggests that UCG could increase coal reserves by as much as 600 Bt, or more than 60%. This survey looked at economically recoverable reserves in selected jurisdictions only (USA, Europe, Russia, China, India, South Africa and Australia), so the total potential resource base could be much larger. Note that details of the methodology used to derive these figures were not provided, and these estimates have not been independently verified by WM.

UCG resources could also potentially be the target for coal bed methane (CBM) extraction[13]. It is therefore worth briefly comparing the three main resource conversion pathways – conventional mining, UCG, and CBM extraction – in terms of resource recovery efficiency.[14]

4.1.5 Comparative resource recovery efficiency

Extraction efficiencies for underground mining can vary dramatically from mine to mine depending on local conditions, but extraction efficiencies of 50–60% of the deposit for bord & pillar operations, and 75% or more for longwalls, are typical. Whilst the reported extraction efficiencies from UCG trials are less reliable, reported efficiencies in the range of 80–90% suggest that UCG extraction efficiency is likely to be high relative to conventional underground mining techniques, in particular for thick coal seams. For conventional mining, regardless of the mining technique used the raw coal must often be washed and processed to produce a marketable product, further reducing the overall resource recovery efficiency relative to UCG.

Of course, this is not a like-for-like comparison, as the primary product of UCG is syngas rather than marketable product coal in its solid form. A more comprehensive analysis would compare the energy recovery efficiency across the entire value-chain to the end user; necessitating various assumptions regarding subsequent processing and utilisation (see Section 4.2). CBM extraction on the other hand recovers only a small fraction of the energy recovered by either conventional mining or UCG, because by definition it recovers only the energy from the methane (CH_4) contained in the coal seam, without utilising any of the energy in the coal itself.

There are also other apparent benefits of UCG over alternative resource conversion pathways. Compared to conventional mining, there is a reduction in the scale of the surface environmental footprint of the operation, and an elimination of human safety hazards associated with underground mining. Further, in the UCG process solid waste such as ash remains in the depleted coal seam, mitigating the need for surface disposal. Depending on the subsequent utilisation of the syngas, UCG may also lead to a reduction in greenhouse gas emissions – relative to conventional mining combined with coal-fired power generation in a conventional subcritical pulverised fuel (PF) power station – and could therefore be characterised as a 'clean coal' technology.

When compared to CBM extraction, the key benefits of UCG relate to the role that water plays in the two processes. CBM extraction requires that most of the water be drained from the coal in order to relieve the pressure and allow the CBM to be released from the coal. CBM extraction therefore produces large volumes of saline wastewater that must be treated at the surface. Conversely, UCG requires that water remains in the coal and adjacent environment to provide the hydrostatic pressure needed to contain the gasification reaction and ensure that the syngas produced flows to the surface under pressure via the production well; only a relatively small portion of the water takes part in the reaction to produce syngas, and groundwater quality is thereby maintained.

4.2 UCG value chain & applications

The primary product of the UCG process is syngas. Syngas consists primarily of H_2 and CO, and will also contain smaller amounts of CO_2, CH_4, nitrogen, water, and impurities such as sulphur.

Syngas is a highly versatile product that can be used directly for power generation, converted into a synthetic crude oil ('syncrude') and then refined into a variety of liquid fuels, reformed into synthetic natural gas (SNG), or used as a chemical feedstock to produce a variety of value-added products. Figure 4.3 outlines the UCG value chain and illustrates some of the major downstream processing options, and potential applications and products.

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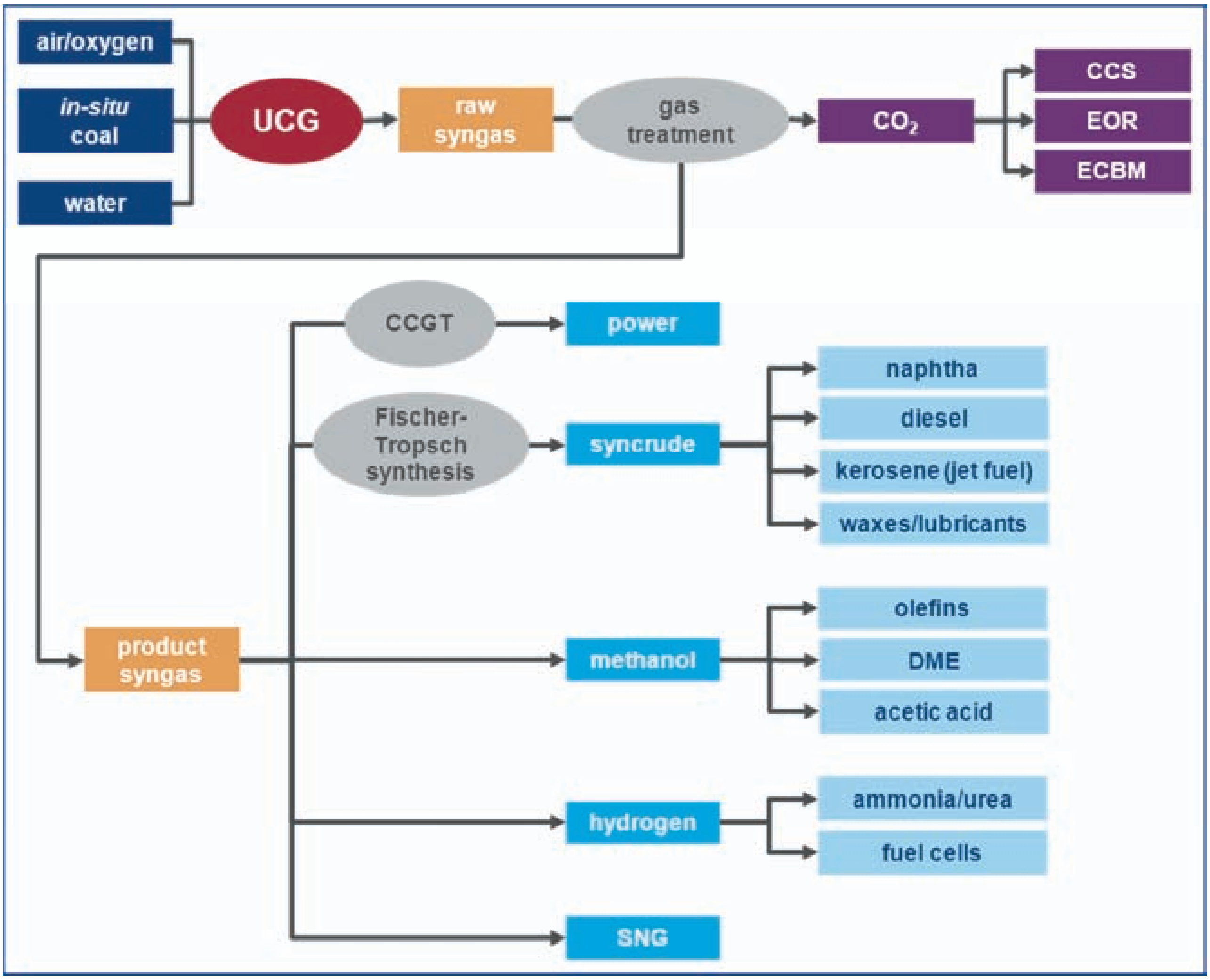
[13] CBM (also referred to as coal seam gas (CSG)) is formed as a by-product of the coalification process. About 1,300 cubic metres of gas is produced per tonne of coal formed. Most of the gas produced escapes during coalification, but a small amount is retained in the coal seam, either as 'free gas' in fractures, adsorbed in pores in the coal, or in adjacent rock strata. The final gas content is up to 25 cubic metres per tonne of coal. In general, the higher the rank of the coal, the deeper the coal seam, and the lower the moisture content, the greater the volume of gas. This residual methane is released when the pressure within the coal seam is reduced.

CBM extraction involves drilling a well into the seam and employing techniques to increase the local gas permeability of the seam (e.g. the seam is hydraulically fractured ('fraccing') by injecting a suitable fluid at high pressure). Groundwater is then pumped out, which lowers the hydrostatic pressure in the seam and allows the CBM to release from the coal, move to the well, and be brought to the surface for processing. The recovered CBM is typically 95% to 99% methane and is relatively easy to process. CBM extraction has now become a major industry in a number of locations.

[14] Another alternative worth mentioning, though still at an early stage of research and development, is microbial coal conversion (MCC). MCC technology has been developed by U.S. biotechnology company Arctech Incorporated and its commercialisation is being promoted by Australian company Mitchell Energy. Similar to UCG, MCC is a process for coal conversion in situ. It involves the use of microbes to convert the coal to acetic acid underground; this is then extracted and converted to methane at the surface.

Figure 4.3 Simplified UCG value chain, applications & products



Source: Wood Mackenzie

The UCG value chain is essentially the same as that for 'traditional' ACG. The ACG industry is more developed than the nascent UCG sector and, as such, gives an indication of current syngas market demand, with the chemical sector accounting for around 45% of global syngas output, liquid fuels for around 30%, power generation for around 20%, and gaseous fuels for the remainder.

The composition of the raw syngas produced by the UCG process depends on a number of factors including coal characteristics, choice of oxidant, water influences, and operating temperature and pressure. The raw syngas typically undergoes further treatment on the surface to remove impurities, producing a clean syngas product which is then further processed according to the desired use.

The raw UCG syngas will also contain CO_2 in varying concentrations depending on process conditions. Because the raw syngas is produced under pressure and at a moderate temperature, it easily lends itself to CO_2 removal by a range of standard methods at a relatively low cost.

The range of downstream processing options available for the primary syngas product, and the relative ease of CO_2 capture compared to other coal conversion pathways, constitute two of the key benefits of UCG.

4.2.1 Syngas utilisation options

Power generation

The energy value of the H_2, CO and CH_4 components of syngas mean that it can be used directly for power generation. The most common power generation option for syngas uses a combined cycle gas turbine (CCGT), whereby the syngas is first combusted in a gas turbine to generate power, and waste heat from the combustion process is then used in a second steam turbine for further power generation.

CCGTs need to be designed slightly differently when operating on syngas rather than natural gas, however integrated gasification combined cycle (IGCC) plants based on ACG are already being widely developed for their increased efficiency and carbon capture and storage (CSS) potential relative to conventional coal-fired power plants. The UCG-CCGT route could potentially provide all the same benefits of IGCC power generation, and in addition without the need to mine the coal and construct aboveground gasification facilities.

Syngas can also be used in gas engines, or conceivably could be co-fired with coal in existing conventional coal-fired power plants.

Gas-to-liquids

Gas-to-liquids (GTL) in this context refers to the process of converting the syngas produced from the UCG process to syncrude, via a series of catalytic reactions known as the Fischer-Tropsch (FT) synthesis process. The syncrude can then be refined or upgraded into various different higher value end products through both traditional and syncrude specific refining processes.

The product range depends on the FT technology, process conditions and the refinery scheme or setup, with the optimal target product range heavily dependent on local market conditions. New generation GTL plants are aimed primarily at producing middle distillates for transport fuels, such as diesel and kerosene (which can be used as a jet fuel), as well as naphtha, which can be used as a blendstock for lighter fuels and in the manufacture of olefins (e.g. ethylene and propylene). Base oils and waxes are also produced, and form the basis for lubricant production.

Synthetic coal-derived FT fuels are compatible with existing engine technologies, meaning that they can be directly substituted for traditional oil-derived fuels without any large scale modifications to fleets or infrastructure. In addition, due to the removal of impurities before the GTL process, FT fuels generally have superior properties in terms of combustion efficiency; are sulphur free; and produce lower emissions of nitrogen oxide and particulates.

The UCG-FT process is one of a number of coal-to-liquids (CTL) options, the other main processing routes being conventional mining followed by either ACG-FT processing or a direct liquefaction process. The latter process is highly efficient, but the liquid products require further refining to achieve high grade fuel characteristics.

CTL is an established process: South Africa has been producing coal-derived fuels since 1955. The UCG-FT route would utilise commercially proven technology and provide the same benefits with respect to fuel properties as ACG-FT. UCG should additionally benefit from being able to access a larger potential coal resource base, and not requiring the construction of surface gasification facilities (though surface plant for the downstream processing steps is still required). Whilst either the ACG-FT or UCG-FT routes are more CO_2 intensive than conventional oil refining, CCS is a potential option.

Because CTL essentially allows coal to be used as an alternative to oil, it could be particularly suited to countries that rely heavily on oil imports but have large domestic coal resources, enabling them to improve national energy security. Production of liquid fuels from coal will be especially attractive in times of high oil prices.

Methanol production

Methanol is a key intermediate product that can be produced from UCG syngas. Key downstream processing options for methanol are the production of olefins (and hence polyolefins such as polyethylene and polypropylene); as well as dimethyl ether (DME), a non-carcinogenic and non-toxic alternative to traditional biomass fuels or liquefied petroleum gas (LPG) for domestic use in developing countries.

Hydrogen production

Hydrogen generated as part of the GTL process was previously considered a low-value by-product, but it can potentially be used as a feedstock for ammonia and urea production, with the end use markets for these products being the manufacture of fertilisers and industrial explosives. Hydrogen can also be used in fuel cell applications.

Synthetic natural gas production

Syngas can also be used as a feedstock to produce pipeline quality SNG.

4.2.2 CO_2 utilisation options

The CO_2 by-product from the gas treatment process can potentially be used for either enhanced oil recovery (EOR) or enhanced coal bed methane (ECBM) recovery.

Enhanced oil recovery

EOR involves the injection of CO_2 into depleted oil fields in order to increase reservoir pressure and oil fluidity, thus enabling oil to escape from rock pores and flow more easily towards production wells. Successful application of EOR can extend the productive life of mature oil reservoirs. Any CO_2 that comes to the surface with the recovered oil is captured and recycled at the end of the EOR process to be stored permanently underground.

EOR using CO_2 has been demonstrated at a commercial scale for over 30 years in the Permian Basin in Texas and New Mexico, with oil (and gas) recovered using EOR accounting for around a third of production in this region. Until recently, most of the CO_2 used for EOR has come from naturally occurring underground reservoirs. Capturing and sequestering anthropogenic CO_2 from applications such as UCG is a more recent development. Historically, the cost of CO_2 capture and the lack of existing pipelines have made it less attractive than the use of natural CO_2, but high oil prices, combined with the positive environmental aspects of CCS have made this option more appealing in recent years. The proportion of CO_2 from anthropogenic sources will likely grow as the necessary infrastructure is developed and natural CO_2 reservoirs are depleted.

Thus far, EOR using CO_2 has primarily been applied in North America, but it is feasible that the process could be expanded globally.

Enhanced coal bed methane recovery

ECBM recovery is a new technique being researched by the CBM industry, and involves sweeping the coal seam with CO_2. The CO_2 preferentially adsorbs in the pores of the coal, and the CH_4 is displaced, thus allowing the CH_4 to be recovered whilst simultaneously sequestering the CO_2.

Carbon capture and storage

As well as providing an additional revenue stream, each of the above approaches constitutes a commercially attractive means of CCS, whereby the CO_2 is permanently sequestered underground.

There are also potential synergies between CCS and the UCG process itself, in that UCG creates a cavity that could potentially sequester its own CO_2. It has been suggested that the remnant coal and ash would increase the available surface area for CO_2 adsorption, though further investigation is required to demonstrate this. Further, the necessary infrastructure and wells would already be in place. Not all UCG sites would be suitable though, with some seams too shallow to allow for permanent CO_2 storage.

4.3 UCG industry overview

4.3.1 Historical development of UCG

Whilst UCG is not yet commercially established, neither is it a new technology. The process has existed for over 100 years, and has been researched, piloted and trialled by a number of companies and organisations, including research organisations such as the Lawrence Livermore National Laboratory in the U.S. and the Commonwealth Scientific and Industrial Research Organisation (CSIRO) in Australia. UCG has also seen long term operation on a commercial scale in the FSU.

UCG was first envisaged in the late 19^{th} century, and a number of trials were conducted in the early 20^{th} century in the UK, before development was halted by the onset of World War I. The first significant research program was commenced in the FSU during the 1930s, which led to the implementation of a number of industrial scale UCG plants, commencing in 1937 and continuing into the 1950s. Whilst many of these were shut down after the discovery of Siberian natural gas reserves in the 1960s, at least one site in Uzbekistan is still in operation today.

The success of the Soviet projects briefly reignited interest in UCG technology in Western Europe in the 1950s, before low oil and gas prices in the 1960s resulted in most programs being abandoned. During the 1970s and 1980s additional technological development and trials occurred in the U.S. However, significant environmental problems at two sites – due to operational mistakes and poor site selection – combined with low natural gas prices in the 1990s, again halted development.

Historically, interest in UCG has been driven by a number of factors at various times, including high mortality rates in underground mines, national energy security, high energy prices, and an undersupply of conventional oil and gas. In recent years, a combination of high oil prices, increasing global energy demand, a focus on environmental issues related to conventional fossil fuel use, and technological improvements – especially in directional drilling and remote monitoring techniques – has interest in UCG increasing.

Since the 1930s there have been over 50 UCG trials or pilot operations worldwide, and indications are that the technology is now sufficiently well advanced to allow for the commercial development of a global UCG industry – should economic conditions be favourable.

4.3.2 Current UCG activities

The last few years has seen renewed interest in UCG in most coal producing regions of the world, with a number of commercial and pilot-scale operations and trials commencing operation, and many more exploration and planning activities underway. Table 4.1 provides an overview of global UCG projects and exploration activity.

The Yerostigaz operation at Angren in Uzbekistan is the world's oldest UCG site, having been operational for more than 50 years. Yerostigaz is now majority owned by Linc Energy. Linc Energy is also actively engaged in a number of other UCG activities. Foremost amongst these is the Chinchilla demonstration facility in Queensland. Chinchilla has been operational since 1999 and is currently the only operating UCG-GTL facility in the world. Linc Energy is also exploring commercial opportunities with local partners in Asia (Siberian Russia, China, Mongolia, Indonesia and Vietnam); Europe (Poland and the UK); North America (Canada and the US); and sub-Saharan Africa (Botswana and South Africa). Linc Energy's business model is based on revenue from licensing, royalty and technical consulting fees; as well as equity participation in JV arrangements in some cases.

Carbon Energy is another Australian company that has been increasingly active in the UCG sector. Carbon Energy was formed in 2006 following a JV between Metex and the CSIRO to develop and commercialise the CRIP UCG technique. A proof-of-concept demonstration of the technology at the Bloodwood Creek project in Queensland is reported to have been successful, and Carbon Energy is now pursuing further opportunities in South America (Argentina and Chile), China and Turkey.

Cougar Energy is the third key Australian UCG player. However, the company's Kingaroy demonstration facility in Queensland was forced to shut down in 2010 by the Queensland Department of Environment and Resource Management (DERM), due to concerns about groundwater being contaminated by benzene and toluene. As a result, Cougar Energy is now focussing its business development activities in Asia, particularly Indonesia, China and Mongolia.

Another key player in the global UCG sector is Canadian based Ergo Exergy Technologies. Ergo Exergy was formed in 1994 and is an experienced UCG technology provider. The company offers several types of licences for its UCG technology and technical services, and has an extensive international portfolio of projects with various local partners.

One of Ergo Exergy's key partners is the South African power utility Eskom. Eskom's UCG operation at the Majuba mine has been operating since 2010, with the syngas produced co-fired with coal at the adjacent Majuba power plant. Majuba is the first commercial UCG operation outside of the FSU, and Eskom has recently signed a research agreement with Sasol to jointly explore further UCG technology development in South Africa.

Though not represented in the list of projects in Table 4.1, Russia has a long history of UCG activity, as well as a number of current projects. China also has an active UCG research program, and it's estimated that there are now around 30 UCG projects at different stages of development in China. Other important regions of activity include India (which has huge lignite resources), Indonesia, Eastern Europe, and the UK (which has a number of offshore coal seams).

Table 4.1 Overview of global UCG activities

Country	Participant(s)	Project name & location	Development status	Comments	Downstream processing
Argentina	Carbon Energy; Delmo Group	Claromeco Coal Basin	Exploration/planning	Signed MOU; Over 600,000 hectares of coal exploration rights	Power generation
Australia	Linc Energy	Chinchilla (Surat Basin, Queensland)	Demonstration facility (operational since 1999)	World's only operating UCG-GTL facility; 80,803 acres of coal tenements	GTL; EOR
Australia	Linc Energy	Walloway and Arckaringa basins (South Australia)	Exploration/planning	904,402 acres of coal tenements	GTL
Australia	Carbon Energy	Bloodwood Creek (Surat Basin, Queensland)	Pilot-scale demonstration facility (operational since 2011)	Proof-of-concept demonstration of oxygen injected CRIP technique; 432 PJ of 2P certified syngas resource	Power generation
Australia	Cougar Energy; Ergo Exergy	Kingaroy (Surat Basin, Queensland)	Demonstration facility (ceased operation)	Shut down in 2010 by Queensland Department of Environment and Resource Management (DERM) due to concerns about groundwater being contaminated by benzene and toluene	-
Canada	Laurus Energy; Ergo Exergy	Drayton Valley, west central Alberta	Exploration/planning	Coal leases	Power generation (co-fired with coal/ petcoke)
Canada	Swan Hills Synfuels	Alberta	Exploration/planning	-	-
Chile	Carbon Energy; Antofagasta Minerals SA	Mulpun	Exploration/planning	Signed agreement to jointly assess and develop the deposit in 2009	-
China	Carbon Energy; Zhengxhou Coal Industry Group	Haoqin Coal Field (Inner Mongolia)	Exploration/planning	Signed Technology Licence Agreement (TLA) in June 2013	-
Indonesia	Cougar Energy; MedcoEnergi	South Sumatra & East Kalimantan	Exploration/planning	Signed MOU in 2011 to jointly assess the opportunity to introducing CSG technology into Indonesia and set up a JV once suitable sites have been identified	Power generation; SNG production; methanol, ethanol or urea production
New Zealand	Solid Energy; Ergo Exergy	Huntley Coal Field (North Island)	Pilot-scale demonstration facility (operational since 2012)	-	-
Poland	Linc Energy	Polanka-Wielki Drogi (PWD) (Upper Silesian Coal Basin)	Exploration/planning	53,374 acres of coal exploration leases	-
Russia	Linc Energy; LLC YakutMinerals	Chukotka (Siberia)	Exploration/planning	Signed agreement in June 2013	GTL
South Africa	Eskom; Ergo Exergy	Majuba	Commercial operation (operational since 2010)	First commercial operation outside of the FSU	Power generation (co-fired with coal)

Country	Participant(s)	Project name & location	Development status	Comments	Downstream processing
South Africa	Eskom; Sasol; Ergo Exergy	-	Exploration/planning	Signed research agreement in June 1013 to jointly explore UCG technology development in South Africa	-
South Africa & Botswana	Linc Energy; Exxaro	-	Exploration/planning	Signed agreement in May 2013 to jointly evaluate coal tenements	-
Turkey	Carbon Energy	Amasra	Exploration/planning	Acquisition of UCG mining rights	-
UK	Linc Energy; UK Coal	Warwickshire, Yorkshire & Leicestershire Coalfields	Exploration/planning	Signed MOU in 2011	Power generation; SNG production; FT diesel production
Ukraine	Linc Energy; DTEK	-	Exploration/planning	Signed agreement in December 2012	-
US	Linc Energy	Cook Inlet Basin & Interior (Alaska)	Exploration/planning	167,917 acres of coal exploration tracts	-
US	Linc Energy	PRB and Washakie Basin (Wyoming)	Exploration/planning	180,651 acres of coal leases; project design specifications have been prepared	EOR
US	Linc Energy	Williston Basin (Montana & North Dakota)	Exploration/planning	5,710 acres of coal leases	
US	Laurus Energy; Ergo Exergy	Stone Horn Ridge (Cook Inlet Basin, Alaska)	Under development (operations scheduled to commence in 2014)	-	Power generation (CCGT); EOR
US	Laurus Energy	Wyoming	Exploration/planning	-	-
Uzbekistan	Linc Energy (91.6%)	Yerostigaz (Angren)	Commercial operation (operational since 1961)	-	Power generation
Vietnam	Linc Energy; VINACOMIN; Marubeni	Tonkin project (Red River Delta)	Exploration/planning	-	-

Source: Company websites

4.4 UCG SWOT analysis

A SWOT analysis has been conducted summarising the attractiveness of UCG relative to alternative coal conversion pathways. Note that analysis of the economics and commercial viability of UCG is outside the scope of this report, and is not considered here.

Table 4.2 UCG SWOT analysis

Strengths & opportunities	Weaknesses & threats
• Has been extensively researched, piloted and trialled, and seen long term operation on a commercial scale in the FSU. • Has the ability to utilise coal that is poor quality (e.g. lignite), inaccessible (e.g. deep or offshore coal seams), or otherwise difficult to mine (e.g. coal seams with unfavourable geology) – hence increasing the potential resource base. • Able to target coal deposits that are not targets for conventional mining (due to poor financial returns) – hence minimising competition with the traditional miners. • Relatively high resource extraction efficiency relative to conventional underground mining, particularly for thick coal seams (overall energy recovery efficiency will depend on the downstream processing route employed); and high energy recovery efficiency relative to CBM extraction. • Smaller surface environmental footprint relative to conventional mining and/or traditional ACG. • Elimination of human safety hazards associated with underground mining. • Solid waste such as ash remains in the depleted coal seam, mitigating the need for surface disposal. • Smaller volumes of saline wastewater produced relative to CBM extraction. • Produces syngas as the primary product – hence a wide variety of downstream processing options, applications, and potential value-added products. • Downstream processing options for the syngas essentially the same as for traditional ACG, so could utilise commercially proven technology. • When combined with GTL, produces clean-burning liquid fuels (e.g. diesel, jet fuel) that are compatible with existing engine technologies, allowing coal to be used as an oil alternative – hence potentially allowing countries that rely heavily on oil imports but have large domestic coal resources to improve national energy security • Relative ease of CO_2 capture compared to other coal conversion pathways produces a CO_2 by-product that could be used for EOR or ECBM recovery (in certain locations) – hence providing both an additional revenue stream and a commercially attractive means of CSS.	• Not yet a commercially established technology – hence the economics of the process are still uncertain • Likely only to be commercially viable in periods of high oil and/or natural gas prices – hence the development of unconventional hydrocarbons (e.g. shale gas) constitutes a threat in some markets. • Potential environmental risks such a groundwater contamination and surface subsidence (though these are also potential risks for conventional underground mining and CBM extraction). • Only suitable for deeper coal seams, in order to maintain the hydrostatic pressure necessary to contain the gasification process, and reduce the risk of subsidence – hence limiting suitable sites and increasing drilling costs. • Preferable to avoid operating in the vicinity of good quality water aquifers, in order to minimise the risk of groundwater contamination – hence limiting suitable sites. • Technologically complex and challenging, with effective operation dependent on the interaction of numerous process parameters, many of which are governed by site specific geological and hydrogeological properties. • Process monitoring and control more difficult than for ACG. • Negative public perception likely to be an issue in some jurisdictions (e.g. Australia, USA). • Lack of an appropriate regulatory environment in some jurisdictions (e.g. Indonesia) likely to extend development timelines. • Syngas is an intermediate product that requires integrated processing to produce end products that are sensitive to local and regional demand and competition.

Source: Wood Mackenzie

5 Coal market review

5.1 Summary

Demand for seaborne thermal coal is expected to increase from 936 Mt in 2013 to 1,122 Mt in 2018 (a compound annual growth rate (CAGR) of 3.7%) with the majority of growth a result of increased coal demand in Asia. Large developing economies in the region, such as China and India, will need significant volumes of coal to support their coal-fired power generation requirements. Whilst both countries have significant domestic reserves, production growth will be unable to meet total demand, resulting in rising import demand.

Traditional thermal coal suppliers, Indonesia and Australia, are expected to meet the bulk of incremental growth in demand due, in large part, to their freight advantage into Asia. However, increasing volumes of coal from regions that have typically supplied the European market, such as Colombia, will increasingly be diverted towards the high growth Asian markets.

Australia is the largest supplier of high energy, low sulphur thermal coal traded on the seaborne market. Short term growth in exports will be derived from brownfield expansions and greenfield projects in established thermal coal mining basins, although there will also be increasing production from emerging basins in both New South Wales and Queensland. Whilst Australian export growth has been constrained by infrastructure in recent years, significant investment in infrastructure has alleviated existing bottlenecks. Additional investment in export infrastructure will be required to unlock developing coal supply regions. Australian costs have risen substantially in recent years but producers are now focussed on productivity improvements and cost reductions. Australia is expected to continue to supply traditional markets in Northeast Asia whilst increasing exports of lower quality coals to China.

Thermal coal prices have experienced significant volatility in the past few years as demand has, at times, outstripped supply capability. Producers have responded by increasing supply capacity and the market is now oversupplied. In response to subsequently falling prices, producers have continued to supply the market in an effort to lower unit production costs and extract some margin, further suppressing prices. Market balance is expected to return around 2018 as rising coal demand absorbs excess production.

5.2 Coal market fundamentals

Coal is a widely distributed natural resource that is produced in numerous countries worldwide. Most coal is used in the country in which it was mined. China and the U.S. in particular – the world's two largest coal producers – consume the majority of their coal domestically.

The coal market can be divided into two major sub-markets, thermal and metallurgical, based on the end-use of the coal:

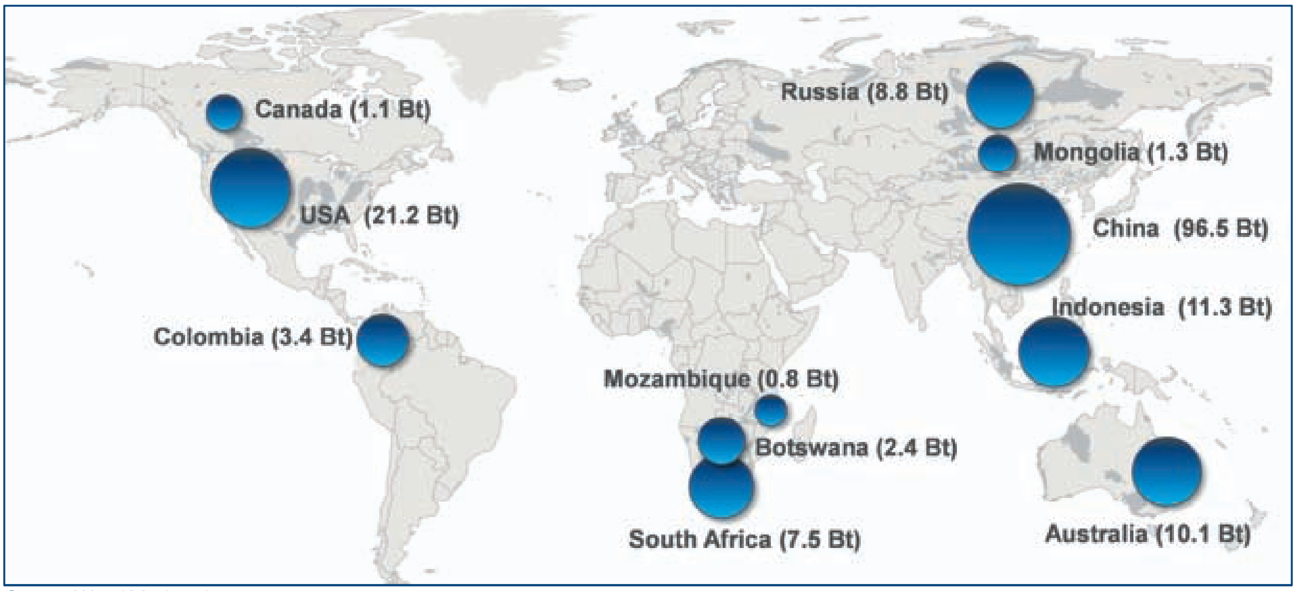
Thermal coal is used in combustion processes to produce steam for power generation, heating, and industrial applications such as cement manufacture. Thermal coal can be further sub-divided into different market tiers based on energy content. The following energy-based classifications for thermal coal are used in this report:

- **Bituminous** Specific energy > 5,400 kcal/kg (gar)
- **Sub-bituminous** Specific energy 4,500–5,400 kcal/kg (gar)
- **Low rank** Specific energy <4,500 kcal/kg (gar)

Wood Mackenzie estimates that the majority of marketable[15] thermal coal reserves are located in China. Other countries with significant thermal coal reserves are the U.S., Indonesia, Australia, South Africa, Russia and Colombia.

[15] *The reserves data in this report is based on Wood Mackenzie's view of likely future commercial production, rather than JORC (or equivalent) compliant reserves estimates. Marketable reserves are defined as the total forecast of future marketable coal production over the life of each identified mine and project.*

Figure 5.1 Marketable thermal coal reserves by country



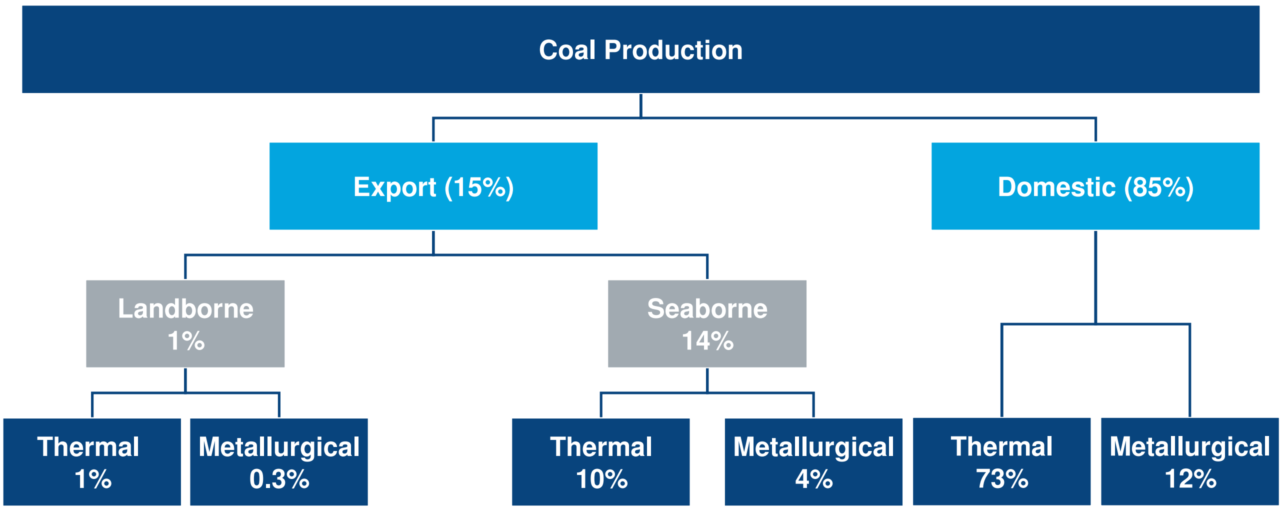
Source: Wood Mackenzie

Metallurgical coal is used in steel production. It is used either to produce coke, which is then fed into the top of the blast furnace along with the iron ore; or for pulverised coal injection (PCI), where the coal is injected directly into the base of the blast furnace. Metallurgical coal is classified based primarily on the strength of the coke it produces.

For the most part, the markets for thermal and metallurgical coal operate independently of each other, although some degree of substitution between thermal coals and lower ranked metallurgical coals is possible. Thermal coal currently accounts for just under 75% of the total seaborne coal market.

The market for international coal trade can also be divided based on the method of trade; either landborne or seaborne. The seaborne market is far more significant in terms of size and will be the focus of this report; landborne coal trade is confined to just a few key areas: primarily Russia, China and Eastern Europe.

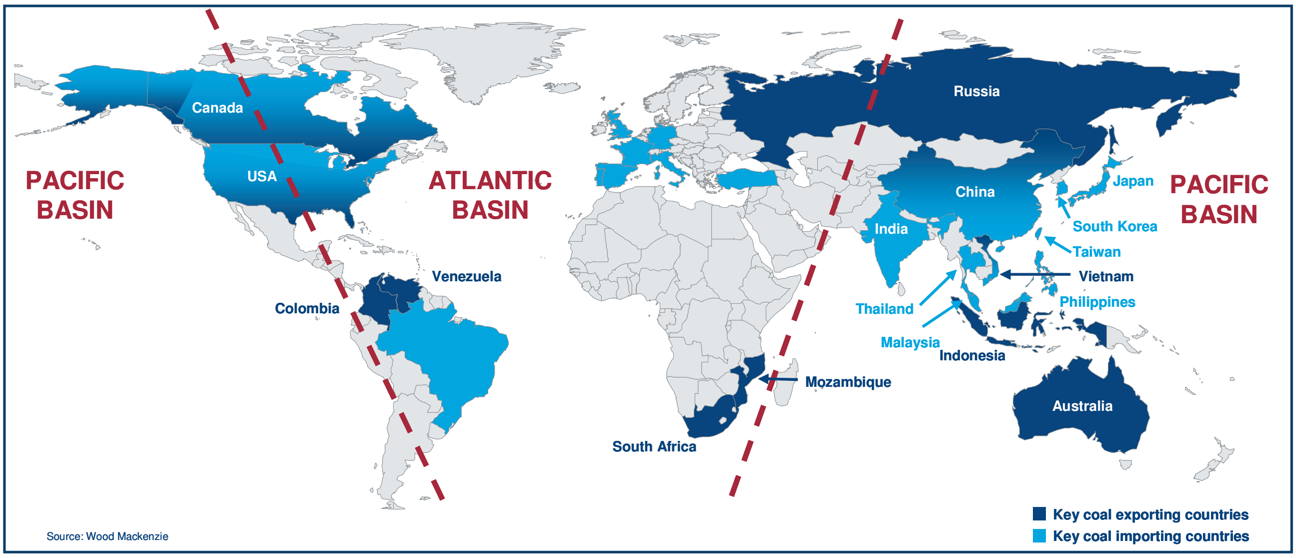
Figure 5.2 Global coal production by market and end-use



Source: Wood Mackenzie

The seaborne market for thermal coal can be divided into two sub-markets geographically, based around the Atlantic and Pacific basins. The two markets are relatively segregated, primarily due to the relative cost of shipping between the two regions. However, some inter-basin trade does occur, either due to quality considerations or when freight and price differentials allow exporters to compete in non-traditional markets.

Figure 5.3 Atlantic and Pacific basins



Pacific Basin trade currently accounts for around 75% of the seaborne market, with Australia and Indonesia being the largest suppliers. The developed Asian economies of Japan, South Korea and Taiwan have traditionally been the principal Pacific Basin importers. However, growth in these markets has been limited in recent years with import growth instead concentrated in the developing economies of China, India and, to a lesser extent, Southeast Asia. In the Atlantic, South Africa, Russia and Colombia are the largest producers, and until recently, supplied coal primarily into the European market.

Historically, a certain amount of thermal coal from Australia, Indonesia and China has been exported into the European market. However, the net trade flow between the Pacific and Atlantic basins is now positive into the Pacific as traditional Atlantic Basin suppliers such as South Africa and Colombia are increasingly diverting coal exports away from Europe into high growth Asian markets.

5.3 Global seaborne thermal coal demand

5.3.1 Historical thermal coal demand

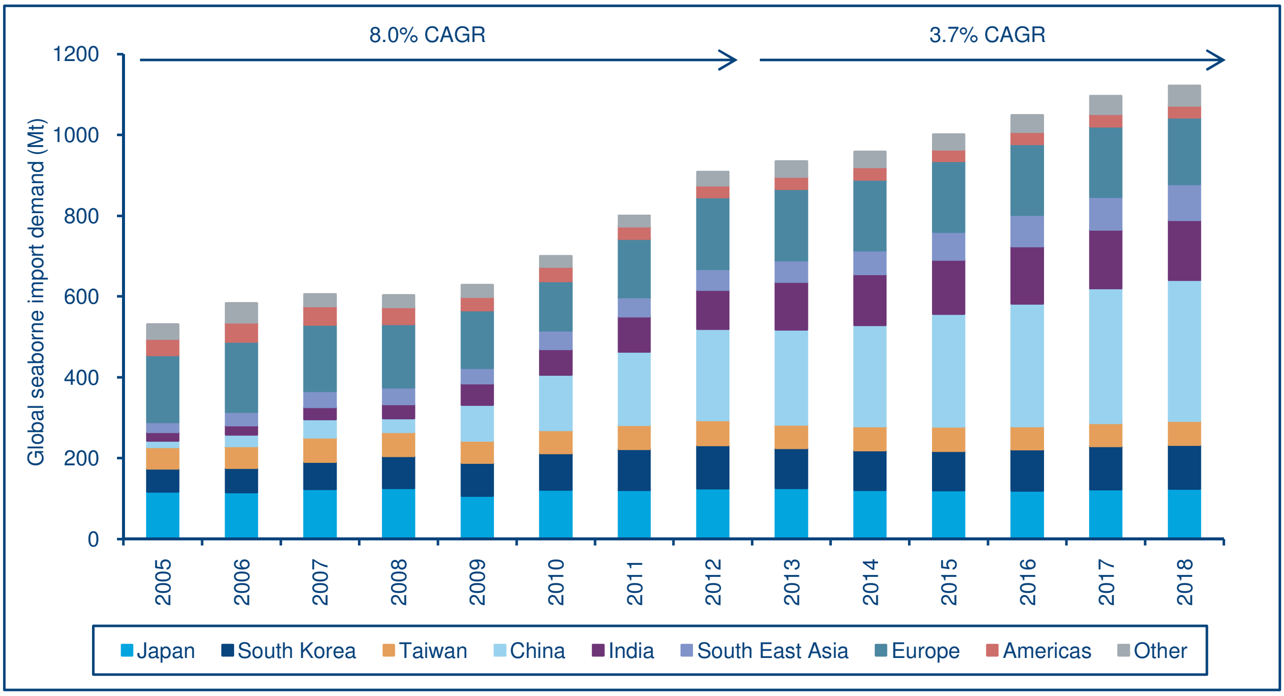
The seaborne thermal coal market has developed and grown rapidly following the two oil crises of the 1970s. Growth in international coal trade can also be attributed to the decline in domestic coal production in many countries – particularly in Europe – due to prohibitive costs and reserve depletion.

Traditionally the largest importers of thermal coal have been the developed economies of Northeast Asia – Japan, South Korea and Taiwan – and Europe. As large economies with little or no domestic coal resources, significant volumes of coal imports were required for power generation. However, growth in these economies has been restrained in recent years leading to limited growth in import coal demand. In Europe, demand for power, and subsequently coal, fell during the global financial crisis and is only now recovering to pre-crisis (2006) levels. In the developed economies of Asia, a declining population, and increased focus on diversified fuel supply has resulted in minimal coal demand growth.

In other parts of the world, import demand for coal is minimal. The Americas are largely self-sufficient in coal and have not been a major driver of seaborne thermal coal demand whilst Africa and the Middle East have relied on domestic coal reserves or alternative sources of fuel.

Demand for seaborne thermal coal increased by an average of 8% per annum between 2005 and 2012. Asia has accounted for almost all import demand growth as regional demand for coal – due to strong economic growth – has outstripped domestic supply. Demand growth has been strongest in large developing economies, such as China and India, with strong, albeit less volumetrically substantial, growth in smaller developing economies in Southeast Asia.

Figure 5.4 Historical and forecast seaborne thermal coal import demand by key country and region (2005–2018)



Source: Wood Mackenzie

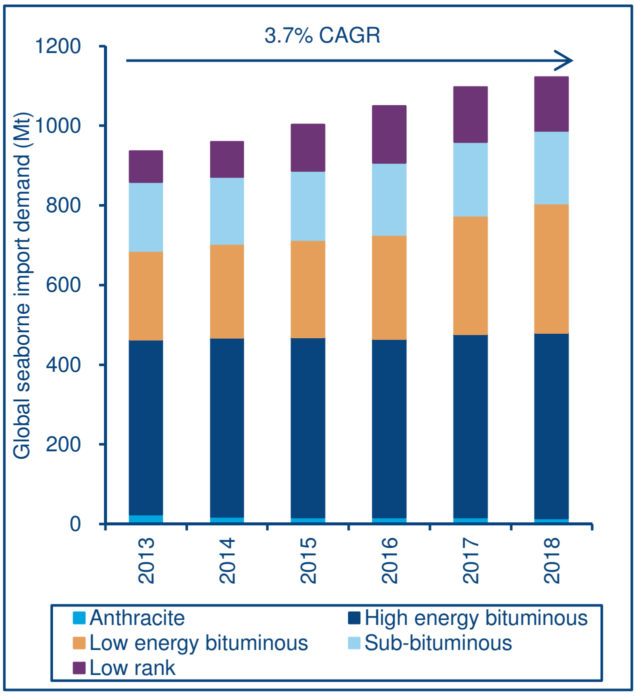
5.3.2 Forecast thermal coal demand

Global seaborne demand for coal will continue to rise; imports are forecast to increase from 936 Mt in 2013 to 1,122 Mt in 2018. This demand growth will be underpinned by increasing energy demand worldwide, but particularly in Asia due to anticipated strong regional economic growth. Consequently, seaborne demand growth for coal will be concentrated in the Pacific Basin. Growth in the Atlantic market will be minimal as slower economic growth, environmental restrictions, and inter-fuel competition, particularly with natural gas, limits increased use of coal for power generation.

Demand growth will be led by China and India, which, combined, will account for 85% of global import demand growth between 2013 and 2018. Despite both having large coal reserves, production (which is generally located inland at some distance from coastal demand centres) will be insufficient to meet demand.

The majority of import coal demand will be for bituminous coals. Existing Northeast Asian power build specifications require high energy coals to operate efficiently, and this will support considerable on-going demand for these types of coal. Demand for higher energy coals is expected to grow as they are increasingly used by developing Asian economies, particularly in India and Southeast Asia, to supplement (and be blended with) insufficient quantities of low energy domestic coal

Figure 5.5 Forecast seaborne thermal coal import demand by coal type (2013–2018)



Source: Wood Mackenzie

Sub-bituminous coal demand will grow moderately over the forecast period, increasing from 172 Mt in 2013 to 182 Mt in 2018.

Demand for low rank coal is expected to increase significantly, nearly doubling between 2013 and 2018. Demand will be focussed in Asia, as plant modifications are made, or new plants are built, that can operate efficiently using lower quality coal.

5.3.3 Overview of key demand countries

Japan, South Korea, Taiwan

The traditional Northeast Asian demand centres of Japan, South Korea and Taiwan will continue to import significant quantities of thermal coal, although demand will remain flat, or increase only moderately, throughout the forecast period. This will be due to declining populations, decreasing energy demand profiles and increased environmental concerns. However, safety concerns in relation to nuclear plants, following the nuclear accident at Fukushima in 2011, will mean coal will continue to underpin power generation.

All three countries currently rely on high quality, high energy bituminous coals, particularly those from Australia, due to boiler design specifications. However, it is anticipated that any new coal-fired capacity will have lower quality, lower energy coal requirements. Some re-configurations to boiler design specification have already been made to take advantage of lower cost, lower energy coals entering the market. Whilst Australia is, and will remain, the predominant supplier in this region, power utilities are keen to diversify supply sources with increased volumes of Indonesian, U.S. and Russian coal being utilised.

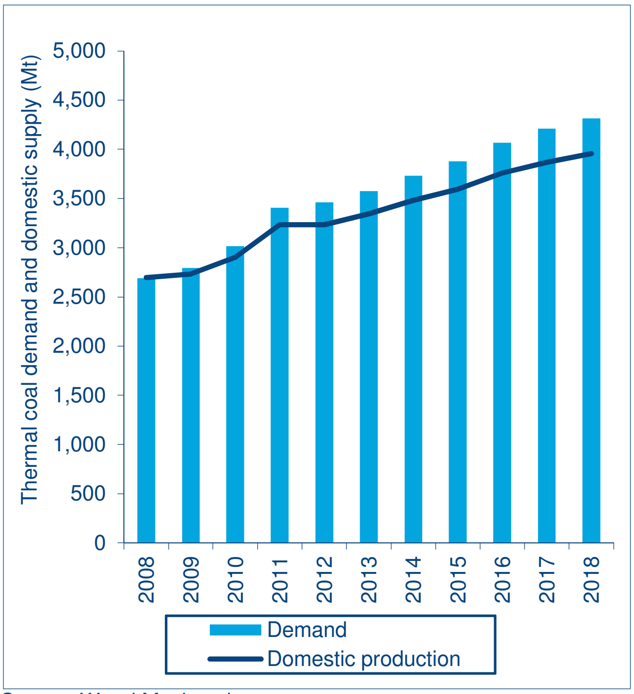
China

China has recently become the largest thermal coal importer in the seaborne market, following its shift from a net exporter to a net importer in 2009. Recent strong growth in import demand has been driven by a rapidly growing economy and increased demand for power. Coal has been the predominant source of power due to its relative low cost. Whilst China possesses significant domestic coal reserves, domestic supply growth has been unable to match demand growth, leading to a rapid rise in import requirements.

Despite efforts to reduce energy intensity, demand for electricity is still expected to rise. Whilst there will be strong growth in alternate power generation capacity, coal will remain the primary fuel source. The majority of the demand for coal will be met domestically, but an increasing proportion of imports will be utilised. Whilst some import demand will be met by landborne coal from Mongolia, the majority will be provided by the seaborne market. The volumes required will have a significant impact on the seaborne market; Chinese imports are expected to increase from 235 Mt in 2013 to 349 Mt in 2018 (a CAGR of 8.2%), increasing China's seaborne market share from 25% to 31%.

Indonesia is currently the largest supplier to China as Chinese buyers prefer low rank coals due to the associated price discount relative to higher rank coals. However, China is expected to increase imports of higher rank coals in the future, particularly of high-ash coal from Australia, as they will prove more economical relative to lower rank coal on a $/MWh of electricity generated basis. In addition, a ban on low-energy coal imports was recently proposed in response to environmental concerns regarding their use. The details of this new policy are yet to be released and its impact on the seaborne market is currently uncertain.

Figure 5.6 Historical and forecast Chinese demand and domestic supply of thermal coal (2013–2018)



Source: Wood Mackenzie

India

India is forecast to become the world's third largest importer of thermal coal in 2013 and is likely to surpass Japan to become the second largest importer in 2014; imports are expected to increase from 118 Mt in 2013 to 149 Mt in 2018, a CAGR of 4.8%. This strong growth in imports will be caused by a rise in demand for coal from both the power and cement industries, in conjunction with an increasing inability of domestic production to keep pace with demand.

Demand growth for coal from the power sector is due to the electrification of rural and urban areas and industrial and infrastructure development. In response to rapidly rising power demand, the government plans to substantially increase coal-fired generation capacity. A major component of its plans will be the Ultra Mega Power Project (UMPP) – a series of new generators each with 4 GW of capacity.

Demand for coal from non-power sources, particularly cement, is also expected to increase. Indian cement plants will rely heavily on imports to meet their coal demand requirements as they are generally located on the coast, far from domestic mines.

Like China, India possesses significant thermal coal resources but development has been unable to keep pace with rising demand, leading to an increased import requirement. Inadequate domestic production has been caused by a variety of issues including; legal issues (e.g. environmental constraints, land use conflict), bureaucratic delays, depleted reserves, and declining coal quality.

A number of other factors will underpin increased imports including; the need to blend high quality coal with lower quality domestic coal; the geographic separation between new power plant build along the coast and inland domestic coal production; and equity ownership by Indian power companies in coal mines abroad.

India will import both high and low energy thermal coal. The former to inland power plants as part of a blend to overcome low energy domestic coal, and the latter to coastal power plants that have limited access to domestic supply. Indonesia is currently the largest supplier of thermal to India followed by South Africa. These two countries will continue to dominate India's import market through to 2018.

Southeast Asia

Import demand from developing Southeast Asian economies (particularly Malaysia, Thailand, the Philippines and Vietnam) is expected to grow rapidly, albeit from a smaller base than the larger Asian economies of China and India. Total seaborne imports are expected to increase from 53 Mt in 2013 to 88 Mt in 2018, a CAGR of 10.7%.

These Southeast Asian countries are at different stages in the development cycle but are all fast growing economies characterised by growing manufacturing and/or construction industries. To support aggressive GDP growth targets, power consumption will increase substantially. As domestic gas reserves are depleted, coal-fired generation is expected to increase its share of the fuel mix as the cheapest form of electricity production. Thailand has placed greater emphasis on meeting energy requirements via alternative fuels due to strong anti-coal sentiment. However, the pressure to reduce fuel costs will mean Thailand has few alternatives but to use coal-fired generation in the longer term to meet power demand growth.

The Southeast Asian economies will utilise domestic coal reserves but production will be inadequate to meet demand growth. Due to its close proximity and relative freight advantage, Indonesia is the primary supplier to the region. The majority of imports are sub-bituminous coals but there will be increasing volumes of higher energy coals from Indonesia, Australia and South Africa.

Europe

In Europe, low economic growth coupled with decreasing energy intensity, will translate into minimal growth in energy demand and declining coal demand for power generation. Whilst small increases in the use of coal in Turkey and Germany are forecast, developed European economies are transitioning away from the use of thermal coal in response to increasing anti-coal sentiment. Increased regulations that reduce the cost incentives for new coal-fired build – based on sulphur and carbon dioxide – and concurrent financial support for the development of renewable energy sources will be common. This will result in a steady decline in installed coal-fired generation capacity as existing plants retire and are replaced by alternative sources of power generation such as gas and renewables.

5.4 Global seaborne thermal coal supply

5.4.1 Historical thermal coal supply

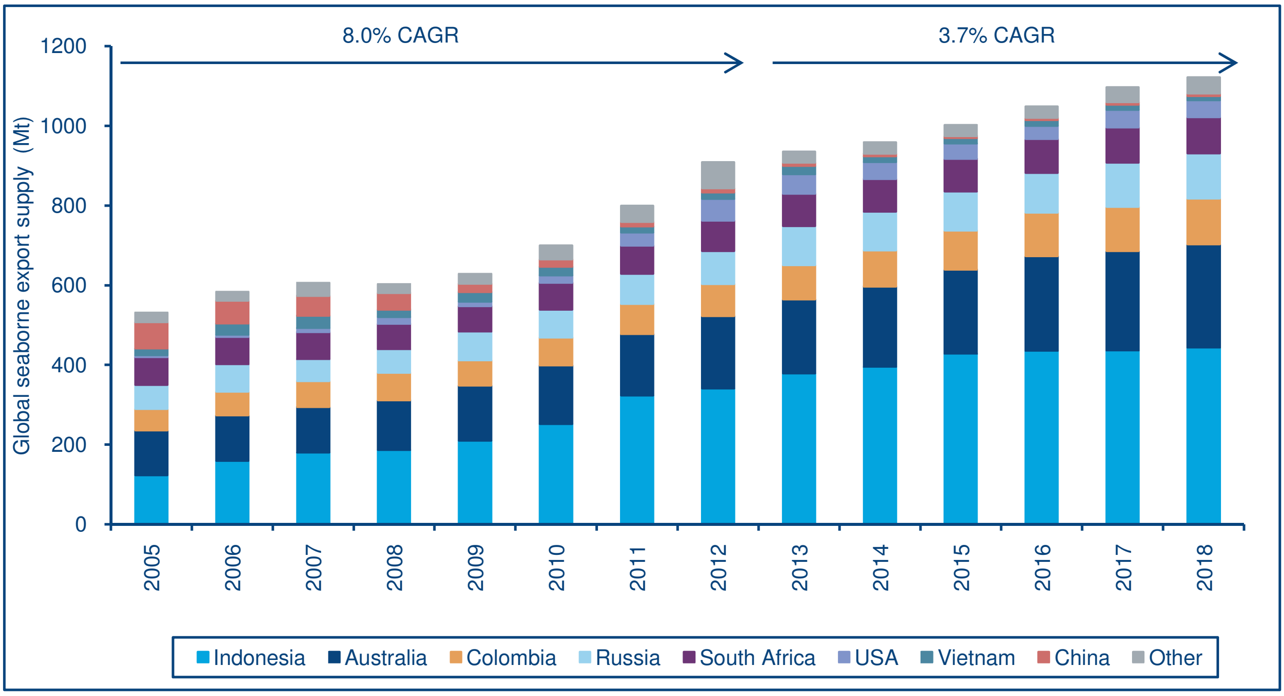
Supply of coal to the seaborne market has traditionally been dominated by six countries: Australia, Indonesia, South Africa, China, Colombia and Russia. However, rampant economic growth in China has seen Chinese demand outstrip domestic supply, and China became a net importer of coal in 2009.

Seaborne thermal coal supply has increased in line with demand over the past eight years, supported largely by increased production from the Pacific Basin suppliers Indonesia and Australia.

Indonesia has been the largest exporter of thermal coal since 2005 and strong growth of nearly 16% per annum has seen it consolidate its market share from 23% in 2005 to 37% in 2012. This expansion has partly been the result of strong demand growth for lower energy coals – of which Indonesia has abundant reserves – from the developing Asian market.

Whilst initially constrained by insufficient export infrastructure, Australian exports have increased throughout the past few years. Investment in new port and rail capacity has supported the development of projects and enabled the development of new coal supply regions. Meanwhile infrastructure constraints in South Africa have persisted and there has been no growth in exports. Export growth in Russia and Colombia has largely kept pace with overall growth in seaborne supply and they have each maintained a roughly 10% share of the seaborne market.

Figure 5.7 Historical and forecast seaborne thermal coal export supply by key country and region (2005–2018)



Source: Wood Mackenzie

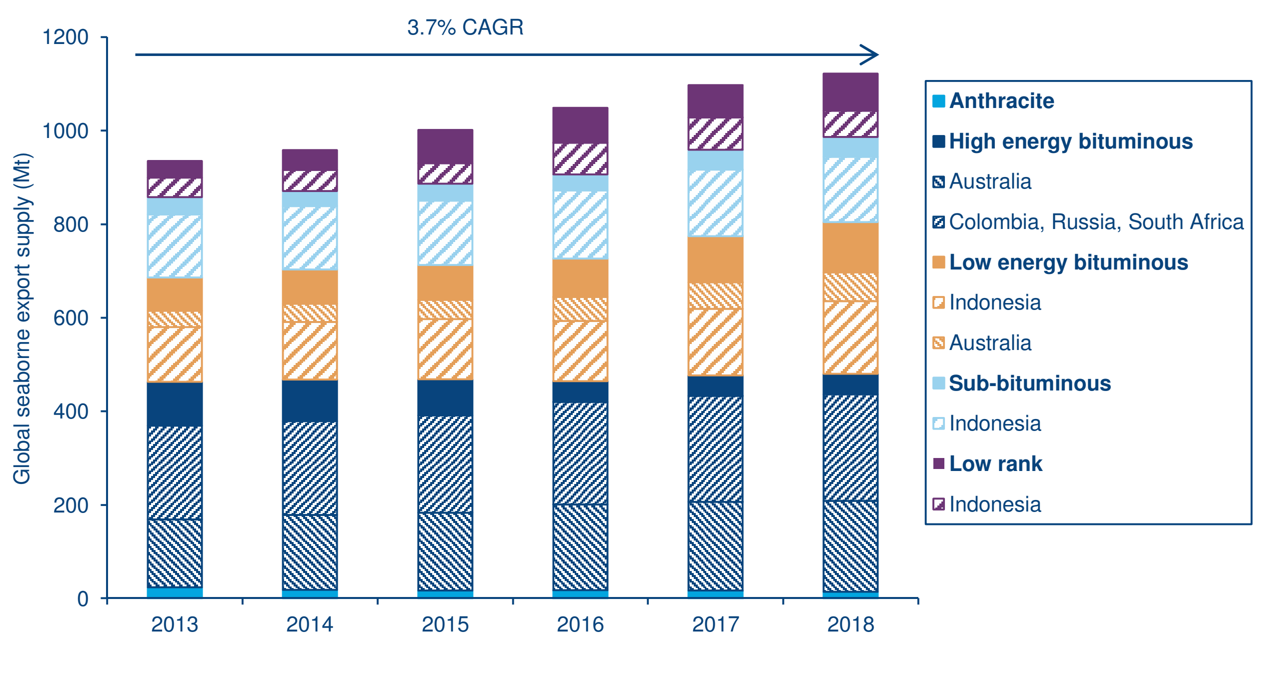
5.4.2 Forecast thermal coal supply

Seaborne export supply of thermal coal is expected to increase in line with demand, growing from 936 Mt in 2013 to 1,122 Mt in 2018. Traditional Pacific Basin suppliers, Indonesia and Australia, will continue to supply the majority of the seaborne market. However, strong growth in Pacific Basin demand will encourage other producers to increase exports to Asia, particularly South Africa and Colombia.

Australia will remain the largest supplier of high energy bituminous coals and is expected to increase its market share of the high energy market from 33% in 2013 to 42% in 2018. Other high energy coal suppliers – South Africa, Russia and Colombia, will also increase supply but their share of the market is not expected to change significantly during the forecast.

Whilst Indonesia will continue to be the largest supplier of low energy bituminous, sub-bituminous and low rank coals, Australian exports of low energy bituminous coals are expected to steadily increase throughout the forecast period.

Figure 5.8 Forecast seaborne thermal coal export supply by coal type (2013-2018)



Source: Wood Mackenzie

5.4.3 Overview of key supply countries

Australia

Australian exports of thermal coal are expected to grow from 186 Mt in 2013 to 259 Mt in 2018, a compound annual growth rate of 7%. This growth in export supply will be underpinned by both brownfield expansions and new projects. The majority of export thermal coal production is currently sourced from the Sydney Basin in New South Wales (NSW), with significant volumes also sourced from the Bowen Basin in Queensland. Supply growth between 2013 and 2018 will primarily be driven by increased production from these two basins.

The emergence of substantial volumes of coal from undeveloped basins will be dependent on new rail and port capacity. Prior to 2011 Australian export growth had been restricted by inadequate port and rail capacity. Significant investment has since been made and bottlenecks began to ease post 2011. However, additional infrastructure will be required to unlock new coal supply regions in the long term. In the current low price environment, there is increased uncertainty surrounding future infrastructure developments and significant additional capacity is unlikely to be commissioned until the later part of the forecast and beyond.

Port capacity at the end of 2013 is expected to be 480 Mt, contingent on the continuation of expansions currently underway in NSW. Total port capacity is expected to increase to 566 Mt by the end of 2018 as several expansion projects and new terminals are commissioned in both NSW and Queensland. Investment in rail capacity is also expected as both expansions and new lines will be required to provide producers access to new port capacity.

Australia is the largest supplier of high energy, low sulphur thermal coal traded on the seaborne market; standard bituminous coals from New South Wales, with an energy content of 6,322 kcal/kg GAR, provide the reference point for coal pricing in the Pacific. Australia will remain the dominant supplier of high energy coal over the forecast period, continuing to supply its established customer base in Japan and Taiwan. However, growth in demand for cheap, low energy coal in China and India has precipitated the trend towards higher ash, lower energy coals from Australia. Exports of this mid-energy 5,500 kcal/kg NAR "high ash" coal product are expected to increase steadily over the forecast period.

Although Australia will face increased competition from other high rank suppliers, such as Russia, and high rank producers in Indonesia, enormous growth in Pacific Basin demand will require reciprocal growth in Australian coal supply over the forecast period.

Indonesia

Indonesia will remain the largest supplier of thermal coal throughout the forecast period, accounting for around 40% of the seaborne market. Growth in Indonesian exports will be driven by lower energy coal types, with most low rank coal exports destined for China and India, and smaller but increasing volumes shipped to other developing Asian countries.

Short term growth in Indonesian exports will be supported by their low cost structure on both an FOB and a delivered basis. In the longer term, as new supply regions are developed further inland, producers will face higher mining and transport costs and the competitive edge of some Indonesian producers will be lost.

Besides changes in seaborne trade flows, Indonesian export capability could also be limited by growth in domestic coal consumption and regulation. Regulatory issues have always plagued the Indonesian coal industry and there has been on-going ambiguity about the potential introduction of a low rank coal export ban. Whilst the government has clarified that there will not be an export ban, they have not ruled out introducing production quotas instead. In addition, the government has acknowledged the importance of a reliable domestic coal supply and requires coal producers to set aside a portion of their production for domestic sales. This is known as the Domestic Market Obligation (DMO). Wood Mackenzie does not expect that domestic demand will impede Indonesian exports in the near term but as domestic demand grows, and DMO increases in-line with demand, potential export growth may be restricted.

South Africa

South Africa contains vast thermal coal resources, however, significant challenges exist in financing and providing infrastructure to monetise these resources. South African exports have historically been constrained by inadequate rail infrastructure, leaving ports underutilised – particularly Richards Bay. This situation is expected to improve in the short term and it is anticipated that exports will increase from 82 Mt in 2013 to 91 Mt in 2018. Exports will be increasingly oriented away from Europe towards the Pacific market, particularly to India.

Colombia

Colombia is expected to maintain a 10% share of the seaborne market as export production increases from 87 Mt in 2013 to 115 Mt in 2018. Given the ambiguous nature of Colombia's mining policy, it will be difficult for companies to obtain new mining licences and environmental permits. Consequently, the majority of future growth will be sourced from expansions at existing mines. These operations are located inland and expansion of transport and port infrastructure capacity will be required to accommodate the forecast supply growth. Whilst the government has provided support to mining projects, additional infrastructure capacity will most likely be developed without financial assistance. Europe and South America will continue to be the main destinations for high energy Colombian coal. However, due to their low production costs, and a continuation of low freight costs, shipments to Asia will continue to increase

Russia

Russia is the third largest thermal coal exporter globally, and exports predominantly high energy coal. The majority of reserves are located in south central Russia but only around 36% of its exports enter the Pacific Basin; the rest supplies the European market. An expansion of eastern port capacity will be required to increase access to the growing Asian market. Russian export production growth will be restricted by infrastructure capacity constraints but also reduced investment in projects and increased domestic demand. Due to large transport distances, Russia is a high cost seaborne supplier and capital expenditure on new projects has diminished in response to global economic conditions and lower thermal coal prices.

U.S.

The U.S. is the world's second largest coal producer, but most of this is consumed domestically. Distance from Asia historically priced U.S. coal out of the Pacific market, but as Asian demand rises beyond the supply capacity of traditional coal exporters, the U.S. could emerge as a major supplier. To do so, the U.S. would need to put in place new West coast rail and port connectivity, enabling large volumes of sub-bituminous coal from the PRB to reach the Pacific market. Given on-going delays in port permitting, a significant increase in exports is not considered possible until after 2018.

5.4.4 Cost Competitivness

Seaborne coal costs[16] of production are typically compared on a Free-on-Board (FOB) basis as this is most commonly the point of sale. The ninetieth percentile on the supply curve is often used as a proxy for the marginal cost of production, representing a price floor below which supply can be expected to ultimately drop out of the market if the low price persists.

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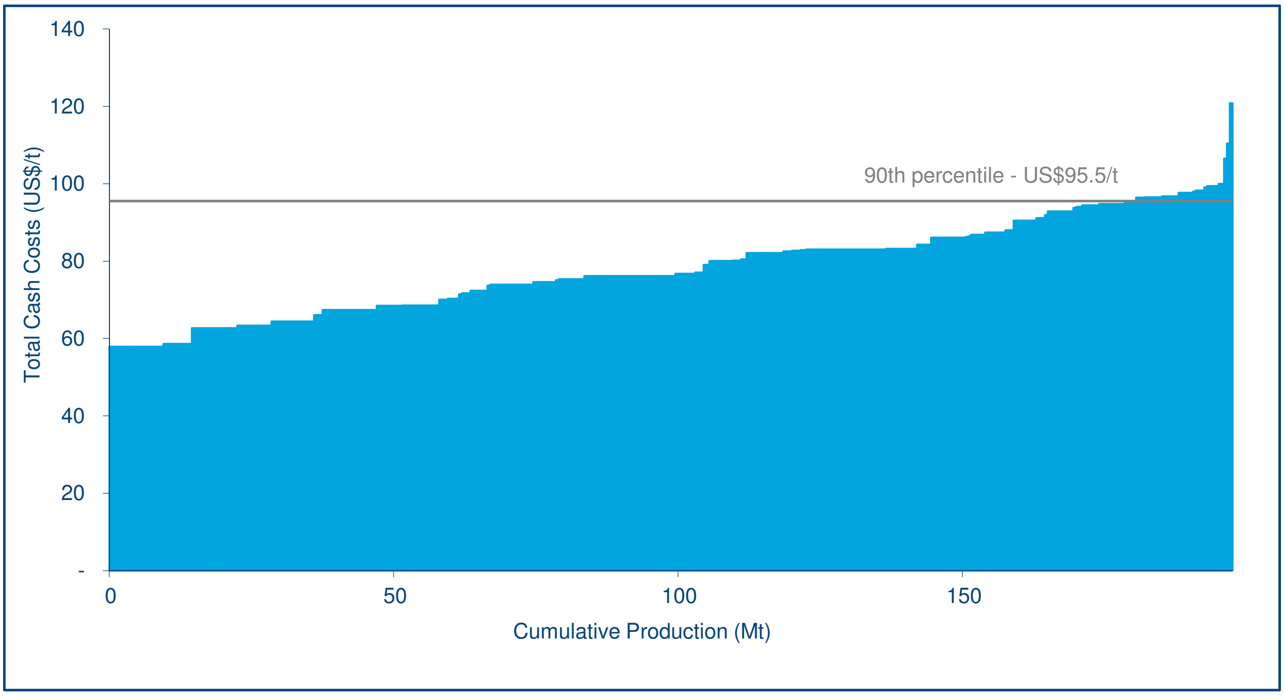
[16] *FOB costs include: mining, coal preparation, transport, overheads, port charges, taxes and royalties.*

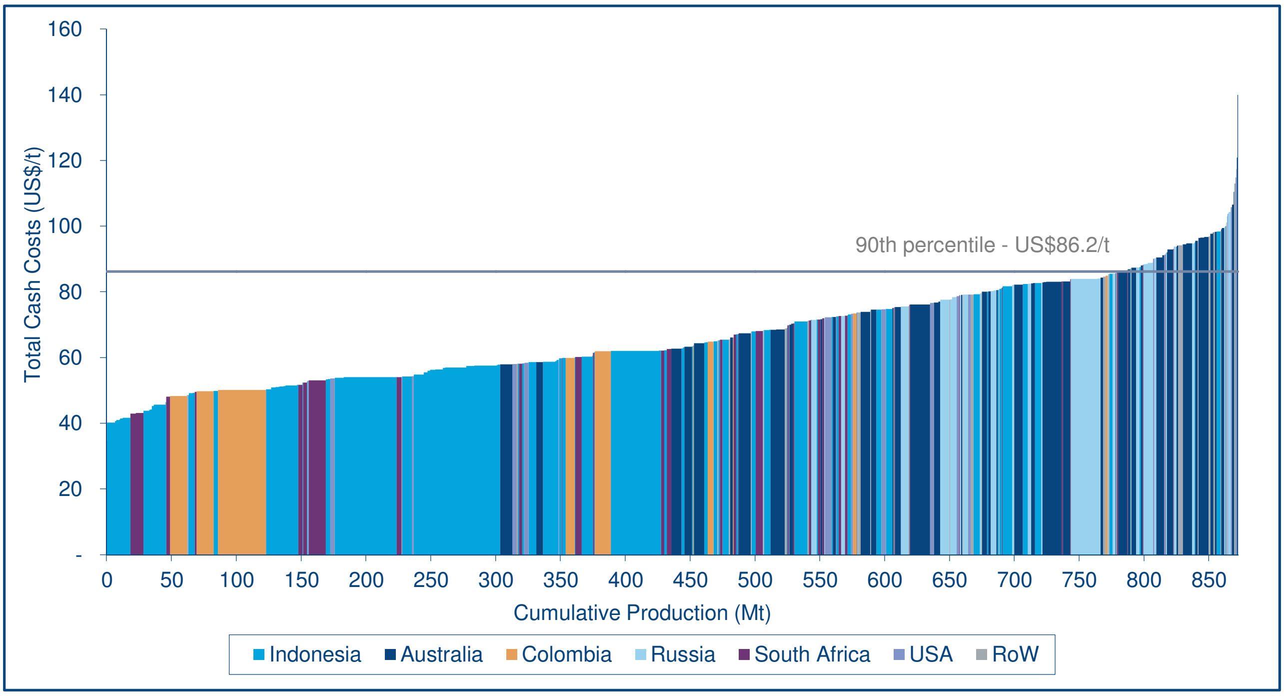
Figure 5.9 Australian seaborne thermal coal FOB supply cost curve (2014, energy adjusted)



Source: Wood Mackenzie

Australian costs vary across a broad range, from a low of US$ 58/t to a high of well over US$ 100/t, with a weighted average cost of production (on an energy adjusted basis) of US$ 78/t. This makes Australia one of the higher cost suppliers into the seaborne market, occupying largely the upper quartiles of the supply curve.

Figure 5.10 Global seaborne thermal coal FOB supply cost curve (2014, energy adjusted[17])



Source: Wood Mackenzie

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[17] *FOB costs have been adjusted based on energy content to the reference specification of 6322 kcal/kg gar*

The competitiveness of Australian coal production has been impacted by high margins in recent years which provided few incentives for scrutiny of mining practices and cost control. Producers instead sought to maximise production to take advantage of high prices. Allied with a boom across the resource sector, this resulted in extreme competition for labour, materials and mining services, which, compounded by a high Australian dollar, caused mining costs to rise substantially. In addition, record levels of capital spending were witnessed in 2011 and 2012 as new projects were commissioned to expand export production capacity.

As prices have fallen and margins have shrunk, operators have been prompted to review costs and have been introducing various cost saving initiatives over the last few months. This has resulted in the closure of some high cost mines, mine plan revisions and expansion delays to preserve capital. Australia's mines have a relatively high fixed cost structure, with take or pay commitments likely to be a key driver of costs in the short term as mines are forced to pay higher transport and port costs when output volumes fall below capacity or planned expansion levels. Unit cost reductions will be largely achieved by production increases, in an effort to improve returns to scale, but an expected continued depreciation of the Australia dollar will improve the cost competitiveness of Australian coals.

Australian producers have also faced increased regulatory pressures following the introduction of the carbon tax, the Mineral Resources Rent Tax (MRRT) and increased royalty payments as State and Federal Governments sought to increase the returns to taxpayers from the mining boom. The carbon tax, designed to reduce the country's carbon emissions, has been in operation since July 2012. The impact on most coal mines has been small with gassy underground mines in NSW the most affected. The MRRT is a federal tax based on the profit achieved by the companies and it targets the 'upstream' profit from the extraction of the coal prior to processing and transport. The payments under MRRT are highly sensitive to future coal price assumptions and, given the presently subdued margins, the MRRT is unlikely to have a material impact in the short- to mid-term.

Indonesian mines tend to occupy the low quartiles of the global supply curve, even after costs are adjusted for energy content. Their competitiveness is based on a combination of factors: inexpensive surface mining operations, an extensive system of natural inland waterways enabling low cost-barging from mine to port, the use of transhipment facilities that have lower capital and operating costs than coal terminals and low labour costs compared to other Pacific Basin producers. U.S. and Russian mines are largely in the fourth quartile, indicative of often very high transportation costs.

5.5 Seaborne thermal coal prices

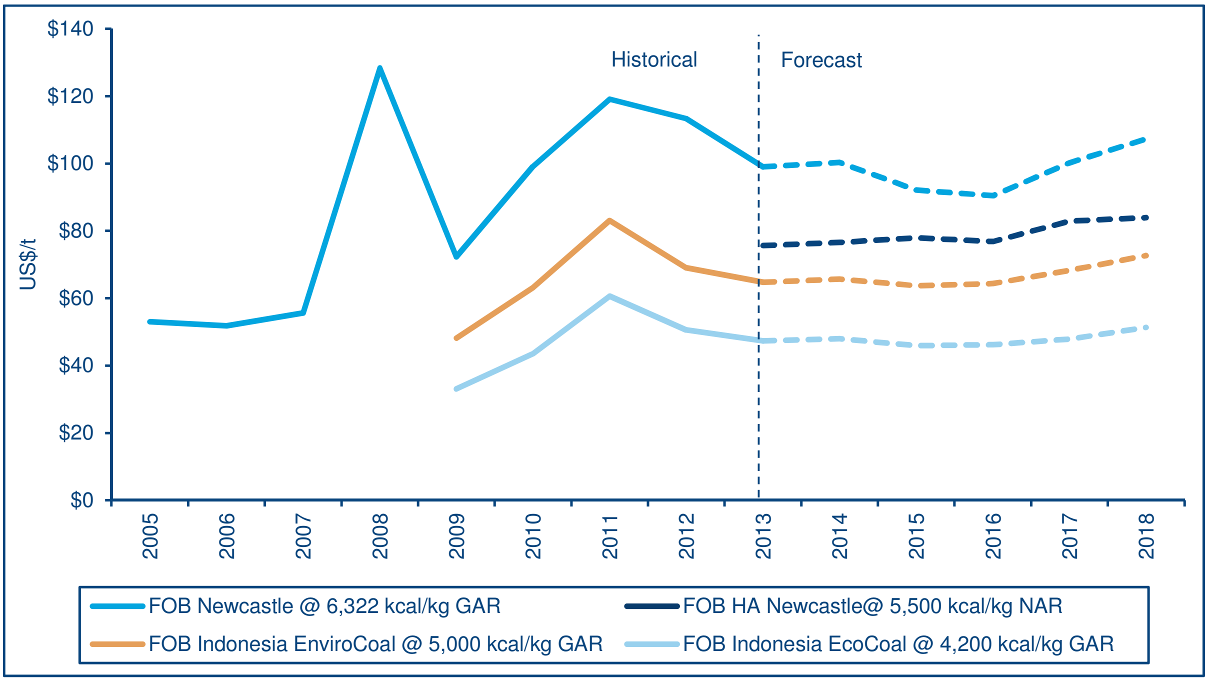
The seaborne thermal coal market is reasonably transparent, with prices generally related to agreed reference prices or indices. The reference price for term contracts in the Pacific market have traditionally been based on the prices settled between Australian exporters and the Japanese Power Utilities (JPU). The JPU reference price applies to bituminous coal of "Newcastle benchmark" quality, with a specific energy of 6,322 kcal/kg (gar).

Prior to 2004, the seaborne thermal coal market was closely balanced and buyers had the greater negotiating power. Long term contracts were therefore common – with suppliers willing to discount prices in exchange for off-take security – and there was negligible spot trade. This period was characterised by regular prices cycles within a narrow band of around US$25 to 40/tonne (FOB) for Newcastle benchmark coal, with prices related to the marginal cost of production. In 2004 the market entered a period of unprecedented volatility due to increased demand coupled with a slow supply-side response, and the emergence of significant spot trading. Spot prices reached unprecedented highs of almost US$ 180/t in 2008 and US$ 130/t in early 2011 following flooding in Queensland, Australia. With the advent of published spot price indices for thermal coal, index-linked pricing for both spot and term contracts has now become common practice and there is a growing financial market for coal products. However, the volume of coal traded on the thermal coal spot market remains small in comparison to the contracted market.

Prices for Indonesian sub-bituminous and low rank coal are linked to the Newcastle benchmark price and domestic coastal Chinese prices. Since the introduction of Indonesia's new mining law in 2009, the Indonesian government also publishes its own monthly coal reference price, the Harga Batubara Acuan (HBA). The 'headline' HBA for Newcastle benchmark quality coal is calculated based on a basket of spot price indices, with minimum prices for Indonesian export brands then calculated by applying quality-based adjustments for energy, moisture, ash and sulphur. These minimum prices are used to calculate the royalty payments for each producer. The aim of the regulation is to protect the government's royalty take by preventing transfer pricing (selling to a subsidiary at below market price). In theory this market-driven approach should also mean that producers are more or less indifferent to selling into either domestic or export markets, guaranteeing more secure access to supply for domestic consumers.

Following the recent rise in demand, particularly by Chinese and Indian buyers, for low cost coals, there has been increased interest in mid-energy coals produced in Australia. A "high ash" 5,500 kcal/kg NAR benchmark has emerged and has rapidly become a key price indicator as exports of this non-traditional coal have increased.

Figure 5.11 Historical and forecast FOB prices for key thermal coal brands (nominal, 2008–2018)



Source: Wood Mackenzie

The JPU settlement price in April 2013 was US$95/t, US$20/t lower than the JFY 2012–2013 settlement price. Whilst demand for coal has been growing continuously, especially in the Pacific Basin, there has been an excess of thermal coal supply in many regions of the world. In Australia this has been the result of additional capacity coming on line and enforced take-or-pay contracts which are causing some miners to elect to produce large volumes in order to increase productivity and lower costs. In Indonesia, low rank coal producers are reluctant to give up even very low margin potential by lowering production, whilst producers in the U.S. are also aggressively exploring export opportunities as domestic regulations force the closure of numerous coal-fired power plants.

Global oversupply is expected to peak by 2017, as slowing export growth coupled with continued Asian demand growth, act together to reduce the supply surplus, with a modest recovery in price ensuing. Although the reduction in oversupply will be significant, the market will remain in excess, meaning that prices are not expected to recover to 2011 levels (in real terms) until well beyond 2018.

For and on behalf of

Wood Mackenzie (Australia) Pty Ltd

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18 November 2013

Gero Farruggio

Director

All the information and data presented in this section, including the analysis of the global oil and gas market, underground coal gasification, and seaborne thermal coal market has been provided by our energy industry consultant, Wood Mackenzie. Wood Mackenzie has advised that the statistical and graphical information contained herein is drawn from its database and other publicly available sources. In connection therewith, Wood Mackenzie has advised that:

(i) certain information in Wood Mackenzie's database is derived from estimates or subjective judgments;
(ii) the information in the databases of other data collection agencies may differ from the information in Wood Mackenzie's database; and
(iii) while Wood Mackenzie has taken reasonable care in the compilation of the statistical and graphical information and believes it to be accurate and correct, data compilation is subject to limited audit and validation procedures.

Wood Mackenzie's methodologies for collection of information and data are proprietary, and therefore the information discussed in this section, may differ from that of other sources. The information and data presented in this section has not been independently verified and neither we nor the Joint Issue Managers, Global Coordinators, Bookrunners and Underwriters make any representation as to the accuracy or completeness of such data or any assumptions relied upon thereon. See "Forward-Looking Statements" and "Experts" which are included elsewhere in this offering document.

APPENDIX H—OUR OIL, GAS AND COAL TENEMENTS AND LEASES

Details of our relevant oil, gas and coal tenements, as at the Latest Practicable Date, are set out below.

QUEENSLAND COAL TENEMENTS

No.	Tenement Name	Tenement Number	Location	Area[(1)]	Expiry Date	Use of Property	Working Interest (%)	Equity Interest (%)
1.	Rathdowney	EPC 910	40km South Ipswich—Clarence Moreton Basin	38 sub-blocks	08/02/15	Exploration	100	100
2.	Wowan	EPC 908	40km North Biloela—Biloela Basin	99 sub-blocks	08/02/15	Exploration	100	100
3.	Galilee South	EPC 1227	60 km West Clermont—Drummond Basin	107 sub-blocks	08/02/15	Exploration	100	100
4.	Pentland	EPC 526	220km South West Townsville—Galilee Basin	12 sub-blocks	26/04/14	Exploration	100	100
5.	Jambin	EPC 909	25km North Biloela—Biloela/Callide Basin	118 sub-blocks	27/04/15	Exploration	100	100
6.	Tipton Sth	EPC 938[(2)]	60km South West Dalby—Surat Basin	32 sub-blocks	14/05/13	Exploration	100	100
7.	Teresa/ Lucknow	EPC 1226	30 km North Emerald—South West Bowen Basin	58 sub-blocks	13/07/13	Exploration	100	100
8.	Biloela	EPC 1248	40km North Biloela—Biloela Basin	90 sub-blocks	20/07/13	Exploration	100	100
9.	Cloncurry Nth	EPC 1525	120km North West Hughenden—Galilee/ Eromanga Basin	120 sub-blocks	23/05/15	Exploration	100	100
10.	Cloncurry Sth	EPC 1526	85km North West Hughenden—Galilee/ Eromanga Basin	155 sub-blocks	22/07/14	Exploration	100	100
11.	Saxby	EPC 1549	150km North West Hughenden—Galilee/ Eromanga Basin	260 sub-blocks	23/05/15	Exploration	100	100
12.	Wilkie	EPC 897	40km South East Chinchilla—Surat Basin	40 sub-blocks	04/08/15	Exploration	100	100
13.	Wilkie	EPC 898	30km South East Chinchilla—Surat Basin	50 sub-blocks	04/08/15	Exploration	100	100
14.	Wilkie	EPC 899	20km North West Dalby—Surat Basin	47 sub-blocks	04/08/15	Exploration	100	100
15.	Teresa	EPC 980	20km N Emerald—South West Bowen Basin	37 sub-blocks	03/11/15	Exploration	100	100
16.	Tipton	EPC 1770	20kms West South West of Dalby / 190kms West of Brisbane	111 sub-blocks	11/11/14	Exploration	100	100
17.	Chinchilla West	EPC 1046	20 km South West of Chinchilla—Surat Basin	16 sub-blocks	15/11/14	Exploration	100	100
18.	Tipton 2	EPC 902	30km South Dalby—Surat Basin	51 sub-blocks	02/12/16	Exploration	100	100
19.	Teresa North	EPC 1267	20km North Emerald—South West Bowen Basin	10 sub-blocks	04/12/13	Exploration	100	100
20.	Wowan West	EPC 1323	20 km North West Woman—Biloela Basin	24 sub-blocks	04/12/17	Exploration	100	100
21.	Chinchilla	EPC1247	15km South West Chinchilla—Surat Basin	8 sub-blocks	04/12/15	Exploration	100	100
22.	Chinchilla	EPC 635	15km South Chinchilla—Surat Basin	32 sub-blocks	24/12/14	Exploration	100	100
23.	Dunmore	EPC 1537	50km SW Dalby—Surat Basin	36 sub-blocks	02/05/15	Exploration	100	100

No.	Tenement Name	Tenement Number	Location	Area[(1)]	Expiry Date	Use of Property	Working Interest (%)	Equity Interest (%)
24.	Lily Pond	EPC 1550	130km North East Cloncurry—Galilee/ Eromanga Basin	240 sub-blocks	12/07/15	Exploration	100	100
25.	Dingo	EPC 1536	15km North West Biloela—Biloela/Callide Basin	46 sub-blocks	28/10/15	Exploration	100	100
26.	Cloncurry Central	EPC 1527	50km SW Dalby—Surat Basin	162 sub-blocks	28/10/15	Exploration	100	100
27.	Agnes	EPC 2541	90km North East Hughenden—Eromanga/ Galilee Basin	300 sub-blocks	28/08/17	Exploration	100	100
28.	Walker	EPC 2551	7km South Hughenden—Eromanga/Galilee Basin	298 sub-blocks	21/10/17	Exploration	100	100
29.	Teresa East	EPC 2841	35km North East Emerald—Bowen Basin	300 sub-blocks	27/09/17	Exploration	100	100
30.	Pelican	EPC 2549	120km North Hughenden—Eromanga/Galilee Basin	300 sub-blocks	20/05/18	Exploration	100	100
31.	Galilee North	EPC 1228	75km North West Clermont—Drummond Basin	299 sub-blocks	08/04/18	Exploration	100	100
32.	Cuthbert	EPC 2552	95km North Hughenden—Eromanga/Galilee Basin	300 sub-blocks	20/10/18	Exploration	100	100

Notes:

(1) Each sub-block is approximately 2.8 sq km (720 acres)

(2) Renewal application made on 14 February 2013, however, this has not been reflected on the Queensland Department of Natural Resources and Mines' register.

SOUTH AUSTRALIA TENEMENTS

No.	Tenement Name	Tenement Number	Location	Area (km^2)	Expiry Date	Use of Property	Working Interest (%)	Net Attributable to Issuer (%)
1.	Arckaringa	PEL117	Arckaringa Basin	6329	02/04/17	Exploration for petroleum	100	100
2.	Arckaringa	PEL118	Arckaringa Basin	7400	31/12/13	Exploration for petroleum	100	100
3.	Arckaringa	PEL119	Arckaringa Basin	9751	31/12/13	Exploration for petroleum	100	100
4.	Arckaringa	PEL120	Begins North Adelaide, extends North 257km ~ 50km West Port Augusta—St Vincent/Walloway Basins	6335	02/10/16	Exploration for petroleum	100	100
5.	Arckaringa	PEL121	Arckaringa Basin	6415	02/04/17	Exploration for petroleum	100	100
6.	Arckaringa	PEL122	Arckaringa Basin	5581	02/04/17	Exploration for petroleum	100	100
7.	Arckaringa	PEL123	Arckaringa Basin	9646	07/10/13	Exploration for petroleum	100	100
8.	Arckaringa	PEL124	Arckaringa Basin	9848	02/10/14	Exploration for petroleum	100	100
9.	Eromanga	PEL 568	Eromanga Basin	3657	14/06/17	Exploration for petroleum	100	100
10.	Eromanga	PEL 569	Eromanga Basin	2555	14/06/17	Exploration for petroleum	100	100
11.	Arckaringa	PELa 604	Arckaringa Basin	9454	-	Exploration for petroleum	100	100
12.	Walloway	PEL 606	Walloway & Stansbury Basin	8508	28/08/18	Exploration for petroleum	100	100
13.	Arckaringa	EL 4502	130 North-East Coober Pedy—Arckaringa Basin	185	30/05/12	Exploration for coal	100	100
14.	Williams Bore	EL 4501	90 North-East Coober Pedy—Arckaringa Basin	304	30/05/12	Exploration for coal	100	100
15.	Walloway	EL 5293	Approx. 90 km southeast of Port Augusta	173	11/05/15	Exploration for coal	100	100
16.	Cadaree Hill	EL 4272	80km North-East Coober Pedy	885	23/06/13	Exploration for coal	100	100
17.	Mt Andrews	EL 4273	70km South-West Oodnadatta	948	24/06/14	Exploration for coal	100	100
18.	Orroroo	EL4454	90km East Port Augusta, Orroroo Region—Walloway Basin	693	17/03/15	Exploration for coal	100	100
19.	Weira Plain	EL 4540	90km East North-East Port Augusta, Orroroo Region—Walloway Basin	87	22/08/13	Exploration for coal	100	100
20.	Mt Andrews	EL 4934	20km SW Oodnadatta	893	21/06/14	Exploration for coal	100	100
21.	Eurelyana Creek	EL 5319	Eurelyana Creek Area—approximately 100km North-East of Coober Pedy	154	05/08/15	Exploration for coal	100	100

WYOMING OIL AND GAS LEASES

No.	Lease Name	Location	Gross Acres	Expiration Date[(1)]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
1.	CONTINENTAL OIL COMPANY	Converse	89.7	Held by unit	Oil and gas production	100	77
2.	WYW 164691	Converse	200	November 2015	Oil and gas production	100	78
3.	WYW 164394	Converse	391.3	September 2015	Oil and gas production	100	78
4.	E R MCQUAID ET UX	Converse	320	Held by unit	Oil and gas production	100	73
5.	C M KOPP ET UX	Converse	640	Held by unit	Oil and gas production	100	86
6.	IONA M CAMPBELL ET VIR	Converse	320	Held by unit	Oil and gas production	100	78
7.	T R KOPP ET UX	Converse	280	Held by unit	Oil and gas production	100	86
8.	WYW 077076	Converse	400	Held by unit	Oil and gas production	100	78
9.	WYW 002217	Converse	40	Held by unit	Oil and gas production	100	78
10.	WYW 003035	Converse	199.9	Held by unit	Oil and gas production	100	78
11.	ST WY 0-02900	Converse	600	Held by unit	Oil and gas production	100	78
12.	WYW 077837	Converse	79.9	Held by unit	Oil and gas production	100	75
13.	GARY POTHE UT UX	Converse	317.1	Held by unit	Oil and gas production	100	77
14.	ST WY 0-4592	Converse	40	Held by unit	Oil and gas production	100	78
15.	C E KOPP ET UX	Converse	640	Held by unit	Oil and gas production	100	86
16.	WYW 164393	Converse	120	December 2015	Oil and gas production	100	78
17.	A J KOPP ET UX	Converse	640	Held by unit	Oil and gas production	100	86
18.	GEORGE A LEACH ET AL	Converse	320	Held by unit	Oil and gas production	100	77
19.	USA WYW 077843	Converse	1,025.5	Held by unit	Oil and gas production	100	78
20.	ST WY 0-6117	Converse	903.4	Held by unit	Oil and gas production	100	78
21.	ST WY 0 7790	Converse	959.8	Held by unit	Oil and gas production	100	78
22.	ST WY 0-4392	Converse	160	Held by production	Oil and gas production	100	78
23.	GUS ENGLEKING ET AL	Converse	320	Held by production	Oil and gas production	100	78
24.	CHICAGO & N WESTERN TRANS	Converse	17	Held by production	Oil and gas production	100	78
25.	ST WY 0-7787	Converse	800	Held by production	Oil and gas production	95	78
26.	H C YOUNG ET AL	Converse	800	Held by unit	Oil and gas production	100	77
27.	ST WY 0-3459	Converse	40	Held by unit	Oil and gas production	100	78
28.	V R RANCH	Converse	1,612.2	Held by unit	Oil and gas production	100	85
29.	FENEX OIL COMPANY	Converse	150	Held by unit	Oil and gas production	100	78
30.	KGN MINERAL TRUST DTD 09/0	Converse	800	Held by unit	Oil and gas production	100	77
31.	LOUISE M BRUNS	Converse	120	Held by unit	Oil and gas production	100	78
32.	ST WY 0-4393	Converse	80.5	Held by unit	Oil and gas production	100	78
33.	EDWARD WALKINSHAW ET UX	Converse	80	Held by unit	Oil and gas production	100	85
34.	ST WY 0-9125	Converse	120.1	Held by unit	Oil and gas production	100	78
35.	WYW 162618	Converse	40	Held by unit	Oil and gas production	100	86
36.	WYW 178089	Converse	160	May 2015	Oil and gas production	100	78
37.	WYW 172991	Converse	640	July 2016	Oil and gas production	100	78
38.	WYW 172989	Natrona	160	July 2016	Oil and gas production	100	78
39.	WYW 173001	Natrona	2,161.4	July 2016	Oil and gas production	100	78
40.	ST WY 05-00268	Converse	320.5	Held by unit	Oil and gas production	100	78

No.	Lease Name	Location	Gross Acres	Expiration Date[1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
41.	ST WY 05-00269	Converse	479	Held by unit	Oil and gas production	100	78
42.	ST WY 05-00270	Converse	640	Held by production	Oil and gas production	100	78
43.	ST WY 04-00241	Converse	600	Held by unit	Oil and gas production	100	78
44.	WYW 163900	Converse	596.4	Held by unit	Oil and gas production	100	83
45.	WYW 161771	Converse	320	November 2014	Oil and gas production	100	78
46.	WYW 0170073	Converse	40	Held by unit	Oil and gas production	100	80
47.	J L GOODNER ET UX	Converse	40.1	Held by unit	Oil and gas production	47	45
48.	TED STEWART ET AL	Converse	40.1	Held by unit	Oil and gas production	56	78
49.	WYW 161772	Converse	160	Held by unit	Oil and gas production	100	79
50.	WYW 178088	Converse	600	November 2014	Oil and gas production	100	78
51.	LESLIE GAY BOLIN, A WIDOW	Converse	681	Held by unit	Oil and gas production	100	80
52.	MINER D CRARY JR	Converse	681	Held by unit	Oil and gas production	100	80
53.	HORACE I CRARY	Converse	681	Held by unit	Oil and gas production	100	77
54.	KGN MINERAL TRUST (SUSAN)	Converse	681	Held by unit	Oil and gas production	100	77
55.	ST WY 0-04329	Converse	120	Held by unit	Oil and gas production	100	78
56.	KGN MINERAL TRUST (PHYLLIS	Converse	681	Held by unit	Oil and gas production	100	77
57.	ARTHUR E SYMONS	Converse	681	Held by unit	Oil and gas production	100	82
58.	ST WY 0-6048	Converse	1076.3	Held by unit	Oil and gas production	98	78
59.	WYW 000249	Converse	237.5	Held by unit	Oil and gas production	100	78
60.	KGN MINERAL TR (MARY LOUIS	Converse	681	Held by unit	Oil and gas production	100	80
61.	WYW 070469	Converse	160	Held by unit	Oil and gas production	98	78
62.	ST WY 0-9299	Converse	120	Held by unit	Oil and gas production	100	78
63.	KGN MINERAL TRUST(RICH EYR	Converse	681	Held by unit	Oil and gas production	100	80
64.	KGN MINERAL TRUST(D C BRAM	Converse	681	Held by unit	Oil and gas production	100	80
65.	WYW 079294	Converse	240	Held by unit	Oil and gas production	100	78
66.	ST WY 0-6876	Converse	120	Held by unit	Oil and gas production	25	78
67.	KGN MINERAL TRUST(T C DAVI	Converse	681	Held by unit	Oil and gas production	100	77
68.	KGN MINERAL TRUST(R H DAVI	Converse	681	Held by unit	Oil and gas production	100	77
69.	KGN MINERAL TRUST(W H DAVI	Converse	681	Held by unit	Oil and gas production	100	77
70.	WESTPORT OIL AND GAS CO LP	Converse	801	Held by unit	Oil and gas production	100	78
71.	KGN MINERAL TRUST(R G W MA	Converse	681	Held by unit	Oil and gas production	100	80
72.	KGN MINERAL TRUST(L C GRIS	Converse	801	Held by unit	Oil and gas production	100	77
73.	KGN MINERAL TRUST(D G DAVI	Converse	681	Held by unit	Oil and gas production	100	77
74.	STEPHEN T CRARY MARITAL TR	Converse	681	Held by unit	Oil and gas production	100	78
75.	ANN OBRZUT	Converse	681	Held by unit	Oil and gas production	100	80
76.	KGN MINERAL TRUST(C Y KELL	Converse	681	Held by unit	Oil and gas production	100	80
77.	THE NORTHWEST OIL COMPANY	Converse	40	Held by unit	Oil and gas production	100	77
78.	ST WY 00-1822	Converse	1040	Held by unit	Oil and gas production	100	78
79.	WYW 085311	Converse	33.6	Held by unit	Oil and gas production	100	72
80.	ST WY 0-23543	Converse	320	Held by unit	Oil and gas production	100	78
81.	ST WY 0-7791	Converse	640	Held by unit	Oil and gas production	98	78

No.	Lease Name	Location	Gross Acres	Expiration Date(1)	Use of Property	Working Interest (%)	Net Revenue Interest (%)
82.	ST WY 0-6049	Converse	635.9	Held by unit	Oil and gas production	98	78
83.	CAROLYN L RIDLEY ET AL	Converse	681	Held by unit	Oil and gas production	100	82
84.	ST WY 0-6050	Converse	699.4	Held by unit	Oil and gas production	98	78
85.	WESTPORT OIL AND GAS CO	Converse	40	Held by unit	Oil and gas production	100	78
86.	KGN MINERAL TRUST DT 9/9/9	Converse	40	Held by unit	Oil and gas production	100	80
87.	J L GOODNER ET AL	Converse	197.3	Held by unit	Oil and gas production	98	45
88.	CLYDE M WATTS ET AL	Converse	157.3	Held by unit	Oil and gas production	98	77
89.	JAMES C TVARUZEK ET UX	Converse	197.3	Held by unit	Oil and gas production	98	78
90.	ST WY 0-6051	Converse	922	Held by unit	Oil and gas production	98	78
91.	ST WY 0-6052	Converse	1,280	Held by unit	Oil and gas production	98	78
92.	FRED WALKINSHAW ET AL	Converse	76.6	Held by unit	Oil and gas production	98	80
93.	CHARLES B OLIN ET AL	Converse	938.4	Held by unit	Oil and gas production	98	77
94.	MINNIE O MOFFETT	Converse	165	Held by unit	Oil and gas production	98	77
95.	PAMELA DUGAN	Converse	681	Held by unit	Oil and gas production	100	77
96.	WILLILAM BARBER	Converse	90.3	Held by unit	Oil and gas production	75	78
97.	FENEX OIL COMPANY, ET AL	Converse	160	Held by unit	Oil and gas production	100	78
98.	S M ANDERSON ET AL	Converse	447.7	Held by unit	Oil and gas production	100	78
99.	C LEONARD SMITH ESTATE	Converse	410.1	Held by unit	Oil and gas production	100	78
100.	LINCOLN PETROLEUM COMPANY	Converse	447.7	Held by unit	Oil and gas production	100	78
101.	WYW 0-000610	Converse	160	Held by unit	Oil and gas production	100	78
102.	GLENROCK SHEEP COMPANY	Converse	200	Held by unit	Oil and gas production	100	79
103.	ST WY 0-4063	Converse	122.8	Held by unit	Oil and gas production	100	78
104.	SUSANNE B BRUBAKER	Converse	160	Held by unit	Oil and gas production	100	78
105.	WYW 072335	Converse	40	Held by unit	Oil and gas production	100	78
106.	SUSANNE B BRUBAKER	Converse	120	Held by unit	Oil and gas production	100	78
107.	SUSANNE B BRUBAKER	Converse	40	Held by unit	Oil and gas production	100	78
108.	GEORGE W KELLY ET AL	Converse	1,612.2	Held by unit	Oil and gas production	100	77
109.	CHRIS EYRE	Converse	681	Held by unit	Oil and gas production	100	78
110.	KGN MINERAL TRUST(M S YERK	Converse	681	Held by unit	Oil and gas production	100	80
111.	KGN MINERAL TRUST(S STROUG	Converse	681	Held by unit	Oil and gas production	100	80
112.	KGN MINERAL TRUST(G H ANDE	Converse	681	Held by unit	Oil and gas production	100	80
113.	KGN MINERAL TRUST(W C VALE	Converse	681	Held by unit	Oil and gas production	100	80
114.	KGN MINERAL TRUST(J K CARR	Converse	681	Held by unit	Oil and gas production	100	80

Note:

(1) In respect of our Wyoming oil and gas assets, HBU means the lease is held by unit, and has no expiration date, while HBP means that the lessee can continue drilling activities on the property as long as it is producing a minimum paying amount or oil or gas.

WYOMING COAL LEASES

No.	Tenement Name	Location	Gross Acres	Expiry Date	Use of Property	Working Interest (%)	Net Revenue Interest (%)
1.	STATE OF WYOMING NO 0-41150	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]
2.	STATE OF WYOMING NO 41097	Sheridan	640	01/06/21	Coal mining	100	-[(1)]
3.	STATE OF WYOMING NO 0-41098	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
4.	STATE OF WYOMING NO 0-41099	Johnson	1,120	01/04/15	Coal mining	100	-[(1)]
5.	STATE OF WYOMING NO 42164	Sheridan	1,280	01/06/17	Coal mining	100	-[(1)]
6.	STATE OF WYOMING NO 42165	Sheridan	640	01/06/17	Coal mining	100	-[(1)]
7.	STATE OF WYOMING NO 41100	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
8.	STATE OF WYOMING NO 41101	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
9.	STATE OF WYOMING NO 41102	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
10.	STATE OF WYOMING NO 41103	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
11.	STATE OF WYOMING NO 41104	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
12.	STATE OF WYOMING NO 41105	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
13.	STATE OF WYOMING NO 41106	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
14.	STATE OF WYOMING NO 41107	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
15.	STATE OF WYOMING NO 41108	Johnson	640	01/04/15	Coal mining	100	-[(1)]
16.	STATE OF WYOMING NO 41109	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
17.	STATE OF WYOMING NO 41110	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
18.	STATE OF WYOMING NO 41111	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
19.	STATE OF WYOMING NO 41112	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
20.	STATE OF WYOMING NO 41113	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
21.	STATE OF WYOMING NO 41114	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
22.	STATE OF WYOMING NO 41115	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
23.	STATE OF WYOMING NO 41116	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
24.	STATE OF WYOMING NO 41117	Johnson	1,120	01/04/15	Coal mining	100	-[(1)]
25.	STATE OF WYOMING NO 41118	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
26.	STATE OF WYOMING NO 41119	Johnson	1,280	01/04/15	Coal mining	100	-[(1)]
27.	STATE OF WYOMING NO 41120	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]
28.	STATE OF WYOMING NO 41121	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]
29.	STATE OF WYOMING NO 41122	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]
30.	STATE OF WYOMING NO 41123	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]
31.	STATE OF WYOMING NO 41124	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]
32.	STATE OF WYOMING NO 41127	Campbell	640	01/04/15	Coal mining	100	-[(1)]
33.	STATE OF WYOMING NO 41128	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]
34.	STATE OF WYOMING NO 41129	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]
35.	STATE OF WYOMING NO 41130	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]
36.	STATE OF WYOMING NO 41131	Campbell	1,273.1	01/04/15	Coal mining	100	-[(1)]
37.	STATE OF WYOMING NO 41132	Campbell	1,280	01/04/15	Coal mining	100	-[(1)]

No.	Tenement Name	Location	Gross Acres	Expiry Date	Use of Property	Working Interest (%)	Net Revenue Interest (%)
38.	STATE OF WYOMING NO 41133	Campbell	1,280	01/04/15	Coal mining	100	-[1]
39.	STATE OF WYOMING NO 41134	Campbell	1,280	01/04/15	Coal mining	100	-[1]
40.	STATE OF WYOMING NO 41135	Campbell	1,280	01/04/15	Coal mining	100	-[1]
41.	STATE OF WYOMING NO 41136	Campbell	1,280	01/04/15	Coal mining	100	-[1]
42.	STATE OF WYOMING NO 41139	Campbell	1,280	01/04/15	Coal mining	100	-[1]
43.	STATE OF WYOMING NO 41140	Campbell	1,280	01/04/15	Coal mining	100	-[1]
44.	STATE OF WYOMING NO 41141	Campbell	640	01/04/15	Coal mining	100	-[1]
45.	STATE OF WYOMING NO 41142	Campbell	1,280	01/04/15	Coal mining	100	-[1]
46.	STATE OF WYOMING NO 41143	Campbell	1,280	01/04/15	Coal mining	100	-[1]
47.	STATE OF WYOMING NO 41144	Campbell	1,280	01/04/15	Coal mining	100	-[1]
48.	STATE OF WYOMING NO 41145	Campbell	1,280	01/04/15	Coal mining	100	-[1]
49.	STATE OF WYOMING NO 41146	Campbell	640	01/04/15	Coal mining	100	-[1]
50.	STATE OF WYOMING NO 41146A	Campbell	640	01/04/15	Coal mining	100	-[1]
51.	STATE OF WYOMING NO 41149	Campbell	1,280	01/04/15	Coal mining	100	-[1]
52.	STATE OF WYOMING NO 41151	Campbell	1,280	01/04/15	Coal mining	100	-[1]
53.	STATE OF WYOMING NO 41152	Campbell	1,280	01/04/15	Coal mining	100	-[1]
54.	STATE OF WYOMING NO 41153	Campbell	640	01/04/15	Coal mining	100	-[1]
55.	STATE OF WYOMING NO 41154	Campbell	1,280	01/04/15	Coal mining	100	-[1]
56.	STATE OF WYOMING NO 41155	Campbell	640	01/04/15	Coal mining	100	-[1]
57.	STATE OF WYOMING NO 41156	Campbell	1280	01/04/15	Coal mining	100	-[1]
58.	STATE OF WYOMING NO 41157	Campbell	1,280	01/04/15	Coal mining	100	-[1]
59.	STATE OF WYOMING NO 41158	Campbell	1,280	01/04/15	Coal mining	100	-[1]
60.	STATE OF WYOMING NO 41159	Campbell	1,280	01/04/15	Coal mining	100	-[1]
61.	STATE OF WYOMING NO 41160	Campbell	1,280	01/04/15	Coal mining	100	-[1]
62.	STATE OF WYOMING NO 41161	Johnson	640	01/06/15	Coal mining	100	-[1]
63.	STATE OF WYOMING NO 41162	Campbell	320	01/06/15	Coal mining	100	-[1]
64.	STATE OF WYOMING NO 41163	Campbell	1,280	01/06/15	Coal mining	100	-[1]
65.	STATE OF WYOMING NO 41316	Campbell	1,280	01/12/15	Coal mining	100	-[1]
66.	STATE OF WYOMING NO 41317	Campbell	1,280	01/12/15	Coal mining	100	-[1]
67.	STATE OF WYOMING NO 41318	Campbell	1,280	01/12/15	Coal mining	100	-[1]
68.	STATE OF WYOMING NO 41319	Campbell	1,280	01/12/15	Coal mining	100	-[1]
69.	STATE OF WYOMING NO 41320	Sheridan	1,280	01/12/15	Coal mining	100	-[1]
70.	STATE OF WYOMING NO 41321	Sheridan	1,280	01/12/15	Coal mining	100	-[1]
71.	STATE OF WYOMING NO 41323	Sheridan	320	01/12/15	Coal mining	100	-[1]
72.	STATE OF WYOMING NO 41324	Sheridan	160	01/12/15	Coal mining	100	-[1]
73.	STATE OF WYOMING NO 41325	Sheridan	1,280	01/12/15	Coal mining	100	-[1]
74.	STATE OF WYOMING NO 41326	Sheridan	1,280	01/12/15	Coal mining	100	-[1]
75.	STATE OF WYOMING NO 41322	Sheridan	795	01/12/15	Coal mining	100	-[1]
76.	STATE OF WYOMING NO 41327	Johnson	1,280	01/12/15	Coal mining	100	-[1]

No.	Tenement Name	Location	Gross Acres	Expiry Date	Use of Property	Working Interest (%)	Net Revenue Interest (%)
77.	STATE OF WYOMING NO 41328	Johnson	1,280	01/12/15	Coal mining	100	-[(1)]
78.	STATE OF WYOMING NO 41329	Johnson	1,280	01/12/15	Coal mining	100	-[(1)]
79.	STATE OF WYOMING NO 41330	Johnson	1,280	01/12/15	Coal mining	100	-[(1)]
80.	STATE OF WYOMING NO 41331	Johnson	886.3	01/12/15	Coal mining	100	-[(1)]
81.	STATE OF WYOMING NO 41332	Johnson	1,125.2	01/12/15	Coal mining	100	-[(1)]
82.	STATE OF WYOMING NO 41333	Johnson	1,188.5	01/12/15	Coal mining	100	-[(1)]
83.	STATE OF WYOMING NO 41334	Johnson	356.6	01/12/15	Coal mining	100	-[(1)]
84.	STATE OF WYOMING NO 41335	Johnson	1,280	01/12/15	Coal mining	100	-[(1)]
85.	STATE OF WYOMING NO 41336	Sheridan	1,160	01/12/15	Coal mining	100	-[(1)]
86.	STATE OF WYOMING NO 41337	Sheridan	1,280	01/12/15	Coal mining	100	-[(1)]
87.	STATE OF WYOMING NO 41338	Johnson	1,280	01/12/15	Coal mining	100	-[(1)]
88.	STATE OF WYOMING NO 41339	Johnson	1,040	01/12/15	Coal mining	100	-[(1)]
89.	STATE OF WYOMING NO 41340	Johnson	760	01/12/15	Coal mining	100	-[(1)]
90.	STATE OF WYOMING NO 41341	Johnson	720	01/12/15	Coal mining	100	-[(1)]
91.	STATE OF WYOMING NO 41342	Sheridan	1,120.1	01/12/15	Coal mining	100	-[(1)]
92.	STATE OF WYOMING NO 42156	Campbell	680	01/06/17	Coal mining	100	-[(1)]
93.	STATE OF WYOMING NO 42157	Campbell	160	01/06/17	Coal mining	100	-[(1)]
94.	STATE OF WYOMING NO 42158	Campbell	1,200	01/06/17	Coal mining	100	-[(1)]
95.	STATE OF WYOMING NO 42159	Campbell	1,280	01/06/17	Coal mining	100	-[(1)]
96.	STATE OF WYOMING NO 42160	Campbell	1,280	01/06/17	Coal mining	100	-[(1)]
97.	STATE OF WYOMING NO 42161	Campbell	80	01/06/17	Coal mining	100	-[(1)]
98.	STATE OF WYOMING NO 42162	Campbell	1,280	01/06/17	Coal mining	100	-[(1)]
99.	STATE OF WYOMING NO 42163	Campbell	640	01/06/17	Coal mining	100	-[(1)]
100.	STATE OF WYOMING NO 42166	Johnson	1,286.7	01/06/17	Coal mining	100	-[(1)]
101.	STATE OF WYOMING NO 42167	Sheridan	1,280	01/06/17	Coal mining	100	-[(1)]
102.	STATE OF WYOMING NO 42168	Sheridan	1,280	01/06/17	Coal mining	100	-[(1)]
103.	STATE OF WYOMING NO 42169	Sheridan	1,280	01/06/17	Coal mining	100	-[(1)]
104.	STATE OF WYOMING NO 42170	Johnson	1,280	01/06/17	Coal mining	100	-[(1)]
105.	STATE OF WYOMING NO 42171	Johnson	1,280	01/06/17	Coal mining	100	-[(1)]
106.	STATE OF WYOMING NO 42310	Johnson	1,280	01/04/18	Coal mining	100	-[(1)]
107.	STATE OF WYOMING NO 42311	Sheridan	640.1	01/04/18	Coal mining	100	-[(1)]
108.	STATE OF WYOMING NO 42312	Sheridan	640	01/04/18	Coal mining	100	-[(1)]
109.	STATE OF WYOMING NO 42313	Sheridan	640	01/04/18	Coal mining	100	-[(1)]
110.	STATE OF WYOMING NO 42314	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]
111.	STATE OF WYOMING NO 42315	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]
112.	STATE OF WYOMING NO 42316	Sheridan	640	01/04/18	Coal mining	100	-[(1)]
113.	STATE OF WYOMING NO 42317	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]
114.	STATE OF WYOMING NO 42318	Sheridan	320	01/04/18	Coal mining	100	-[(1)]
115.	STATE OF WYOMING NO 42319	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]

No.	Tenement Name	Location	Gross Acres	Expiry Date	Use of Property	Working Interest (%)	Net Revenue Interest (%)
116.	STATE OF WYOMING NO 42320	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]
117.	STATE OF WYOMING NO 42321	Sheridan	622.8	01/04/18	Coal mining	100	-[(1)]
118.	STATE OF WYOMING NO 42322	Sheridan	640	01/04/18	Coal mining	100	-[(1)]
119.	STATE OF WYOMING NO 42323	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]
120.	STATE OF WYOMING NO 42324	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]
121.	STATE OF WYOMING NO 42325	Sheridan	640	01/04/18	Coal mining	100	-[(1)]
122.	STATE OF WYOMING NO 42378	Johnson	1,040	01/10/18	Coal mining	100	-[(1)]
123.	STATE OF WYOMING NO 42379	Johnson	635.5	01/10/18	Coal mining	100	-[(1)]
124.	STATE OF WYOMING NO 42380	Johnson	640	01/10/18	Coal mining	100	-[(1)]
125.	STATE OF WYOMING NO 42381	Johnson	1,196.4	01/10/18	Coal mining	100	-[(1)]
126.	STATE OF WYOMING NO 42382	Johnson	318.8	01/10/18	Coal mining	100	-[(1)]
127.	STATE OF WYOMING NO 42309	Sheridan	640	01/04/18	Coal mining	100	-[(1)]
128.	STATE OF WYOMING NO 42308	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]
129.	STATE OF WYOMING NO 42307	Sheridan	960	01/04/18	Coal mining	100	-[(1)]
130.	STATE OF WYOMING NO 42306	Sheridan	1,112.2	01/04/18	Coal mining	100	-[(1)]
131.	STATE OF WYOMING NO 42305	Sheridan	640	01/04/18	Coal mining	100	-[(1)]
132.	STATE OF WYOMING NO 42304	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]
133.	STATE OF WYOMING NO 42303	Sheridan	1,280	01/04/18	Coal mining	100	-[(1)]
134.	STATE OF WYOMING NO 42302	Sheridan	1,120	01/04/18	Coal mining	100	-[(1)]
135.	STATE OF WYOMING NO 42301	Sheridan	880	01/04/18	Coal mining	100	-[(1)]
136.	STATE OF WYOMING NO 42300	Johnson	1,280	01/04/18	Coal mining	100	-[(1)]
137.	STATE OF WYOMING NO 42299	Johnson	1,280	01/04/18	Coal mining	100	-[(1)]
138.	STATE OF WYOMING NO 42298	Campbell	640	01/04/18	Coal mining	100	-[(1)]
139.	STATE OF WYOMING NO 42297	Sheridan	1,120	01/04/18	Coal mining	100	-[(1)]
140.	STATE OF WYOMING NO 42296	Campbell	640	01/04/18	Coal mining	100	-[(1)]
141.	STATE OF WYOMING NO 42295	Campbell	1,280	01/04/18	Coal mining	100	-[(1)]
142.	STATE OF WYOMING NO 42294	Campbell	1,280	01/04/18	Coal mining	100	-[(1)]
143.	STATE OF WYOMING NO 42293	Campbell	1,280	01/04/18	Coal mining	100	-[(1)]
144.	STATE OF WYOMING NO 42292	Campbell	1,280	01/04/18	Coal mining	100	-[(1)]
145.	STATE OF WYOMING NO 42177	Johnson	320	01/06/17	Coal mining	100	-[(1)]
146.	STATE OF WYOMING NO 42176	Johnson	1,200	01/06/17	Coal mining	100	-[(1)]
147.	STATE OF WYOMING NO 42175	Johnson	480	01/06/17	Coal mining	100	-[(1)]
148.	STATE OF WYOMING NO 42174	Johnson	1,159.7	01/06/17	Coal mining	100	-[(1)]
149.	STATE OF WYOMING NO 42173	Johnson	1,280	01/06/17	Coal mining	100	-[(1)]
150.	STATE OF WYOMING NO 42172	Johnson	1,280	01/06/17	Coal mining	100	-[(1)]
151.	STATE OF WYOMING NO 42528	Johnson	1,280	01/04/19	Coal mining	100	-[(1)]
152.	STATE OF WYOMING NO 42388	Johnson	638.8	01/10/18	Coal mining	100	-[(1)]
153.	STATE OF WYOMING NO 42384	Sheridan	1,156.4	01/10/18	Coal mining	100	-[(1)]
154.	STATE OF WYOMING NO 42383	Sheridan	480.2	01/10/18	Coal mining	100	-[(1)]

No.	Tenement Name	Location	Gross Acres	Expiry Date	Use of Property	Working Interest (%)	Net Revenue Interest (%)
155.	STATE OF WYOMING NO 42385	Sheridan	640	01/10/18	Coal mining	100	-[(1)]
156.	STATE OF WYOMING NO 42386	Johnson	638.1	01/10/18	Coal mining	100	-[(1)]
157.	STATE OF WYOMING NO 42387	Johnson	320	01/10/18	Coal mining	100	-[(1)]
158.	STATE OF WYOMING NO 42719	Converse	640	01/04/21	Coal mining	100	-[(1)]
159.	STATE OF WYOMING NO 42720	Converse	640	01/04/21	Coal mining	100	-[(1)]
160.	STATE OF WYOMING NO 42721	Converse	640	01/04/21	Coal mining	100	-[(1)]
161.	STATE OF WYOMING NO 42722	Converse	640	01/04/21	Coal mining	100	-[(1)]
162.	STATE OF WYOMING NO 42723	Converse	640	01/04/21	Coal mining	100	-[(1)]
163.	STATE OF WYOMING NO 42724	Converse	640	01/04/21	Coal mining	100	-[(1)]
164.	STATE OF WYOMING NO 42725	Converse	640	01/04/21	Coal mining	100	-[(1)]
165.	STATE OF WYOMING NO 42726	Converse	640	01/04/21	Coal mining	100	-[(1)]
166.	STATE OF WYOMING NO 42727	Converse	640	01/04/21	Coal mining	100	-[(1)]
167.	STATE OF WYOMING NO 42728	Converse	640	01/04/21	Coal mining	100	-[(1)]
168.	STATE OF WYOMING NO 42729	Converse	640	01/04/21	Coal mining	100	-[(1)]
169.	STATE OF WYOMING NO 42730	Converse	640	01/04/21	Coal mining	100	-[(1)]
170.	STATE OF WYOMING NO 42731	Converse	640	01/04/21	Coal mining	100	-[(1)]
171.	STATE OF WYOMING NO 42732	Converse	640	01/04/21	Coal mining	100	-[(1)]
172.	STATE OF WYOMING NO 42733	Converse	640	01/04/21	Coal mining	100	-[(1)]
173.	STATE OF WYOMING NO 42734	Converse	640	01/04/21	Coal mining	100	-[(1)]
174.	STATE OF WYOMING NO 42735	Converse	640	01/04/21	Coal mining	100	-[(1)]
175.	STATE OF WYOMING NO 42736	Converse	640	01/04/21	Coal mining	100	-[(1)]
176.	STATE OF WYOMING NO 42737	Converse	640	01/04/21	Coal mining	100	-[(1)]
177.	STATE OF WYOMING NO 42784	Converse	640	01/04/21	Coal mining	100	-[(1)]
178.	STATE OF WYOMING NO 42785	Converse	640	01/04/21	Coal mining	100	-[(1)]
179.	STATE OF WYOMING NO 42786	Converse	640	01/04/21	Coal mining	100	-[(1)]
180.	STATE OF WYOMING NO 42787	Converse	640	01/04/21	Coal mining	100	-[(1)]
181.	STATE OF WYOMING NO 42788	Converse	640	01/04/21	Coal mining	100	-[(1)]
182.	STATE OF WYOMING NO 42789	Converse	640	01/04/21	Coal mining	100	-[(1)]
183.	STATE OF WYOMING NO 42790	Converse	640	01/04/21	Coal mining	100	-[(1)]
184.	STATE OF WYOMING NO 42791	Converse	640	01/04/21	Coal mining	100	-[(1)]
185.	STATE OF WYOMING NO 42799	Carbon	640	01/06/21	Coal mining	100	-[(1)]
186.	STATE OF WYOMING NO 42798	Carbon	640	01/06/21	Coal mining	100	-[(1)]
187.	STATE OF WYOMING NO 42797	Carbon	640	01/06/21	Coal mining	100	-[(1)]
188.	STATE OF WYOMING NO 42802	Carbon	640	01/06/21	Coal mining	100	-[(1)]
189.	STATE OF WYOMING NO 42801	Carbon	640	01/06/21	Coal mining	100	-[(1)]
190.	STATE OF WYOMING NO 42800	Carbon	120	01/06/21	Coal mining	100	-[(1)]
191.	STATE OF WYOMING 42810	Carbon	640	01/08/21	Coal mining	100	-[(1)]
192.	STATE OF WYOMING 42809	Carbon	640	01/08/21	Coal mining	100	-[(1)]
193.	STATE OF WYOMING 42808	Carbon	640	01/08/21	Coal mining	100	-[(1)]

No.	Tenement Name	Location	Gross Acres	Expiry Date	Use of Property	Working Interest (%)	Net Revenue Interest (%)
194.	STATE OF WYOMING 42813	Sweetwater	640	01/08/21	Coal mining	100	-[(1)]
195.	STATE OF WYOMING 42807	Carbon	640	01/08/21	Coal mining	100	-[(1)]
196.	STATE OF WYOMING NO 42811	Lincoln	640	01/08/21	Coal mining	100	-[(1)]

Note:

(1) The net revenue interests takes into account the 8% royalty on all coal mined due to the State of Wyoming as lessor, and an additional overriding royalty paid Gastech, Inc. and Wold Oil Properties, Inc., the sellers who sold the abovementioned coal leases to us, amounting to one quarter of the coal production royalty payable to the State of Wyoming under the leases provided, however, the overriding royalty shall never exceed 2%.

ALASKA OIL AND GAS LEASES

No.	Tenement Name	Location	Gross Acres	Expiry Date	Use of Property	Working Interest (%)	Net Revenue Interest (%)
1.	Linc Energy (Alaska) Inc	Matanuska—Susitna Borough	10	N.A.	Exploration	100	100
2.	State Of Alaska ADL 390720	North Slope Borough	907.5	31/06/16	Exploration	100	80
3.	State Of Alaska ADL 390884	North Slope Borough	807.5	31/01/14	Exploration	100	80
4.	AA 084141 (Bureau of Land Mgmt)	North Slope Borough	11,500	01/10/22	Exploration	100	80
5.	AA 081726 (Bureau of Land Mgmt)	North Slope Borough	6,133	01/10/19	Exploration	100	80

ALASKA COAL LICENCES

No.	Tenement Name	Location	Gross Acres	Expiry Date	Use of Property	Working Interest (%)	Net Revenue Interest (%)
1.	AK Mental Health Trust MHT 9400434	Denali & Fairbanks N.Star Borough	59,099.1	01/05/18	Coal Exploration	N.A.	N.A.
2.	AK Mental Health Trust MHT 9200462	Kenai Penninsula Borough	82,122.7	01/05/18	Coal Exploration	N.A.	N.A.
3.	AK Mental Health Trust MHT 9200461	Matanuska-Susitna Borough	25,374.9	01/05/18	Coal Exploration	N.A.	N.A.

GULF COAST OIL AND GAS LEASES

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date[(1)]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
1.	State Tract 126	State of Texas Lease #74324	Chambers	Texas	360	Upon permanent cessation of production	Oil and gas production	100	77.2
2.	State Tract 125	State of Texas Lease No. M-115873	Chambers	Texas	320	Upon permanent cessation of production	Oil and gas production	100	80
3.	State Tract 127	State of Texas Lease No. M-115903	Chambers	Texas	320	Upon permanent cessation of production	Oil and gas production	100	80
4.	State Tract 72	State of Texas Lease No. M-115872	Chambers	Texas	40	Upon permanent cessation of production	Oil and gas production	100	80
5.	State Tract 126A	State of Texas Lease #M-108139	Chambers	Texas	280	Upon permanent cessation of production	Oil and gas production	100	77.2
6.	E.W. Barber “D” (Samson) Lease	J. R. Barber, et al	Chambers	Texas	25	Upon permanent cessation of production	Oil and gas production	100	74.5
7.	A.E. Barber Lease	Arthur E. Barber, et ux	Chambers	Texas	73	Upon permanent cessation of production	Oil and gas production	100	79.0
8.	L.E. Fitzgerald Unit	Mary O. Scott, et vir	Chambers	Texas	47.77	Upon permanent cessation of production	Oil and gas production	100	78.6
		Sarah E. Morgan, et vir et al	Chambers	Texas					
		Alma A. Eberspacher, et al	Chambers	Texas					
		Anna Davis and A. C. Davis	Chambers	Texas					
		F.M. Fitzgerald, et al	Chambers	Texas					
		T.C. Fitzgerald and Wife	Chambers	Texas					
9.	Kirby “B” Lease	Kirby Petroleum Company, et al	Chambers	Texas	107.864	Upon permanent cessation of production	Oil and gas production	100	79.1
10.	Kirby “C” Lease	John Shearer	Chambers	Texas	15	Upon permanent cessation of production	Oil and gas production	100	79.0
		Kirby Petroleum Company, et al	Chambers	Texas					
11.	Kirby Petroleum Company (Samson) Lease	Kirby Petroleum Company	Chambers	Texas	49.5	Upon permanent cessation of production	Oil and gas production	100	74.0
12.	Espey Lease	Robert H. Espey II, Lin G. Espey and William P. Espey and Union Seaboard Corporation	Chambers	Texas	60.26	Upon permanent cessation of production	Oil and gas production	100	74.0

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date[1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
13.	Gulf Fee Fisher (mineral ownership—Linc fee to 6000')	Conveyed mineral fee from surface to and including 6,000' in Assignment, Conveyance and Bill of Sale from ERG RESOURCES, L.L.C. to LINC GULF COAST PETROLEUM, INC., dated 1 October 2011 (1295/698	Chambers	Texas	23.5	Upon permanent cessation of production	Oil and gas production	100	84.0
14.	Kirby Petroleum Company 15 Acres	John Shearer	Chambers	Texas	15	Upon permanent cessation of production	Oil and gas production	100	73.6
		George W. Collier, et al	Chambers	Texas					
		Kirby Petroleum Corporation	Chambers	Texas					
15.	J. Wilburn	Jerry Wilburn, et ux., et al	Chambers	Texas	65	Upon permanent cessation of production	Oil and gas production	100	83.5
16.	J. F. Wilburn "B"	Jerry Wilburn, et al	Chambers	Texas	50	Upon permanent cessation of production	Oil and gas production	100	77.7
		Mrs. Amanda McKinney, Guardian	Chambers	Texas					
17.	Wilburn "C" #9 and #10 / Wilburn "D" / Wilburn "E"	J.F. Wilburn, et al	Chambers	Texas	93.95	Upon permanent cessation of production	Oil and gas production	100	67.0 – 71.6
18.	Wilburn, J. "A"	Lillian Wilburn, et al	Chambers	Texas	52.5	Upon permanent cessation of production	Oil and gas production	100	74.3
		W. Howard Lee, et al	Chambers	Texas					
19.	Higgins	Annie Higgins, et al	Chambers	Texas	16.57	Upon permanent cessation of production	Oil and gas production	100	81.5
20.	Higgins -B-	Annie Higgins and Pattillo Higgins	Chambers	Texas	7.05	Upon permanent cessation of production	Oil and gas production	100	75.9
21.	Chambers County Agricultural Company	Chambers County Agricultural Company	Chambers	Texas	205.1	Upon permanent cessation of production	Oil and gas production	100	86.5
22.	Fitzgerald, J.M. ("A")	Frank M. Fitzgerald, et al	Chambers	Texas	50.44	Upon permanent cessation of production	Oil and gas production	94.5	66.0
23.	State Tract 118	State of Texas Lease #19819	Chambers	Texas	640	Upon permanent cessation of production	Oil and gas production	75.0 – 100	56.3 – 84.0

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date[(1)]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
24.	Lot 3A Strip Leases	David Glenn Barber, et ux	Chambers	Texas	4.485	Upon permanent cessation of production	Oil and gas production	87.5 – 100	65.2 – 74.5
		Big Sky Mineral Trust	Chambers	Texas					
		Raymond E. Brizendine	Chambers	Texas					
		James M. Brown II	Chambers	Texas					
		Bevis Jerome Minter	Chambers	Texas					
		William Michael Minter, et ux	Chambers	Texas					
		Cheri Barber Orchin	Chambers	Texas					
		S & C Properties	Chambers	Texas					
		Southwest Petroleum Company L.P.	Chambers	Texas					
		Frank D. Schubert	Chambers	Texas					
		Nancy Barber Welwood	Chambers	Texas					
25.	Lot 5A Strip Leases	Dolores P. Direzza	Chambers	Texas	4.427	Upon permanent cessation of production	Oil and gas production	93.8 – 100	71.6 – 76.3
		Edward C. Kerley	Chambers	Texas					
		Patty Lou Kyffin	Chambers	Texas					
		Eddie Clyde Bell	Chambers	Texas					
		James Lee McLean, Trustee	Chambers	Texas					
		Pamela S. Pilkington	Chambers	Texas					
		Stephen M. Wright	Chambers	Texas					
		Thomas F. Wright	Chambers	Texas					
26.	Conoco Lease	ConocoPhillips Company	Chambers	Texas	101.33	Upon permanent cessation of production	Oil and gas production	100	74
27.	UPRC Lease (3.3 ac.)	Union Pacific Railroad Company	Chambers	Texas	3.3	Upon permanent cessation of production	Oil and gas production	100	74
28.	UPRC Lease (21.93 ac.).....	Union Pacific Railroad Company	Chambers	Texas	21.93	Upon permanent cessation of production	Oil and gas production	100	74
29.	UPRC Lease (2.323 ac.).....	Union Pacific Railroad Company	Chambers	Texas	2.323	Upon permanent cessation of production	Oil and gas production	100	74
30.	NEQ Lease...................	NEQ Investments, LTD	Chambers	Texas	13.52	Upon permanent cessation of production	Oil and gas production	100	76.5
31.	M Winfree Heirs Lease	M Winfree Heirs, LLC	Chambers	Texas	58.88	Upon permanent cessation of production	Oil and gas production	100	74
32.	Brian Collins	Brian Collins	Chambers	Texas	84.95	Upon permanent cessation of production	Oil and gas production	100	82.3

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date[(1)]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
33.	Farish Fund Leases	William Stamps Farish Fund	Chambers	Texas	7.28	Upon permanent cessation of production	Oil and gas production	100	79
		COO, LLC	Chambers	Texas					79
		Hudson Gas and Oil, Ltd	Chambers	Texas					79
		Martha Botts Farish Article XIII Testamentary Trust	Chambers	Texas					79
		William S Farish III	Chambers	Texas					79
		Texas Gulf Bank, N.A. Trustee of The Joan H. Blaffer Trust A	Chambers	Texas					74
		Texas Gulf Bank, N.A. Trustee of Sarah B Hrdy Trust A	Chambers	Texas					74
		Texas Gulf Bank, N.A. Trustee of The Catherine Blaffer Taylor Trust A	Chambers	Texas					74
		Texas Gulf Bank, N.A. Trustee of the Camilla Blaffer Royall Mallard Trust A	Chambers	Texas					74
		Sarah B Hrdy, Trustee of the Sarah B. Hardy Trust B	Chambers	Texas					74
		Texas Gulf Bank, N.A. Trustee of the Joan B. Johnson Trust B	Chambers	Texas					74
		Camilla Blaffer, Trustee of the Camilla Blaffer Royall Mallard Trust B	Chambers	Texas					74
34.	Maranatha Temple Lease ...	Judith A Honsinger	Chambers	Texas	26.91	Upon permanent cessation of production	Oil and gas production	100	77.5
		Brian Honsinger	Chambers	Texas					
		Virgil Sanders & Janise Karen Sanders	Chambers	Texas					
		Nancy Franklin Wyckoff	Chambers	Texas					
		Scott Franklin Jordan	Chambers	Texas					
35.	Mills Bennett / Accent Investments Lease	Mills Bennett Estate Properties Trust d.b.a. Mills Bennett Estate	Chambers	Texas	31.1	Upon permanent cessation of production	Oil and gas production	100	75

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date[1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
36.	T.S. Fitzgerald Heirs	Mary Beth Dyer	Chambers	Texas	10	Upon permanent cessation of production	Oil and gas production	100	75
		Deborah F Nelson	Chambers	Texas					
		Temple Benson Dunaway	Chambers	Texas					
		Michael S Lansford	Chambers	Texas					
		Carl Wesley Benson	Chambers	Texas					
		T. Steve Fitzgerald	Chambers	Texas					
		Bennie L Lansford	Chambers	Texas					
		Tyler S. Fitzgerald	Chambers	Texas					
		Carlene Fitzgerald Egloff	Chambers	Texas					
37.	Welch Foundation	The Robert A. Welch Foundation	Brazoria	Texas	2,500	Upon permanent cessation of production	Oil and gas production	65 – 100	47.8 – 71.5
38.	State Tract 216	State of Texas Lease No. M-71950	Calhoun	Texas	640	Upon permanent cessation of production	Oil and gas production	100	78.4
39.	State Tract 210	State of Texas Lease No. M-97186	Calhoun	Texas	320	Upon permanent cessation of production	Oil and gas production	100	74.6
40.	State Tract 224	State of Texas Lease No. M-99176	Calhoun	Texas	320	Upon permanent cessation of production	Oil and gas production	100	70.0 – 80.0
41.	Harrell "C" Lease	Edwin Tabb Harrell, et al	Harris	Texas	1	Upon permanent cessation of production	Oil and gas production	100	70.0 – 74.3
42.	Rena Berry Fee	Mary Addilea Koehl, Executor of the Estate of Rena Berry, Deceased	Harris	Texas	2.5	Upon permanent cessation of production	Oil and gas production	100	74.3
43.	Tabb "A" Lease / Tabb "B" Lease / W. Tabb "A" Lease	Edwin Harrell	Harris	Texas	14.63	Upon permanent cessation of production	Oil and gas production	100	70.0 – 72.0
		C. Tabb Harrell, et ux	Harris	Texas					
44.	Stark	W. H. Stark	Orange	Texas	986.75	Upon permanent cessation of production	Oil and gas production	100	82.3
45.	Polk "A"	James V. Polk, et al	Orange	Texas	600	Upon permanent cessation of production	Oil and gas production	100	83.2
46.	Polk "B"	James V. Polk, et al	Orange	Texas	1016	Upon permanent cessation of production	Oil and gas production	100	83.2
47.	Kuhn	Harry J. Kuhn, et al	Orange	Texas	1,199.5	Upon permanent cessation of production	Oil and gas production	100	83.4
48.	Armelin, L. Fee	Louis Armelin, et ux	Liberty	Texas	98	Upon permanent cessation of production	Oil and gas production	100	91.7
49.	Baldwin, J. C. Fee	Jacob C. Baldwin	Liberty	Texas	35	Upon permanent cessation of production	Oil and gas production	100	86.5
50.	Failor, E. K. Fee	E. K. Failor	Liberty	Texas	160	Upon permanent cessation of production	Oil and gas production	100	92.8

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date[(1)]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
51.	Hannah, D. Lease	David Hannah, et ux	Liberty	Texas	50	Upon permanent cessation of production	Oil and gas production	100	82.3
52.	Hannah, D. Fee	David Hannah	Liberty	Texas	50	Upon permanent cessation of production	Oil and gas production	100	86.5
53.		Marie Howell Cade, et al	Galveston	Texas	10	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
		Beverly Hodges Davis	Galveston	Texas					
		Roy Hamilton Davis, Individually & as Agent and Attorney in Fact	Galveston	Texas					
		Frances Henshaw Gill	Galveston	Texas					
		Ashbel Burnham Henshaw	Galveston	Texas					
		Linda Jean Lee Henshaw, et al	Galveston	Texas					
		Thomas R. Howell Jr., Individually and as Successor Trustee	Galveston	Texas					
		Mary Henshaw Jernigan	Galveston	Texas					
		James & Tolley Odom Family, LLC, by Martha Tolley Davis Odom, Manager	Galveston	Texas					
		Barbara Henshaw Roberts	Galveston	Texas					
		Linda Henshaw Weeks	Galveston	Texas					
54.		Amoco Production Company	Galveston	Texas	10	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
		Blair Lea Ellis	Galveston	Texas					
		D. Caffery McCay, et al	Galveston	Texas					
		Maryann Ellis Bohr	Galveston	Texas					
		Lloyd Addison Ellis, III	Galveston	Texas					
55.		Charles H. Barker	Galveston	Texas	20	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
		Robert C. Barker	Galveston	Texas					
		Melanie Speer Wiggins	Galveston	Texas					
		T. C. Craighead & Company	Galveston	Texas					
		David T. Speer	Galveston	Texas					
		Katherine C. Holt Trust under an Agreement for the Benefit of Charles H. Barker	Galveston	Texas					
		Katherine C. Holt Trust under an Agreement for the Benefit of Melanie Wiggins	Galveston	Texas					

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date[(1)]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
		Katherine C. Holt Trust under an Agreement for the Benefit of Betty Speer Taylor	Galveston	Texas					
56.		Katherine C. Holt Trust under an Agreement for the Benefit of Margaret S. Carter	Galveston	Texas					
		Katherine C. Holt Trust under an Agreement for the Benefit of David T. Speer	Galveston	Texas					
		Katherine Taylor Miller	Galveston	Texas					
		Ruth McLean Bowers	Galveston	Texas					
57.		Marie Howell Cade, et al	Galveston	Texas	10	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
		Beverly Hodges Davis	Galveston	Texas					
		Roy Hamilton Davis, Individually and as Agent and Attorney in Fact	Galveston	Texas					
		Frances Henshaw Gill, by Gregory D. Gill, Agent and Attorney in Fact	Galveston	Texas					
		Ashbel Burnham Henshaw	Galveston	Texas					
		Linda Jean Lee Henshaw, et al	Galveston	Texas					
		Thomas R. Howell, Jr., Individually and as Successor Trustee	Galveston	Texas					
		Mary Henshaw Jernigan	Galveston	Texas					
		James & Tolley Odom Family, LLC, by Martha Tolley Davis Odom, Manager	Galveston	Texas					
		Barbara Henshaw Roberts	Galveston	Texas					
		Linda Henshaw Weeks	Galveston	Texas					
58.		D. Caffery McCay, et al	Galveston	Texas	10	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
		Maryann Ellis Bohr	Galveston	Texas					
		Blair Lea Ellis	Galveston	Texas					
		Lloyd Addison Ellis, III	Galveston	Texas					
		Marion Caffery Campbell, Trustee	Galveston	Texas					

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date[(1)]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
59.		Charles H. Barker	Galveston	Texas	20	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
		Robert C. Barker	Galveston	Texas					
		T. C. Craighead & Company	Galveston	Texas					
		Katherine C. Holt Trust	Galveston	Texas					
		David T. Speer	Galveston	Texas					
		Betty Speer Taylor	Galveston	Texas					
		Ruth McLean Bowers	Galveston	Texas					
60.		BP America Production Company	Galveston	Texas	126.51	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
61.		Ruth McLean Bowers	Galveston	Texas	50	Upon permanent cessation of production	Oil and gas production	100	74.0 – 80.5
		Barbara Gordon McNeill & Melinda Gordon Paret	Galveston	Texas					
62.		George E. Smith	Galveston	Texas	88.28	Upon permanent cessation of production	Oil and gas production	100	73.6 – 73.8
63.		George E. Smith	Galveston	Texas	96.48	Upon permanent cessation of production	Oil and gas production	100	73.8
64.		Verna Hooks McLean, et al	Galveston	Texas	2.48	Upon permanent cessation of production	Oil and gas production	100	74.0
65.		Nellie B. League, et al	Galveston	Texas	24.83	Upon permanent cessation of production	Oil and gas production	100	74.0
66.		Virginia B. Ball Estate by American National Trust & Robert B. Ball	Galveston	Texas	9	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
		Wells Stewart	Galveston	Texas					
		Stewart Mineral Company	Galveston	Texas					
		Robert George Bisbey, Trustee	Galveston	Texas					
67.		Charlotte E. Smith	Galveston	Texas	253	Upon permanent cessation of production	Oil and gas production	100	84.4
68.		Elizabeth Ker Cade, et al	Galveston	Texas	50.86	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
69.		BP America Production Company	Galveston	Texas	35.49	Upon permanent cessation of production	Oil and gas production	100	71.8 – 74.0
70.		The Gulf and Inter-State Railway Company of Texas	Galveston	Texas	19.3	Upon permanent cessation of production	Oil and gas production	100	96.9
71.		The Estate Of Shearn Moody, Jr., deceased	Galveston	Texas	40	Upon permanent cessation of production	Oil and gas production	100	73.0
72.		Robert L. Moody	Galveston	Texas	180	Upon permanent cessation of production	Oil and gas production	100	73.0

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date[1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
73.		Robert L. Moody	Galveston	Texas	10	Upon permanent cessation of production	Oil and gas production	100	73.0
74.		Carey Stehling Independent Executor of the Estate of Edward Jakovich, Deceased	Galveston	Texas	40	Upon permanent cessation of production	Oil and gas production	100	73.0
		Donna Cameron Goode	Galveston	Texas					
		Linda Jakovich Meyer Independent Executrix of the Estate of Andrew Jakovich, Deceased	Galveston	Texas					
		DJS Land Company, Ltd	Galveston	Texas					
		Carol Ann Burns	Galveston	Texas					
75.	JB Watkins	Bonne Terre Exploration Company, L.L.C	Cameron	Louisiana	2435	Upon permanent cessation of production	Oil and gas production	87.5 - 100	61.8 - 72.0
76.	Constantin #2	Constantin Land Trust	Lafourche	Louisiana	100	Upon permanent cessation of production	Oil and gas production	41.4	28.1
		Emily Adams Bourg, A.K.A. Mrs. Sidney A. Bourg, Independent Executrix for the Estate of Sidney Adams Bourg, deceased	Lafourche	Louisiana					
		Tennessee Gas Pipeline Company	Lafourche	Louisiana					

Note:

(1) The leases in the Gulf Coast Region typically remain in effect for the primary term of approximately a year and subsequently for so long thereafter as there is production in commercial quantities. See "Appendix I—Qualified Persons' Reports—Appraisal of Certain Oil and Gas Interests owned Linc Gulf Coast Petroleum, Inc. located in Louisiana and Texas as of 1 September 2013 prepared by Haas Petroleum Engineering Services, Inc" on further information on the remaining lease periods.

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