Established in 2009, KrisEnergy Ltd is an independent oil and gas company engaged in the exploration, appraisal, development and production of hydrocarbon resources in Southeast Asia.

Our vision is to become the leading Asian independent upstream oil and gas company.

Our strategy is to acquire rigorously selected assets in geological basins where we have extensive technical knowledge garnered through decades of experience.
**FOCUS AREA**

Our target area stretches from the Surma Basin in Bangladesh in the West to the Papuan Basin in the East, and from offshore southern China in the North to Indonesia in the South.

**OUR OFFICES**

We are dedicated to establishing and maintaining an on-the-ground presence in the countries in which we have assets. We currently have offices in Dhaka in Bangladesh, Jakarta in Indonesia, Bangkok in Thailand, in Singapore and in Ho Chi Minh City in Vietnam. In addition, we have a full complement of operational staff at the Bangora field location onshore Bangladesh.

By maintaining local offices in these countries, we are able to respond quickly and efficiently to business opportunities that arise in these areas. Moreover, we largely employ local technical and professional staff, who bring valuable knowledge of the regional geology, business culture and regulatory environment.

Our target area stretches from the Surma Basin in Bangladesh in the West to the Papuan Basin in the East, and from offshore southern China in the North to Indonesia in the South.
NEW COUNTRY ENTRY
We acquired all the outstanding shares in Tullow Bangladesh Ltd (“Tullow Bangladesh”), which holds a 30% working interest in Block 9 onshore Bangladesh. Block 9 contains the Bangora gas producing field. The acquisition, which was completed with the approval of the Bangladesh authorities on 17 December 2013, doubled our working interest daily production and increased our 2P reserves almost twofold.

INITIAL PUBLIC OFFERING (“IPO”)
On 19 July 2013, KrisEnergy Ltd listed all existing shares and issued 246,154,000 new shares by way of an IPO on the Mainboard of Singapore Exchange Securities Trading Limited (“SGX-ST”). The offering price was S$1.10 per share. The offer was more than six times oversubscribed and raised net proceeds of US$200.5 million. KrisEnergy’s ticker on SGX-ST is SK3.

FIRST STEEL CUT
Partners in G11/48 in the Gulf of Thailand declared final investment decision (“FID”) for the Nong Yao oil development in August 2013. Preliminary fabrication of the platforms and processing facilities commenced in November 2013 and the engineering, procurement, construction, installation and commissioning (“EPCIC”) contract was awarded in January 2014.

SUCCESSFUL GAS APPRAISAL
KrisEnergy drilled its first well as an operator in the Bulu production sharing contract (“PSC”) offshore East Java. The Lengo-2 appraisal well encountered gas in multiple intervals and was successfully tested resulting in a 58% increase to 25.4 million barrels of oil equivalent (“mmboe”) in our working interest 2C resources1 associated with the Bulu PSC as estimated by NSAI2 as at 31 December 2013.

RESERVES & CONTINGENT RESOURCES
- 2P reserves1 up 88% at 32.3 mmboe1
- 2C resources1 increased 32% to 53.9 mmboe1

PRODUCTION
- Average working interest production in 2013 rose to an average 7,075 barrels of oil equivalent per day (“boepd”) on a pro forma basis3
- The Kambuna gas-condensate field in the Glagah-Kambuna Technical Assistance Contract (“TAC”) in Indonesia reached the end of its economic life as expected and ceased production on 11 July 2013

1 2P reserves refers to proved plus probable reserves and 2C resources refers to best estimate contingent resources, in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers
2 2P reserves and 2C resources are based on estimates by Netherland, Sewell & Associates, Inc. (“NSAI”) as at 31 December 2013
3 Pro forma production for 2013 represents our working interest production from B8/32, B9A, Glagah-Kambuna TAC and Block 9 in Bangladesh from the effective date of 1 January 2013
Dear Shareholders,

KrisEnergy’s successful IPO in the face of weakening capital markets was a significant achievement and a testament to the strong investor interest. The offering was more than six times oversubscribed by institutional investors and almost 23 times oversubscribed in the retail tranche. The Board of Directors welcomes the new shareholders, sincerely appreciates your trust, and is determined to provide good governance in fulfilling our fiduciary responsibilities to all of you.

Notwithstanding the attention directed towards the IPO process, the team remained focused on managing the business. Highlights during 2013 included a corporate acquisition in Bangladesh, marking a new country entry with operatorship of a producing gas field as well as the addition of an experienced workforce; the farm-in to an appraisal asset in the Gulf of Thailand, providing KrisEnergy with its first operatorship in a strategically important core area for growth; and the operation of two successful exploration/appraisal wells offshore Indonesia.

While the outcomes of two non-operated high profile exploration wells offshore Vietnam were not the immediate commercial discoveries that we had all hoped for, it must be kept in mind that these two large areas have seen hardly any prior exploration activity. Both wells encouragingly confirmed active working hydrocarbon systems and provided valuable data to improve the geological interpretation of the other multiple prospects on the blocks. Progress has been made along the learning curve in the continued search for commercial accumulations.

Investors should keep in mind that exploration, even when employing the latest science and proven techniques in the hands of experienced, skillful, world class practitioners, has risks. Accordingly, KrisEnergy’s portfolio strategy aims to spread opportunities and risks across multiple prospects (within any given block), basins and countries as well as across the hydrocarbon life cycle from exploration to production.

KrisEnergy is positioned today with an opportunity-rich portfolio comprising 17 contract areas in five countries. While the company’s share price was hit hard in January 2014 when the results of the Vietnam wells were announced, we believe that investors will increasingly understand and benefit from the risk-mitigation afforded by KrisEnergy’s portfolio approach to its business plans. The next 12 months are expected to be a busy year for the company with management’s prime focus on good execution. The Board remains committed to the long-term success of KrisEnergy and to ensuring that its values and its governance are fully aligned with the core principles of respect, integrity and transparency.

On behalf of the Board of Directors, I thank you for your support.

Sincerely,

Will Honeybourne
Non-executive chairman

28 February 2014
Our vision in 2009 when we established KrisEnergy was to build a sustainable upstream E&P company with a diverse portfolio of assets in core Asian basins and spanning the entire upstream life cycle from exploration to appraisal, development and production. In 2013, we continued to progress towards this vision, ending the year with two important additions to our asset base and a stronger capital structure to fund our growth aspirations going forward.

At the start of 2014, we are producing above 7,000 boepd from two oil and gas fields in the Gulf of Thailand and the Bangora onshore gas field in Bangladesh. We completed the transaction for the Bangladesh asset in December 2013, which brought our average working interest production in the fourth quarter to 4,192 boepd. Going forward, as the Bangora gas field is now fully consolidated into our operations, we expect our working interest production to average above 7,000 boepd for this year. We have six contract areas under development, which we expect to begin to add to our cash flow and hence EBITDAX1 from 2015, and we have a series of appraisal and exploration targets that we plan to test near term and add to our development portfolio.

Our IPO in Singapore in July 2013 was significant in cementing our foundations as an independent, Asian E&P company. Since our debut, we have worked hard to meet the investor community to communicate our strategy. The upstream industry inherently carries risk in all phases of the E&P value chain and it is important that shareholders understand those risks and how we take measures to mitigate them.

Smooth execution & success in Indonesia

We saw in 2013 that it is not always possible to plan for all eventualities. The typhoon season was particularly hard in the third quarter, which caused widespread destruction in Southeast Asia and resulted in severe delays in our exploration drilling in Vietnam. However, our two-well program as an operator in Indonesia in the first half of the year was executed smoothly and successfully.

An appraisal well in the Lengo gas discovery resulted in a 58% uplift in our 2C resources in the Bulu PSC to 25.4 mmboe. Our team in Jakarta is working on the plan of development for the Lengo field and is in discussions over the gas sales agreement. Directly after Bulu drilling, the Tayum exploration well in the Kutai PSC encountered gas and derisked the three gas discoveries in the block as a development project. We plan to drill an appraisal well in the Kutai area in 2014 prior to submitting the plan of development.

Our two non-operated exploration wells offshore Vietnam, whilst both intersected hydrocarbon columns, did not discover commercial volumes, highlighting the risk of drilling in unexplored territories and confirming the validity of our strategy of risk mitigation through diversification.

Our thesis is to drill a combination of low and high risk prospects each year to achieve modest reserves growth as a minimum with the potential to make a step change in our resource base if a high-impact well is successful.
KrisEnergy is making great strides across all elements of its business. We believe in our strategy, our people and our assets. We are well positioned geographically in Asia, where energy demand is rising at one of the fastest rates in the world.

Expanding to new horizons
The cumulative years of experience of our teams of geoscientists, engineers and operations specialists, their knowledge base and their ability to think out of the box is at the heart of the company. We were delighted to welcome our new colleagues in Bangladesh into the KrisEnergy network following the completion of a corporate acquisition in December 2013. We plan to expand our technical team in Dhaka as we grow our portfolio in Bangladesh. We are also boosting our technical capabilities in Jakarta and Thailand to support our exploration and appraisal work programs and development activities.

Our IPO strengthened our capital structure and will allow us greater flexibility with our financing strategy going forward. At the end of January 2014, we redeemed the US$120 million senior guaranteed secured bonds due 2016 and we are currently progressing plans to put in place suitable debt instruments at attractive terms which we believe will further support our capital growth. It is important that we have flexibility in our capital structure to ensure we are fully funded for our activities on the existing portfolio and can act decisively when new venture opportunities arise.

Vigilance on EHSS & costs
For 2014, we expect to keep up the pace of the last few years and we have a robust work program planned. We will execute and deliver on the six development projects we have in hand. We will step up our operated exploration and appraisal drilling and we will continue to seek opportunities both for organic growth and for a step change. All these activities will require constant vigilance on environment, health, safety and security (“EHSS”) and costs. We are committed to EHSS first and foremost and are implementing monitoring processes to meet or exceed international standards in our operations. We also closely track costs and look for ways to manage any escalation without risk to our EHSS standards.

At the same time, we are working with the communities and government authorities in the locations where we are operationally active. Our team in Jakarta has made remarkable progress in reaching out to the communities within the Udan Emas PSC onshore West Papua. This is an extremely remote area and our planned 2D seismic acquisition program will cross numerous villages.

Our efforts to communicate each step of our plans have been rewarded with the support of the villages and government officials and we will continue this open dialogue throughout the program.

KrisEnergy is making great strides across all elements of its business. We believe in our strategy, our people and our assets. We are well positioned geographically in Asia, where energy demand is rising at one of the fastest rates in the world. We have built a strong platform for growth and we have the expertise to create opportunities and to execute on those opportunities.

I would like to thank our Board of Directors for their guidance throughout 2013, our shareholders for their continued trust and support and the KrisEnergy network of people without whom we could not have achieved so much in so little time and whose commitment will bring about our further progress in 2014.

KEITH CAMERON
CHIEF EXECUTIVE OFFICER
28 February 2014
FY2013
FINANCIAL SUMMARY

REVENUE¹
US$84.5 mm
-5.7%
(2012: US$89.6 mm)

EBITDA¹
US$39.8 mm
-16.4%
(2012: US$47.6 mm)

LIFTING COST¹
US$7.59/bbl
-49.8%
(2012: US$15.13/bbl)

OUTSTANDING BORROWINGS
US$119.1 mm
(2012: US$81.1 mm)

GEARING AT 31 DECEMBER 2013
26%
(2012: 29%)

REALISED OIL SALES PRICE¹
US$109.19/bbl
(2012: US$114.19/bbl)

REALISED GAS SALES PRICE¹
US$3.05/mcf

OIL AND GAS PROPERTIES
US$140.6 mm
+34.3%
(2012: US$104.7 mm)

EXPLORATION AND EVALUATION ASSETS
US$200.3 mm
+47.6%
(2012: US$135.7 mm)

CASH POSITION
US$128.7 mm
+47.6%
(2012: US$40.8 mm)

CASH FLOW FROM OPERATING ACTIVITIES
US$16.2 mm
+9.5%
(2012: US$14.8 mm)

GROSS TANGIBLE ASSETS
US$422.9 mm
+80.3%
(2012: US$234.6 mm)

¹ Pro forma represents our working interest in B8/32 and B9A, Glagah-Kambuna TAC and includes contribution from Block 9 from the effective date 1 January 2013. Excluding revenue and EBITDA attributable from Block 9, Bangladesh revenue and EBITDA for the financial year ended 31 December 2013 amounted to US$68.1 million and US$81.0 million.
For KrisEnergy, 2013 was another transformational year in the Company’s relatively short history as we remained focused on balance sheet optimisation, reserves accretion and expansion of our diverse portfolio of upstream E&P assets. Following two successful and landmark debt and equity capital markets transactions, we ended 2013 with a well-funded balance sheet, relatively low gearing (remaining in a net cash position) and a pipeline of development projects that will continue to see KrisEnergy evolve on a year-on-year basis.

Significant acquisitions
In line with our strategy of building a sustainable upstream oil and gas company, we were delighted with our acquisition of a 30% working interest and operatorship of the Block 9 PSC, which completed on 17 December 2013. The transaction to acquire Tullow Bangladesh was signed on 8 April 2013 with Tullow Oil plc and had an effective date of 1 January 2013. For the financial year ended 31 December 2013, our working interest production, revenue and EBITDAX from the B9/B32 and B9A oil and gas fields in the Gulf of Thailand, the Bangpra gas field in Block 9 and the Glagah-Kambuna TAC in Indonesia was 7,075 boe/d, US$684.5 million and US$39.8 million, respectively. We view our future operations from B9/B32, B9A and Bangpra to be an annuity production, revenue and EBITDAX stream to KrisEnergy due to its stable and long-term production profile.

We further strengthened our position in the Gulf of Thailand by signing an agreement to acquire 30% working interest and operatorship of G6/48. We have signed the supplementary concession agreement and are awaiting final Ministerial decree and upon receipt, we will be an operator in the Gulf of Thailand, where our management team has an established track record for oil-field development.

Reserves and resources accretion
We delivered a significant increase in 2P reserves and 2C resources additions in 2013. Our 2P reserves grew 88.2% year-on-year to 32.3 mmbbl as a result of our acquisition of Tullow Bangladesh, which was not only reserves accretive, but more than doubled our existing production and materially enhances our revenue and EBITDAX. Our 2C resources grew 32.4% year-on-year to 53.9 mmbbl, primarily as a result of our successful appraisal well in the Bulu PSC. On a combined basis, our total 2P reserves and 2C resources grew 48.8% year-on-year, marking another significant year of reserves and resources accretion for KrisEnergy.

Financial results summary
We closed a successful year with the completion of our acquisition of Tullow Bangladesh, which contributed to our 2013 results. Our audited Financials include one month of production, revenues and associated costs from the Block 9 PSC, however on a pro forma basis, we recognise production and revenue for the full year and the movement in working capital as the effective date of our acquisition was 1 January 2013.

Revenue
Working interest pre-pro forma production for 2013 increased 142.6% to 7,075 boe/d. Production in the fourth quarter 2013 averaged 4,192 boe/d, which more than doubled average production from third quarter 2013 of 1,979 boe/d. On a pro forma basis, taking into account a full year of production and revenue from Block 9, total revenue decreased 6.0% to US$684.5 million (2012: US$689.6 million).

Audited consolidated revenue decreased 21.5% to US$699.1 million (2012: US$699.6 million) for the financial year ended 31 December 2013. Our working interest production decreased 13.8% to 2,306 boe/d (2012: 3,384 boe/d), which was partially in line with expectations as a result of the anticipated cessation of gas and condensate production from the Kambuna field on 11 July 2013. Revenue from oil and gas production from B9/B32 and B9A declined by approximately 14.6% to US$63.4 million in 2013 (2012: US$72.4 million), primarily due to production disruptions, including unplanned shuts down, which were prolonged by bad weather. Revenue was also impacted by lower average selling prices for oil and gas compared with 2012.

EBITDAX
Our earnings before interest, tax, depreciation, amortisation, impairment and exploration expense (“EBITDAX”), which is a measure of our ability to generate income from our operations, decreased 41.2% to US$28.0 million in 2013 (2012: US$47.6 million). On a pro forma basis, EBITDAX decreased 16.4% to US$39.8 million.

Cost of sales
Cost of sales decreased by 17.3% to US$426.3 million during 2013 (2012: US$527.2 million), primarily attributed to lower Thai petroleum special remuneration benefits and royalties paid, as well as lower operating costs incurred during 2013.

We incurred lower operating cost in 2013 as a result of production ceasing at the Kambuna field and reduced charges for depreciation, depletion and amortisation (“DDA”). DDA charges decreased 11.4% to US$20.0 million in 2013 (2012: US$22.6 million) due to lower capital expenditure at the Glagah-Kambuna TAC, which was offset by higher expenditure from drilling activities at B9/B32 and B9A, where we participated in the drilling of 57 wells in 2013 (2012: 53 wells).

Our operating cost and production both decreased by approximately 14.0% in 2013, which resulted in our lifting cost remaining flat year on year at US$15.14/boe for 2013 (2012: US$15.13/boe). However, on a pro forma basis, our lifting cost was US$17.59/boe representing a 49.8% reduction versus 2012.

<table>
<thead>
<tr>
<th>FOR THE YEAR ENDED 31 DECEMBER</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total sales revenue (US$ million)</td>
<td>684.5</td>
<td>63.4</td>
</tr>
<tr>
<td>Cost of sales (US$ million)</td>
<td>426.3</td>
<td>47.6</td>
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<tr>
<td>EBITDAX (US$ million)</td>
<td>258.2</td>
<td>22.6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FOR THE YEAR ENDED 31 DECEMBER</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sales of crude oil (US$/bbl)</td>
<td>56.5</td>
<td>54.7</td>
</tr>
<tr>
<td>Sales of gas (US$/mcf)</td>
<td>28.0</td>
<td>29.3</td>
</tr>
<tr>
<td>Revenue (US$ million)</td>
<td>84.5</td>
<td>65.1</td>
</tr>
<tr>
<td>Production volumes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil and liquids (bbl)</td>
<td>1441</td>
<td>1396</td>
</tr>
<tr>
<td>Gas (mcf/d)</td>
<td>33.8</td>
<td>39.3</td>
</tr>
<tr>
<td>Total (bbl)</td>
<td>7075</td>
<td>2916</td>
</tr>
<tr>
<td>Sales volumes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil and liquids (bbl)</td>
<td>1441</td>
<td>1396</td>
</tr>
<tr>
<td>Gas (mcf/d)</td>
<td>32.9</td>
<td>39.6</td>
</tr>
<tr>
<td>Total (bbl)</td>
<td>6922</td>
<td>2801</td>
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<tr>
<td>Average sales price</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil and liquids (US$/bbl)</td>
<td>109.19</td>
<td>108.40</td>
</tr>
<tr>
<td>Gas (US$/mcf)</td>
<td>3.05</td>
<td>4.81</td>
</tr>
</tbody>
</table>

Kiran Raj
Chief Financial Officer

We believe our Group’s fundamentals are well placed to capitalise on our balance sheet strength as we progress our projects under development and continue to deliver shareholder value.
**FINANCIAL REVIEW**

**Finance costs**  
Finance costs increased 11.0% in 2013 to US$13.3 million (2012: US$12.0 million) due primarily to the successful completion of our tap issue in May 2013 in relation to the 10.5% senior guaranteed secured bonds due in July 2016 (“2016 Notes”), which added US$35.0 million to the face value of the 2016 Notes (see the following section entitled “2013 – Financial Review, Capital Management”).

**Tax expense**  
Our tax expense decreased 31.1% to US$12.8 million in 2013 (2012: US$18.5 million) primarily due to lower revenue from Kambuna, BB/32 and B9A.

**Capital expenditures and capital investments**  
Exploration and development expenditures include, among others, exploration, appraisal and well expenditures, geological and geophysical activities, general and administrative costs, field development costs, platform and facility costs, and pipeline and equipment expenditures. Capital investments include the acquisition by our Group of shares in third-party entities.

In 2013, we increased spending on capital projects and investments by 273.3% to US$121.2 million (2012: US$32.8 million) which was mainly attributable to our exploration and appraisal activities in Indonesia and Vietnam and our acquisition of Tullow Bangladesh.

In 2013, we spent US$64.6 million (2012: US$16.8 million) on exploration and appraisal activities. The share of our expenditure from our successful exploration and appraisal activities in the Bulu PSC and Kutai PSC amounted to US$11.7 million and US$13.5 million, respectively, and the share of our well and drilling costs in Block 105-110/04 (“Block 105”) and Block 120 offshore Vietnam amounted to US$29.9 million and US$14.1 million, respectively. Our share of development drilling costs at BB/32 and B9A, and Block 9 amounted to US$12.1 million and US$1.6 million, respectively in 2013.

**Capital management**  
On 19 July 2013, we listed all our existing shares and issued 248,154,000 new shares by way of an IPO on the Mainboard of SGX-ST where we raised US$200.5 million (US$524.6 million) in net proceeds. The IPO was over six times subscribed. We believe our Group’s fundamentals are well placed to capitalise on our balance sheet strength as we progress our projects under development and continue to deliver shareholder value.

On 2 May 2013, we increased the size of our revolving credit facility from US$30.0 million to US$42.5 million, which was undrawn as at 31 December 2013. We successfully completed the US$35.0 million tap issue of the 2016 Notes on 31 May 2013, the subscription of which was over three times subscribed. On 30 January 2014, the outstanding 2016 Notes were fully redeemed at 105.25% of the principal amount, being US$126.8 million (which includes accrued interest of US$0.3 million).

As at 31 December 2013, our unutilised sources of liquidity was US$290.3 million and our total gearing was 26.0% (2012: 29.0%). We continue to be in a net cash position, with net cash and bank balances of US$251.8 million.

Our net cash flow generated from financing activities increased 120.1% to US$231.8 million in 2013 (2012: US$105.3 million). Following the full redemption of the 2016 Notes, we are debt free, although we are currently progressing plans to put in place suitable debt instruments at attractive terms.

**Debt profile**  
Our borrowings as at 31 December 2013 consisted of the 2016 Notes amounting to US$119.1 million. Following our redemption of the 2016 Notes on 30 January 2014, the total outstanding amounts repayable to bondholders within the current year, was US$127.3 million, which includes repayment of principal and accrued interest.

**Cash**  
Our net cash flow from operating activities increased 9.9% to US$101.2 million in 2013 (2012: US$14.8 million), primarily due to an increase in trade payables and lower estimated tax payable in relation to our interests in BB/32 and B9A.

Our net cash flow generated from financing activities increased 120.1% to US$231.8 million in 2013 (2012: US$105.3 million), mainly attributable to receipt of net proceeds of US$200.5 million from our IPO and proceeds from the tap issue of US$38.8 million, which were offset by the payment of bond interest amounting to US$69.4 million.

**Outlook statement**  
Moving into 2014, we will recognise a full year of production and revenue from the Bangora field in Block 9, where production is currently above 100 million cubic feet per day (“mmcfd”) and also at BB/32 and B9A where we will participate in the drilling of at least 50 development wells.

We expect 2014 to be another busy year for exploration, appraisal and development, with our planned capital expenditure amounting to US$198.1 million, based on the work program and budget for our existing assets. We believe 2014 will provide for further significant milestones. Capital management is core to our strategic vision of building a sustainable upstream oil and gas E&P company and we intend to fund our planned capital expenditure from cash flows from operations, existing cash resources and new debt financing. Some seismic acquisition which was deferred from 2013 is already underway. In February 2014, we completed the acquisition of 1.284 km of 2D seismic data at the East Muriah PSC and we have awarded a contract for a 500 sq km 3D seismic program in the Tanjung Aru PSC, which is anticipated to be completed before the end of the second quarter.

Our preliminary work program for 2014 includes the drilling of up to 13 exploration and appraisal wells, at least 50 development wells, up to five seismic programs and continued activities to deliver production in 2015 from the Nong Yao field in G11/46 and the Wassana field in G10/48, both in the Gulf of Thailand. In Indonesia, we continue to progress the development of the Lengo and East Lengo gas discoveries in the Bulu and East Muriah PSCs, respectively, and the Kutai PSC. Lastly, in Cambodia, we together with our other joint venture partners will seek to progress the development of Block A. 2014 is expected to be another defining year for KrisEnergy and we believe we have in place the required sources of funds to execute our work program.

<table>
<thead>
<tr>
<th>(US$ million)</th>
<th>ASVP</th>
<th>PROSPECTUS</th>
<th>ACTUAL</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net IPO Proceeds</strong></td>
<td>203.6</td>
<td>200.5</td>
<td></td>
</tr>
<tr>
<td><strong>Utilisation</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tranche 1: For acquisitions (including farm-ins)</td>
<td>60.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tranche 2: For our planned capital expenditures, including the exploration, appraisal and development of our existing assets</td>
<td>112.9</td>
<td>22.7</td>
<td></td>
</tr>
<tr>
<td>Tranche 3: For general working capital</td>
<td>30.0</td>
<td>15.0</td>
<td></td>
</tr>
<tr>
<td><strong>Total utilisation of net IPO proceeds</strong></td>
<td>203.6</td>
<td>37.7</td>
<td></td>
</tr>
<tr>
<td><strong>Net IPO proceeds unutilised</strong></td>
<td>-</td>
<td>162.8</td>
<td></td>
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</tbody>
</table>

* Mainly attributed to planned drilling activities at the Kutai PSC, Block 105 and Block 120.
* Mainly attributed to general working capital for employees salaries, SGX-ST compliance costs and general office expenses.

**IPO net proceeds**  
Net proceeds from our IPO (after deducting expenses for professional fees, underwriting and placement commissions and other share issuance expenses relating to our IPO amounting to approximately US$12.5 million (US$15.9 million) was approximately US$200.5 million (US$254.6 million).

As of 31 December 2013, total IPO proceeds of US$37.7 million had been used. The use of proceeds is in accordance with the use of proceeds as described in the section “Use of Proceeds” of our Prospectus dated 12 July 2013. No single expenditure was greater than US$5.0 million.

<table>
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<tr>
<th>(US$ million)</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net cash flows from operating activities</strong></td>
<td>16.2</td>
<td>14.8</td>
</tr>
<tr>
<td><strong>Net cash flows from investing activities</strong></td>
<td>(122.1)</td>
<td>(32.8)</td>
</tr>
<tr>
<td><strong>Net cash flows from financing activities</strong></td>
<td>231.8</td>
<td>105.3</td>
</tr>
<tr>
<td><strong>Cash at banks and on hand</strong></td>
<td>247.8</td>
<td>121.9</td>
</tr>
<tr>
<td><strong>Short-term structured deposits</strong></td>
<td>0.0</td>
<td>8.0</td>
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<tr>
<td><strong>Cash and bank balances</strong></td>
<td>251.8</td>
<td>129.9</td>
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<td>Tranche 2: For our planned capital expenditures, including the exploration, appraisal and development of our existing assets</td>
<td>112.9</td>
<td>22.7</td>
</tr>
<tr>
<td>Tranche 3: For general working capital</td>
<td>30.0</td>
<td>15.0</td>
</tr>
</tbody>
</table>
TECHNICAL REVIEW
Our production in 2013 averaged 2,916 boepd from the B8/32 and B9A oil and gas fields in the Gulf of Thailand, the Kambuna gas-condensate field in the Glagah-Kambuna TAC and one month of gas and condensate production from the Bangora field in Block 9 onshore Bangladesh following the completion of our acquisition in December. Since the Block 9 acquisition completed with an effective date of 1 January 2013, our average working interest production in 2013 would have been 7,076 boepd.

The Kambuna field came to the end of its economic life as anticipated and ceased production on 11 July 2013. The operator is in the process of decommissioning the facilities and relinquishing the contract area to the Indonesian authorities. Production in Thailand was marginally below expectations owing to delays to maintenance and repairs due to bouts of poor weather in both the second and third quarters, as well as a six-day interruption to gas sales from the Benchamas field due to gas specification issues.

The outlook for our production volumes for 2014 looks much improved. In January, we were producing more than 7,000 boepd. We now benefit from the full integration into our portfolio of our 30% working interest in Block 9.

In January 2014, we were producing more than 7,000 boepd. We now benefit from the full integration into our portfolio of our 30% working interest in Block 9. Workovers undertaken at two wells in the Bangora field to replace corroded tubing were successfully completed in 2013 and subsequent gross production has surpassed expectations at 110 mmcfd.

In addition, 57 development wells were drilled in B8/32 and B9A in 2013 and more than half of these are slated to be brought into production early in 2014. We expect to drill at least 50 development wells in 2014 and bring two new platforms into production.

Reserves & resources
As at 31 December 2013, our working interest 2P reserves were 32.3 mmboe as estimated by NSAI compared with 17.2 mmboe at 31 December 2012 before the acquisition of Block 9 in Bangladesh and the relinquishment of the Glagah-Kambuna TAC.

At the time of our acquisition of Block 9, our working interest 2P reserves from Bangladesh were estimated by NSAI at 14.5 mmboe. NSAI has adjusted upwards the estimate for our working interest 2P reserves to 18.3 mmboe as at 31 December 2013 as a result of better-than-expected reservoir pressure performance. The 2P reserves attributed to B8/32 and B9A by NSAI as at 31 December 2013 were 12.7 mmboe, slightly below year-earlier estimates due to drilling not fully replacing reserves. The 6% change from a year ago is within our range of expectations for an asset of this nature which, due to the geology of the Gulf of Thailand, requires continual drilling of development wells to maintain production and reserves.

Our working interest 2P reserves for G11/48, a block currently under development reduced by 0.4 mmboe from 13.4 mmboe owing to NSAI taking into account the Thai requirement for a farm-out of a 10% gross working interest to a local Thai participant before the start of production. The Nong Yao oil field development is underway with the FID agreed by the partners in August 2013, therefore NSAI have taken into consideration the execution of the farm-out, which will reduce KrisEnergy’s working interest to 22.5% from the current 25%.

Our 2C resources of 53.9 mmboe as at 31 December 2013 and estimated by NSAI received an uplift from the acquisition of Block 9 as well as the increased resource from the drilling of the Lengo-2 appraisal well in the first half of 2013. As the result of the Lengo-2 well, the 2C resources associated with the Bulu PSC increased by 58% to 25.4 mmboe as estimated by NSAI as at 31 December 2013. The addition of Block 9 to the portfolio contributed a further 1.4 mmboe to our 2C resources from the undeveloped Lalmai gas discovery within the contract area.

Development & appraisal
We made good headway on appraisal and development projects last year, specifically the Nong Yao oil field in the Gulf of Thailand and the Lengo gas field in the Bulu PSC, offshore East Java.

The partners in the Nong Yao project declared FID in August 2013 and preliminary fabrication of the facilities began in November 2013 with the EPCIC contract awarded in January 2014. The facilities are now taking shape in Thailand and the project remains scheduled to commence oil production in the first half of 2015.

We continue to work closely with the operator of G10/48, which lies adjacent to G11/48 in the Gulf of Thailand, on the development concept for the Wassana oil field. We have reviewed several alternative facilities’ concepts with a view to the near-term availability of equipment, materials and third-party services.

Our team in Jakarta ran a back-to-back two-well drilling program in the first half 2013 with an appraisal well in the Bulu PSC and an exploration well in the Kutai PSC in the Makassar Strait, Kalimantan.

1 Includes G6/48, the transaction for which is pending host government approval.
RESERVES & RESOURCES

All 2P reserves and 2C resources are estimated by NSAI, as at 31 December 2013

RESERVES REPLACEMENT

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>2P reserves as at 31 December (mmboe)</td>
<td>15.84</td>
<td>14.38</td>
<td>17.16</td>
<td>32.30</td>
</tr>
<tr>
<td>Average production (boepd)</td>
<td>4,817</td>
<td>3,384</td>
<td>2,916</td>
<td></td>
</tr>
<tr>
<td>Total production (mmboe)</td>
<td>1.759</td>
<td>1.235</td>
<td>1.064</td>
<td></td>
</tr>
<tr>
<td>Reserves replacement ratio (%)</td>
<td>17</td>
<td>325</td>
<td>1,523</td>
<td></td>
</tr>
</tbody>
</table>

1. Includes one month (December 2013) of liquids and gas production at the Bangora field following the completion of the acquisition of a 30% working interest in Block 9, Bangladesh, on 17 December 2013.

2P - reserves
2C - development pending
2C - development unclarified

The appraisal well in the Bulu PSC at the Lengo discovery location successfully tested gas and resulted in the increase of 2C resource estimates by NSAI. Lengo-2 was located approximately 3.3 km south of the Lengo-1 gas discovery well and was drilled to a total depth of 2,748 feet (838 metres) measured depth (“MD”) and encountered producible gas within the Kujung I reservoir formation.

A drill stem test (“DST”) over an interval from 2,415 feet to 2,485 feet flowed 4.3 mmcfd with a flowing wellhead pressure (“FWHP”) of 587 pounds per square inch (“psig”). A second DST over the interval between 2,415 feet to 2,571 feet flowed 21 mmcfd with a FWHP of 487 psig with the flow rate limited by surface equipment. The well gathered new information including 137 feet of core from the Kujung reservoir interval and the excellent test results in the second DST indicated that the main reservoir interval is better developed in Lengo-2 than in the initial discovery well.

Following integration of the Lengo-2 results, a review of the geological model and commercial analysis, we are drafting a plan of development for the Lengo gas field and holding negotiations with potential offtakers of the gas in East Java.

In addition, we completed a 1.284 km 2D seismic survey on 22 February 2014 in the adjacent East Muriah PSC over the East Lengo gas discovery. The acquisition is prior to an appraisal well anticipated to be drilled in the second half of the year to confirm the eventual development of East Lengo gas resources as a single-well tie-back to the Lengo facilities.

Exploration

The Tayum-1 exploration well in the Kutai PSC offshore East Kalimantan was located between the earlier Dambus and Mangkok gas discoveries. It was drilled directionally to a total depth of 11,095 feet MD. Preliminary well log evaluation indicated that the well encountered approximately 49 vertical feet of net gas pay from multiple sandstone intervals between 2,377 feet MD and 7,180 feet MD within the Miocene to Pliocene section, from which two gas samples were recovered. Two further gas samples were also recovered from what are interpreted to be shaly-sand gas pay intervals between 6,647 feet MD and 6,660 feet MD and between 7,366 feet MD to 7,402 feet MD.

The well was plugged as a gas discovery by modular dynamic tester (“MDT”) sampling and we plan to drill a further appraisal well updip to the Mangkok discovery in the second half of 2014 while concurrently writing the plan of development for the gas resources and negotiating with potential buyers of the gas.

Offshore Vietnam, we participated in the drilling of two high-risk exploration wells, one each in Block 105 and Block 120. Both of these blocks have little by way of previous exploration with a single well drilled in Block 120 and none in Block 105. The partners in the blocks acquired 2D seismic data in 2010 and undertook a 3D seismic acquisition program in 2012 in both licences. Subsequent processing and interpretation of the data identified four independent drillable oil and/or gas prospects in each block as well as multiple oil and/or gas leads.
Based on updated mapping from the seismic data and a new depth conversion scheme, the Cua Lo gas prospect was the first prospect selected to be drilled in Block 105. The Ensco 107 jack-up rig commenced drilling of the Cua Lo-1 exploration well on 11 August 2013. Unfortunately, a series of strong typhoons passed through the region in the ensuing four months and drilling operations were interrupted four times due to safety requirements to evacuate the rig.

Cua Lo-1 reached a total depth at 2,867 metres MD in December and initial well log interpretation identified several gas-bearing sandstone reservoirs. A DST on a reservoir evaluated with the largest potential within the prospect flowed gas but poor reservoir deliverability rate combined with high carbon dioxide content suggested that development of the tested reservoir would be unlikely. Although disappointing, Cua Lo-1 confirmed both the trapping mechanism and the existence of a petroleum system within a block with no prior exploration.

In October 2013, the Songa Mercur semi-submersible rig began drilling the oil and/or gas Ca Ngu prospect in Block 120 offshore central Vietnam. Of note is that the single well that was drilled in the early 1990s in the current boundaries of the block encountered oil.

Despite interruption from three rig evacuations due to typhoons, similar to the Cua Lo drilling program, the Ca Ngu-1 well reached a total depth of 1,290 metres MD at the end of December. Wireline log data confirmed a 15.2 metre gross hydrocarbon column within the Miocene carbonate reservoir, comprising a 10.6 metre gas column above a 4.8 metre oil rim.

Although neither of these wells offshore Vietnam encountered commercial volumes of hydrocarbons, both confirmed the existence of a petroleum system in the respective blocks and provided valuable data that we are integrating with existing data and will review before deciding, along with our partners, the future exploration strategy. It is important to emphasise that Block 105 and Block 120 contain additional mapped prospects and furthermore multiple leads for us to investigate further.

Work ahead & technical resources

Both the Lengo and Kutai development programs, together with the oil projects in the Gulf of Thailand, are core to our approach to maintain a balanced portfolio of oil and gas. We operate all but one of our assets in Indonesia, which include three blocks under development – Bulu, East Muriah and Kutai – and four exploration blocks – East Seruway, Sakti, Tanjung Aru and Udan Emas for which this year we will undertake seismic acquisition, community socialisation or exploration drilling.

To that extent, we are enhancing our technical capabilities in Indonesia and streamlining workflows to efficiently manage multiple projects at different stages of the E&P life cycle.

We are also boosting our technical resources in Bangkok, which oversees our assets in the Gulf of Thailand. As well as the Nong Yaoi and Wassana developments, we intend to undertake appraisal drilling in G6/48 where the Rossukon oil discovery is located, and exploration drilling in G10/48 and G11/48 in parallel with the development work. We are also hopeful of a resolution to the outstanding fiscal issues in the Block A oil development project offshore Cambodia.

In Bangladesh, we plan to conduct a further well workover program in addition to that undertaken in 2013 and which was successful in lifting and stabilising production at current levels. We will also build our technical resources in Bangladesh going forward as we strive to expand our portfolio in other areas in the country including offshore.

Our preliminary work program for 2014 comprises up to five 2D or 3D seismic acquisition programs, up to 13 exploration and appraisal wells and at least 50 development wells, together with building platform facilities and writing plans of development. The timeframe for this schedule will be dependent upon the securing of equipment, materials and third-party services and we are mindful of achieving this cost-effectively and with a continual focus on EHSS matters.

CHRIS GIBSON-ROBINSON
DIRECTOR EXPLORATION & PRODUCTION
28 February 2014
Reserves are quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterised by development and/or evaluations are currently ongoing with a view to confirming that an appropriate development plan.

Contingent resources are  quantifies of petroleum estimated, as a given data, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

In the “low estimate” scenario of contingent resources (“1C”), the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 10%.

In the “best estimate” scenario of contingent resources (“1C”), the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 50%

In the “high estimate” scenario of contingent resources (“1C”), the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 10%.

Contingent resources are classified as Development Unclarified when there is a discovered accumulation where project activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal and/or evaluation activities are required to clarify the potential for eventual commercial development.

Contingent resources are classified as Development Unclassified when there is a discovered accumulation where project activities are as ongoing to justify commercial development in the foreseeable future. The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan.

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Our Health and Safety Policy emphasizes our responsibility for the health, safety and security of every individual involved in our activities. We undertake risk management and ensure we comply with, or exceed, the relevant legal requirements for our operations. We will develop and nurture safety awareness and a safety culture among all employees and as a result of this, create individual responsibility for health and safety at all levels.

We are aware that successful health and safety management is based upon five key principles: a suitable and sufficient policy; organisation; planning; implementation; and performance review. It is the Company’s policy to adopt these principles.

We engage in an effective Environmental, Health and Safety Management System as it is our legal obligation to comply with legislations, our moral obligation as a company to our people and lastly to protect our business reputation. As such we are able to manage our risks, reduce potential accidents and improve operational performance. We recently consolidated our regional incident and accident reporting system onto one platform in a swift and structured Business Management System.

We recognise and understand that our activities affect the environment and the communities in which we operate. We take our responsibility seriously to identify and manage these impacts as effectively as possible. We are committed to continually improving our environmental performance and moving towards best practices in corporate sustainability.

Our Environment Policy highlights our commitment to comply with all applicable environmental legislation requirements and to minimise and prevent pollution at the source wherever and whenever possible.

In addition to the OHSAS 18001 certification in 2012, our Singapore office became ISO 14001 certified in 2013, awarded by SGS International Certification Services and accredited by the United Kingdom Accreditation Services. Our Jakarta office is working towards similar certifications. We plan for all KrisEnergy regional offices to eventually attain full OHSAS 18001 and ISO 14001 certifications. Subsequently, these standards and accreditations will be applied to all new operations. The acquisition of Tullow Bangladesh allows us to continue the process of ISO 14001 certification, which commenced prior to the completion of the transaction, with the intention to work to an OHSAS 18001 certification at a later date.
CSR

CORPORATE SOCIAL RESPONSIBILITY

KrisEnergy recognises that a diverse workforce coming from all sections of the community, offering differing skills, experiences, backgrounds and cultures will result in an organisation that is better able to respond to the needs of our stakeholders and the communities in which we work. We actively participate in initiatives that are beneficial to both our local communities and operational activities within those communities.

We ensure that our activities and all personnel involved in those activities comply with KrisEnergy EHSS policies. Our aim is to have minimal impact on the environment where we have operations.

Our CSR vision focuses on the alleviation of poverty and the sustainable well-being of the communities in the host countries through social investment, volunteering, research and the robust exchange of ideas. As such, we ensure our activities are measurable and long lasting for the communities. Our priority lies in education, which provides individuals the knowledge and skills to improve their lives and participate in the wider society. Education reduces poverty, boosts economic growth, promotes gender equality and leads to improved healthcare.

We also support healthcare and community development programs that lead to better standards of living and promote self-sufficiency. In 2013, we supported several educational programs throughout Southeast Asia and contributed to the welfare and development of children and teenagers. Our contributions included educational sponsorships, mentoring and supporting students in social entrepreneurship initiatives, financial and equipment donations to orphanages and donations for disaster relief.

As we continue to increase our CSR activities in the region, our future endeavours will include community development in our operational areas where we intend to support local communities in the areas of education, training, health, and village and social development. We will continue to engage in projects involving local communities and, where appropriate, our programs will be planned in consultation with governments and the local communities and authorities to provide practical solutions and sustainable results.

Diversity & equality

We are committed to promote equality of opportunity and to the elimination of unlawful discrimination. Our goal is to create and maintain a healthy and positive working and learning environment, which creates mutual respect and dignity and enables everyone to realise their full potential.

We respect human rights and will not tolerate any level of bullying, discrimination, harassment or victimisation by or towards any of our employees, contractors, suppliers, stakeholders and visitors. Any such cases are taken seriously and may result in disciplinary or other appropriate action including termination of contract.

We firmly uphold fair employment practices and in formulating employment policies KrisEnergy is guided by the relevant legislation when establishing employee contracts. These policies are regularly reviewed and new policies are introduced following consultation with employees.
Building an oil and gas E&P company is in our DNA. It takes vision, faith and tenacity. It is a high-risk endeavour that requires long-term commitment and patience.
KrisEnergy’s focus area stretches from the Surma Basin in Bangladesh in the West to the Papuan Basin in the East, and from offshore southern China in the North to Indonesia in the South. Although the vast area spans numerous geographies, the geology is similar across much of the map with the exception of the far eastern flank.

Our approach is to build a portfolio of assets across each stage of the exploration-to-production life cycle and to spread our exposure to political and fiscal risks by operating in several countries with different taxation regimes and regulations.

Our approach is to build a portfolio of assets across each stage of the exploration-to-production life cycle and to spread our exposure to political and fiscal risks by operating in several countries with different taxation regimes and regulations. Lastly, we aim to balance our production between oil and gas, the latter being under long-term supply contracts in Asia and less vulnerable to sharp swings in global benchmark commodity prices.

Our activities include all facets of exploration, appraisal, development and production, from identifying potential prospects to discovery and commercialisation. Our producing assets provide cash flow with which we appraise and develop our discoveries. We continually add exploration blocks, both moderate and high risk, into the appraisal stage and subsequently into the development phase. This pipeline of independent projects provides a continuous flow of opportunities to increase our oil and gas production and to grow our reserves and resources base.

Under the terms of the licences for the contract areas, KrisEnergy holds various rights to explore, develop and extract oil and gas resources in a specifically demarcated area under agreement with the host government or the regulatory body.

Richard Lorentz
Director
Business Development

Our geoscientists work up exploration concepts in areas where we have detailed knowledge and experience. When a target area is identified, we acquire and interpret existing data including seismic and other geological or geophysical data. The successful interpretation of data requires a high level of technical skill and significant local knowledge of the specific area. If an area remains of interest after evaluation, we seek to acquire an exploration licence from either the host government or a company holding the existing rights. The acquisition process typically requires us to pay a signature bonus, as well as to commit to a work program with certain financial and exploration milestones.

Each of our assets is rigorously selected based on our technical team’s deep understanding of the geology and complexities of the regional basins. Our focus on core areas in Asia provides an operating niche with deep-seated ties to potential partners in the region and a transfer of skills and knowledge within the company.

Early stage pre-exploration

Each project is unique but will encompass a combination of key stages:

1. Prospect identification / concept
2. Acquire existing data
3. Interpret existing data
4. Acquire contract area

Pre-Exploration
- Prospect identification / concept
- Acquire existing data
- Interpret existing data
- Acquire contract area

PRE-EXPLORATION
- Exploration
- Pre-Exploration
- Exploration

*Geological model used in advanced seismic data analysis offshore Indonesia*
Once we have secured an exploration licence, we gather and interpret additional data to plan an exploration drilling program. This stage may include the reprocessing and/or acquisition of 2D or 3D seismic data and will typically take up to 12 months.

Based on our interpretation of the data, we identify locations to drill exploration wells and at this point, we may seek to mitigate risk and defray costs by farming out to third parties a portion of the exploration drilling costs. A typical arrangement in a farm-out agreement involves the partner or partners committing to fund a portion of the work program (wells or seismic data acquisition) up to an agreed amount in return for earning a working interest in the licence. Subsequent to the activities in the agreement, costs are usually split pro rata in proportion to each party’s working interests. While the terms of such farm-outs vary, we generally prefer to retain the right to operate the contract area.

Our exploration opportunities are largely independent of one another, which helps ensure that the outcome of drilling individual wells does not affect the prospectivity of the remaining opportunities in the block.

Once production has commenced, we endeavour to maintain the field and extract oil or gas as efficiently as possible. This may include re-entry of wells to repair production equipment, the drilling of infill wells (wells drilled between existing producing wells in an attempt to improve the efficiency of petroleum recovery from a reservoir) and the close monitoring of reservoir/production performance.

Within the upstream oil and gas industry, the volume of oil or gas commercially produced is typically 20-40% for oil and 60-80% for gas versus the total amount of resource in place. To increase the recovery percentage of the total amount of oil and gas in place, we model the subsurface formations by computer simulation and conduct reservoir pressure maintenance studies based on this model. The results of those studies guide us in optimising recovery using well-known industry techniques.

In addition, we continue exploration and appraisal work even after production has commenced in order to make additional discoveries and to convert our resources into reserves, as well as to extend the life of the field.
Acquisitions & portfolio management

Acquisitions provide another opportunity for our growth and we are proactive in seeking out complimentary assets at varying stages of the E&P life cycle to enhance our portfolio. These asset deals may be bi-lateral, or may involve a competitive bid or auction process. Once we identify an asset for acquisition, we undertake in-house analysis to build an independent view of the opportunity leading to a valuation through the assessment of a number of scenarios around critical factors. We follow a disciplined approach with regards to evaluating new opportunities with a thorough technical, operational and financial evaluation as well as the consideration of other factors such as level of synergy with the current portfolio, our geographic focus areas, the type and level of technical expertise required, macroeconomic trends, political stability and economic risk.

We continually review new opportunities as they come to market, including new contract areas for award and asset sales. Concurrently, we continually review our existing portfolio for partial or entire divestment opportunities to mitigate risk, decrease our exploration and development costs or divest assets that are no longer consistent with our overall portfolio strategy. In the five years since we set up our business we have undertaken transactions or direct awards covering 19 assets in five countries, two of those assets, Block 06/34 and the Glagah-Kambuna TAC, have been relinquished or are in the process of being relinquished as part of our on-going portfolio management.

Portfolio building across the E&P life cycle

1. Our production and the lion’s share of our 32.3 mmbce of 2P reserves come from the Bangora gas field in Block 9 onshore Bangladesh and the BB/32 and B9A oil and gas complex in the Gulf of Thailand. The Glagah-Kambuna TAC reached the end of its economic life in July 2013 and ceased production. The TAC will be relinquished in 2014. We also derive 3.4 mmbce of 2P reserves from the Nong Yao oil field in G11/48 in the Gulf of Thailand, which is currently under development and is expected to commence production in the first half of 2015.

2. Nong Yao will be the first of six developments we intend to bring into production over the next four years to underpin our growth. The remaining development projects provide our 2C resources in the development pending category on which we are working to submit plans of development or awaiting final government approvals before we are able to declare final investment decision.

The Wassana oil project is located in G10/48, which neighbours G11/48, and is anticipated to come on stream in the second half of 2015. In 2016, we plan to start gas production at three locations in Indonesia, in the Bulu PSC, East Muriah PSC and the Kutai PSC and a year later we expect to finalise developments at the Rossukon field in G6/48 in the Gulf of Thailand and at the Apsara production area in Block A offshore Cambodia. Both of these developments will produce oil.

3. Our 2C resources categorised as development unclarified are the discoveries that we have made that require additional technical work and appraisal drilling that may mature the discovery into development pending. We are planning exploration or appraisal drilling in 2014 on several of our 2C development unclarified discoveries as well as seismic data acquisition to bring these assets further along the value chain.

KrisEnergy — building a sustainable company

KrisEnergy acquired its first assets, a 25% working interest in each of G10/48 and G11/48, in November 2009. As at 31 December 2013, our portfolio comprised 16 contract areas in five countries and we have subsequently acquired one exploration block bringing the tally to 17 licences as at 28 February 2014. These asset additions have been achieved through a variety of direct award from government, farm-in and asset and/or corporate acquisition.

Our portfolio may be considered in five distinct strata each falling under one of the E&P stages described previously and defined in our reserves and resources inventory.

1. Our production and the lion’s share of our 32.3 mmbce of 2P reserves come from the Bangora gas field in Block 9 onshore Bangladesh and the BB/32 and B9A oil and gas complex in the Gulf of Thailand. The Glagah-Kambuna TAC reached the end of its economic life in July 2013 and ceased production. The TAC will be relinquished in 2014. We also derive 3.4 mmbce of 2P reserves from the Nong Yao oil field in G11/48 in the Gulf of Thailand, which is currently under development and is expected to commence production in the first half of 2015.

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3. Our 2C resources categorised as development unclarified are the discoveries that we have made that require additional technical work and appraisal drilling that may mature the discovery into development pending. We are planning exploration or appraisal drilling in 2014 on several of our 2C development unclarified discoveries as well as seismic data acquisition to bring these assets further along the value chain.

Our exploration portfolio provides the fourth strand of our strategy. We strive to achieve a balance of oil and gas opportunities and high and moderate risk prospects. All of our blocks, including those with production or development, contain exploration prospects and leads. In 2014, for example, we will drill exploration wells in G10/48 and G11/48 as well as continuing the development activities for the Wassana and Nong Yao fields, respectively.

In addition, we have some licences that have seen little by way of exploration activity. These contain multiple prospects and would rank as higher exploration risk: East Serunay, Sakti, Tanjung Aru and Utan Emas, all in Indonesia and Block 105 and Block 120 in Vietnam. These blocks provide the potential for large-scale hydrocarbon discovery and we plan to drill wells in each of these over the next two to three years.

The final strand in our portfolio strategy is New Ventures activity. Our organic growth comes from adding assets into the exploration portfolio and requires our geoscientists to work up exploration concepts and be successful in finding an entry point into acreage. For transaction-based arrangements, we will look at opportunities at other stages of the E&P value chain, for example to provide additional development projects or production, however, we generally require such assets to have exploration potential.

KrisEnergy’s portfolio is shaping up well. We are active across all areas of the E&P life cycle and we have a good mix of oil and gas. We will continue to aggressively seek new opportunities but remain committed to maintaining our rigorous standards in the selection process. Likewise, the divestment of assets is also critical to efficient and successful portfolio management.

RICHARD LORENTZ
DIRECTOR BUSINESS DEVELOPMENT
28 February 2014
Our portfolio as at 28 February 2014 comprised 17 contract areas in five countries, of which we operate nine. In this section, all reserves and contingent resource data are based on estimates by our third-party independent qualified person NSAI as at 31 December 2013.

We have a diversified multi-asset portfolio across the exploration, appraisal, development and production life cycle. This portfolio provides a balance of cash flow generation from producing assets that allows us to fund development and exploration activities and to evaluate our exploration upside potential.

Our technical and regional expertise provides us with significant growth opportunities through several pathways along the value curve: developing our contingent resources into production; proving and developing our prospective resources; acquiring additional exploration areas and production assets; and applying for new acreage through government bid rounds or via direct application.

We maintain rigorous discipline in the business development process with thorough technical, operational and commercial evaluations focused on creating value. We also consider other factors such as synergy with our existing portfolio, our geographic focus area and the type and level of technical expertise required.

We continually review our portfolio for optimisation opportunities including partial divestment to mitigate risk (farm-out) or full divestment for assets that no longer meet our overall portfolio strategy.
**ONSHORE BANGLADESH**

Bangladesh's hydrocarbon industry is dominated by natural gas, which is the main source of domestic energy. However, demand for gas has risen faster than supply, leaving the country facing shortages.

KrisEnergy agreed in April 2013 to acquire all the outstanding shares in Tullow Bangladesh, which held a 30% operated working interest in onshore Block 9 where the Bangora gas field is located. The transaction was approved by the Bangladesh authorities on 17 December 2013 and had an effective date of 1 January 2013. KrisEnergy now holds 100% of Tullow Bangladesh and its assets.

**GULF OF THAILAND / OFFSHORE CAMBODIA**

The Gulf of Thailand, including both Thai and Cambodian waters, is a core area in our portfolio, containing oil and gas producing assets as well as the majority of our development projects. Structurally, the Gulf of Thailand is divided into a series of north-south oriented horsts and intervening half-grabens, which define a series of basins. The basins are characterised by an early Palaeogene phase of rifting with non-marine and lacustrine deposition, followed by a Neogene thermal subsidence phase with alluvial plain sedimentation. A typical oil and gas field in the Gulf of Thailand has multiple fault blocks with hydrocarbons trapped in multiple reservoirs.

**Block 9**

Block 9 covers 1,770 sq km over the Bangora-Lalmai anticline onshore Bangladesh, approximately 50 km east of Dhaka. It contains the Bangora gas-producing field and the Lalmai gas discovery. Two discoveries, Lalmai-3 and Bangora-1 (“B-1”) were made in Block 9 in 2004. These wells encountered a thick section of the Late Miocene Upper Bhuban Formation which provides the main reservoir objective in the Surma Basin. The Bangora field commenced production under long-term test from well B-1 in 2006. Three further development wells were added into the production stream between late 2008 and 2009. Well workovers to replace corroded production tubing with corrosion-resistant chrome tubing were completed at B-2 and B-5 in 2013 and gas production rose to approximately 110 mmcfd from 85 mmcfd prior to the workovers. Plans are in place to convert B-1 from a producer to a water disposal well in 2014 and to install compression equipment in the field to maintain plateau production.

The gross cumulative gas production at the end of December 2013 was 255 bcf and the NSAI estimate for the gross remaining 2P reserves as at 31 December 2013 was 319 bcf of gas and 785,400 barrels of condensate.

In addition to Block 9 gas production, there exists additional potential including contingent resources and prospective resources within a lead portfolio along the crest and flanks of the anticline. We intend to undergo a complete review all seismic data in the block to identify future exploration drilling targets.

**Gulf of Thailand**

Our production in the Gulf of Thailand comes from the oil and gas fields in B8/32 and B8A, from which we acquired a 30% working interest in 2013 and the transaction is pending the approval of the Government of Thailand. Assuming approval is granted, G6/48 will be our first operatorship in the Gulf of Thailand. The area contains the Rossukon oil discovery, which contributes 2.5 mboe to our working interest 2C resources in the category development pending. We plan to drill two appraisal wells to appraise the Rossukon discovery in 2014 before submitting a plan of development to the authorities.

**Gulf of Thailand / Offshore Cambodia**

The Gulf of Thailand, including both Thai and Cambodian waters, is a core area in our portfolio, containing oil and gas producing assets as well as the majority of our development projects. Structurally, the Gulf of Thailand is divided into a series of north-south oriented horsts and intervening half-grabens, which define a series of basins. The basins are characterised by an early Palaeogene phase of rifting with non-marine and lacustrine deposition, followed by a Neogene thermal subsidence phase with alluvial plain sedimentation. A typical oil and gas field in the Gulf of Thailand has multiple fault blocks with hydrocarbons trapped in multiple reservoirs.

The G11/48 licence contains the Nong Yao oil discovery. Final investment decision was declared in August 2013 and preliminary fabrication work commenced in November 2013. The EPIC contract for production and processing facilities was awarded in January 2014. Nong Yao accounts for 3.4 mboe of our total working interest 2P reserves as at 31 December 2013, as estimated by NSAI and taking into account the farm-in of a local Thai participant as required under the petroleum concession when commerciality of a well is first demonstrated and a production area is defined. G11/48 also contains 0.7 mboe of working interest 2C resources development unclarified associated with two additional discoveries, Angun and Mantana.

The G10/48 licence in the Gulf of Thailand contains the Wassana oil discovery, which contributes 3.4 mboe of 2C resources development pending to our working interest. The development concept for the Wassana development is under review between the joint-venture partners and a production area application (“PAA”) and Environmental Impact Assessment (“EIA”) are expected to be submitted to the Thai authorities in 2014. Two further discoveries, Nirami and Mayura, account for an additional 1.2 mboe development pending and 0.3 mboe development unclarified associated with two additional platforms in the area.

We acquired a 20% working interest in G6/48 in 2013 and the transaction is pending the approval of the Government of Thailand. Assuming approval is granted, G6/48 will be our first operatorship in the Gulf of Thailand. The area contains the Rossukon oil discovery, which contributes 2.5 mboe to our working interest 2C resources in the category development pending. We plan to drill two appraisal wells to appraise the Rossukon discovery in 2014 before submitting a plan of development to the authorities.

**Gulf of Thailand**

We hold a working interest in Block A, which overlies the Khmer Basin and contains several oil discoveries in the Apsara area within the block. A production permit application (“PPA”) for the development of the Apsara area was submitted to the Cambodian authorities in September 2010 and was updated in 2012. The Apsara area accounts for 2.5 mboe of our working interest 2C resources, divided between 2.0 mboe 2C development pending associated with the first platform in the development plan and a further 0.4 mboe 2C development unclarified pertaining to two additional platforms in the area.
As at 31 December 2013, gross cumulative production at B8/32 is anticipated to begin operation. In the B8/32 and B9A licences, up to 50 development wells were drilled in 2013. 31 January 2014, there were 40 platforms and 242 wells in production and two new production platforms were brought on stream. Up to 60 metres of oil and gas pay in the well. Due to the particular geology of the Gulf of Thailand, maintaining more than 200 feet of oil and gas pay in the well is critical. KrisEnergy (operator) was awarded a 15,000 barrels of oil per day (“bopd”) and 30,000 barrels of fluids per day. First oil is anticipated in the first half of 2015.

The development concept for the Nong Yao oil field comprises a wellhead platform with the export of crude oil via a floating storage and offloading (“FSO”) vessel. The production capacity will be up to 10,000 bopd from a single zone. Seven additional leads have been identified around the Niramai and Mayura discoveries, which could add as many as four further platforms with gross reserves of approximately 40 mmbo. To date, 17 oil prospects have been identified and mapped and multiple exploration wells are planned to be drilled in 2014 and 2015.

KrisEnergy agreed to acquire a 30% working interest and operatorship in G6/48 in March 2013. The transaction is pending the approval of the Government of Thailand. The Rossukan 1 exploration well was drilled in 2009 and encountered 31 feet of net oil pay and 19 feet of net gas pay. The well tested 851 bopd from a single zone. Seven additional leads have been identified around the Rossukan discovery along the eastern and western flank of the Karaweke kitchen. A 270 sq km 3D seismic acquisition program was completed in August 2013 and up to four appraisal wells are scheduled to be drilled from two locations in the second half 2014.

### B8/32 & B9A
**PRODUCTION, DEVELOPMENT, EXPLORATION**

- **2,072 sq km**

### G11/48
**DEVELOPMENT PENDING, EXPLORATION**

- **3,374 sq km**

### G10/48
**DEVELOPMENT PENDING, EXPLORATION**

- **4,696 sq km**

### G6/48
**DEVELOPMENT PENDING, EXPLORATION**

- **566 sq km**

---

**PARTNERS:**

Gulf of Thailand

- KrisEnergy 4.83%
- Chevron (operator) 51.66%
- PDOG 25.00%
- MDECO 18.73%
- PTT Exploration and Production 2.80%

**LOCATION:**

- Northern Pattani Basin, Gulf of Thailand
- Water Depths: 42 – 113 metres

**WORKING INTEREST**

- **Reserves**
  - OIL (bbl): 1,416,088
  - GAS (scf): 4,953,328
  - TOTAL (boe): 6,369,414

- **Contingent resources**
  - OIL (bbl): 1,962,232
  - GAS (scf): 6,946,019
  - TOTAL (boe): 8,908,251

---

**PARTNERS:**

Gulf of Thailand

- KrisEnergy 25%
- Muhabadi (operator) 79%
- Southern margin of the Pattani Basin and the northwest margin of the Malay Basin, Gulf of Thailand

**LOCATION:**

- Up to 75 metres

**WORKING INTEREST**

- **Reserves**
  - OIL (bbl): 2,092,000
  - GAS (scf): 7,078,000
  - TOTAL (boe): 9,170,000

- **Contingent resources**
  - OIL (bbl): 51,000
  - GAS (scf): 190,000
  - TOTAL (boe): 241,000

---

**PARTNERS:**

Gulf of Thailand

- KrisEnergy 25%
- Muhabadi (operator) 79%
- Location: Gulf of Thailand

**LOCATION:**

- Up to 60 metres

**WORKING INTEREST**

- **Reserves**
  - OIL (bbl): 1,400,000
  - GAS (scf): 4,000,000
  - TOTAL (boe): 5,400,000

- **Contingent resources**
  - OIL (bbl): 8,030
  - GAS (scf): 25,000
  - TOTAL (boe): 33,030

---

**PARTNERS:**

Gulf of Thailand

- KrisEnergy (operator) 30%
- Muhabadi Petroleum 30%
- Northern Gulf Petroleum 40%

**LOCATION:**

- Gulf of Thailand over the Karaweke Basin on the western margin of the Pattani Basin

**WORKING INTEREST**

- **Reserves**
  - OIL (bbl): 1,110,000
  - GAS (scf): 3,330,000
  - TOTAL (boe): 4,440,000

- **Contingent resources**
  - OIL (bbl): 3,300
  - GAS (scf): 10,000
  - TOTAL (boe): 13,300

---

Several producing oil and gas fields are located within B8/32 and B9A in the Gulf of Thailand. These fields produce from Early Miocene age channel sands. Numerous normal faults provide structural closures for hydrocarbon accumulation. It is not uncommon for an individual well to penetrate more than 10 separate reservoirs with a total of more than 200 feet of oil and gas pay in the well.

Due to the particular geology of the Gulf of Thailand, maintaining more than 200 feet of oil and gas pay in the well is critical. KrisEnergy (operator) was awarded a 15,000 barrels of oil per day (“bopd”) and 30,000 barrels of fluids per day. First oil is anticipated in the first half of 2015.

The development concept for the Nong Yao oil field comprises a wellhead platform with the export of crude oil via a floating storage and offloading (“FSO”) vessel. The production capacity will be up to 10,000 bopd from a single zone. Seven additional leads have been identified around the Niramai and Mayura discoveries, which could add as many as four further platforms with gross reserves of approximately 40 mmbo.

To date, 17 oil prospects have been identified and mapped and multiple exploration wells are planned to be drilled in 2014 and 2015.
Cambodia is yet to become an oil and gas producing country although it has multiple exploration areas under licence both offshore and onshore. Block A lies over the Khmer Basin, which is similar to other basins in the Gulf of Thailand and is characterised by an early Palaeocene phase of rifting with non-marine and lacustrine deposition followed by a Neogene thermal subsidence phase with alluvial plain sedimentation.

To date, 26 exploration wells have been drilled within the current outline of Block A, of which 23 have encountered oil and/or gas. A PPA for the development of the Apsara area within Block A was submitted to the Cambodian authorities in September 2010 and was updated in 2012. Phase one of the development of the Apsara area includes 23 development wells from a single platform producing to an FPSHORE.

INDONESIA

We hold working interests in eight contract areas in Indonesia, of which we operate seven. The single non-operated asset, the Glagah-Kambuna TAC, ceased production as anticipated on 11 July 2013 and the operator is working to relinquish the TAC, which should be finalised in 2014.

Indonesia is the leading oil and gas producing country in Southeast Asia and is one of the largest economies in the region. To date, our portfolio comprises four core areas around the archipelagos running West to East: North Sumatra (Glagah-Kambuna TAC and East Seruyaw PSC), offshore East Java (Bulu PSC, East Muriah PSC and Sakti PSC), offshore East Kalimantan (Kutai PSC and Tanjung Aru PSC), and onshore West Papua (Udan Emas PSC).

EAST JAVA CORE

The East Java Basin is dominated by two principal structural trends: a northeast-southwest extensional regime represented by horst blocks and intervening half-grabens which have been overprinted by an east-west compressional trend. The stratigraphic section comprises Eocene-Early Miocene transgressive clastics with carbonate developments on structural highs overlain with regressive clastics.

<table>
<thead>
<tr>
<th>PARTNERS:</th>
<th>KrisEnergy (operator) 42.5%</th>
<th>AWE LTD 28.5%</th>
<th>PT Satria Wijayakusuma 10.0%</th>
</tr>
</thead>
<tbody>
<tr>
<td>LOCATION:</td>
<td>East Java Sea</td>
<td></td>
<td></td>
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<tr>
<td>WATER DEPTHS:</td>
<td>50 – 60 metres</td>
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</table>

BULU PSC

DEVELOPMENT PENDING 697 sq km

Of the three separate Bulu areas – A, B and C - Bulu A and B are situated within the East Bawean Trough, whereas Bulu C occurs along the southernmost part of the northeast-southwest trending Bawean Arch and contains the Lengo-1 gas discovery.

The Lengo-2 appraisal well was drilled by the Randolph Yost jack-up rig in the first half of 2013 and was located approximately 3.3 km south of the Lengo-1 discovery well. Lengo-2 encountered producible gas within the Kujung I reservoir formation. A DST over an interval from 2,415 feet to 2,571 feet flowed 21 mmcfd with a FWHP of 487 psig with the flow rate limited by surface equipment.

Data from Lengo-2 has been integrated into the geological model and a plan of development for the Lengo gas field is anticipated to be submitted to the regulator in the first half of 2014. Concurrently, we have commenced discussions with potential offtakers of the gas.

The development concept comprises an unmanned wellhead platform with four to five well slots located with a possible single tie-back well from the Lengo gas discovery, 15 km away in the adjacent East Muriah PSC. Production is anticipated to commence in the second half 2016 with gas evacuation to market via a 65-km pipeline directly to shore.

Three additional drillable prospects and three leads have been identified and mapped using revised seismic interpretation, a new depth conversion scheme and a review of volumetric input parameters. Further technical work on these leads is ongoing.
The East Muriah PSC is adjacent to the eastern boundary of the Bulu C area. The East Lenggo 1 exploration well was drilled in 2010 and encountered gas. The well was drilled underbalanced and produced gas through the surface underbalance facilities with a continuous flare for three days although the flow rate was unmeasured.

The Sakti PSC comprises one onshore and four offshore areas in the Mahakam River delta. The block contains the Mangkiek and Dambus gas discoveries from 2001 and 2010, respectively. In June 2013, the Randolph Yost jack-up rig commenced drilling the Tayum-1 exploration well under the operatorship of KrisEnergy. The well encountered approximately 49 vertical feet of net gas pay from multiple sandstone intervals between 2,377 feet MD (7,180 feet TVDSS) and 7,366 feet MD to 7,402 feet TVDSS within the Mahakam to Pliocene section, from which two gas samples were recovered.

Further two gas samples were also recovered from what are interpreted to be shaly-sand gas pay intervals between 6,647 feet MD and 6,680 feet MD (5,576 to 5,575 feet TVDSS) and 7,366 feet MD to 7,402 feet MD (6,623 feet TVDSS to 6,646 feet TVDSS). The well was plugged as a gas discovery by MDT sampling.

A further appraisal well updp to the Mangkiek discovery is anticipated to be drilled in the second half of 2014. A plan for a gas development is being drafted and negotiations with potential buyers of the gas are underway.

The development concept would comprise three wells with individual support structures, and a pipeline to an adjacent gas facility 25 km away. First gas production is envisaged for late 2015.
ONSHORE WEST PAPUA

The Udan Emas PSC is located onshore West Papua over the Bintuni Basin, which formed during the Cenozoic. The stratigraphic section comprises Miocene and Pliocene sequences dominated by limestone and claystones. Since we became operator of the block in December 2011, we have conducted work to integrate the existing 
2D and 3D seismic interpretations, review the volumetrics of existing discoveries and undertake study of additional geophysical data. Preliminary evaluation has identified 11 gas leads in the current outline of the block, of which two – Halimun-1 and Papandayan-1 – encountered gas. We have identified and mapped 11 gas leads in the current outline of the block, of which two – Halimun-1 and Papandayan-1 – encountered gas. We have identified and mapped 11 gas leads in the current outline of the block, of which two – Halimun-1 and Papandayan-1 – encountered gas. We have identified and mapped 11 gas leads in the current outline of the block, of which two – Halimun-1 and Papandayan-1 – encountered gas. We have identified and mapped 11 gas leads in the current outline of the block, of which two – Halimun-1 and Papandayan-1 – encountered gas.

We are in the early stages of data compilation and geophysical integration and we are planning geological fieldwork and seismic data acquisition. Preliminary evaluation has identified a Mesozoic play fairway and two leads, supported by legacy seismic data. We are in the early stages of data compilation and geophysical integration and we are planning geological fieldwork and seismic data acquisition. Preliminary evaluation has identified a Mesozoic play fairway and two leads, supported by legacy seismic data. We are in the early stages of data compilation and geophysical integration and we are planning geological fieldwork and seismic data acquisition. Preliminary evaluation has identified a Mesozoic play fairway and two leads, supported by legacy seismic data.

In 2013, we began site surveys and logistics planning for a 300 km 2D seismic acquisition program due to commence around mid-2014. We are in the early stages of data compilation and geophysical integration and we are planning geological fieldwork and seismic data acquisition. Preliminary evaluation has identified a Mesozoic play fairway and two leads, supported by legacy seismic data. We are in the early stages of data compilation and geophysical integration and we are planning geological fieldwork and seismic data acquisition. Preliminary evaluation has identified a Mesozoic play fairway and two leads, supported by legacy seismic data. We are in the early stages of data compilation and geophysical integration and we are planning geological fieldwork and seismic data acquisition. Preliminary evaluation has identified a Mesozoic play fairway and two leads, supported by legacy seismic data. We are in the early stages of data compilation and geophysical integration and we are planning geological fieldwork and seismic data acquisition. Preliminary evaluation has identified a Mesozoic play fairway and two leads, supported by legacy seismic data.

In addition to the East Seruway exploration PSC, we hold a 25% non-operated working interest in the Glagah-Kambuna TAC, which contains the Kambuna gas-condensate field. Kambuna reached the end of its economic life and ceased production on 11 July 2013. The wells have been shut in and the operator is winding down the operations in preparation to relinquish the TAC.
VIETNAM

There are more than 60 contract areas under licence in Vietnam, mostly located in the southern offshore Nam Con Son Basin. KrisEnergy holds working interest in two exploration licences, Block 105 covering 7,192 sq km in shallow waters of the Song Hong Basin offshore north-central Vietnam, and Block 120 covering 8,574 sq km in moderate water depths in the northern Phu Khanh Basin, offshore central Vietnam.

Both of these licences are relatively unexplored and contain multiple large prospects. In 2013, we drilled the Cu Lo-1 exploration well in Block 105 and the Ca Ngu-1 exploration well in Block 120. Drilling operations were significantly delayed by a series of strong typhoons, which caused widespread damage across Southeast Asia and into China.

**Block 105**

**EXPLORATION**

7,192 sq km

*PARTNERS:* KrisEnergy 25%

Eni (operator) 50%

Neos Energy 25%

*LOCATION:* Central Song Hong Basin

*WATER DEPTHS:* 20-80 metres

**Block 120**

**EXPLORATION**

8,574 sq km

*PARTNERS:* KrisEnergy 25%

Eni (operator) 50%

Neos Energy 25%

*LOCATION:* South China Sea overlying Quang Ngai Graben in north- and central areas, passing into Phu Khanh Basin in the south

*WATER DEPTHS:* 50-1,100 metres

Block 105 is located at the outlet of the extensive Song Ca river system in a favourable position for the deposition of quartz-rich sand reservoirs in slope fans and basin floor fan/channel complexes. The oil play consists of stacked Early to Late Miocene fluvio-deltaic sandstone reservoirs trapped in large upthrown fault blocks along the faulted western margin of the Song Hong Basin. These fault-bounded structural closures are similar to Miocene and gas fields in the Gulf of Thailand. The gas play consisted of large structural/stratigraphic traps associated with faulted diapiric zones. All the prospects exhibit high amplitudes and favorable AVO responses from stacked fan/channel sequences within the Mi-Pliocene section.

Prior to the drilling of the Cu Lo gas prospect in 2013, there were no wells drilled to date in Block 105. The Eni Cu Lo-1 jack-up rig commenced drilling of the Cu Lo-1 exploration well on 11 August 2013. Due to an unexpected high pressure kick, the initial wellbore was plugged back from a depth of 2,531 TVDSS and sidetracked before reaching early December a total depth of 2,867 metres MD, or 2,800 metres TVDSS. Based on log interpretation, several gas-bearing sandstone reservoirs were identified. A drill stem test was conducted on a reservoir evaluated with the largest potential within the prospect. Although gas flowed during the test, poor reservoir deliverability rate combined with high carbon dioxide content suggested that development of the tested reservoir will be unlikely. The well was plugged and abandoned.

Cu Lo-1 confirmed both the trapping mechanism and the existence of a petroleum system in Block 105 and provided valuable data for deciding the future exploration strategy in the block. Additional oil and gas prospectivity exists within the block, providing opportunities for further exploration, and a thorough technical review including the data from the Cu Lo-1 well is underway in 2014.

Block 120 lies offshore central eastern Vietnam over the Quang Ngai Graben and the Tri Ton Horst. The graben connects the Song Hong and Quangbomnan basins in the north, to the Phu Khanh Basin in the south. Well penetrations in the area suggest that the pre-tertiary basement consists exclusively of granites. Rifting began in the late Eocene as the South China Sea commenced breakup and the Indochina block extruded to the southeast. Major left-lateral movement occurred along the basin bounding Red River Fracture Zone, controlling half-graben development over a wide area. Lacustrine, fluvial and shallow margin synrift sediments were deposited in the resultant elongate rift valleys in the Song Hong, Quang Ngai and Phu Khanh basins.

In 2010, 2,031 km 2D seismic data was acquired and in 2012, 2,502 sq km 3D seismic acquisition program was completed. The seismic data identified tertiary carbonate reefs, fractured granitic basement, sandstone within tilted fault blocks and structural inversion plays. Four drillable prospects were identified in addition to nine oil and gas leads, which were identified and mapped.

Only one exploration well, 120-CS-1X, had been drilled in Block 120 prior to the drilling of the Ca Ngu-1 exploration well in 2013. Well 120-CS-1X encountered a six metre oil column overlying 32 metres of oil shows and proved the existence of an active petroleum system in the block.

On 21 October 2013, the Songa Percut semi-submersible rig began drilling the Ca Ngu-1 exploration well to a water depth of approximately 270 metres. As with Block 105, drilling was delayed by a series of strong typhoons resulting in multiple evacuations of the rig as a safety precaution. The well reached a total depth of 1,280 metres MD or 1,287 metres TVDSS at the end of December 2013.

Wireline log data confirmed the presence of gas in Pliocene sandstone reservoirs, and a 15.2 metre gross hydrocarbon column within the Miocene carbonate reservoir, comprising a 10.6 metre gas column above a 4.6 metre oil rim. Although Ca Ngu-1 did not encounter significant volumes of hydrocarbons, it confirmed the existence of a petroleum system in the block and provided valuable data for analysis before the partners decide the exploration strategy going forward.
**Fiscal Terms**

The petroleum licences in which we have interests contain the terms of our concessions as agreed between the participants and the relevant host government. The economic terms of these licences, commonly known as fiscal terms, vary depending on jurisdiction.

### Bangladesh

The table below sets out the material fiscal terms of Block 9 PSC.

<table>
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<tr>
<th>BLOCK 9</th>
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<tr>
<td><strong>DMD for oil</strong></td>
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<td><strong>DMD for gas</strong></td>
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<td><strong>DMD for gas</strong></td>
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<td><strong>DMD price for gas</strong></td>
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</tr>
<tr>
<td><strong>Cost recovery limit</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Profit oil split (to contractor)</th>
<th><strong>DURING COST RECOVERY</strong></th>
<th><strong>AFTER COST RECOVERY</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Up to 10,000 bopd</td>
<td>33.0 %</td>
<td>30.0 %</td>
</tr>
<tr>
<td>Portion over 10,000 and up to 25,000 bopd</td>
<td>30.0 %</td>
<td>25.0 %</td>
</tr>
<tr>
<td>Portion over 25,000 and up to 50,000 bopd</td>
<td>25.0 %</td>
<td>20.0 %</td>
</tr>
<tr>
<td>Portion over 50,000 and up to 100,000 bopd</td>
<td>20.0 %</td>
<td>15.0 %</td>
</tr>
<tr>
<td>Portion over 100,000 bopd</td>
<td>17.0 %</td>
<td>10.0 %</td>
</tr>
</tbody>
</table>

### Cambodia

The table below sets out the material fiscal terms of Cambodia Block A.

<table>
<thead>
<tr>
<th>BLOCK A</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Royalty</strong></td>
</tr>
<tr>
<td><strong>Cost recovery petroleum</strong></td>
</tr>
<tr>
<td><strong>Allocation of remaining oil (to contractor) (average annual production)</strong></td>
</tr>
<tr>
<td><strong>Income Tax (not payable on the royalty petroleum or cost recovery petroleum)</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Profit oil split (to contractor)</th>
<th><strong>DURING COST RECOVERY</strong></th>
<th><strong>AFTER COST RECOVERY</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Up to 150 mcmcf</td>
<td>39.0 %</td>
<td>34.0 %</td>
</tr>
<tr>
<td>Portion over 150 and up to 300 mcmcf</td>
<td>34.0 %</td>
<td>27.5 %</td>
</tr>
<tr>
<td>Portion over 300 and up to 450 mcmcf</td>
<td>27.5 %</td>
<td>22.0 %</td>
</tr>
<tr>
<td>Portion over 450 and up to 600 mcmcf</td>
<td>25.0 %</td>
<td>17.5 %</td>
</tr>
<tr>
<td>Portion over 600 mcmcf</td>
<td>18.0 %</td>
<td>15.0 %</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Profit condensate/liquids (to contractor)</th>
<th><strong>DURING COST RECOVERY</strong></th>
<th><strong>AFTER COST RECOVERY</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Up to 3,000 boepd</td>
<td>35.0 %</td>
<td>30.0 %</td>
</tr>
<tr>
<td>Portion over 3,000 and up to 6,000 boepd</td>
<td>32.0 %</td>
<td>27.0 %</td>
</tr>
<tr>
<td>Portion over 6,000 and up to 10,000 boepd</td>
<td>28.0 %</td>
<td>25.0 %</td>
</tr>
<tr>
<td>Portion over 10,000 and up to 15,000 boepd</td>
<td>25.0 %</td>
<td>20.0 %</td>
</tr>
<tr>
<td>Portion over 15,000 boepd</td>
<td>20.0 %</td>
<td>15.0 %</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Production bonus payments</th>
<th><strong>GENERAL</strong></th>
<th><strong>DURING COST RECOVERY</strong></th>
<th><strong>AFTER COST RECOVERY</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Within 30 days of first commercial discovery</td>
<td>US$5 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>On</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 10,000 bopd for 30 consecutive days</td>
<td>US$1 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 20,000 bopd for 30 consecutive days</td>
<td>US$1 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 30,000 bopd for 30 consecutive days</td>
<td>US$1 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 40,000 bopd for 30 consecutive days</td>
<td>US$2 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 50,000 bopd for 30 consecutive days</td>
<td>US$2 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 100,000 bopd for 30 consecutive days</td>
<td>US$5 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 75 mcmcf for 30 consecutive days</td>
<td>US$1 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 150 mcmcf for 30 consecutive days</td>
<td>US$1 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 225 mcmcf for 30 consecutive days</td>
<td>US$1 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 300 mcmcf for 30 consecutive days</td>
<td>US$2 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 375 mcmcf for 30 consecutive days</td>
<td>US$2 million</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upon daily average of 600 mcmcf for 30 consecutive days</td>
<td>US$5 million</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Income tax | All Bangladesh income tax levied on petroleum operations are borne and discharged by Petrobangla. |
| Local participant option | None |
### Indonesia

The table below sets out the material fiscal terms of our Indonesian blocks.

<table>
<thead>
<tr>
<th>Block</th>
<th>BULU</th>
<th>EAST MURAH</th>
<th>EAST SERUYAN</th>
<th>KUTAI</th>
<th>SANTIK</th>
<th>TANJUNG ARU</th>
<th>UDAN ENA</th>
<th>KLASAG-KHAMBUJA YAC</th>
</tr>
</thead>
<tbody>
<tr>
<td>FTP (oil and gas) (as a per cent of total petroleum production)</td>
<td>10.0%</td>
<td>20.0%</td>
<td>20.0%</td>
<td>10.0%</td>
<td>20.0%</td>
<td>20.0%</td>
<td>20.0%</td>
<td>None</td>
</tr>
<tr>
<td>Effective tax rate</td>
<td>44.0%</td>
<td>44.0%</td>
<td>44.0%</td>
<td>44.0%</td>
<td>44.0%</td>
<td>44.0%</td>
<td>44.0%</td>
<td>44.0%</td>
</tr>
<tr>
<td>DMD for oil</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>None</td>
</tr>
<tr>
<td>DMD for gas</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>None</td>
</tr>
<tr>
<td>DMD price for oil (% of market price)</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>25.0%</td>
<td>15.0%</td>
<td>None</td>
</tr>
<tr>
<td>DMD price for gas (% of market price)</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Pre-tax profit oil split (to contractor)</td>
<td>35.71%</td>
<td>26.79%</td>
<td>26.79%</td>
<td>35.71%</td>
<td>41.67%</td>
<td>58.33%</td>
<td>58.33%</td>
<td>26.79%</td>
</tr>
<tr>
<td>Pre-tax profit gas split (to contractor)</td>
<td>62.5%</td>
<td>53.57%</td>
<td>53.57%</td>
<td>53.57%</td>
<td>58.33%</td>
<td>66.67%</td>
<td>66.67%</td>
<td>62.5%</td>
</tr>
<tr>
<td>Available investment credit</td>
<td>55.0%</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Production bonus payments upon cumulative production having reached:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>125 mmboe</td>
<td>US$2 million</td>
<td>US$1 million</td>
<td>US$1 million</td>
<td>US$1 million</td>
<td>US$1 million</td>
<td>US$1 million</td>
<td>US$1 million</td>
<td>None</td>
</tr>
<tr>
<td>Indonesian participation option</td>
<td>10.0%</td>
<td>10.0%</td>
<td>10.0%</td>
<td>10.0%</td>
<td>10.0%</td>
<td>10.0%</td>
<td>10.0%</td>
<td>10.0%</td>
</tr>
</tbody>
</table>

### Thailand

The table below sets out the material fiscal terms of our Thai blocks.

<table>
<thead>
<tr>
<th>Block</th>
<th>4/32, 0/44, 0/24/44 and 01/48</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty (as a per cent of the value of petroleum sold or disposed in each month)</td>
<td>12.5%</td>
</tr>
<tr>
<td>0-60,000 barrels</td>
<td>5.00%</td>
</tr>
<tr>
<td>60,001-150,000 barrels</td>
<td>6.25%</td>
</tr>
<tr>
<td>150,001-300,000 barrels</td>
<td>10.00%</td>
</tr>
<tr>
<td>300,001-600,000 barrels</td>
<td>12.50%</td>
</tr>
<tr>
<td>Over 600,000 barrels</td>
<td>15.00%</td>
</tr>
<tr>
<td>Income tax rate</td>
<td>50.0%</td>
</tr>
<tr>
<td>Annual surface reservation fee</td>
<td>50.0%</td>
</tr>
<tr>
<td>THB400.00 per sq km per year</td>
<td>None</td>
</tr>
<tr>
<td>Special remuneration benefit</td>
<td>None</td>
</tr>
<tr>
<td>Payable at the end of each fiscal year in various rates based on the profit earned during the year, up to a maximum payment of 75.0% of the profit earned.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Block</th>
<th>4/32, 0/44, 0/24/44 and 01/48</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production bonus payment</td>
<td>Fully discharged</td>
</tr>
<tr>
<td>US$500,000 payable within 30 days from the day the total production from the contract area first averages 20,000 bopd for 30 consecutive days</td>
<td></td>
</tr>
<tr>
<td>US$900,000 payable within 30 days from the day the total production from the contract area first averages 40,000 bopd for 30 consecutive days</td>
<td></td>
</tr>
<tr>
<td>US$1,000,000 payable within 30 days from the day the total production from the contract area first averages 60,000 bopd for 30 consecutive days</td>
<td></td>
</tr>
<tr>
<td>Thai participant option</td>
<td>None</td>
</tr>
</tbody>
</table>

1. Transaction for 4/32 is pending host government approval.

### Vietnam

The table below sets out the material fiscal terms of our Vietnam blocks.

<table>
<thead>
<tr>
<th>Block</th>
<th>106</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty on oil (bopd)</td>
<td>1.0%</td>
</tr>
<tr>
<td>Royalty on gas (mmcfd)</td>
<td>1.0%</td>
</tr>
<tr>
<td>Cost recovery limit</td>
<td>70.0% of gross reserves</td>
</tr>
<tr>
<td>Pre-tax profit oil split (to contractor) (bopd)</td>
<td>70.0% of gross reserves</td>
</tr>
<tr>
<td>Pre-tax profit gas split (to contractor) (mmcfd)</td>
<td>-</td>
</tr>
<tr>
<td>Income tax (months)</td>
<td>3%</td>
</tr>
<tr>
<td>Oil export Duty</td>
<td>10.0%</td>
</tr>
<tr>
<td>Production bonus payments</td>
<td>Within 30 days of first commercial discovery</td>
</tr>
<tr>
<td>Production bonus payment - Gas (mmcfd) for 30 consecutive days</td>
<td>Within 30 days of first commercial discovery</td>
</tr>
<tr>
<td>Production bonus payment - Oil (bopd) for 30 consecutive days</td>
<td>Within 30 days of first commercial discovery</td>
</tr>
<tr>
<td>PetroVietnam option</td>
<td>20.0%</td>
</tr>
</tbody>
</table>
The following table sets out certain information regarding our oil and gas assets as at 28 February 2014:

<table>
<thead>
<tr>
<th>Country/Asset Name</th>
<th>Effective Share Interest (%)</th>
<th>Status</th>
<th>Effective Date</th>
<th>Production Area</th>
<th>Exploration Period</th>
<th>Production &amp; Export Area</th>
<th>Licence Expiry Date</th>
<th>Licence Area (sq km)</th>
<th>Type of Mineral Oil on Gas Deposit</th>
<th>Licence Type</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>BANGLADESH</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Block 9</td>
<td>30.0</td>
<td>Production &amp; Development Unclarified</td>
<td>11 April 2001</td>
<td>26 August 2033</td>
<td>-</td>
<td>Bangara</td>
<td>26 August 2033</td>
<td>1,770</td>
<td>Gas / Condensate</td>
<td>PSC</td>
<td></td>
</tr>
<tr>
<td>Block 10</td>
<td>23.75</td>
<td>Development Pending &amp; Development Unclarified</td>
<td>18 March 2002</td>
<td>See Note 5</td>
<td>-</td>
<td>-</td>
<td>4,708</td>
<td>OIL PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>CAMBODIA</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Block A1</td>
<td>100.0</td>
<td>Exploration</td>
<td>13 November 2008</td>
<td>12 November 2038</td>
<td>-</td>
<td>-</td>
<td>4,406</td>
<td>OIL/BAS PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Block B</td>
<td>42.5</td>
<td>Development Pending</td>
<td>14 October 2003</td>
<td>13 October 2033</td>
<td>-</td>
<td>-</td>
<td>697</td>
<td>OIL PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>INDONESIA</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bulu</td>
<td>42.5</td>
<td>Development Pending</td>
<td>14 October 2003</td>
<td>13 October 2033</td>
<td>-</td>
<td>-</td>
<td>3,751</td>
<td>OIL PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>East Muriah</td>
<td>75.0</td>
<td>Development Pending</td>
<td>13 November 2008</td>
<td>12 November 2038</td>
<td>-</td>
<td>-</td>
<td>4,377</td>
<td>OIL PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>East Serawun</td>
<td>100.0</td>
<td>Exploration</td>
<td>13 November 2008</td>
<td>12 November 2038</td>
<td>-</td>
<td>-</td>
<td>4,406</td>
<td>OIL/Bas PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Glagah-Kambuna TAC</td>
<td>25.0</td>
<td>Production</td>
<td>17 December 1998</td>
<td>16 December 2038</td>
<td>-</td>
<td>-</td>
<td>380</td>
<td>Gas/Condensate TAC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kutai</td>
<td>54.6</td>
<td>Development Pending</td>
<td>10 January 1998</td>
<td>15 January 2037</td>
<td>-</td>
<td>-</td>
<td>1,533</td>
<td>OIL PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sakti</td>
<td>95.0</td>
<td>Exploration</td>
<td>26 February 2014</td>
<td>25 February 2044</td>
<td>-</td>
<td>-</td>
<td>4,974</td>
<td>OIL/BAS PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tanjung Aru</td>
<td>43.0</td>
<td>Development Unclarified</td>
<td>19 December 2011</td>
<td>18 December 2041</td>
<td>-</td>
<td>-</td>
<td>4,191</td>
<td>OIL PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Udan Emus</td>
<td>100.0</td>
<td>Exploration</td>
<td>20 July 2012</td>
<td>19 July 2042</td>
<td>-</td>
<td>-</td>
<td>5,396</td>
<td>OIL PSC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>THAILAND</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B8/32</td>
<td>4,6345</td>
<td>Production</td>
<td>1 August 1991</td>
<td>See Note 8</td>
<td>-</td>
<td>Tantawan South and Pakarong</td>
<td>22 August 2011</td>
<td>1,992</td>
<td>OIL/BAS</td>
<td>Tax/ Royalty</td>
<td></td>
</tr>
</tbody>
</table>

**NOTES:**

1. Each of our contract areas, with the exception of the Glagah-Kambuna TAC which will be relinquished in 2014, also holds exploration prospects and leads.
2. Resources associated with the Lematge discovery are classified as Development Unclarified.
3. The production permit for gas will be valid for 25 years with an extension period of up to five years.
4. Resources associated with Platform B within Block A are classified as Development Pending and resources associated with Platform II and Platform C within Block A are classified as Development Unclarified.
5. The Block A Petroleum Agreement shall remain in full force and effect pending the Cambodian Government’s approval of the production permit application (“PPA”) for Block A. Upon approval of the PPA, the production permit will be for 30 years from the date of first commercial production.
6. Resources associated with Platform A within Block 9 are classified as Development Pending and resources associated with Platform B are classified as Development Unclarified.
7. The agreement to farm-in to G6/48 was signed on 15 March 2013 and is pending approval from the host government.
8. Resources associated with the Bomas and Benchamas discoveries within G10/48 are classified as Development Pending and resources associated with the Moghura discovery within G10/48 are classified as Development Unclarified.
9. The development of Field within G11/48 is under development and resources associated with the Argus/Mantana discoveries within G11/48 are classified as Development Unclarified.
10. In April 2013, a Thai participant notified us of its intention to exercise its 10.5% option in G11/48. If the Thai participant’s exercise of its option is completed, we will have a remaining 22.5% interest in the contract area.
BOARD OF DIRECTORS

Will Honeybourne, 62
NON-EXECUTIVE NON-INDEPENDENT CHAIRMAN
Bachelor of Science in Oil Technology, Imperial College, University of London; Member of the Society of Petroleum Engineers; Member of the Society of Exploration Geophysicists
Date of first appointment as Director and Chairman: 5 October 2009
Length of service as a Director: 4 years 3 months
KrisEnergy Board Committee(s) served on: N
Present Directorships (as at 31 December 2013):
- KrisEnergy Ltd; Exterran Holdings, Inc.
- Other principal directorships: Barra Holdings GP Limited; First Reserve Energy Infrastructure GP Limited; First Reserve Energy Infrastructure GP II Limited; First Reserve Energy GP XIX Limited; First Reserve Energy GP XXI Limited; First Reserve Energy GP XXII Limited; FR Horizon GP Limited; FR X Offshore GP Limited; FR XI Offshore GP Limited; FR XII Alternative GP Ltd.; KrisEnergy Holdings Ltd; KrisEnergy Ltd; Petroleum Equipment Suppliers Association
Major Appointments (other than directorships): Managing Director of First Reserve
Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- Actionon Group Limited; First Reserve International Limited; FR Actionon Holdings Ltd; FR IX Offshore GP Limited; KrisEnergy Pte Ltd; Red Technology Alliance, LLC; Turbo Cayman Limited
Others: Nil

John Koh, 58
LEAD NON-EXECUTIVE INDEPENDENT DIRECTOR
Bachelor of Arts and Master of Arts, University of Cambridge, United Kingdom; Master of Laws, Harvard Law School
Date of first appointment as Director: 11 January 2013
Length of service as a Director: 1 year
KrisEnergy Board Committee(s) served on: Audit Committee (Chairman); Nominating Committee (Member); Remuneration Committee (Member)
Present Directorships (as at 31 December 2013):
- Listed Companies: KrisEnergy Ltd; NSSLimited; China Lumena New Materials Corp; Mapletree Industrial Fund Ltd; Mapletree Industrial Trust Management Ltd
- Other principal directorships: Bernard Quaritch Limited; School of the Arts, Singapore; National Library Board, Singapore; Worldwide Books Corporation
Major Appointments (other than directorships): Member of Board Trustees, The Library Fund, National Library Board, Singapore; Member of Board of Advisors, National Archives of Singapore
Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- Manda Forestry Finance Limited
- Manda Forestry Holdings Limited
Others: Former Managing Director and Senior Advisor of the Goldman Sachs Group
Former Deputy Public Prosecutor in the Singapore Attorney-General’s Chambers; Former Deputy Director of the Commercial Affairs Department in the Ministry of Finance; Former founding partner of WongPartnership

Keith Cameron, 66
EXECUTIVE DIRECTOR AND CHIEF EXECUTIVE OFFICER
Registered Chartered Accountant; Fellow of the Institute of Chartered Accountants of England and Wales; Member of the Canadian Institute of Chartered Accountants; Member of the Institute of Chartered Accountants, Alberta
Date of first appointment as Director: 5 October 2009
Length of service as a Director: 4 years 3 months
KrisEnergy Board Committee(s) served on: Nil
Present Directorships (as at 31 December 2013):
- Listed Companies: KrisEnergy Ltd.
- Other principal directorships: B Block Ltd; CKR Resources (B.V.I.) Ltd; CKR Resources Pte Ltd; EM Block Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Bangladesh S.S-11) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia) Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy (Khao Phanom Phat) Ltd; KrisEnergy (Song Hong 105) Ltd; KrisEnergy Holding Company Ltd; KrisEnergy International (Thailand) Holdings Ltd; KrisEnergy Ltd; KrisEnergy Management Ltd; KrisEnergy (Management Services) Ltd; KrisEnergy Oil & Gas (Thailand) Ltd; KrisEnergy Pte Ltd; KrisEnergy Resources (Thailand) Ltd; Punh Aircraft Ltd; KrisEnergy Development Pte Ltd
Others: Nil

Chris Gibson-Robinson, 60
EXECUTIVE DIRECTOR
Bachelor of Science and Associate Royal School of Mines Degree, Imperial College of Science and Technology, University of London; Master of Science in Marine Earth Science (Geology & Geophysics), University College of London Chartered Geologist; Chartered Scientist; Fellow of the Geological Society of London; Member of Indonesian Petroleum Association; Member of the South East Asia Petroleum Exploration Society; Member of the Geologists’ Association of United Kingdom; Member of the Petroleum Exploration Society of Great Britain
Date of first appointment as Director: 5 October 2009
Length of service as a Director: 4 years 3 months
KrisEnergy Board Committee(s) served on: Nil
Present Directorships (as at 31 December 2013):
- Listed Companies: KrisEnergy Ltd.
- Other principal directorships: B Block Ltd; CKR Resources (B.V.I.) Ltd; CKR Resources Pte Ltd; EM Block Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Bangladesh S.S-11) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia) Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy (Khao Phanom Phat) Ltd; KrisEnergy (Song Hong 105) Ltd; KrisEnergy Holding Company Ltd; KrisEnergy International (Thailand) Holdings Ltd; KrisEnergy Ltd; KrisEnergy Management Ltd; KrisEnergy (Management Services) Ltd; KrisEnergy Oil & Gas (Thailand) Ltd; KrisEnergy Pte Ltd; KrisEnergy Resources (Thailand) Ltd; Punh Aircraft Ltd; KrisEnergy Development Pte Ltd

Major Appointments (other than directorships): Nil
Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- Nil
Others: Former President and co-owner of Far East Exploration Co Ltd; Former General Manager for Premier Oil (Malaysia); Former Chief Technical Officer of Pearl Energy Ltd; Former Vice President, Operations and Vice President, New Ventures (Southeast Asia); and member of Aabar’s senior executive team after Pearl Energy Ltd was acquired by Aabar

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**BOARD OF DIRECTORS**

**Richard Lorentz, 58**

**EXECUTIVE DIRECTOR**

Bachelor of Science (Geology), Oklahoma State University; Master of Science (Geology), University of Philippines; Member of Indonesian Petroleum Association; Member of American Association of Petroleum Geologists; Member of Oklahoma Geological Society; Member of South East Asia Petroleum Exploration Society

Date of first appointment as Director: 7 May 2009
Length of service as a Director (as at 31 December 2013): 4 years
KrisEnergy Board Committee(s) served on: N/A
Present Directorships (as at 31 December 2013):
- Listed Companies: KrisEnergy Ltd.
- Other principal directorships:
  - B Block Ltd; CKR Resources (B.V.I.) Ltd; CKR Resources Pte Ltd; EM Block Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Bangladesh SS-11) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia Ltd); KrisEnergy (East Malaysia) Ltd; KrisEnergy (Kuala Lumpur) Ltd; KrisEnergy (Thailand) Ltd; KrisEnergy Ltd; KrisEnergy Resources (Thailand) Ltd; KrisEnergy Development Pte Ltd.
Major Appointments (other than directorships): N/A
Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
Franklin Offshore Holding Pte Ltd; Global Tender Barge Pte Ltd.
Others:
- Former: Manager of the New Business Development department for Elf Aquitaine; Former New Ventures & Exploration Manager for Gulf Indonesia and Senior Manager for the New Business Development department for Elf Aquitaine; Former New Ventures & Exploration Manager for Gulf Indonesia and Senior Production Geologist for Asameria (South Sumatra) Ltd; Former Senior Geologist for Oriental Petroleum and Minerals Corp; Former Senior Exploration Geologist and Exploration Manager at Park Exploration Inc; Former Senior Explorationist at Anglo-Suisse (Pakistan) Inc; Former Chief Business Development Officer and co-founder of Pearl Energy Ltd Former Vice President, New Ventures & Corporate Relations and member of Aabar’s senior executive team after Pearl Energy Ltd was acquired by Aabar

**Choo Chiau Beng, 66**

**NON-EXECUTIVE NON-INDEPENDENT DIRECTOR**

Bachelor of Science (First Class Honours), University of Newcastle upon Tyne, United Kingdom (awarded Doh Colombo Plan Scholarship to study Naval Architecture); Master of Science in Naval Architecture, University of Newcastle upon Tyne, United Kingdom; Attended the Programme for Management Development at Harvard Business School; Member of Wharton School of Fellows, University of Pennsylvania

Date of first appointment as Director: 9 July 2012
Length of service as a Director (as at 31 December 2013): 1 year 6 months
KrisEnergy Board Committee(s) served on: Remuneration Committee (Member)
Present Directorships (as at 31 December 2013):
- Listed Companies: Kappel (China) Limited; Kappel Land China Limited
- Other principal directorships:
  - Kappel Car Foundation Limited; Kappel Infrastructure Holdings Pte Ltd; Kappel Offshore & Marine Ltd

Major Appointments (other than directorships):
- Director of First Reserve Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
  - N/A
- Others:
  - Former Director in the Mangers and Acquisitions Group of Credit Suisse Authority of Singapore; Singapore Maritime Foundation Limited; Singapore Petroleum Company; Singapore Refined Oil Company; SMRT Corporation Ltd
Others:
- Confirmed the Public Service Star Award (BBM) in August 2004; Confirmed the Meritorious Service Medal in 2008; Confirmed the NTUC Medal of Commendation (Gold) Award in May 2007
  - Note: Mr. Choo ceased to be a director, with effect from 1 January 2014

**Brooks Shughart, 36**

**NON-EXECUTIVE NON-INDEPENDENT DIRECTOR**

Bachelor of Science in Architecture, University of Texas at Austin

Date of first appointment as Director: 16 October 2012
Length of service as a Director (as at 31 December 2013): 1 year 2 months
KrisEnergy Board Committee(s) served on:
- Audit Committee (Member)
- Remuneration Committee (Member)
Present Directorships (as at 31 December 2013):
- Listed Companies: KrisEnergy Ltd.
- Other principal directorships:
  - KIPC (Non-profit); KrisEnergy Holdings Ltd; Saline Oil (non-profit); Gas & Gas Holdings LLC
Major Appointments (other than directorships):
- Director of First Reserve Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
  - N/A
- Others:
  - Former Director in the Mangers and Acquisitions Group of Credit Suisse Development at Harvard

**Loh Chin Hua, 52**

**NON-EXECUTIVE NON-INDEPENDENT DIRECTOR**

Bachelor in Property Administration, Auckland University (Colombo Plan Scholarship); Presidential Key Executive MBA, Pepperdine University, California; CFA Charterholder; Registered Valuer from the New Zealand Institute of Valuers

Date of first appointment as Director: 3 July 2012
Length of service as a Director (as at 31 December 2013): 1 year 6 months
KrisEnergy Board Committee(s) served on: Remuneration Committee (Member)
Present Directorships (as at 31 December 2013):
- Listed Companies: Kappel (China) Limited; Kappel Land China Limited
- Other principal directorships:
  - Kappel Car Foundation Limited; Kappel Infrastructure Holdings Pte Ltd; Kappel Offshore & Marine Ltd

Major Appointments (other than directorships):
- Former Managing Director of Singapore’s Non-Resident Ambassador to Brazil; Energy Studies Institute (Board Member); National Research Foundation (Board Member); American Bureau of Shipping (Board & Council Member); Naffa Investment Chairman of the Board of Governors; Singapore University of Technology and Design (Member of the Board of Trustees); Assam Council on Petroleum (Council Member); Centre for Maritime Studies of the National University of Singapore (Chairman); Institute for Engineering Leadership at the National University of Singapore (Management Board Member) Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
  - k Ventures Limited; Kappel Land China Limited; Maritime and Port

Others:
- Former: Manager at Prudential Investment Management Inc.; Former Head of European Real Estate Group in London of Government of Singapore Investment Corporation
  - Note: Mr. Loh ceased to be a director of, with effect from 1 January 2014
**BOARD OF DIRECTORS**

**Duane Radtke, 65**  
NON-EXECUTIVE INDEPENDENT DIRECTOR

Bachelor Degree in Mining Engineering, University of Wisconsin  
Date of first appointment as Director: 1 September 2010  
Length of service as a Director (as at 31 December 2013): 3 years 4 months  
KrisEnergy Board Committee(s) served on:  
Audit Committee (Member); Nominating Committee (Member); Remuneration Committee (Member)  
Present Directorships (as at 31 December 2013):  
Listed Companies: Devon Energy Corporation; KrisEnergy Ltd.  
Other principal directorships: NFR Energy LLC (now Sabine Oil & Gas LLC) (Chairman)  
Major Appointments (other than directorships):  
President and Chief Executive Officer of Valiant Exploration LLC  
Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):  
Delta Energy Limited; Datta Energy Limited; Remora Energy; Stone Mountain Resources  
Others: Former Managing Director at Production Testing Services; Former Engineer and Project Manager at Conoco Inc.; Former Managing Director and Chairman at Blackwatch Petroleum Services Ltd.; Former Managing Director of Highland Energy Limited; Former Managing Director at First Reserve; Former Chief Executive of Dominion Exploration and Production

**Jeff MacDonald, 58**  
NON-EXECUTIVE INDEPENDENT DIRECTOR

Bachelor of Science (Hons) in Civil Engineering, Glasgow University  
Date of first appointment as Director: 5 October 2009  
Length of service as a Director (as at 31 December 2013): 4 years 3 months  
KrisEnergy Board Committee(s) served on:  
Audit Committee (Member); Nominating Committee (Member); Remuneration Committee (Chairman)  
Present Directorships (as at 31 December 2013):  
Listed Companies: KrisEnergy Ltd.  
Other principal directorships: Harica Hydrocarbons Ltd  
Major Appointments (other than directorships):  
Nil  
Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):  
Chandara Asri Petrochemical Sdn Bhd; SMRT Corporation Ltd; Transocean Ltd  
Others: Former Vice President (Ventures and Development) of Shell Chemicals, Asia Pacific and Middle East region (based in Singapore); Former Chairman, Shell companies in North East Asia; Former Managing Director, Shell Malaysia Exploration and Production

**Tan Ek Kia, 65**  
NON-EXECUTIVE INDEPENDENT DIRECTOR

BSc Mechanical Engineering (First Class Honours), Nottingham University, United Kingdom  
Management Development Programme, International Institute for Management Development, Lausanne, Switzerland; Fellow of the Institute of Engineers, Malaysia; Professional Engineer, Board of Engineers, Malaysia; Chartered Engineer of Engineering Council, United Kingdom; Member of Institute of Mechanical Engineer, United Kingdom  
Date of first appointment as Director: 11 January 2013  
Length of service as a Director (as at 31 December 2013): 1 year  
KrisEnergy Board Committee(s) served on:  
Audit Committee (Member); Nominating Committee (Chairman)  
Present Directorships (as at 31 December 2013):  
Listed Companies: CitySpring Infrastructure Management Pte Ltd (as Trustee-Manager of CitySpring Infrastructure Trust); Kepco Corporation Ltd; KrisEnergy Ltd.; PT Chandra Asri Petrochemical Sdn Bhd; SMRT Corporation Ltd; Transocean Ltd  
Other principal directorships:  
City Gas Pte Ltd (Chairman); Dialog Systems (Asia) Pte Ltd; Kepco Offshore and Marine Ltd; Star Energy Group Holdings Pte Ltd (Chairman); Singapore LPG Corporation Pte Ltd  
Major Appointments (other than directorships):  
Nil  
Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):  
Orchard Energy Pte Ltd; Power Seraya Ltd  
Others:  
Former Vice President (Ventures and Development) of Shell Chemicals, Asia Pacific and Middle East region (based in Singapore); Former Chairman, Shell companies in North East Asia; Former Managing Director, Shell Malaysia Exploration and Production

Note:  
1 Mr. Tan ceased to be a director of, with effect from 28 February 2014.
Kiran Raj, 41
CFO and VP Finance

Mr. Raj joined us in 2013 and is our Chief Financial Officer and Vice President, Finance. He has more than 15 years investment banking and oil & gas experience in the Asia-Pacific region.

Prior to joining our Group, Mr. Raj was a business analyst with an Australian aerospace firm from 1994 to 1996. From 1996 to 2000, he was an integral senior member of the Corporate and Business Services division of the international chartered accounting firm, Moore Stephens LLP. Mr. Raj then joined CLS-A Merchant Bankers Limited ("CLSAMB") in 2000, where he led CLSAMB’s Southeast Asian investment banking execution business and was the Director of Investment Banking and a member of the board of directors of CLSAMB, the entity regulated by the Monetary Authority of Singapore till 2007. From 2007 to 2008, he was a regional equities sales trader with CLSA Singapore Pte. Ltd.

In 2008, Mr. Raj founded, and was Chief Executive Officer of, Brighton Capital Advisors Pte Ltd, a corporate finance and advisory firm based in Singapore primarily focused on the oil and gas sector. Mr. Raj is a qualified Chartered Accountant with the Institute of Chartered Accountants in Australia and holds a Bachelor of Commerce majoring in Accounting and Finance from Monash University, Australia.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- CLS-A Merchant Bankers Limited; Brighton Capital Advisors Pte Ltd

James Parkin, 55
VP Exploration

Mr. Parkin joined us in 2009 and is the Vice President, Exploration. He has more than 30 years of experience in the oil and gas exploration and production sector, of which he has spent more than 25 years in Southeast Asia.

Mr. Parkin held the position of Regional Vice President, Southeast Asia (acting) at Pearl Energy from 2008 to 2009. Between 2003 and 2008, he was the Corporate Exploration Manager at Pearl Energy. Mr. Parkin began his career in 1979 as a Mudlogger and later as a Wellsite Geologist with Exploration Logging International. From 1986 to 1990, he worked at British Gas as their Operations Geologist. In 1995, he moved to Indonesia and worked as a Senior Geologist with Patromin Trend from 1990 to 1993.

He was a Senior Exploration Geologist in Union Texas Petroleum for the years 1993 to 1997 and at Far East Exploration Co. Ltd. from 1997 to 1998. From 1998 to 2003, he worked as Senior Geologist and then Team Leader East Java at Gulf Indonexia/ConocoPhillips. Mr. Parkin holds a Bachelor of Science (Hons) in Geology from the University of Sheffield and a Master of Science in Petroleum Geology from Imperial College of Science and Technology, University of London. He is a member of the South East Asia Petroleum Exploration Society, Indonesian Petroleum Association and the Petroleum Exploration Society of Great Britain.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- CLSAMB Merchant Bankers Limited; Brighton Capital Advisors Pte Ltd

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- Nil

Brian Helyer, 56
VP Operations

Mr. Helyer joined us on 1 March 2011 and is the Vice President, Operations and is also responsible for the writing and implementation of Environmental Health Safety and Security policy across our Group.

He has worked in the offshore oil and gas industry for over 30 years covering all aspects of project management for facilities construction, operations, maintenance and commissioning.

Prior to joining our Group in 2010, Mr. Helyer was the Project and Operations Director from 2007 to 2009 for Songa Floating Production, where he oversaw the conversion and class approval of the floating production, storage and offloading vessel, FPSO East Fortune. Between 2003 and 2007, Mr. Helyer worked for Petrofac Energy Developments in various roles such as Production Manager, Business Development Manager and Project Manager in Indonesia, Malaysia, United Kingdom and Tunisia. From 1999 until 2005, Mr. Helyer was Field Operation Manager at the Kalgoorlie oil field in the South China Sea for Gulf Indonesia. From 1993 to 1999, Mr. Helyer spent 14 years with Marathon Oil in various roles in the United Kingdom and Indonesia.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- Nil

Tim Kelly, 54
VP Engineering

Mr. Kelly joined us in 2009 and is the Vice President, Engineering. He has more than 30 years of experience in the oil industry with the last 25 years spent in Southeast Asia, during which he has been involved in the appraisal and development of new fields and the reservoir and production management of mature fields.

Mr. Kelly was Corporate Petroleum Engineering Manager with Pearl Energy from 2003 to 2009 in Singapore and was involved in projects in Indonesia, Philippines, Thailand and Vietnam. Between 1989 and 2013, Mr. Kelly was based in Jakarta as Engineering Manager with Marathon Oil, Clyde Petroleum and Gulf Indonesia, and as DST Specialist with ExxonMobil. He began his career in 1981 with Phillips Petroleum as a Drilling & Reservoir Engineer working in the United States and Singapore.

He holds a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines. Mr. Kelly is a member of the Society of Petroleum Engineers and the South East Asia Petroleum Exploration Society.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- Nil

Kelvin Tang, 39
VP Legal

Mr. Tang joined us in 2009 and is the Vice President, Legal. He is responsible for the legal and regulatory functions of our Group.

Prior to joining our Group, Mr. Tang was General Counsel for Aabar, which acquired Pearl Energy, based in Abu Dhabi between 2007 and 2009. Between 2005 and 2008, Mr. Tang was General Counsell and Company Secretary at Pearl Energy. Between 2003 and 2004, he was a Legal Associate at Wong Partnership and Clifford Chance Wong (a joint law venture between Wong Partnership LLP and Clifford Chance Pte Ltd), an Associate Director (Legal) at Temasek Holdings Pte. Ltd. In 2002 and a Legal Associate in the Technology Practice Group of Rajah & Tann LLP from 2000 to 2012.

Mr. Tang holds a Bachelor of Law from the National University of Singapore and is an Advocate and Solicitor of the Supreme Court of Singapore. He is a member of the Association of International Petroleum Negotiators.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- KrisEnergy (Ageni) B.V; KrisEnergy (Arabman Timur) B.V; KrisEnergy Asia Colperatif U.A.; KrisEnergy Asia Holdings B.V; KrisEnergy (Ninomi) B.V; KrisEnergy (Sakti) B.V; KrisEnergy (Tanjung Aria) B.V; KrisEnergy (Jihan Emais) B.V; KrisEnergy East Sarawak B.V; KrisEnergy (Slaag-Kambuna B.V; KrisEnergy (Andaman EII) B.V; KrisEnergy Kuta B.V; KrisEnergy (Bangor) B.V; Pa 80 GmbH; Pa 73 GmbH; Sotrub GmbH; Sopra GmbH; Gusta GmbH; Semax GmbH
Mr. Bujnoch joined us in 2010 in a part-time capacity and on May 1, 2011 became a full-time employee of our Group. Mr. Bujnoch is our Vice President, Drilling and has over 40 years of experience in the offshore oil and gas industry with over 30 years spent as a drilling engineer, rig site manager, or in well operations management. Mr. Bujnoch joined KrisEnergy in 2011.

Mr. Bujnoch began his career as a Meteorology/Oceanography consultant for the oil industry in 1972. In 1979, he joined Conoco Inc. (Now ConocoPhillips) as a Meteorologist/Oceanographer in the Production Engineering Services group, primarily providing project environmental design criteria, and also working on environmental issues and in-house hurricane warning services. Mr. Bujnoch worked in various roles in ConocoPhillips, including Rig Site Manager in Texas, Louisiana, and Gulf of Mexico from 1981 to 1984 and 1990 to 1995, respectively. Workover Engineer in Dubai from 1984 to 1993, Rig Site Manager in the UK North Sea from 1995 to 2000, Completion Specialist and Well Operations Coordinator in Indonesia from 2000 to 2006, and Drilling Superintendent in Qatar in 2006. From July 2006 until 2009, Mr. Bujnoch was Vice President Drilling for Pearl Oil (Thailand), where he was responsible for exploration and development drilling in Thailand and Vietnam. During this period, the company drilled more than 100 wells in the region and brought four platforms into production.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- Global Tender Barge Pte Ltd

Mr. Whibley joined us in 2009 and is the Vice President, Technical. He is a geologist with over 30 years of management, operational and interpretive experience in exploration and development projects and new business development. He has been based in Southeast Asia for more than 20 years.

Prior to joining our Group, Mr. Whibley held senior management and senior technical roles in Singapore with Pearl Energy-Aabar-Mubadala in Singapore between 2006 and 2009, and in Jakarta, Indonesia with Amerada Hess from 2003 and 2006, Santa Fe Energy-Devon Energy-PetroChina between 1998 to 2003, Santos Ltd. from 1997 to 1998, and Apache Corporation from 1993 to 1997. Prior to 1993, Mr. Whibley worked in Perth, Australia originally with Phillips Petroleum as a graduate geologist from 1980 until 1983 and later with Boll Energy Resources-Occidental Petroleum-Hudson Energy between 1983 and 1993 as a senior explorationist. Mr. Whibley holds a Bachelor of Science (Hons) in Geology from the University of Western Australia. He is a member of the Indonesian Petroleum Association and South East Asian Exploration Society.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- N/A

Mr. Clifford joined us in 2009 and is the Chief Strategy Officer and Vice President, Treasury. A Chartered Certified Accountant, Mr. Clifford has more than 20 years of experience in the oil and gas industry worldwide.

Prior to joining our Group in 2009 as Chief Financial Officer, Mr. Clifford was with Pearl Energy as Chief Financial Officer, during which he also served as Group Financial Controller for the upstream division of Pearl Energy’s parent company, Mubadala, from 2007 to 2009. From 1999 to 2007, he served in various financial management and controller roles with Halliburton Company in Europe, the Middle East, Africa, Asia and the United States. He is also a Certified Compliance Officer (2009) and holds a Bachelor of Arts in Business Studies from The Hatfield University, United Kingdom.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- Pearl Oil (Amata) Limited; Pearl Oil (Asia Thal) Limited; Pearl Oil (Petroleum) Limited; Pearl Oil (Resources) Limited; Pearl Oil Onshore Limited; Pearl Oil (Siam) Limited

Mr. Wilson joined us in 2009 and is the Vice President, Business Development. He is responsible for origination and the execution of corporate and asset acquisitions and in particular, the valuation of new business opportunities.

Prior to joining our Group, Mr. Wilson was Financial Advisor at Pearl Energy from 2003 to 2009 in Singapore, working on all aspects of fundraising and acquisition opportunity evaluation, including reserves-based lending facilities, pre-IPO private equity placements, the Pearl Energy’s initial public listing in 2005 and all key asset acquisitions. In 2002, he was a consultant with the Asian Development Bank. Between 1997 and 2003, Mr. Wilson was Assistant Vice President in the Project Finance Group with ABN AMRO focusing initially on project advisory transactions in the power sector and later moving into lending and advisory to the oil and gas sector. He began his career in Asia with Chase Manhattan Bank as a private equity analyst for Chase Capital based in Hong Kong in 1994 and 1995 and then as Assistant Vice President in the Risk Asset Management Group based in Singapore from 1995 to 1997. He holds a Master of Arts in China Studies from the Paul H. Nitze School of Advanced International Studies, The Johns Hopkins University in Washington, D.C. and a Bachelor of Arts in International Relations from The Johns Hopkins University in Baltimore, Maryland. Mr. Wilson is a member of the South East Asia Petroleum Exploration Society and the Association of International Petroleum Negotiators.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- Pansteel Pte Ltd; Cricano Pte Ltd (voluntarily wound up)

Ms. Pang initially joined us as a consultant on 1 August 2009 and became a full-time employee of the Group on 1 May 2012. Ms. Pang is the General Manager, Investor Relations & Corporate Communications and has more than 20 years of experience in journalism and media/investor relations in the energy sector.

In 2009, Ms. Pang established a consultancy providing corporate communications, marketing, public relations and editorial services to clients including KrisEnergy, Schlumberger Business Consulting, Aravak Energy, Vitol and Atlantic Energy. From 2008 to 2009, she was with Aravak Energy Ltd., a dual listed upstream company on the Toronto Stock Exchange and the London Stock Exchange, as General Manager, Investor Relations based in London, United Kingdom. Ms. Pang was with Pearl Energy from 2005 to 2008, where she was responsible for investor relations and all internal and external communications. From 1994 to 2005, she was with Reuters news agency as a journalist and worked on foreign assignments including five years as an International Correspondent in Oslo, Norway, and five years as Editor-in-Charge, Energy for Asia-Pacific based in Singapore. She began her career in 1993 as Deputy Editor on a monthly science journal before moving in 1992 to Platts, the oil price benchmarking agency.

She holds a Bachelor of Science (Hons) in Chemistry from the University of Sussex and is a member of the South East Asia Petroleum Exploration Society.
Ms. Jirapojaporn is our General Manager in Thailand. She holds an Executive MBA from Sasin Graduate Institute of Business Administration of Chulalongkorn University and started her career in 2001 as a business analyst with Thai Shell Exploration and Production. She later went on to work on contract analysis in procurement and contract management. Between 2007 and 2009, she was a business analyst for Hess Corporation with a primary focus on oil and gas assets in Thailand. Prior to joining us, she was a senior manager of group financial planning and analysis at Thoresen Thai Agencies Plc, a strategic investment holding company with three primary business groups – Transport, Energy, and Infrastructure. Ms. Jirapojaporn also holds a Master of Science in Computer Information Systems and a Bachelor in Business Administration, Finance & Banking from Assumption University.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- None

Mr. Huyen is our General Manager in Vietnam. Mr. Huyen has worked both as a geologist and a geophysicist. He has 39 years of experience, largely in Vietnam, but also in Southeast Asia, Middle East, North Africa and Russia.

His previous positions include Party Chief for seismic acquisition, Seismic Interpreter, Researcher in geophysical methodology (Vietnam Petroleum Institute), Chief Geophysicist (American Red River Co., Petroleum Supervising Company (PVSCI), New Ventures Project Manager (PVSCI), Senior Manager for Exploration & Production (Petrovietnam Exploration & Production Company, formerly Petrovietnam Investment and Development Company (PVDCC)). Prior to joining us, Mr. Huyen held the positions of Project Manager and General Manager for PVDCC-Alger Company in Algeria and for Bach Dang PDC.

Mr. Huyen has a Bachelor of Science in Geophysics from the University of Petroleum Geology in Bucharest, Romania. He was a collaborator with Moscow Geophysical Institute (1983-1984) in Seismic Stratigraphy. He is a member of the Vietnam Geophysical Association and is a Committee Member of the Vietnam Petroleum Association. He has a number of reports and published research works relating to petroleum exploration and production.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- None

Mr. Basuki is our General Manager in Indonesia. Mr. Basuki joined us in July 2010, bringing extensive local knowledge and experience in the upstream sector.

He began his career in 1987 as a Consulting Engineer at PT SUKOPINDO, a state-owned inspection, testing and certification company, and later became Vice President of the Mineral Service Division. In 2003, he joined Pearl Energy in Indonesia as General Manager until 2010.

He holds a Bachelor of Science degree in Chemical Engineering from Bandung Institute of Technology and has a MBA from the Institute Pengembangan Manajemen Indonesia. Mr. Basuki is a member of the Indonesian Petroleum Association.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- None

Mr. Bowles is our General Manager in Bangladesh. Mr. Bowles, a geologist, is an executive oil and gas industry professional with more than 35 years of experience in Malaysia, India, Pakistan, UK, Middle East, North Africa and Sub-Saharan Africa. The majority of his career has been spent with British Gas and its overseas subsidiaries. Key roles which he has held include Exploration Manager West Africa, General Manager Pakistan and Managing Director of Gujarat Gas Company, India.

In 2008, Mr. Bowles established RJ Energy, which acts as a strategic advisor for ministries, state oil companies and international oil companies, following an extensive assignment with the UK government as an advisor on oil and gas (Africa and Middle East), where he sat on several advisory energy groups such as the UK/Tunisia and UK-LIBYA associations.

Edwin holds a Bachelor of Science (Hons) in Geology from Southampton University and a Masters of Science, Geology from Imperial College of Science and Technology, University of London. He is a member of Petroleum Exploration Society of Great Britain, American Association of Petroleum Geologists and the Geological Association.

Past Principal Directorships held over the preceding 5 years (from 1 January 2009 to 31 December 2013):
- None
KrisEnergy’s management presenting at our inaugural Shareholders’ Forum on 28 February 2014.
Our Board and Management believe that a firm and genuine commitment to good corporate governance is fundamental to the sustainability of our businesses and performance, and are pleased to confirm that we have complied in all material aspects with the principles and guidelines of the Code of Corporate Governance 2012 (the “2012 Code”). Where there is any deviation, appropriate explanation has been provided within this corporate governance report. The following describes our corporate governance practices with specific reference to the 2012 Code.

**Board Conduct of Affairs**

**Principle 1**

**Board Responsibility**

Our Board directs us in the conduct of our affairs, exercising its fiduciary role in the interests of our Group as a whole. The duties of our Board also include ensuring that corporate responsibility and ethical standards of our Group are met. Our Board is accountable for the activities, strategy and governance, risk management and financial performance. Specifically, its principal functions include:

- setting our strategic direction and long-term targets and ensuring that resources are set aside to meet these targets;
- overseeing the business and affairs of our Company and instituting, with Management, strategies and financial objectives to be enforced by Management, and monitoring the performance of Management;
- approving the appointment of our Chief Executive Officer (“CEO”), Directors and succession planning process;
- overseeing a framework for evaluating adequacy of internal controls, risk management systems, financial reporting and compliance to safeguard shareholders’ interests;
- setting the values and standards (including ethical standards) of our Company;
- assuming responsibility for corporate governance; and
- considering sustainability issues of policies and proposals.

**Independent Judgment**

Our Directors are expected to exercise due diligence and independent judgment in the best interests of our Company.

**Delegation by our Board**

Our Board delegates authority to various Board Committees, namely the Audit, Nominating and Remuneration Committees, to assist it in the oversight of specific responsibilities. These Committees have been constituted with clear written terms of references (“TORs”), in compliance with the 2012 Code, which set out the duties, authority and accountabilities of each Committee. Each Committee plays a pivotal role in ensuring good corporate governance practices within our Group.

**Meetings & Attendance**

The schedule of all Board and Board Committees meetings for the next calendar year is planned well in advance, in consultation with our Directors. Our Board is to meet at least four times a year and ad hoc as warranted by particular circumstances. Further, our non-executive Directors are to attend the meetings without the presence of Management at least once a year. Telephonic attendance and conference of Board meetings are allowed under our Articles of Association (“Articles”).

Our Board and Board Committees may also make decisions by way of circulating written resolutions.

**Board Approval**

We have adopted internal guidelines which set forth matters requiring Board approval. Matters specifically reserved to our Board for approval are: (a) acquisitions and disposals of petroleum assets, (b) plan of development of petroleum assets, (c) amendment of our Group work programme and budget, and (d) all commitments to term loans and lines of credit from banks and financial institutions by our Company. While matters relating to the above require our Board’s direction and approval, Management is responsible for the day-to-day operation and administration of our Company.

**Board Induction**

A formal letter will be sent to newly-appointed Directors upon their appointment setting out their duties and responsibilities as Directors. Newly-appointed Directors shall also undergo an orientation programme which includes Management’s introduction to our business, strategic plans and objectives and governance practices, amongst others, which serves as a comprehensive and tailored induction.

**Board Training**

Our Directors are encouraged to keep abreast of the relevant topics such as directors’ duties and responsibilities, corporate governance, changes in financial reporting standards, insider trading and changes in industry-related matters. As and when available, relevant reading materials are sent to our Directors and our Directors are also kept informed of, and encouraged to attend, any appropriate and pertinent
Board Composition and Guidance

Principle 2

Board Size, Composition & Competency

The size and the composition of our Board are reviewed from time to time and at least annually by our Nominating Committee, with the aim to maintain a size which is conducive and effective for discussion and decision making, while ensuring that our Board has sufficient independent Directors. Our Nominating Committee places emphasis on our Directors having a wide array of expertise, skills and attributes, including relevant core competencies in areas such as accounting and finance, business and management, industry knowledge, strategic planning and knowledge of risk management and takes these factors into account when recommending Director appointments. Our Board, with the concurrence of our Nominating Committee, taking into account the current nature and scope of our operations, the requirements of our business, and the need to avoid undue disruptions from changes to the composition of our Board and Board Committees, considers that the current size and composition provides an appropriate balance and diversity of skills, experience and knowledge of our Company without interfering with efficient and effective decision-making. Nonetheless, our Board, together with the Nominating Committee, takes into account the Board size, composition and competency on a regular basis to cater for the evolving needs of the Company.

Board Independence

Our Nominating Committee conducts an annual review and determines whether each Director is independent, taking into account the 2012 Code definition of an “Independent” Director and guidance as to relationships the existence of which would deem a director not to be independent. In this regard, our Nominating Committee takes into consideration, among other things, whether a director has business relationships with our Company or any of its related companies, and if so, whether such relationships could interfere, or be reasonably perceived to interfere with the exercise of the Director’s independent judgment with a view to the best interests of our Company. The Directors who are considered independent by the Board (taking into account the views of the Nominating Committee) are John Koh, Duane Radtke, Jeff MacDonald and Tan Ek Kia.

Chairman and Chief Executive Officer

Principle 3

Separation of the Role of Chairman & the Chief Executive Officer

We believe that it is essential for the Board to have a Chairman and Chief Executive Officer (“CEO”) who are separate roles. This separation ensures that the Board has a Chairman who can provide strong leadership, and a CEO who is responsible for the day-to-day management of our Company. The Chairman is independent, and the CEO reports to the Board. The Board, in its role of overseeing the performance of our CEO, appoints a lead independent Director, who is responsible for chairing Board meetings in the absence of the Chairman. This separation of roles between the Chairman and CEO ensures that our Board is effective in its oversight of our Company, with the Chairman focusing on the longer-term strategic direction of our Company and the CEO responsible for the day-to-day management. Our Nominating Committee is responsible for reviewing the participation by each independent Director in any competing businesses and taking into account such matters in the re-appointment or re-election or renewal of appointment of such independent Director.

Review of Directors’ Independence

Our Nominating Committee is responsible for reviewing and recommending all nominations and re-nominations of Directors and Board Committee members, taking into account the composition and progressive renewal of our Board and each Director’s competencies, commitment, contribution and performance. Under our Articles, our Directors are required to retire at least once every three years. For this purpose, we adopt a policy of retiring one-third of our Directors from office by rotation at each Annual General Meeting (“AGM”) and these Directors will be eligible for re-election at that AGM. Our Articles also stipulate that Directors appointed by our Board during the financial year, shall only hold office until the next AGM, and thereafter be eligible for re-election at the AGM.

Alternate Directors

We do not have a practice of appointing alternate Directors.
Succession Planning for our Board & Management Team

We place emphasis on succession planning and our Nominating Committee seeks to refresh our Board membership progressively and in an orderly manner. Our Nominating Committee reviews the succession and leadership development plans for our Board and Management, which are subsequently approved by our Board.

Criteria and Process for Nomination & Selection of New Directors

In the search, evaluation and selection of new Directors, our Nominating Committee identifies the main attributes which an incoming director should have, based on the current matrix of our existing Board and the requirements of our Company. Upon our Board’s assent to the identification of the main attributes, our Nominating Committee taps on the resources of our Directors’ personal and business contacts and recommendations of candidates and goes through a shortlisting process. If candidates identified in this process are not suitable, recruitment agencies may be used. Interviews will be set up with potential candidates for our Nominating Committee members to assess them, before a decision is reached. Our Nominating Committee will then recommend the candidate for appointment to our Board.

Key Information on Directors

Please refer to the section entitled “Board of Directors” of this Annual Report for key information on our Directors. The Notice of Annual General Meeting sets out the Directors proposed for re-election and reappointment at the AGM.

Board Performance Principle 5

Board Evaluation Policy

Our Board has implemented a process for assessing its effectiveness as a whole and will implement a process to assess the contribution by each individual Director to the effectiveness of our Board and Committees, which will be carried out by our Nominating Committee. To ensure that the assessments are completed promptly, fairly and confidentially by an independent consultant (who has no other connection with our Company or any of our Directors) has been engaged by our Nominating Committee to assist in collating and analysing the feedback from our Board members.

The evaluation process will comprise questionnaires designed with the assistance of the independent consultant. The questionnaires will be developed through incorporating the best practices in the market on director, board and committee evaluations and revised based on key issues and areas which our Board wishes to focus on. Such questionnaires will be provided to our Directors for their feedback on an annual basis and the results will be collated by the independent consultant and presented to our Nominating Committee. Our Nominating Committee will then assess and discuss such evaluation results and will ascertain main components for improvement and map out the key action steps.

Board Evaluation Process

For the financial year under review, our Directors were provided a questionnaire to evaluate the effectiveness and adequacy of the performance of our Board. Our Nominating Committee discussed the results of such evaluation internally and subsequently with our Board. The results for each section of the questionnaire were above average and certain areas were highlighted for further discussion, including succession plans for key roles in our Company. A general consensus was that as our Company had only just listed, many processes are still in the nascent stages of implementation and thus more substantial and meaningful evaluation can be provided in subsequent years. Regardless, it was agreed amongst our Board that measures and practices adopted to-date are steps in the right direction.

Individual Directors & Board Committees Evaluation Process

Assessment has yet to be conducted for the performance of individual Directors and our Board Committees due to the fact that our Company was only listed on SGX-ST on 19 July 2013 and our Nominating Committee is of the view that a more meaningful evaluation can be conducted for the next financial year when the Board members have had more time and opportunity to work together. Our Nominating Committee is currently working with the independent consultant to prepare individual questionnaire assessments for our Directors and our Board Committees.

Board Performance Criteria

The performance criteria for the Board evaluation (which has been approved by the Board) includes the Board size and composition, Board independence, Board processes, Board information and accountability, risk controls and internal management, standards of conduct of the Board, all of which are in accordance with the guidelines of the 2012 Code.

Access to Information Principle 6

Complete, Adequate & Timely Information

Management recognises that the flow of complete, adequate and timely information on an ongoing basis to our Board is essential for its discharge of its duties. Board meeting agendas and Board papers are sent in advance (at least a week before Board meetings) with items proposed by Management, so that our Directors have the requisite amount of time to better understand the matters to be discussed. This enables the discussion during the meeting to focus on questions which may arise. Any additional material information requested by our Directors is promptly furnished. During Board meetings, Management personnel who are able to provide insight into the matters at hand will be joined to our Directors. Our Directors are also acquainted with the relevant Management personnel, Company Secretaries, internal and external auditors to facilitate direct and independent access to the same.

Board meeting agendas and Board papers include, amongst others, minutes to the previous Board meetings, major operational and financial updates, background or explanations on matters brought before our Board for decision or information, including issues dealt with by Management, relevant budgets, forecasts and projections. In respect of budgets, any material variance between the projections and actual results is disclosed and explained to our Board.

As part of good corporate governance, key matters requiring decisions are reserved for resolution at Board meetings or teleconferences rather than by circulation. Key analysts’ reports and relevant material information on our Group are forwarded to our Directors on an on-going basis.

Company Secretary

Our Company Secretary administers, attends and prepares minutes of Board proceedings, ensuring that Board procedures are followed and that applicable rules and regulations are complied with. The Company Secretary also attends all Board Committees meetings. Assistance is provided to our Chairman to ensure that there is good information flow within our Board and its Committees and between Management and non-executive Directors, as well as facilitate orientation and assist with professional development of our Directors as necessary. Our Company Secretary also assists our Chairman and Board to implement and strengthen corporate governance practices and processes. As primary compliance officer, our Company Secretary is responsible for advising Management to ensure that the Board and our Committees are within the guidelines and rules of the Companies Act, the SGX-ST Listing Rules and the Code. Our Company Secretary also assists our Board to ensure that the Board and its Committees are within the Code.

Remuneration Matters Principle 7

Remuneration Committee

Our Remuneration Committee is chaired by Jeff MacDonald and comprises John Koh, Brooks Shughart, Loh Chin Hua and Duane Radtke. Our Remuneration Committee comprises entirely of non-executive Directors, of which 3 out of 5 (including the Remuneration Committee Chairman) are independent.

Our Remuneration Committee is regulated by a written TOR, which includes key responsibilities such as:

- reviewing and approving our policy for determining the remuneration of its executives including that of executive Directors, CEO and other key Management personnel (“Senior Management”);
- reviewing the ongoing appropriateness and relevance of our executive remuneration policy and other benefit programmes;
- considering, reviewing and approving and/or varying the entire specific remuneration package and service contract terms for each Senior Management;
- considering and approving termination payments, retirement payments, gratuities, ex-gratia payments, severance payments and other similar payments to Board members and/or non-executive Directors; and
- reviewing our obligations arising in the event of termination of Senior Management’s contracts of service;
- reviewing and approving the design of all option plans, stock plans and/or other equity-based plans;
- determining each year whether awards will be made under each of the equity-based plans;
- reviewing and approving each award as well as the total proposed awards under each plan in accordance with the rules governing each plan;
- reviewing, approving and keeping under review performance hurdles and/or fulfilment of performance hurdles of each of the equity-based plans;
- approving and remuneration framework (including directors’ fees) for non-executive Directors; and
- reviewing succession plans for Senior Management positions.

No member of our Remuneration Committee is involved in deliberations in respect of any remuneration, compensation, options or any form of benefits to be granted to him. With regard to its responsibilities, our Remuneration Committee will review and recommend to our Board remuneration packages, annual increments, variable bonuses, performance share grants and other incentive awards or benefits. Our Remuneration Committee may seek advice from independent expert remuneration consultants on remuneration matters, if necessary. Please refer to Principle 9 “Disclosure on Remuneration” of this corporate governance report for further information on our compensation philosophy.
Remuneration of Executive Directors & Key Management Personnel

The remuneration packages of Senior Management comprise the following components:

(a) Fixed and Variable Components

The fixed component consists of basic salary and Central Provident Fund contributions (if applicable). To ensure that Senior Management’s remuneration is consistent and comparable with market practice, our Remuneration Committee will review and consider such remuneration components against those of comparable companies, if such information is publicly available, while continuing to be aware of the general correlation between increased remuneration and performance improvements.

The variable component comprises variable bonus based on our Group’s and the individual’s performance in relation to stipulated key performance indicators, as well as relevant market remuneration benchmarks. A structured assessment of the performance of Senior Management is undertaken each year, measuring their performance against such selected key performance indicators (which take into account risk policies of our Group). Bonuses payable to Senior Management are reviewed by our Remuneration Committee and approved by our Board to ensure (i) alignment of their interests with those of shareholders, (ii) symmetry with risk outcomes, and (iii) sensitivity to time horizons of risks.

Specifically, such performance bonus is designed to support our Group’s business strategy and the continual enhancement of shareholder value through the delivery of annual financial, strategy and operational objectives. On an individual level, the performance bonus will vary according to the actual achievement of our Group’s and individual performance objectives. While these objectives may differ for each executive, they are assessed on the same principles across our Group.

(b) Allowances and Benefits

Allowances and benefits provided are consistent with market practice and include medical benefits, flexible benefits and transportation and education allowance. Eligibility for these allowances and benefits will depend on individual salary grade, employment position and country of residence.

(c) Share Awards and Options

In recognition of the contribution of the Senior Management to our Company and as a tool for long term incentive, Senior Management are also eligible for share options and awards under the KrisEnergy Employee Share Option Scheme (“KrisEnergy ESOS”) and KrisEnergy Performance Share Plan (“KrisEnergy PSP”).

For the financial year under review, awards were granted under the KrisEnergy PSP at the discretion of our Remuneration Committee to Senior Management. Such share awards are conditional upon the achievement of predetermined performance targets over the performance period. These performance conditions include market capitalisation and reserves targets, which were intended to serve as incentives to Senior Management to create value for our Company and to align their interests with our Group’s business objectives. As at the end of the financial year, share awards granted under the KrisEnergy PSP have not yet vested.

For more information on the KrisEnergy ESOS and KrisEnergy PSP and the share awards granted, please refer to the sections entitled “Directors’ Report – KrisEnergy Employee Share Option Scheme and KrisEnergy Performance Share Plan” and “Notes to the Consolidated Financial Statements – Share-based Payments” of this Annual Report.

The Remuneration Committee has the discretion not to award performance bonuses or share-based incentives in any year if any executive is involved in misconduct which has a material impact on our Company.

Remuneration of Non-Executive Directors

The directors’ fees payable to our non-executive Directors are paid in cash (subject to shareholders’ approval at each AGM). Each non-executive Director is paid a basic fee and attendance fee. The Chairman of each Board Committee is paid a higher fee compared to the members of the respective committees in view of the greater responsibility carried by that office. Executive Directors are not paid Directors’ fees

Basic Fee

Our non-executive Directors’ basic fee structure is as disclosed in Table 2 below:

<table>
<thead>
<tr>
<th>Position</th>
<th>Basic Fee</th>
</tr>
</thead>
<tbody>
<tr>
<td>Board Chairman</td>
<td>$70,000 per annum</td>
</tr>
<tr>
<td>Board Member</td>
<td>$50,000 per annum</td>
</tr>
<tr>
<td>Audit Committee Chairman</td>
<td>$20,000 per annum</td>
</tr>
<tr>
<td>Nominating Committee Chairman</td>
<td>$20,000 per annum</td>
</tr>
<tr>
<td>Remuneration Committee Chairman</td>
<td>$20,000 per annum</td>
</tr>
</tbody>
</table>

If a Director occupies a position for part of the financial year, the fee payable will be prorated accordingly.

Attendance Fee

In addition, a non-executive Director will be paid an attendance fee as set out in Table 3 below for each Board meeting which he attended in that financial year and he will also be reimbursed any travel expenses incurred in relation thereto. No attendance fee is payable for attendance of (i) routine Board telephone conference calls or (ii) Board Committee meetings.

<table>
<thead>
<tr>
<th>Position</th>
<th>Attendance Fee ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Board Meeting</td>
<td>$10,000</td>
</tr>
<tr>
<td>Attendance by Travel Conference</td>
<td>$5,000</td>
</tr>
</tbody>
</table>

Share Awards & Options

Non-executive Directors are also eligible for the grant of share options and awards under the KrisEnergy ESOS and KrisEnergy PSP and are also encouraged to acquire Shares in order to align their interests with that of our shareholders. During our IPO, some of our Directors subscribed for, and were allocated reserved shares. Directors’ shareholding interests are disclosed in the section entitled “Directors’ Report – Directors’ interests in shares and debentures” of this Annual Report. For the financial year under review, non-executive Directors will not receive any Shares as part of their remuneration. However, the Remuneration Committee will review and consider the possibility of including a share-based component in the non-executive Directors’ remuneration for future years.

Disclosure on Remuneration Principle 9

Annual Remuneration Report

A breakdown showing the level and mix of each individual Director’s and Senior Management’s remuneration payable for the financial year under review is as disclosed in Tables 4 and 5 below:

<table>
<thead>
<tr>
<th>DIRECTORS</th>
<th>SALARY &amp; INCLUDES CPF, IF ANY</th>
<th>BONUS/PROFIT-SHARING</th>
<th>ALLOWANCES &amp; OTHERS</th>
<th>DIRECTORS’ FEES</th>
<th>PERFORMANCE SHARES</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>$51,000,000 TO $131,250,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Keith Cameron</td>
<td>63</td>
<td>30</td>
<td>7</td>
<td>-</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>Chris Gibson-Robinson</td>
<td>63</td>
<td>30</td>
<td>7</td>
<td>-</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>Richard Lorenz</td>
<td>64</td>
<td>29</td>
<td>7</td>
<td>-</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>BELOW $52,250,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Will Honeybourne</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>100</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>John Koh</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>100</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>Brooks Shughart</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>100</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>Ong Chiai Yong</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>100</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>Loh Choo Hua</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>100</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>Duane Radtke</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>100</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>Jeff MacDonald</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>100</td>
<td>-</td>
<td>100</td>
</tr>
<tr>
<td>Tan Eik Kua</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>100</td>
<td>-</td>
<td>100</td>
</tr>
</tbody>
</table>

NOTE:

Director’s fees for the non-executive Directors totaling US$995,000 (S$1,270,377) (2012: US$1,000,000 (S$1,252,345) is to be tabled for shareholders’ approval at the forthcoming AGM to be held on 24th April 2014.
We believe that disclosure of the precise remuneration amounts of individual Directors and Senior Management, and disclosure of the aggregate total remuneration paid to Senior Management is disadvantageous to our business interests, in view of the shortage of talented and experienced personnel in the upstream oil and gas industry.

No termination, retirement or post-employment benefits have been granted to our Directors or Senior Management.

Remuneration of Employees who are Immediate Family Members of a Director or our CEO

No employee of our Company and its subsidiaries is an immediate family member of a Director or our CEO.

Our Remuneration Committee has reviewed and approved the remuneration packages of our Directors and Senior Management, having regard to their contributions as well as the financial performance and commercial needs of our Group, and has ensured that our Directors and Senior Management are adequately but not excessively remunerated.

Details of the KrisEnergy ESOS & KrisEnergy PSP

For more information of the KrisEnergy ESOS and KrisEnergy PSP, please refer to the sections entitled “Directors’ Report – KrisEnergy Employee Share Option Scheme and KrisEnergy Employee Share Plan” and “Notes to the Consolidated Financial Statements – Share-based Payments” of this Annual Report, respectively.

Audit Committee Principle 12

Audit Committee

Our Audit Committee is chaired by John Koh and comprises Brooks Shughart, Loh Chin Hua, Duane Radtke and Tan Ek Kia. Our Audit Committee comprises entirely of non-executive Directors, of which 3 out of 5 (including the Audit Committee Chairman) are independent.

Our Audit Committee is regulated by a written TOR, which includes key responsibilities such as:

- reviewing all of the financial information and any public financial reporting with Management and external auditors for submission to our Board;
- reviewing the significant financial reporting issues and judgments so as to ensure the integrity of our financial statements and any announcements relating to our financial performance;
- reviewing together with external auditors, their audit plan, audit report, management letter and the responses which the external auditors have received from Management on difficulties which they have encountered with Management in the course of their audit;
- reviewing with external and internal auditors and reporting to our Board at least annually the adequacy and effectiveness of the internal control system, including financial, operational, compliance and information technology controls;
- reviewing with internal auditors, the program, scope of results of the internal audit and Management’s response to their findings to ensure that appropriate follow-up measures are taken;
- reviewing at least annually, the adequacy and effectiveness of the internal audit function;
- reviewing the scope and results of the external audit, and the independence and objectivity of the external auditors;
- reviewing with external auditors the impact of any new or proposed changes in accounting principles or regulatory requirements on the financial information;
- reviewing interested person transactions for potential conflicts of interest as well as all conflicts of interests to ensure that proper measures to mitigate such conflicts of interest have been put in place;
- assessing the suitability of an accounting firm as external auditors and recommending to our Board the appointment or re-appointment of such external auditors, approving their compensation and reviewing and approving their discharge;
- reviewing filings with the SGX-ST or other regulatory bodies which contain financial information and ensuring proper disclosures;
- commissioning and reviewing 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 is likely to be material;
- reviewing risk management policies and guidelines and monitoring compliance therewith;
- reviewing and approving all hedging policies and types of hedging instruments;
- reviewing whistle-blowing policies and arrangements;
- reporting to our Board the work performed by our Audit Committee in carrying out its functions;
- monitoring the investments in the customers, suppliers and competitors made by Directors, controlling shareholders and their respective associates who are involved in the management or have shareholding interests in similar or related business of our Company and making assessments on whether there are any potential conflicts of interests.

Our Audit Committee has explicit authority to investigate any matter within its TOR, with full access to and cooperation from Management and full discretion to invite any Director or Management personnel to attend its meetings, and reasonable resources to enable it to discharge its functions properly.

Our Audit Committee may also examine any other aspects of our Group’s affairs, as it deems necessary where such matters relate to exposure or risk of a regulatory or legal nature, and monitor our Group’s compliance with its legal, regulatory and contractual obligations. Our Audit Committee will meet with the external auditors and internal auditors, in each case without Management’s presence, at least once annually.

Our Board is of the view that our Audit Committee members (including our Audit Committee Chairman) have recent and relevant accounting and related financial management expertise and are familiar with our business and operations and are thus able to discharge their duties as Audit Committee members.

External Auditors

Our Audit Committee recommends to our Board the appointment, re-appointment and removal of the external auditors, the remuneration and terms of engagement of the external auditors. The re-appointment of the external auditors is always subject to shareholder approval at our AGM.

During the financial year under review, the external auditors held a meeting with our Audit Committee Chairman, without the presence of Management. Our Audit Committee reviewed the independence and objectivity of the external auditors through discussions with the external auditors as well as a review of the volume and nature of non-audit services provided by the external auditors during the financial year under review. Based on this information, our Audit Committee is satisfied that the financial, professional and business relationships between our Company and the external auditors will not prejudice their independence and objectivity. Accordingly, our Audit Committee has recommended the re-appointment of the external auditors at the coming AGM.

In the review of the financial statements for the financial year under review, our Audit Committee discussed with Management and the external auditors the accounting principles which were applied and their judgment of items that may affect the integrity of the financial statements. Following a review and a discussion, our Audit Committee recommended to our Board the release of the full year financial statements.

Accountability and Audit Principle 10

Accountability & Audit

Our Board understands its responsibility and provides a balanced and understandable assessment of our performance, position and prospects when presenting interim and other price-sensitive public reports and reports to regulators (if required). We conduct our affairs openly and transparently, and report price-sensitive public reports and reports to regulators in accordance with legislative and regulatory requirements, including key responsibilities such as:

- reviewing the significant financial reporting issues and judgments so as to ensure the integrity of our financial statements and any announcements relating to our financial performance;
- reviewing the scope and results of the external audit, and the independence and objectivity of the external auditors;
- reviewing with external auditors the impact of any new or proposed changes in accounting principles or regulatory requirements on the financial information;
- reviewing interested person transactions for potential conflicts of interest as well as all conflicts of interests to ensure that proper measures to mitigate such conflicts of interest have been put in place;
- assessing the suitability of an accounting firm as external auditors and recommending to our Board the appointment or re-appointment of such external auditors, approving their compensation and reviewing and approving their discharge;
- reviewing filings with the SGX-ST or other regulatory bodies which contain financial information and ensuring proper disclosures;
- commissioning and reviewing 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 is likely to be material;
- reviewing risk management policies and guidelines and monitoring compliance therewith;
- reviewing and approving all hedging policies and types of hedging instruments;
- reviewing whistle-blowing policies and arrangements;
- reporting to our Board the work performed by our Audit Committee in carrying out its functions;
- monitoring the investments in the customers, suppliers and competitors made by Directors, controlling shareholders and their respective associates who are involved in the management or have shareholding interests in similar or related business of our Company and making assessments on whether there are any potential conflicts of interests.

Our Audit Committee has explicit authority to investigate any matter within its TOR, with full access to and cooperation from Management and full discretion to invite any Director or Management personnel to attend its meetings, and reasonable resources to enable it to discharge its functions properly.

Our Audit Committee may also examine any other aspects of our Group’s affairs, as it deems necessary where such matters relate to exposure or risk of a regulatory or legal nature, and monitor our Group’s compliance with its legal, regulatory and contractual obligations. Our Audit Committee will meet with the external auditors and internal auditors, in each case without Management’s presence, at least once annually.

Our Board is of the view that our Audit Committee members (including our Audit Committee Chairman) have recent and relevant accounting and related financial management expertise and are familiar with our business and operations and are thus able to discharge their duties as Audit Committee members.

External Auditors

Our Audit Committee recommends to our Board the appointment, re-appointment and removal of the external auditors, the remuneration and terms of engagement of the external auditors. The re-appointment of the external auditors is always subject to shareholder approval at our AGM.

During the financial year under review, the external auditors held a meeting with our Audit Committee Chairman, without the presence of Management. Our Audit Committee reviewed the independence and objectivity of the external auditors through discussions with the external auditors as well as a review of the volume and nature of non-audit services provided by the external auditors during the financial year under review. Based on this information, our Audit Committee is satisfied that the financial, professional and business relationships between our Company and the external auditors will not prejudice their independence and objectivity. Accordingly, our Audit Committee has recommended the re-appointment of the external auditors at the coming AGM.

In the review of the financial statements for the financial year under review, our Audit Committee discussed with Management and the external auditors the accounting principles which were applied and their judgment of items that may affect the integrity of the financial statements. Following a review and a discussion, our Audit Committee recommended to our Board the release of the full year financial statements.
The total fees paid to our external auditors, Ernst & Young LLP, are as detailed in Table 6 below:

<table>
<thead>
<tr>
<th>TABLE 6</th>
<th>SYSTEM</th>
<th>% OF TOTAL AUDIT FEES</th>
</tr>
</thead>
<tbody>
<tr>
<td>EXTERNAL AUDITOR FEES FOR FINANCIAL YEAR UNDER REVIEW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Audit Fees</td>
<td>1,063</td>
<td>82</td>
</tr>
<tr>
<td>Total Non-Audit Fees</td>
<td>226</td>
<td>18</td>
</tr>
<tr>
<td>TOTAL FEES PAID</td>
<td>1,289</td>
<td>100</td>
</tr>
</tbody>
</table>

**Note:**
1. Non-audit services provided by Ernst & Young LLP Pertain to the (i) provision of financial due diligence on acquisition of Tulino Bangladesh and (ii) fee advisory services for Bangladesh Block 9 PSC tax filing.

We have complied with Rules 712 and 715 of the Listing Manual of the SGX-ST in the appointment of our auditors.

**Whistle-blowing Policy**

We have established clearly defined procedures which encourage employees, customers, third parties to report malpractices and misconduct in the workplace. Concerns about possible improprieties in matters of financial reporting, fraudulent acts and other matters in breach of company policies can be raised confidentially and arrangements are in place for investigations of such matters and for appropriate follow-up action. These procedures aim to promote fairness and consistency in dealing with concerns made in good faith.

There were no whistle-blowing reports made during the financial year under review.

**Interested Person Transactions Policy**

We have established clearly defined procedures which encourage employees, customers, third parties to report malpractices and misconduct in the workplace. Concerns about possible improprieties in matters of financial reporting, fraudulent acts and other matters in breach of company policies can be raised confidentially and arrangements are in place for investigations of such matters and for appropriate follow-up action. These procedures aim to promote fairness and consistency in dealing with concerns made in good faith.

There were no interested person transactions made during the financial year under review.

**Material Contracts (Rule 1207B) of the Listing Manual of the SGX-ST**

There were no material contracts entered into by our Company or any of its subsidiaries involving the interest of our CEO, any Director, or controlling shareholder subjecting at the end of the financial year under review.

**Risk Management and Internal Controls, Internal Audit Principles 11 & 13**

**Risk Management and Internal Controls**

Our Board recognises that it is responsible for risk governance and ensuring that Management maintains a sound system of risk management and internal controls to safeguard shareholders’ investments and our assets. Our Board appreciates that risk management is an on-going process in which Senior Management and operational managers continuously participate to evaluate, monitor and report to our Audit Committee and our Board on significant risks.

We have developed and are implementing a Board Assurance Framework which includes an enterprise risk management framework to identify significant and material risks, measure the potential impact and likelihood of those risks occurring, the internal control effectiveness and any action plans to further mitigate those risks. The risks identified include strategic, financial, operational, compliance and information technology risks. We have also developed a risk governance structure, which provides details on the roles and responsibilities for our Board and Management in risk monitoring, escalation, mitigation and reporting.

We have established risk appetite statements with tolerance limits to monitor shifts in significant risks and to proactively manage them within acceptable levels. These risk appetite statements have been reviewed and approved by our Audit Committee and our Board and will be monitored on a quarterly basis. In addition, our Board has received assurance from the CEO and CFO that our financial records have been properly maintained and give a true and fair view of our operations and finances, and that we have effective risk management and internal control systems.

Our Audit Committee, under its TOR as delegated by our Board, has the responsibility to oversee our risk management framework and policies. Any material non-compliance or failures in internal controls and recommendations for improvements will be reported to our Audit Committee. Our Audit Committee will also review the effectiveness of the actions taken by Management on the recommendations made by the external and internal auditors. Further, our Audit Committee will update the Board on such risk management framework and policies at least annually and from time to time when necessary.

Based on the internal controls established and maintained by our Group, work performed by independent external third parties, and reviews performed by and assurance from Management, various Board Committees and our Board, our Board with the concurrence of our Audit Committee is of the opinion that our Group’s system of risk management and internal controls, addressing financial, operational, compliance and information technology risks, which our Group considers relevant and material to its current business scope and environment, was adequate as at 31 December 2013. However, our Board is also aware that such a system can only provide reasonable, but not absolute, assurance that our Group will not be adversely affected by any event that could be reasonably foreseen as it strives to achieve its business objectives. Our Board also notes that no-system of internal controls and risk management can provide a complete assurance against human error, poor judgment in decision making, losses, fraud or other irregularities.

**Internal Audit**

KPMG has been appointed to act as our Group’s internal audit function (“Internal Auditor”). It is responsible for executing the Internal Audit Plan as set out by our Audit Committee and reporting the findings and recommendations of such audit to our Audit Committee on a quarterly basis. The Internal Auditor’s primary line of reporting is to the Chairman of our Audit Committee, although the function reports administratively to our executive Directors. All internal audit reports are submitted to our Audit Committee for deliberation, with copies of these reports extended to our Chairman, executive Directors (specifically the CEO) and the relevant Board Committees. The Internal Auditor’s primary line of reporting is to the Chairman of our Audit Committee, although the function reports administratively to our executive Directors. All internal audit reports are submitted to our Audit Committee for deliberation, with copies of these reports extended to our Chairman, executive Directors (specifically the CEO) and the relevant Board Committees.

**Shareholder Rights And Responsibilities**

**Principle 14**

We promote a robust corporate governance culture and awareness which encourages fair and equitable treatment of all shareholders. All shareholders enjoy rights and we endeavour to treat all our shareholders fairly and equitably. We recognise that shareholders should be entitled to equal information rights and we strive to provide adequate, timely and sufficient information pertaining to changes and updates in our business which could have a material impact on the share price and value.

Shareholders whose names are registered in the CDP Register and the Register of Members are entitled to participate in, and vote at, our general meetings. Shareholders are informed of shareholders’ meetings through notices published in the newspapers and reports or circulars sent to all shareholders. All shareholders have the opportunity to participate effectively in and vote at general meetings of shareholders and will be informed of the rules, including voting procedures, which govern general meetings of shareholders. If any shareholder is unable to attend, he is allowed to appoint up to two proxies to vote on his behalf at the meeting through proxy forms sent in advance. At shareholders’ meetings, each distinct issue is proposed as a separate resolution and the results of the votes are announced at the shareholders’ meetings.

We advocate shareholder participation and will hold our general meetings in a central location in Singapore. Shareholders will be able to proactively engage our Board and Management on our business activities and financial performance.
Communication
With Shareholders
Principle 15

We value dialogue with our shareholders and believe in regular, effective and fair communication with our shareholders. We are committed to hearing our shareholders’ views and addressing their concerns where possible. To that end, we will hold regular shareholders’ forums to educate our shareholders and also allow our shareholders an avenue to raise their queries to Management. Briefing sessions are also conducted for the media and analysts when quarterly financial results are released.

All press statements, financial results and material information is published on SGXNET and our website www.krisenergy.com, and where appropriate, through media releases on a timely basis. Our announcements and website provides contact details for investors and shareholders to submit their feedback and raise any questions.

Throughout the financial year, Management has also met up with local and foreign investors at investor meetings, participated in local and foreign investor conferences and forums. These meetings are an avenue for Management to explain our business strategy and financial performance and these meetings also provide Management with an opportunity to seek the investors and analysts’ feedback and perceptions of our Company.

As disclosed in our Prospectus, we do not have a fixed dividend policy. Taking into consideration factors including but not limited to our results of operations and cash flow, expected financial performance and working capital needs, future prospects, capital expenditures and other investment plans, other investment and growth plans, general economic and business conditions and other factors deemed relevant by our Board of Directors and statutory restrictions on the payment of dividends, we do not intend to pay dividends.

SECURITIES DEALING

Securities Transactions Policy
We have adopted a formal Securities Transactions Policy on dealings in the securities of our Company, which highlights the implications of insider trading and gives illustrative guidance on such dealing, including the prohibition on dealings with our Company’s securities on short-term considerations or in circumstances when there is possession of material non-public information. Such policy has been distributed to our Directors and officers. In compliance with the Listing Manual of the SGX-ST on best practices on dealing in securities, we also issue a note to our Directors and officers notifying them that our Company, Directors and officers must not deal in listed securities of our Company one month before the release of the full year results and two weeks before the release of quarterly results. Further, Directors and Management are expected to observe insider trading laws at all times, even when dealing in securities outside of the “black-out period” as prescribed.

Conduct Of Shareholder Meetings
Principle 16

At each AGM, our Chairman will address the shareholders and present the progress and performance of our Group. Our external auditors will also be present to address shareholders’ queries on the conduct of the audit and the preparation and content of the auditors’ report. Our Directors, chairpersons of each Board Committee, or members of the respective Committees standing in for them, will be present at each AGM and other general meetings of shareholders held by us, if any, to address shareholders’ queries. Management personnel will also be present at each AGM and other general meetings held by us, if any, to respond to any queries from shareholders.

A Company Secretary will prepare minutes of the general meetings, which will include substantial comments or queries from shareholders and the corresponding responses from our Board and Management. These minutes will be made available to shareholders upon their request.

Each item of special business included in the notice of the general meeting will be accompanied by a full explanation of the effects of a proposed resolution. Separate resolutions are proposed for substantially separate issues at such meetings. Resolutions will be put to vote by electronic poll and detailed results showing the number of votes cast for and against each resolution and their respective percentage will be announced.

The Company is not implementing absentia voting methods such as voting via mail, email or fax until security, integrity and other pertinent issues are satisfactorily resolved.
Directors’ Report

Cutting first steel for the Nong Yao oil development. Photo courtesy of Mubadala Petroleum.
Our Directors present herein their report together with the audited consolidated financial statements of the Group and balance sheet and statement of changes in equity of the Company for the financial year ended 31 December 2013.

Directors

The Directors of our Company in office at the date of this report are:

WILL HONEYBOURNE
Non-Executive Non-Independent Chairman

JOHN KOH
Lead Non-Executive Independent Director

KEITH CAMERON
Executive Director and Chief Executive Officer

CHRIS GIBSON-ROBINSON
Executive Director

RICHARD LORENTZ
Executive Director

BROOKS SHUGHART
Non-Executive Non-Independent Director

CHOO CHIAU BENG
Non-Executive Non-Independent Director

LOH CHIN HUA
Non-Executive Non-Independent Director

DUANE RADTKE
Non-Executive Independent Director

JEFF MACDONALD
Non-Executive Independent Director

TAN EK KIA
Non-Executive Independent Director

Audit Committee

Our Audit Committee comprises three independent non-executive Directors. Members of the Committee are:

JOHN KOH
Chairman

TAN EK KIA

DUANE RADTKE

BROOKS SHUGHART

LOH CHIN HUA

Our Audit Committee carried out its function in accordance with the Code of Corporate Governance, including the following:

• reviewing all of the financial information and any public financial reporting with Management and external auditors for submission to our Board;
• reviewing 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;
• reviewing together with external auditors, their audit plan, audit report, management letter and the responses which the external auditors have received from Management on difficulties which they have encountered with Management in the course of their audit;
• reviewing with external and internal auditors and reporting to our Board at least annually the adequacy and effectiveness of the 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);
• reviewing with internal auditors, the program, scope and results of the internal audit and the management’s response to their findings to ensure that appropriate follow-up measures are taken;
• reviewing at least annually, the adequacy and effectiveness of the internal audit function;
• reviewing the scope and results of the external audit, and the independence and objectivity of the external auditors;
• reviewing with external auditors the impact of any new or proposed changes in accounting principles or regulatory requirements on the financial information;
• reviewing interested person transactions for potential conflicts of interest as well as all conflicts of interests to ensure that proper measures to mitigate such conflicts of interests have been put in place;
• assessing the suitability of an accounting firm as external auditors and recommending to our Board the appointment or re-appointment of such external auditors for the coming year, approving their compensation as negotiated by the management and to review and approve their discharge;
• reviewing filings with the SGX-ST or other regulatory bodies which contain the financial information and ensure proper disclosure;
• commissioning and reviewing 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 the operating results and/or financial position;
• reviewing risk management policies and guidelines and monitoring compliance therewith;
• reviewing policy and arrangements by which the staff and any other persons may, in confidence, raise concerns about possible improprieties in matters of financial reporting or other matters and ensuring that arrangements are in place for such concerns to be raised and independently investigated, and for appropriate follow-up action to be taken;
• reviewing and approving all hedging policies and types of hedging instruments to be implemented by us, if any;
• reporting to our Board the work performed by our Audit Committee in carrying out functions;
• monitoring the investments in the 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 making assessments on whether there are any potential conflicts of interests;
• reviewing the whistle-blower arrangements instituted by our Group through which staff may in confidence, raise concerns and possible improprieties in matters of financial or other matters; and
• undertaking generally such other functions and duties as may be required by the Listing Manual and by amendments made thereto from time to time.

Our Audit Committee has recommended to our Board of Directors the nomination of Ernst & Young LLP for re-appointment as external auditors at the forthcoming Annual General Meeting of our Company.
Arrangements to enable Directors to acquire shares and debentures

Neither at the end of the financial year nor at any time during the financial year did there exist any arrangement whose object is to enable the Directors of our Company to acquire benefits by means of the acquisition of shares or debentures in our Company or any other body corporate other than the performance shares granted under the KrisEnergy Performance Share Plan ("KrisEnergy PSP").

Directors’ interest in shares and debentures

The interests of the Directors holding office at the end of the financial year in the share capital of our Company or its related corporations according to the Register of Directors’ Shareholdings kept by our Company were as follows:

<table>
<thead>
<tr>
<th>NAME OF DIRECTOR</th>
<th>HOLDINGS REGISTERED IN NAME OF DIRECTORS OR NOMINEES AS AT 31 DECEMBER 2013</th>
<th>HOLDINGS IN WHICH DIRECTORS ARE DEEMED TO HAVE AN INTEREST AS AT 1 JANUARY 2013</th>
<th>HOLDINGS IN WHICH DIRECTORS ARE DEEMED TO HAVE AN INTEREST AS AT 31 DECEMBER 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>WILL Honeybourne</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>John Koh</td>
<td>100,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Keith Cameron</td>
<td>100,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Chris Gibson-Robinson</td>
<td>114,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Richard Lorentz</td>
<td>100,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Brooks Shughart</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Choo Chiau Beng</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Loh Chin Hua</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Duane Radtke</td>
<td>-</td>
<td>-</td>
<td>1,615,008†</td>
</tr>
<tr>
<td>Jeff MacDonald</td>
<td>362,536</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Tien Ek Kia</td>
<td>100,000</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

NOTES:

(i) Keith Cameron’s deemed interests as at 31 December 2013 comprised:
(a) 4,208,216 Shares held by CKR Resources, B.V., of which he is a controlling shareholder;
(b) up to 321,208 Shares awarded to him under the KrisEnergy PSP on 13 November 2013, subject to certain performance conditions being met and other terms and conditions; and
(c) up to 321,208 Shares awarded to him under the KrisEnergy PSP on 13 November 2013, subject to certain performance conditions being met and other terms and conditions.

(ii) Chris Gibson-Robinson’s deemed interests as at 31 December 2013 comprised:
(a) 4,208,216 Shares held by CKR Resources, of which he is a controlling shareholder;
(b) up to 321,208 Shares awarded to him under the KrisEnergy PSP on the Listing Date comprising up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied, subject to certain performance conditions being met and other terms and conditions; and
(c) up to 321,208 Shares awarded to him under the KrisEnergy PSP on 13 November 2013, subject to certain performance conditions being met and other terms and conditions.

(iii) Richard Lorentz’s deemed interests as at 31 December 2013 comprised:
(a) 4,208,216 Shares held by CKR Resources, of which he is a controlling shareholder;
(b) shares awarded to him under the KrisEnergy PSP on the Listing Date comprising up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied, subject to certain performance conditions being met and other terms and conditions; and
(c) up to 321,208 Shares awarded to him under the KrisEnergy PSP on 13 November 2013, subject to certain performance conditions being met and other terms and conditions.

(iv) Duane Radtke is deemed interested in the 1,615,008 Shares held by Radtke Investments L.P. (“RILP”) as Duane Radtke and his wife are the general partners of RILP and each is able to make investment decisions for RILP. RILP is owned by Duane Radtke (2.0%) and his wife (2.0%) and their two sons (96.0%).

According to the Register of Directors’ Shareholdings kept by our Company, there were no changes to any of the above-mentioned interests between the end of the financial year and 21 January 2014.

Directors’ receipt and entitlement to contractual benefits

Since the end of the previous financial year, no Director has received or become entitled to receive a benefit by reason of a contract made by our Company or a related corporation with the Director or with a firm of which he is a member, or with a company in which he has a substantial financial interest, except as disclosed in the accompanying financial statements and in this Annual Report.

KrisEnergy Employee Share Option Scheme and KrisEnergy Performance Share Plan

Our Remuneration Committee is responsible for administering the KrisEnergy Employee Share Option Scheme ("KrisEnergy ESOS") and the KrisEnergy PSP. As at the date of this Directors’ Report, the members of our Remuneration Committee are as follows:

JEFF MACDONALD Chairman
JOHN KOH
DUANE RADTKE
BROOKS SHUGHART
LOH CHIN HUA

The KrisEnergy ESOS and KrisEnergy PSP were adopted on 10 July 2013, in conjunction with the initial public offering of our Company. The duration of these share-based incentive schemes is 10 years commencing from 10 July 2013. The KrisEnergy ESOS and KrisEnergy PSP were established with the objective of rewarding, motivating and retaining our employees and Directors to achieve better performance. Through these share-based incentive schemes, we will be able to recognise and reward past contributions and services and motivate eligible employees and Directors to continue to strive for our long-term success.

Restrictions: The aggregate number of Shares which may be issued pursuant to the options and/or awards granted under the KrisEnergy ESOS and/or the KrisEnergy PSP, when added to the number of Shares issued and/or issuable in respect of all options and awards granted under the KrisEnergy ESOS and KrisEnergy PSP, shall not exceed 15% of the total issued share capital of our Company on the day immediately preceding the date of the relevant grant.
Share awards
Participants of the KrisEnergy PSP will receive fully paid Shares free of charge, the equivalent in cash, or combinations thereof, provided that performance targets are met within a prescribed performance period.

Since the commencement of the KrisEnergy PSP to the end of the financial year under review, awards comprising an aggregate of 963,624 Shares have been granted to employees of our Company, including an aggregate of 963,624 Shares awarded to the Executive Directors of our Company. In addition, awards have been granted under the KrisEnergy PSP on the Listing Date to nine Directors and executive officers of our Company, subject to certain performance conditions being met and other terms and conditions (MS-Awards). The maximum number of Shares that may be issued under the MS-Awards is 3% of the issued share capital of the Company. Under an MS-Award, each grantee has the conditional right to receive from our Company such number of Shares (fully paid up by our Company as required by law, as to par value) as represents up to one-ninth of 3% of the issued ordinary share capital of our Company.

Share awards granted, vested and cancelled during the financial year, and share awards outstanding as at the end of the financial year, are reflected in the table below:

<table>
<thead>
<tr>
<th>DATE OF GRANT</th>
<th>SHARE AWARDS VESTED</th>
<th>SHARE AWARDS CANCELLED</th>
</tr>
</thead>
<tbody>
<tr>
<td>19 JULY 2013 (MS-AWARDS)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>DIRECTORS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Keith Cameron</td>
<td>up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied</td>
<td>-</td>
</tr>
<tr>
<td>Chris Gibson-Robinson</td>
<td>up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied</td>
<td>-</td>
</tr>
<tr>
<td>Richard Lorentz</td>
<td>up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied</td>
<td>-</td>
</tr>
<tr>
<td>Other staff</td>
<td>up to six-ninths of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied</td>
<td>-</td>
</tr>
<tr>
<td>13 NOVEMBER 2013</td>
<td></td>
<td></td>
</tr>
<tr>
<td>DIRECTORS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Keith Cameron</td>
<td>321,208</td>
<td>321,208</td>
</tr>
<tr>
<td>Chris Gibson-Robinson</td>
<td>321,208</td>
<td>321,208</td>
</tr>
<tr>
<td>Richard Lorentz</td>
<td>321,208</td>
<td>321,208</td>
</tr>
<tr>
<td>Other staff</td>
<td>4,466,065</td>
<td>4,466,065</td>
</tr>
</tbody>
</table>

Save as disclosed in the table above, no Shares have been awarded under the KrisEnergy PSP to:
(a) any other Director of our Company;
(b) any Controlling Shareholder or its associate;
(c) any director or employee of any parent company and its subsidiaries; or
(d) any participant who has received Shares pursuant to the vesting of awards granted under the KrisEnergy PSP which, in aggregate, represent 5% or more of the total number of Shares available under the KrisEnergy PSP.
INDEPENDENT AUDITOR’S REPORT

Independent auditor’s report to the members of KrisEnergy Ltd.
We have audited the accompanying consolidated financial statements of KrisEnergy Ltd. and its subsidiaries (collectively, the “Group”), which comprise the consolidated statement of financial position as at 31 December 2013 and the consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management’s responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor’s responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with International Standards on Auditing. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgement, including the assessment of the risks of material misstatement of the consolidated financial statements, 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 consolidated financial statements 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 management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Group as of 31 December 2013, and of its financial performance and cash flows for the year then ended in accordance with International Financial Reporting Standards.

Ernst & Young LLP
Public Accountants and Chartered Accountants
Singapore
18 March 2014

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR THE FINANCIAL YEAR ENDED 31 | 12 | 2013

<table>
<thead>
<tr>
<th>NOTE</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue</td>
<td>6</td>
<td>69,050,403</td>
</tr>
<tr>
<td>Cost of sales</td>
<td>6</td>
<td>(43,586,834)</td>
</tr>
<tr>
<td>Gross profit</td>
<td>6</td>
<td>25,463,569</td>
</tr>
<tr>
<td>Other income</td>
<td>6</td>
<td>16,235,154</td>
</tr>
<tr>
<td>General and administrative expenses</td>
<td>6</td>
<td>(31,736,435)</td>
</tr>
<tr>
<td>Other operating income/(expenses)</td>
<td>6</td>
<td>1,631,311</td>
</tr>
<tr>
<td>Finance income</td>
<td>6</td>
<td>1,853,888</td>
</tr>
<tr>
<td>Finance costs</td>
<td>6</td>
<td>(13,333,991)</td>
</tr>
<tr>
<td>Profit before tax</td>
<td>6</td>
<td>113,496</td>
</tr>
<tr>
<td>Tax expense</td>
<td>7</td>
<td>(2,758,629)</td>
</tr>
<tr>
<td>Loss for the year</td>
<td>7</td>
<td>(12,645,133)</td>
</tr>
<tr>
<td>Other comprehensive income</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Items that may be reclassified subsequently to profit or loss</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Exchange differences on translation of foreign operations</td>
<td>(79,567)</td>
<td>(64,809)</td>
</tr>
<tr>
<td>Total comprehensive income attributable to owners of the Company</td>
<td>(12,724,700)</td>
<td>(17,737,688)</td>
</tr>
<tr>
<td>Loss per share attributable to owners of the Company (cents per share)</td>
<td></td>
<td>(2)</td>
</tr>
</tbody>
</table>

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements.
Consolidated statement of 
FINANCIAL POSITION 

AS AT 31 | 12 | 2013

<table>
<thead>
<tr>
<th>NOTE</th>
<th>GROUP</th>
<th>2013</th>
<th>2012</th>
<th>COMPANY</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
</table>

**ASSETS**

**Non-current assets**
- Exploration and evaluation assets: 8 200,261,113 135,653,818 - -
- Oil and gas properties: 9 140,598,081 104,691,623 - -
- Other property, plant and equipment: 10 332,225 254,769 - -
- Intangible assets: 11 43,890,735 43,890,735 - -
- Embedded derivatives: 12 6,137,228 2,864,000 - -
- Investment securities: 13 182,057 182,057 - -
- Investment in subsidiaries: 14 - - 327,434,237 326,700,000
- Other receivables: 16 - - 65,000,000 -

**Total assets** 391,399,437 287,537,002 392,434,237 326,700,000

**Current assets**
- Inventories: 15 7,027,163 6,054,728 - -
- Trade and other receivables: 16 54,149,712 34,743,446 122,982 -
- Prepayments: 2,762,318 1,188,574 237,146 20,450
- Other current assets: 17 - - 500,000 -
- Cash and bank balances: 18 251,809,697 129,900,954 211,400,012 75,150,506

**Total assets** 315,748,890 172,307,702 211,760,140 75,670,956

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements.

**EQUITY AND LIABILITIES**

**Equity**
- Share capital: 19 1,307,693 1,000,000 1,307,693 1,000,000
- Share premium: 19 602,938,278 402,750,000 602,938,278 402,750,000
- Foreign currency translation reserve: 19 (1,299,652) (1,220,085) - -
- Employee share option reserve: 19 527,8 47 – 527,8 47 –
- Accumulated losses: (136,641,361) (123,996,228) (1,481,415) (1,965,586)

**Total equity** 466,832,805 278,533,687 603,292,403 401,784,414

**Non-current liabilities**
- Employee benefit liability: 23 884,691 – – –
- Loans and borrowings: 21 119,141,003 – – –
- Deferred tax liabilities: 7 41,909,685 41,744,525 – –
- Other payables: 20 – – 281,741 –

**Total liabilities** 66,535,608 144,911,223 281,741 –

**Current liabilities**
- Trade and other payables: 20 35,990,001 11,961,015 26,130 26,095
- Accrued operating expenses: 20 13,012,320 9,902,998 594,103 560,447
- Loans and borrowings: 21 119,141,003 – – –
- Provisions: 22 – 2,500,000 – –
- Withholding tax payable: 56,880 30,427 – –
- Tax payable: 5,578,710 12,005,354 – –

**Total liabilities** 240,315,522 181,311,017 901,974 586,542

**Total equity and liabilities** 707,148,327 459,844,704 604,194,377 402,370,956

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements.
## Consolidated statement of changes in equity

### FOR THE FINANCIAL YEAR ENDED 31 | 12 | 2013

<table>
<thead>
<tr>
<th>SHARE CAPITAL</th>
<th>SHARE PREMIUM</th>
<th>ACCUMULATED LOSSES</th>
<th>FOREIGN CURRENCY TRANSLATION RESERVE</th>
<th>EMPLOYEE SHARE OPTION RESERVE</th>
<th>TOTAL EQUITY</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GROUP</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Balance at 1 JANUARY 2013</td>
<td>1,000,000</td>
<td>402,750,000</td>
<td>(123,996,228)</td>
<td>(1,220,085)</td>
<td>278,533,687</td>
</tr>
<tr>
<td>Loss net of tax</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>(1,220,085)</td>
</tr>
<tr>
<td>Other comprehensive income</td>
<td>–</td>
<td>–</td>
<td>(79,567)</td>
<td>–</td>
<td>(79,567)</td>
</tr>
<tr>
<td>Total comprehensive income for the year</td>
<td>–</td>
<td>–</td>
<td>(79,567)</td>
<td>–</td>
<td>(79,567)</td>
</tr>
<tr>
<td>Grant of equity-settled share options to employees</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>527,847</td>
</tr>
<tr>
<td>Issue of shares</td>
<td>307,693</td>
<td>212,678,368</td>
<td>–</td>
<td>–</td>
<td>212,986,061</td>
</tr>
<tr>
<td>Share issuance expense</td>
<td>(12,490,090)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>(12,490,090)</td>
</tr>
<tr>
<td><strong>Balance at 31 December 2013</strong></td>
<td>1,307,693</td>
<td>602,938,278</td>
<td>(136,641,361)</td>
<td>(1,299,652)</td>
<td>466,832,805</td>
</tr>
<tr>
<td>Balance at 1 JANUARY 2012</td>
<td>1</td>
<td>(106,323,349)</td>
<td>(1,155,276)</td>
<td>–</td>
<td>(107,478,624)</td>
</tr>
<tr>
<td>Loss net of tax</td>
<td>–</td>
<td>(17,672,879)</td>
<td>–</td>
<td>–</td>
<td>(17,672,879)</td>
</tr>
<tr>
<td>Other comprehensive income</td>
<td>–</td>
<td>(64,809)</td>
<td>–</td>
<td>–</td>
<td>(64,809)</td>
</tr>
<tr>
<td>Total comprehensive income for the year</td>
<td>–</td>
<td>(64,809)</td>
<td>–</td>
<td>–</td>
<td>(64,809)</td>
</tr>
<tr>
<td>Issue of shares</td>
<td>999,999</td>
<td>402,750,000</td>
<td>–</td>
<td>–</td>
<td>403,749,999</td>
</tr>
<tr>
<td><strong>Balance at 31 December 2012</strong></td>
<td>1,000,000</td>
<td>402,750,000</td>
<td>(123,996,228)</td>
<td>(1,220,085)</td>
<td>278,533,687</td>
</tr>
<tr>
<td>Balance at 1 JANUARY 2013</td>
<td>1,000,000</td>
<td>402,750,000</td>
<td>(1965,586)</td>
<td>–</td>
<td>401,784,414</td>
</tr>
<tr>
<td>Profit net of tax</td>
<td>–</td>
<td>484,171</td>
<td>–</td>
<td>–</td>
<td>484,171</td>
</tr>
<tr>
<td>Other comprehensive income</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Total comprehensive income for the year</td>
<td>–</td>
<td>484,171</td>
<td>–</td>
<td>–</td>
<td>484,171</td>
</tr>
<tr>
<td>Grant of equity-settled share options to employees</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>527,847</td>
</tr>
<tr>
<td>Issue of shares</td>
<td>307,693</td>
<td>212,678,368</td>
<td>–</td>
<td>–</td>
<td>212,986,061</td>
</tr>
<tr>
<td>Share issuance expense</td>
<td>(12,490,090)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>(12,490,090)</td>
</tr>
<tr>
<td><strong>Balance at 31 December 2013</strong></td>
<td>1,307,693</td>
<td>602,938,278</td>
<td>(1481,415)</td>
<td>527,847</td>
<td>603,292,403</td>
</tr>
<tr>
<td>Balance at 1 JANUARY 2012</td>
<td>1</td>
<td>(23,800)</td>
<td>–</td>
<td>–</td>
<td>(23,799)</td>
</tr>
<tr>
<td>Loss net of tax</td>
<td>–</td>
<td>(1,945,786)</td>
<td>–</td>
<td>–</td>
<td>(1,945,786)</td>
</tr>
<tr>
<td>Other comprehensive income</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Total comprehensive income for the year</td>
<td>–</td>
<td>(1,945,786)</td>
<td>–</td>
<td>–</td>
<td>(1,945,786)</td>
</tr>
<tr>
<td>Issue of shares</td>
<td>999,999</td>
<td>402,750,000</td>
<td>–</td>
<td>–</td>
<td>403,749,999</td>
</tr>
<tr>
<td><strong>Balance at 31 December 2012</strong></td>
<td>1,000,000</td>
<td>402,750,000</td>
<td>(1965,586)</td>
<td>–</td>
<td>401,784,414</td>
</tr>
</tbody>
</table>

### FOR THE FINANCIAL YEAR ENDED 31 | 12 | 2013

#### Operating activities
- Profit before tax: 113,496
- Adjustment to reconcile profit before tax to net cash flows:
  - Depreciation, depletion and amortisation: 20,404,684
  - Dry hole expenses: 8
  - Decommissioning provisions: 22
  - Grant of equity-settled share options to employees: 24
- Net fair value gain on embedded derivatives: (2,284,698)
- Finance cost: 12,902,199
- Unwindings of discount on decommissioning provisions: 22
- IRS write-back of unused decommissioning provisions: (667,226)
- Interest income: (1,853,888)
- Operating cash flows before changes in working capital: 17,922,717
- Changes in working capital:
  - (Increase)/decrease in inventories: (883,084)
  - Increase in trade and other receivables: (6,458,170)
  - Decrease in other current assets: 500,000
  - Increase/(decrease) in trade and other payables: 23,896,407
- Cash flows from operations: 34,977,870
- Interest received: 1,853,888
- Interest paid: (1,568,367)
- Taxes paid: (19,019,114)
- Net cash flows from operating activities: 16,244,277

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements.
CASH FLOWS

FOR THE FINANCIAL YEAR ENDED 31 | 12 | 2013

Investing activities

<table>
<thead>
<tr>
<th>NOTE</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>USD</td>
<td>USD</td>
</tr>
<tr>
<td>Additions to exploration and evaluation assets</td>
<td>8</td>
<td>(6,607,295)</td>
</tr>
<tr>
<td>Additions to oil and gas properties</td>
<td>9</td>
<td>(13,794,344)</td>
</tr>
<tr>
<td>Expenditure on decommissioning provisions</td>
<td>22</td>
<td>(1,832,774)</td>
</tr>
<tr>
<td>Purchase of other plant and equipment</td>
<td>10</td>
<td>(427,875)</td>
</tr>
<tr>
<td>Purchase of investment securities</td>
<td>13</td>
<td>—</td>
</tr>
<tr>
<td>Acquisition of subsidiary, net of cash acquired</td>
<td>4</td>
<td>(41,396,066)</td>
</tr>
<tr>
<td>Net cash flows used in investing activities</td>
<td>(122,058,354)</td>
<td>(32,772,828)</td>
</tr>
</tbody>
</table>

Financial activities

<table>
<thead>
<tr>
<th>NOTE</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>USD</td>
<td>USD</td>
</tr>
<tr>
<td>Proceeds from issuance of shares</td>
<td>19</td>
<td>212,986,061</td>
</tr>
<tr>
<td>Proceeds from issuance of bonds</td>
<td>21</td>
<td>36,750,000</td>
</tr>
<tr>
<td>Share issuance expense</td>
<td>19</td>
<td>(12,490,090)</td>
</tr>
<tr>
<td>Payment of bond interest</td>
<td>(9,445,625)</td>
<td>(8,925,000)</td>
</tr>
<tr>
<td>Decrease in amount due to holding company</td>
<td>—</td>
<td>(756,969)</td>
</tr>
<tr>
<td>Decrease in restricted cash</td>
<td>4,000,000</td>
<td>—</td>
</tr>
<tr>
<td>Net cash flows from financial activities</td>
<td>231,800,346</td>
<td>105,318,031</td>
</tr>
</tbody>
</table>

Net increase in cash and cash equivalents | 129,986,269 | 87,324,637 |

Net effect of exchange rate changes | (77,526) | (83,383) |

Cash and cash equivalents at 1 January | 121,900,954 | 34,659,700 |

Cash and cash equivalents at 31 December | 247,809,697 | 121,900,954 |

NOTE: The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements.

Corporate information

KrisEnergy Ltd. (the "Company") was incorporated on 5 October 2009 as a limited liability company in Cayman Islands.

The registered office of the Company is located at 190 Elgin Avenue, George Town, Grand Cayman KY1-8005, Cayman Islands.

The principal activity of the Company is that of investment holding. The principal activities of the subsidiaries and joint arrangements are disclosed in Note 14 to the consolidated financial statements.

Summary of significant accounting policies

2.1 Basis of preparation

The consolidated financial statements of the Company and its subsidiaries, (collectively the "Group") have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements have been prepared on a historical cost basis except as disclosed in the accounting policies below. The consolidated financial statements are presented in United States Dollars ("USD" or "US$").

2.2 Basis of consolidation

The consolidated financial statements comprise the financial statements of the Company and its subsidiaries as at 31 December 2013. The financial statements of the subsidiaries used in the preparation of the consolidated financial statements are prepared for the same reporting date as the Company. Consistent accounting policies are applied to like transactions and events in similar circumstances.

All intra-group balances, income and expenses and unrealised gains and losses resulting from intra-group transactions and dividends are eliminated in full.

Subsidiaries are consolidated from the date of acquisition, being the date on which the Group obtains control, and continue to be consolidated until the date when such control ceases.

Where the ownership of a subsidiary is less than 100% and, therefore, a non-controlling interest ("NCI") exists, losses within a subsidiary are attributed to the NCI even if that results in a deficit balance.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction. If the Group loses control over a subsidiary, it:

- Derecognises the assets (including goodwill) and liabilities of the subsidiary at their carrying amounts as at the date when control is lost
- Derecognises the carrying amount of any NCI
- Derecognises the cumulative translation differences recognised in equity
- Recognises the fair value of the consideration received
- Recognises the fair value of any investment retained
- Recognises any surplus or deficit in profit or loss
- Reclassifies the parent’s share of components previously recognised in other comprehensive income to profit or loss or retained earnings, as appropriate.

2.3 Changes in accounting policy and disclosures

Changes in accounting policies

The accounting policies adopted are consistent with those of the previous financial year except in the current financial year, the Group has adopted all the new and revised standards which are effective for annual financial periods beginning on or after 1 January 2013. The adoption of these standards did not have any effect on the financial performance or position of the Group.

On 1 January 2012, the Group early adopted IFRS 11, IFRS 12 and the consequential amendments to Revised IAS 27 and Revised IAS 28 which are effective for annual financial periods beginning on or after 1 January 2013.

2.4 Standards issued but not yet effective

The Group has not adopted the following standards and interpretations that have been issued but not yet effective:

<table>
<thead>
<tr>
<th>DESCRIPTION</th>
<th>EFFECTIVE FOR ANNUAL PERIODS BEGINNING ON OR AFTER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amendments to IAS 32 (Revaluing Financial Assets and Financial Liabilities)</td>
<td>1 January 2014</td>
</tr>
<tr>
<td>Amendments to IAS 36 (Recoverable Amount Disclosures for Non-financial Assets)</td>
<td>1 January 2014</td>
</tr>
<tr>
<td>IFRS 9 Financial Instruments: Classification and Measurement</td>
<td>To be determined</td>
</tr>
</tbody>
</table>

The directors expect that the adoption of the standards above will have no material impact on the financial statements in the period of initial application.
2.5 Business combination and goodwill

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate consideration transferred, measured at acquisition date fair value and the separation of any NCI in the acquiree. For each business combination, the Group elects whether it measures NCI in the acquiree at fair value or at the acquisition date fair value and the portion of the Group’s cash generated units (“CGUs”) that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units. Where goodwill forms part of a CGU and part of the operation in that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill disposed in these circumstances is measured based on the relative values of the disposed operation and the portion of the CGU retained.

2.6 Joint arrangements

A joint arrangement is a contractual arrangement whereby two or more parties to the arrangement share control, joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

A joint arrangement is classified either as joint operation or joint venture, based on the rights and obligations of the parties to the arrangement.

To the extent the joint arrangement provides the Group with rights to the assets and obligations for the liabilities relating to the arrangement, the arrangement is a joint operation. To the extent the joint arrangement provides the Group with rights to the net assets of the arrangement, the arrangement is a joint venture.

The Group reassesses whether the type of joint arrangement in which it is involved has changed when facts and circumstances change.

Joint operations/party to joint arrangements

The Group recognises in relation to its interest in a joint operation/party to joint arrangements:
• its assets, including its share of any assets held jointly;
• its liabilities, including its share of any liabilities incurred jointly;
• its revenue from the sale of its share of the output arising from the joint operation;
• its share of the revenue from the sale of the output by the joint operation; and
• its expenses, including its share of any expenses incurred jointly.

The Group accounts for the assets, liabilities, revenues and expenses relating to its interest in a joint operation in accordance with the accounting policies applicable to the particular assets, liabilities, revenues and expenses.

When the Group enters into transaction involving a sale or contribution of assets with a joint operation in which it is a joint operator, the Group recognises gains and losses resulting from such a transaction only to the extent of the interests held by the other parties to the joint operation.

When the Group enters into a transaction involving purchase of assets with a joint operation in which it is a joint operator, the Group does not recognise its share of the gains and losses until it resells those assets to a third party. When such transactions provide evidence of a reduction in the net realisable value of the assets to be purchased or of an impairment loss of those assets, the Group recognises its share of those losses.

2.7 Foreign currency

The Group’s consolidated financial statements are presented in USD, which is also the Company’s functional currency. Each entity in the Group determines its own functional currency and items included in the financial statements of each entity are measured using that functional currency.

(i) Transactions and balances

Transactions in foreign currencies are initially recorded by the Group’s entities at their respective currency spot rate at the date of the transaction.

Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency spot rate of exchange ruling at the reporting date.

Non-monetary items that are measured at historical cost in a foreign currency are translated using the exchange rates as at the date of the initial transaction. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined.

Exchange differences arising on the settlement of monetary items or on translating monetary items at the end of the reporting period are recognised in profit or loss except for exchange differences arising on monetary items that form part of the Group’s net investment in foreign operations, which are recognised initially in other comprehensive income and accumulated under foreign currency translation reserve in equity. The foreign currency translation reserve is reclassified from equity to profit or loss of the Group on disposal of the foreign operation.

(ii) Group companies

On consolidation, the assets and liabilities of foreign operations are translated into USD at the rate of exchange prevailing at the reporting date and their profit or loss are translated at exchange rates prevailing at the date of the group’s net investment in foreign operations.\n
Exchange differences arising on consolidation purposes are recognised in other comprehensive income. On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss.

In the case of a partial disposal without loss of control of a subsidiary that includes a foreign operation, the proportionate share of the cumulative amount of the exchange differences are reattributed to non-controlling interest and are not recognised in profit or loss. For partial disposals of associated or jointly controlled entities that are foreign operations, the proportionate share of the accumulated exchange differences are reclassified to profit or loss.

2.8 Oil and natural gas exploration, evaluation and development expenditure

Oil and natural gas exploration, evaluation and development expenditure is accounted for using the successful efforts method of accounting.

Pre-licence costs

Pre-licence costs are expensed in the period in which they are incurred.

Licence and property acquisition costs

Exploration and licence and leasehold property acquisition costs are capitalised in intangible assets.

Licence costs paid in connection with a right to explore in an existing exploration area are capitalised and amortised over the term of the permit.

Licence and property acquisition costs are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned, or that it has been determined, or work is under way to determine that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing.

If no future activity is planned or the licence has been relinquished or has expired, the carrying value of the licence and property acquisition costs is written off through profit or loss. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to oil and gas properties.

Exploration and evaluation costs

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource.

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalised as exploration and evaluation intangible assets until the drilling of the well is completed. Once the results have been evaluated. These costs include directly attributable employee remuneration, materials and fuel used, rig costs and payments made to contractors.

If no potentially commercial hydrocarbons are discovered, the exploration asset is written off through profit or loss as a dry hole. If extractable hydrocarbons were found and, subject to further appraisal activity (e.g. the drilling of additional wells), it is probable they can be commercially developed, the costs continue to be capitalised as an intangible asset while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons. Costs directly associated with appraisal activity are capitalised in the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalised as an intangible asset.
All such capitalised costs are subject to technical, commercial and management review, as well as review for indicators of impairment at least once a year. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this no longer is the case, the costs are written off through profit or loss.

When proved reserves of oil and natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and if required any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties. Other than licence costs, no amortisation is charged during the exploration and evaluation phase.

Farm-outs – in the exploration and evaluation phase
The Group does not record any expenditure made by the farmee on its account. It also does not recognise any gain or loss on its exploration and evaluation farm-out arrangements, but redesignates any costs previously capitalised in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal.

Development costs
Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalised within oil and gas properties.

2.9 Oil and gas properties and other property, plant and equipment

Initial recognition
Oil and gas properties and other property, plant and equipment are stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and for qualifying assets (where relevant), borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalised value of a finance lease is also included within property, plant and equipment.

When a development project moves into the production stage, the capitalization of certain construction/development costs ceases and costs are either regarded as part of the cost of inventory or, if applicable, except for costs qualifying for capitalization relating to oil and gas property assets addition, improvements or new developments.

Depreciaiton, depletion and amortisation
Oil and gas properties are depreciated, depleted and amortised on a unit-of-production basis over the total proved developed and undeveloped reserves of the field concerned. Rights and concessions are depleted on the unit-of-productions basis over the relevant area. The unit-of-production rate calculation for the depreciation, depletion and amortisation of field development costs takes into account expenditures incurred to date, together with sanctioned future development expenditure.

Other property, plant and equipment are generally depreciated on a straight-line basis over their estimated useful lives which are as follows:

- Renovation: 3 years
- Furniture and fittings: 3 years
- Office equipment: 3 years
- Computers: 2 years

An item of property, plant and equipment and any significant part initially recognised is derecognised upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in profit or loss when the asset is derecognised.

The asset’s residual values, useful lives and methods of depreciation, depletion and amortisation are reviewed at each reporting period, and adjusted prospectively, if appropriate.

Farm-outs – outside the exploration and evaluation phase
In accounting for a farm-out arrangement outside the exploration and evaluation phase, the Group:

- Derecognises the proportion of the asset that it has sold to the farmee
- Recognises the consideration received or receivable from the farmee, which represents the cash received and/or the farmee’s obligation to fund the capital expenditure in relation to the interest retained by the farmor
- Recognises a gain or loss on the transaction for the difference between the net disposal proceeds and the carrying amount of the asset disposed of. A gain is only recognised when the value of the consideration can be determined reliably. If not, then the Group accounts for the consideration received as a reduction in the carrying amount of the underlying assets.
- Tests the retained interests for impairment if the terms of the arrangement indicate that the retained interest may be impaired.

The consideration receivable on disposal of an item of property, plant and equipment or an intangible asset is recognised initially at its fair value by the Group. However, if payment for farmouts is deferred, the consideration received is recognised initially at the cash price equivalent.

The difference between the nominal amount of the consideration and the cash price equivalent is recognised as interest revenue. Any part of the consideration that is receivable in the form of cash is treated as a definition of a financial asset and is accounted for at amortised cost.

Major maintenance, inspection and repairs
Expenditure on major maintenance re-fits, inspections or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset, that was separately depreciated and is now written off, is replaced and it is probable that future economic benefits associated with the item will flow to the Group, the expenditure is capitalised. When part of the asset replaced was not separately considered as a component and therefore not depreciated separately, the replacement value is used to estimate the carrying amount of the replaced asset(s) which is immediately written off. Inspection costs associated with major maintenance programmes are capitalised and amortised over the period to the next inspection. All other day-to-day repairs and maintenance costs are expensed as incurred.

2.10 Intangible assets
Intangible assets acquired separately are measured on initial recognition at cost. The cost of intangible assets acquired in a business combination is their fair value at the date of acquisition. Following initial recognition, intangible assets are carried at cost less any accumulated amortisation (calculated on a straight-line basis over their useful lives) and any accumulated impairment losses, if any.

Internally generated intangible assets, excluding capitalised development costs, are not capitalised. Instead, the related expenditure is recognised in profit or loss in the year in which the expenditure is incurred.

The useful lives of intangible assets are assessed as either finite or indefinite.

Intangible assets with finite lives are amortised over the useful economic life and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortisation period and the amortisation method for an intangible asset with a finite useful life is reviewed at least at the end of each reporting period. Changes in the expected useful life or the expected pattern of consumption of future economic benefits embodied in the asset are considered to modify the amortisation period or method, as appropriate, and are treated as changes in accounting estimates. The amortisation expense on intangible assets with finite lives is recognised in profit or loss in the expense category consistent with the function of the intangible assets.

Intangible assets with indefinite useful lives are not amortised, but are tested for impairment annually, either individually or as part of the CGU level. The assessment of indefinite life is reviewed annually to determine whether the indefinite life continues to be supportable. If not, the impairment test is reversed only if there has been a change in the assumptions used to

Gains or losses arising from derecognition of an intangible asset are measured as the difference between the net disposal proceeds and the carrying amount of the asset and are recognised in profit or loss when the asset is derecognised.

2.11 Impairment of non-financial assets

Assets (excluding goodwill and indefinite life intangibles)
The Group assesses at each reporting date whether there is an indication that an asset or CGU may be impaired. Management has assessed that the value-in-use of each individual asset, which is the lowest level for which cash inflows are largely independent of those of other assets, may be impaired. If any indication exists, or when annual impairment testing for an asset is required by the Group the estimates the asset’s or CGU’s recoverable amount. The recoverable amount is the higher of an asset’s or CGU’s fair value less costs to sell (“FVLS”) and value in use (“VII”). The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, in which case, the asset is tested as part of a larger CGU to which it belongs. Where the carrying amount of an asset or CGU exceeds its recoverable amount, the asset/CGU is considered impaired and is written down to its recoverable amount.

The Group bases its impairment calculation on detailed budgets and forecasts which are prepared separately for each of the Group’s CGUs to which the individual assets are allocated. These budgets and forecasts generally cover the term of the contract area.

VII does not reflect future cash flows associated with improving or enhancing an asset’s performance, whereas anticipated enhancements to assets are included in FVLS calculations.

In calculating VII, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset/CGU. In determining FVLS, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model is used. These calculations are corroborated by valuation multiples or other available fair value indicators.

Impairment losses are recognised in profit or loss in those expense categories consistent with the function of the impaired asset, except for property previously revalued where the revaluation was taken to other comprehensive income. For such properties, the impairment is also recognised in other comprehensive income up to the amount of any previous revaluation.

For assets/CGUs excluding goodwill, an assessment is made at each reporting date to determine whether there is an indication that previously recognised impairment losses may have been reversed or decreased. If such indication exists, the Group estimates the asset’s or CGU’s recoverable amount. A previously recognised impairment loss is reversed only if there has been a change in the assumptions used to
determine the asset’s/CGU’s recoverable amount since the last impairment loss was recognised. The reversal is limited so that the carrying amount of the asset/CGU does not exceed its recoverable amount or exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset/CGU in prior years. Such reversal is recognised in profit or loss unless the asset is carried at a revalued amount, in which case, the reversal is treated as a revaluation increase.

Goodwill

Goodwill is tested for impairment annually (at 31 December) and when circumstances indicate that the carrying value may be impaired.

Impairment is determined for goodwill by assessing the recoverable amount of the CGU or group of CGUs to which the goodwill relates. Where the recoverable amount of the CGU is less than its carrying amount including goodwill, an impairment loss is recognised. Impairment losses relating to goodwill cannot be reversed in future periods.

Intangible assets with indefinite useful lives

Intangible assets with indefinite useful lives are tested for impairment annually (at 31 December) at the CGU level, as appropriate, and when circumstances indicate that the carrying value may be impaired.

2.12 Financial instruments – initial recognition and subsequent measurement

2.12.1 Financial assets

Initial recognition and measurement

Financial assets are classified, at initial recognition, as financial assets at fair value through profit or loss, loans and receivables, held-to-maturity investments, available-for-sale financial assets, or derivatives designated as hedging instruments in an effective hedge, as appropriate.

All financial assets are recognised initially at fair value plus, in the case of financial assets recorded not at fair value, transaction costs that are attributable to the acquisition of the financial asset.

The Group’s financial assets include cash and bank balances, trade and other receivables, investment securities and embedded derivatives.

Derecognition

A financial asset (or, where applicable a part of a financial asset or part of a group of similar financial assets) is derecognised when:

• The rights to receive cash flows from the asset have expired, or
• The Group has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a pass-through arrangement; and either (a) the Group has transferred substantially all the risks and rewards of the asset, or (b) the Group has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

When the Group has transferred its rights to receive cash flows from an asset or has transferred control of the asset, it evaluates if and to what extent it has retained the risks and rewards of ownership. When it has neither transferred nor retained substantially all the risks and rewards of the asset, nor transferred control of the asset, the asset is recognised to the extent of the Group’s continuing involvement in the asset. In that case, the Group also recognises an associated liability. The transferred asset and the last impaired liability are measured on the near term basis to reflect the rights and obligations that the Group has retained.

Impairment of financial assets

The Group assesses at each reporting date whether there is any objective evidence that a financial asset or a group of financial assets is impaired. A financial asset or a group of financial assets is deemed to be impaired if, there is objective evidence of impairment as a result of one or more events that has occurred since the initial recognition of the asset (an incurred loss event) and that loss event has an impact on the estimated future cash flows of the financial asset or the group of financial assets that can be reliably estimated. Evidence of impairment may include indications that the debtor or group of debtors is experiencing significant financial difficulty, default or delinquency in interest or principal payments, the probability that they will enter bankruptcy or other financial reorganisation and observable data indicating that there is a measurable decrease in the estimated future cash flows, such as changes in arrears or economic conditions that correlate with defaults.

Financial assets carried at amortised cost

For financial assets carried at amortised cost, the Group first assesses whether objective evidence of impairment exists individually for financial assets that are individually significant, or collectively for financial assets that are not individually significant. If the Group determines that there is no objective evidence of impairment exists for an individually assessed financial asset, whether significant or not, it includes the asset in a group of financial assets with similar credit risk characteristics and collectively assesses them for impairment. Assets that are individually assessed for impairment and for which an impairment loss is, or continues to be, recognised are not included in a collective assessment of impairment.

The amount of the loss is measured as the difference between the asset’s carrying amount and the present value of estimated future cash flows (excluding future expected credit losses that have not yet been incurred). The present value of the estimated future cash flows is discounted at the financial asset’s original EIR.

The carrying amount of the asset is reduced through the use of an allowance account and the amount of the loss is recognised in profit or loss. Interest income (recorded as finance income in the profit or loss) continues to be recognised are not included in a collective assessment of impairment.

Subsequent measurement

The subsequent measurement of financial assets depends on their classification, as follows:

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss include financial assets held for trading and financial assets designated upon initial recognition at fair value through profit or loss. Financial assets are classified as held for trading if they are acquired for the purpose of selling or repurchasing the asset at short notice, or if they are designated as trading derivatives, are also classified as held for trading unless they are designated as effective hedging instruments as defined by IAS 39.

Financial assets at fair value through profit or loss are carried in the statement of financial position at fair value with net changes in fair value presented as finance costs (negative changes in fair value) or finance revenue (positive net changes in fair value) in profit or loss. The Group has not designated any financial assets at fair value through profit or loss.

Derivatives embedded in host contracts are accounted for as separate derivatives and recorded at fair value if their economic characteristics and risks are not closely related to those of the host contracts and the host contracts are not held for trading or designated at fair value through profit or loss. These embedded derivatives are measured at fair value, with changes in fair value recognised in profit or loss. Reassessment only occurs if there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, such financial assets are subsequently measured at amortised cost using the effective interest rate ("EIR") method, less impairment. Amortised cost is calculated by taking into account any discount or premium on acquisition and fee or costs that are an integral part of the EIR. The EIR amortisation is included in finance income in the profit or loss. The losses arising from impairment are recognised in other operating expenses for receivables.

2.12.2 Financial liabilities

Initial recognition and measurement

Financial liabilities are classified, at initial recognition, as financial liabilities at amortised cost (including those with integral features), financial liabilities at fair value through profit or loss, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate.

All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

The Group’s financial liabilities include trade and other payables, accrued operating expenses and loans and borrowings.

Subsequent measurement

The subsequent measurement of financial liabilities depends on their classification as described below:

2.12.3 Offsetting of financial instruments

Financial assets and financial liabilities are offset and the net amount reported in the consolidated statement of financial position if there is a legally enforceable right to offset the recognised amounts and there is an intention to settle on a net basis, or to realise the assets and settle the liabilities simultaneously.

2.12.4 Fair value of financial instruments

The fair value of financial instruments that are traded in active markets at each reporting date is determined by reference to quoted market prices or dealer price quotations (bid price for long positions and ask price for short positions), without any deduction for transaction costs.

For financial instruments not traded in an active market, the fair value is determined using appropriate valuation techniques.
Such techniques may include using recent arm’s length market transactions; reference to the current fair value of another instrument that is substantially the same; a discounted cash flow analysis or other valuation models.

An analysis of fair value of financial instruments and further details as to how they are measured are provided in Note 27.

2.12.5 Current versus non-current classification
Derivative instruments that are not designated as effective hedging instruments are classified as current or non-current or separated in a current and non-current portion based on an assessment of facts and circumstances (i.e., the underlying contracted cash flows):

- Where the Group expects to hold a derivative as an economic hedge (and does not apply hedge accounting) for a period beyond 12 months after the reporting date, the derivative is classified as non-current (or separated into current and non-current portions) consistent with the classification of the underlying item.
- Embedded derivatives that are not closely related to the host contract are classified consistently with the cash flows of the host contract.
- Derivatives instruments that are designed as, and are effective hedging instruments, are classified consistently with the classification of the underlying hedged item. The derivative instrument is separated into a current portion and a non-current portion only if a reliable allocation can be made.

2.12.6 Cash and cash equivalents
Cash and cash equivalents comprise cash at banks and on-hand and short-term deposits with an original maturity of three months or less, but exclude any restricted cash which is not available for use by the Group and therefore not considered highly liquid.

2.13 Inventories
Inventories are stated at the lower of cost and net realizable value. Cost includes all costs incurred in the normal course of business in bringing each product to its present location and condition and is accounted for on a first-in-first-out basis. Net realisable value is the estimated selling price in the ordinary course of business, less estimated costs of completion and the estimated costs necessary to make the sale.

2.14 Leases
The determination of whether an arrangement is, or contains, a lease is based on the substance of the arrangement at date of inception. The arrangement is assessed to determine whether fulfillment of the arrangement is dependent on the use of a specific asset or assets or the arrangement conveys a right to use the asset or assets, even if that right is not explicitly specified in an arrangement.

Operating lease payments are recognised as an operating expense in profit or loss on a straight-line basis over the lease term.

2.15 Provisions

General
Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Group expects some or all of a provision to be reimbursed, the reimbursement is recognised as a separate asset but only when the reimbursement is virtually certain. The reimbursement is not related to any specific event in profit or loss net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognised as part of finance costs in profit or loss.

Decommissioning liability
The Group recognises a decommissioning liability when it 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 a reliable estimate of the amount of obligation can be made.

The obligation generally arises when the asset is installed or the ground/environment is disturbed at the field location. When the liability is initially recognised, the present value of the estimated costs is capitalised by increasing the carrying amount of the related oil and gas assets to the extent that it was incurred by the development/employee share of the field. Any decommissioning obligations that arise through the production of inventory are recognised when the inventory item is recognised in cost of goods sold.

Changes in the estimated timing of decommissioning or changes to the decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to oil and gas assets.

Any reduction in the decommissioning liability and, therefore, any deduction from the asset to which it relates, may not exceed the carrying amount of that asset. If it does, the resulting carrying amount of the asset is reduced immediately to profit or loss.

If the change in estimate results in an increase in the decommissioning liability and, therefore, an addition to the carrying value of the asset, the Group considers whether this is an indication of impairment of the asset as a whole, and if so, tests for impairment in accordance with IAS 36. If, for mature fields, the estimate for the revised value of oil and gas assets net of decommissioning provisions exceeds the Group’s share of cash flows, that portion of the increase is charged directly to expense.

Over time, the discount liability is increased for the change in present value based on the discount rate that reflects current market assessments and the risks specific to the liability. The periodic unвидный of the discount is recognised in profit or loss as a finance cost.

The Group recognises either the deferred tax asset in respect of decommissioning obligation liability or the corresponding deferred tax liability in respect of the temporary difference on a decommissioning asset.

Environmental expenditures and liabilities
Environmental expenditures that relate to current or future revenues are expensed or capitalised as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognised when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognised is the best estimate of the expenditure required. If the effect of the time value of money is material, the amount recognised is the present value of the estimated future expenditure.

2.16 Revenue recognition
Revenue is recognised to the extent it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured. Revenue is measured at the fair value of the consideration received or receivable, excluding discounts, sale taxes, excise duties and similar levies.

The Group has concluded that it is acting as a principal when:
- The Group has the right to take delivery. These commitments contain protective provisions in consideration for a commitment from the buyer to take delivery. These commitments contain protective (force majeure) and adjustment provisions. If a buyer has a right to a ‘make-up’ delivery at a later date, revenue recognition is deferred and only recognised when the product is delivered, or the make-up product can no longer be taken.
- The receipt of cash, or cash equivalent, is probable at the date of the sale or delivery of the product.
- The Group has title or will receive remuneration in the form of share-based payments, and are granted share appreciation rights, which are settled in cash (cash-settled transactions).

The cost of equity-settled transactions is determined by the fair value at the date when the grant is made using an appropriate valuation model.

That cost is recognised, together with a corresponding increase in the employee share option reserve in equity, over the period in which the performance and/or service conditions are fulfilled in employee benefits expense. The cumulative expense not for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group’s best estimates of the number of equity instruments that will ultimately vest. The profit or loss expense or credit for a period represents the movement in cumulative expense recognised as at the beginning and end of that period and is recognised in employee benefits expense in Note 24.

No expense is recognised for awards that do not ultimately vest, except for equity-settled transactions at vesting. Expenses that are conditional upon a market or non-vesting condition. These are treated as vesting irrespective of whether or not the market or non-vesting condition is satisfied, provided that all other performance and/or service conditions are satisfied.

When the terms of an equity-settled award are modified, the minimum expense recognised is the expense had the terms not been modified, if the original terms of the award are met. An additional expense is recognised for any modification that increases the total fair value of the share-based payment transaction, or is otherwise beneficial to the employee as measured at the date of modification.
Cash-settled transactions
Cash-settled transactions is measured initially at fair value at the grant date using a binomial model, further details of which are given in Note 24. This fair value is expressed over the period until the vesting date with recognition of a corresponding liability. The liability is re-measured to fair value at each reporting date up to, and including the settlement date, with changes in fair value recognised in employee benefits expense in Note 24.

(4) Defined benefit plans
The Group operates a defined benefit pension plan in Indonesia, which is governed by the Labour Law Number 13/2003 and Collective Labour agreement in Indonesia. The net defined benefit liability or asset is the aggregate of the present value of the defined benefit obligation (derived using a discount rate based on high quality government bonds) at the end of the reporting period reduced by the fair value of plan assets (if any) adjusted for any effect of limiting a net defined benefit asset to the assets ceiling. The assets ceiling is the present value of any economic benefits available in the form of refunds from the plan or reductions in future contributions to the plan. The cost of providing benefits under the defined benefit plans is determined separately for each plan using the projected unit credit method.

Defined benefit costs comprise the following:
• Service cost
• Net interest on the net defined benefit liability or asset
• Remeasurements of net defined benefit liability or asset

Service costs which include current service costs, past service costs and gains or losses on non-routine settlements are recognised as expense in profit or loss. Past service costs are recognised when plan amendment or curtailment occurs.

Net interest on the net defined benefit liability or asset is the change during the period in the net defined benefit liability or asset that arises from the passage of time which is determined by applying the discount rate based on high quality government bonds to the net defined benefit liability or asset. Net interest on the net defined benefit liability or asset is recognised as expense or income in profit or loss.

Remeasurements comprising actuarial gains and losses, return on plan assets and any change in the effect of the asset ceiling (excluding net interest on defined benefit liability) are recognised immediately in other comprehensive income in the period in which they arise. Remeasurements are recognised in retained earnings within equity and are not reclassified to profit or loss in subsequent periods.

Plan assets are assets that are held by a long-term employee benefit fund (e.g. insurance policies. Plan assets are not available to the creditors of the Group, nor can they be paid directly to the Group. Fair value of plan assets is based on market price information. When no market price is available, the fair value of plan assets is estimated by discounting expected future cash flows using a discount rate that reflects both the risk associated with the plan assets and the maturity or expected disposal date of those assets (e.g. if they have no maturity, the expected period until the settlement of the related obligations).

The Group’s right to be reimbursed of some or all of the expenditure required to settle a defined benefit obligation is recognised as a separate asset at fair value when and only when reimbursement is virtually certain.

2.18 Taxes

Current tax
Current tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted, at the reporting date in the countries where the Group operates and generates taxable income.

Current taxes are recognised in profit and loss except to the extent that the tax relates to items recognised outside profit or loss, either in other comprehensive income or directly in equity. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretations and establishes provisions where appropriate.

Deferred tax
Deferred tax is provided using the liability method on temporary differences at the end of the reporting period between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax liabilities are recognised for all taxable temporary differences, except:
• Where the deferred tax liability arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
• In respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, where the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognised for all deductible temporary differences, the carry forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences, and the carry forward of unused tax credits and unused tax losses can be utilised, except:
• Where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
• In respect of deductible temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, deferred tax assets are recognised only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available, against which the temporary differences can be utilised.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilised. Unrecognised deferred tax assets are reassessed at the end of each reporting period and are recognised to the extent that it has become probable that future taxable profits will be available to allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realised or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted by the end of the reporting date.

Deferred tax relating to items recognised outside profit or loss is recognised outside profit or loss. Deferred tax items are recognised in correlation to underlying transaction either in other comprehensive income or directly in equity and deferred tax arising from a business combination is adjusted against goodwill on acquisition.

Deferred tax assets and deferred tax liabilities are offset, if a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

Tax benefits acquired as part of a business combination, but not satisfying the criteria for separate recognition at that date, are recognised subsequently if new information about facts and circumstances arises. The adjustment is either treated as a reduction to goodwill (as long as it does not exceed goodwill) if it occurred during the measurement period or recognised in profit or loss.

Ratios, resource rent taxes and revenue-based taxes are accounted for under IAS 12 when they have the characteristics of an income tax. This is considered to be the case when they are imposed under government tax authority and the amount payable is based on taxable income – rather than based on physical quantity produced or as a percentage of revenue – after adjustment for temporary differences. For such arrangements, current and deferred tax is provided on the same basis as described above for other forms of taxation. Obligations arising from royalty arrangements and other types of taxes that do not satisfy these criteria are recognised as current provisions and included in cost of sales.

Production-sharing arrangements
According to the production-sharing agreement (“PSA”), the share of the profit oil to which the Group is entitled in any calendar year, is deemed to include a portion representing the corporate income tax imposed upon and due by the Group. This amount will be paid directly by the government on behalf of the Group to the appropriate tax authorities. This portion of tax and revenue are presented net in profit or loss.

Significant accounting judgements, estimates and assumptions
The preparation of the Group’s consolidated financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, and the disclosure of contingent liabilities at the date of the consolidated financial statements. Estimates and assumptions are continuously evaluated and are based on management’s experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

In particular, the Group has identified the following areas where significant judgements, estimates and assumptions are required. Changes in these assumptions may materially affect the financial position or financial results reported in future periods.

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Where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and

Ratios, resource rent taxes and revenue-based taxes are accounted for under IAS 12 when they have the characteristics of an income tax. This is considered to be the case when they are imposed under government tax authority and the amount payable is based on taxable income – rather than based on physical quantity produced or as a percentage of revenue – after adjustment for temporary differences. For such arrangements, current and deferred tax is provided on the same basis as described above for other forms of taxation. Obligations arising from royalty arrangements and other types of taxes that do not satisfy these criteria are recognised as current provisions and included in cost of sales.

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Significant accounting judgements, estimates and assumptions
The preparation of the Group’s consolidated financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, and the disclosure of contingent liabilities at the date of the consolidated financial statements. Estimates and assumptions are continuously evaluated and are based on management’s experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

In particular, the Group has identified the following areas where significant judgements, estimates and assumptions are required. Changes in these assumptions may materially affect the financial position or financial results reported in future periods.

Further information on each of these areas and how they impact the various accounting policies are described below and also in the relevant notes to the financial statements.
Hydrocarbon reserve and resource estimates

The carrying value of exploration and evaluation assets, oil and gas properties, property, plant and equipment, and goodwill may be affected due to changes in estimated future cash flows.

Depreciation and amortisation charges in profit or loss may change where such charges are determined using the UOP method, or where the useful life of the related assets change.

Provisions for decommissioning may change where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities.

The recognition and carrying value of deferred tax assets may change due to changes in judgements regarding the existence of such assets and in estimates of the likely recovery of such assets.

Exploration and evaluation expenditures (Note 8)

The application of the Group’s accounting policy for exploration and evaluation expenditure requires judgement to determine whether it is likely that future economic benefits are likely, either from future exploitation or sale, or whether activities undertaken permit a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying assumptions depending on how the resources are classified. These estimates directly impact when the Group defers exploration and evaluation expenditure. The deferral policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular, whether an economic viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in profit or loss in the period when the new information becomes available.

Units of production depreciation of oil and gas assets (Note 9)

The calculation of the UOP rate of depreciation could be impacted to the extent that actual production in the future is different from current forecast production based on total proved and probable reserves, or future capital expenditure estimates changes. Changes to proved and probable reserves could arise due to changes in the factors or assumptions used in estimating reserves, including:

- The effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions;
- Unforeseen operational issues.

Any changes in reserves are accounted for prospectively. A formal estimate of the future production-based amounts is made at total proved and probable reserves from management’s estimates would result in approximately 0.1% (2012: 0.2%) variance in the net book value of oil and gas properties.

Recoverability of oil and gas assets (Note 11)

The Group assesses each asset or CGU (excluding goodwill, which is assessed annually regardless of its carrying amount) at least annually to determine whether it is probable that the asset’s carrying amount will be recovered through its continued use or disposal. The recoverability test is performed at the next lower level of cash generating unit (CGU) which is considered to be the higher of fair value less costs to sell and in use. These assessments require the use of estimates and assumptions, such as long-term oil prices (considering probable oil prices, price trends and related factors), discount rates, operating costs, future capital requirements, decommissioning costs, exploration potential, reserves and operating performance (which includes production and sales volumes). These estimates and assumptions are subject to risk and uncertainty. Therefore, there is a possibility that changes in circumstances will impact these projections, which may impact the recoverable amount of assets, and/or CGU.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value for oil, and gas assets is generally determined as the present value of estimated future cash flows arising from the continued use of the assets, which includes estimates such as the cost of future expansion plans and eventual disposal, using assumptions that an independent market participant may take into account. All information compiled by appropriately qualified persons relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and production technique is taken into account in determining the fair value. Commercial reserves are determined using estimates of oil in place, recovery factors and future commodity prices, the latter having an impact on the recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the Production Sharing Agreements. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs. The current long-term Brent oil price assumption used in the estimation of commercial reserves is US$109.95 (2012: US$101.08). The carrying amount of oil and gas properties at 31 December 2013 is shown in Note 9.

As the economic assumptions used may change and as additional geological information is gathered during the operation of a field, estimates of recoverable reserves may change. Such changes may impact the Group’s reported financial position and results, which include:

- The carrying value of exploration and evaluation assets, and oil and gas properties, property, plant and equipment, and goodwill may be affected due to changes in estimated future cash flows;
- Depreciation and amortisation charges in profit or loss may change where such charges are determined using the UOP method, or where the useful life of the related assets change;
- Provisions for decommissioning may change where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities;
- The recognition and carrying value of deferred tax assets may change due to changes in judgements regarding the existence of such assets and in estimates of the likely recovery of such assets.

The Group uses valuation techniques that are appropriate in the circumstances and are designed to allow the carrying amount of assets to be measured as the fair value of those assets. The Group applies these techniques in a manner that is consistent with the requirements of IFRS 13 Fair Value Measurement. The Group operates in markets where the values of similar assets and liabilities are readily available for measurement. The Group tests for goodwill impairment annually, as required by IFRS 13. The Group reviews the carrying amount of each of its reporting units on a regular basis in order to ensure that it is not impaired.
The carrying value of the trade and other receivables amounting to US$22,263,386 was an approximate of its fair value. None of the trade and other receivables has been impaired and it is expected that full contractual amounts can be collected.

Included trade and other receivables is KEBL intra-group receivable of US$1,936,286, which is set-off against the cash consideration paid to Tulow Oil International Limited.

The excess of fair value of net assets acquired over consideration paid of US$41,396,066 arises from the probable, possible and contingent reserves arising from the oil and gas properties acquired.

From the date of acquisition to 31 December 2013, KEBL has contributed US$1,980,915 of revenue and US$22,328 of net profit to the Group. If the business combination had taken place at the beginning of the year, the Group revenue would have been US$848,514,791, and the loss for the year would have been US$4,913,107.

Transaction costs related to the acquisition of US$245,190 have been recognised in the “general and administrative expenses” line item in the Group’s profit or loss for the year ended 31 December 2013.

### Interests in joint operations

The Group, jointly with other participants, holds interests in each contract area for the right to explore and produce oil and gas properties. The Group’s interests in joint operations is as follows:

<table>
<thead>
<tr>
<th>CONTRACT AREA (DATE OF EXPIREY)</th>
<th>HELD BY</th>
<th>DESCRIPTION</th>
<th>PLACE OF OPERATION</th>
<th>% OF WORKING INTEREST</th>
</tr>
</thead>
<tbody>
<tr>
<td>G10/48 Concession (7 December 2015)</td>
<td>KrisEnergy (Gulf of Thailand) Ltd</td>
<td>Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources</td>
<td>Gulf of Thailand</td>
<td>25.00 25.00</td>
</tr>
<tr>
<td>G11/48 Concession (12 February 2016)</td>
<td>KrisEnergy (Gulf of Thailand) Ltd</td>
<td>Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources</td>
<td>Gulf of Thailand</td>
<td>25.00 25.00</td>
</tr>
<tr>
<td>Block A PSC (No expiry date for exploration stage)</td>
<td>KrisEnergy (Cambodia) Ltd</td>
<td>Drilling of exploration wells under the Petroleum Agreement with Cambodian National Petroleum Authority</td>
<td>Offshore Cambodia</td>
<td>25.00 25.00</td>
</tr>
<tr>
<td>Olghah Kambuma TAC (16 December 2016)</td>
<td>KrisEnergy-Olghah-Kambuma B.V.</td>
<td>Exploration and production of petroleum under Technical Assistance contract with Indonesia Governmental Authority</td>
<td>Indonesia</td>
<td>25.00 25.00</td>
</tr>
<tr>
<td>Kupai PSC (15 January 2017)</td>
<td>KrisEnergy Kupai B.V. (24.4%) and Kupai B.V. (30.0%)</td>
<td>Exploration and production of petroleum under Production Sharing contract with Indonesia Governmental Authority</td>
<td>Indonesia</td>
<td>54.60 54.60</td>
</tr>
<tr>
<td>Block BB/32 Concession (18 October 2020)</td>
<td>KrisEnergy (Gulf of Thailand) Ltd</td>
<td>Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources</td>
<td>Gulf of Thailand</td>
<td>4.63 4.63</td>
</tr>
<tr>
<td>Block B9A Concession (18 May 2024)</td>
<td>KrisEnergy (Gulf of Thailand) Ltd</td>
<td>Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources</td>
<td>Gulf of Thailand</td>
<td>4.63 4.63</td>
</tr>
<tr>
<td>Block 105 PSC (2 February 2040)</td>
<td>KrisEnergy (Song Hong 105) Ltd</td>
<td>Exploration and development of petroleum under Production Sharing Contract with Vietnam Government Authority</td>
<td>Offshore Vietnam</td>
<td>25.00 25.00</td>
</tr>
<tr>
<td>Block 120 PSC (22 January 2019)</td>
<td>KrisEnergy (Phil Khach 120) Ltd</td>
<td>Exploration and development of petroleum under Production Sharing Contract with Vietnam Government Authority</td>
<td>Offshore Vietnam</td>
<td>25.00 25.00</td>
</tr>
<tr>
<td>East Seruyau PSC (12 November 2014)</td>
<td>KrisEnergy East Seruyau B.V.</td>
<td>Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority</td>
<td>Indonesia</td>
<td>100.00 100.00</td>
</tr>
<tr>
<td>Bulu PSC (13 October 2014)</td>
<td>KrisEnergy (Satui) Ltd</td>
<td>Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority</td>
<td>Indonesia</td>
<td>42.50 42.50</td>
</tr>
<tr>
<td>East Muriah PSC (12 November 2013)</td>
<td>KrisEnergy (East Muriah) B.V.</td>
<td>Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority</td>
<td>Indonesia</td>
<td>50.00 50.00</td>
</tr>
<tr>
<td>Tanjung Ara PSC (13 December 2014)</td>
<td>KrisEnergy (Tanjung Ara) B.V.</td>
<td>Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority</td>
<td>Indonesia</td>
<td>43.00 43.00</td>
</tr>
<tr>
<td>Udan Enas PSC (18 July 2014)</td>
<td>KrisEnergy (Udan Enas) B.V.</td>
<td>Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority</td>
<td>Indonesia</td>
<td>100.00 100.00</td>
</tr>
<tr>
<td>Block 9 PSC (26 August 2003)</td>
<td>KrisEnergy Bangladesh Limited</td>
<td>Exploration and production of petroleum under Production Sharing Contract with Bangladesh Government Authority</td>
<td>Bangladesh</td>
<td>30.00 –</td>
</tr>
<tr>
<td>G06/48 Concession (7 January 2014)</td>
<td>KrisEnergy (Gulf of Thailand) Ltd</td>
<td>Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources</td>
<td>Gulf of Thailand</td>
<td>30.00 –</td>
</tr>
</tbody>
</table>

1. On 2 September 2013, KrisEnergy Oil and Gas (Thailand) Ltd and KrisEnergy Resources (Thailand) Ltd transferred G10/48 concession and G11/48 concession to KrisEnergy (Gulf of Thailand) Ltd.
2. On 21 August 2019, KrisEnergy (Gulf of Thailand) Ltd has entered into a farm-out agreement with Palang Sophon Limited, to assign and transfer 2.5% of the Group’s working interests in G11/48 concession. As at 31 December 2013, the approval from the government has not been received.
3. On 22 November 2013, the Company announced to exercise its right to take 5% working interest in the contract area. Upon government’s approval, the Group’s working interests in the contract area will decrease from 25.00% to 23.75%. As at 31 December 2013, the approval from the government has not been received.
4. On 22 March 2013, KrisEnergy (Gulf of Thailand) Ltd has entered into a farm-out agreement with Pearl Oil (Amata) Ltd, an affiliate of Mubadala Petroleum, for a 30% working interest in block G06/48 in the Gulf of Thailand. As at 31 December 2013, the approval from the government has not been received.
Profit before tax

The following items have been included in arriving at profit before tax:

<table>
<thead>
<tr>
<th>NOTE</th>
<th>GROUP</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>USD</td>
<td>USD</td>
</tr>
</tbody>
</table>

Revenue:
- Sale of crude oil 54,663,754 67,404,375
- Sale of gas 14,386,649 22,188,207
- Other revenue 69,050,403 89,592,582

Cost of sales:
- Drilling and completion of oil and gas properties 20,056,305 22,638,042
- Exploration and operating costs 16,113,008 18,741,758
- Thai Petroleum royalties and remuneration paid 8,084,747 11,349,486
- Overprovision of decommissioning cost 22,687,226 52,728,286

Other income is mainly made up of the following items:
- Excess of fair value of net assets acquired over consideration paid 12,936,286
- Joint operator overhead charges 1,285,389 4,766,677
- Foreign exchange differences 66,806 97,502
- Income from shared facilities in joint operations 437,864 674,367
- Value added tax recovered 609,063

General and administrative expenses are mainly made up of the following items:
- Consultants’ fees 690,491 408,348
- Data purchase and subscriptions 1,073,840 501,936
- Database rental 669,898 203,705
- Depreciation of other property, plant and equipment 10,348,379 583,400

Employee benefits expense:
- Salaries and bonuses 16,813,305 10,730,440
- Share-based payments 24,674,582
- Central Provident Fund Contributions 250,575 161,771
- Employee defined benefits 23,884,691
- Other short-term benefits 774,305 529,680
- Expenses incurred for acquisition of joint operations 2,000,000
- Operating lease expense 814,255 538,688
- Professional fees 4,529,631 3,129,933
- Travel and entertainment 1,636,740 1,366,734

Other operating income/ (expenses) is mainly made up of the following items:
- Dry hole expenses 8 1,283,288
- Gain on settlement of commodity options 121,980
- Joint study expenses 653,387 1,771,529
- Net fair value gain on embedded derivatives 2,284,698 1,444,000
- Premium paid on commodity options 540,000

Finance income:
- Interest income from banks 1,853,888 411,332

Income before tax is mainly made up of the following items:
- Gain on settlement of assets 2,284,698 1,444,000
- Premium paid on commodity options 540,000

Profit before tax

The major components of tax expense for the years ended 31 December 2013 and 2012 are:

<table>
<thead>
<tr>
<th>NOTE</th>
<th>GROUP</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>USD</td>
<td>USD</td>
</tr>
</tbody>
</table>

Current tax:
- Current tax charge 14,181,088 19,403,263
- Deferred tax charge 12,758,629 18,518,399

Deferred tax:
- Origination (reversal) of temporary differences 165,160 746,069

Tax expense recognised in profit or loss 21,758,529 21,518,599

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- Dry hole expenses 8 1,283,288
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- Joint study expenses 653,387 1,771,529
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Profit before tax

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</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>USD</td>
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</tr>
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</table>

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- Deferred tax charge 12,758,629 18,518,399

Deferred tax:
- Origination (reversal) of temporary differences 165,160 746,069

Tax expense recognised in profit or loss 21,758,529 21,518,599

Relationship between tax expense and accounting profit

A reconciliation between tax expense and the accounting profit multiplied by the applicable tax rate for the years ended 31 December 2013 and 2012 is as follows:

<table>
<thead>
<tr>
<th>NOTE</th>
<th>GROUP</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>USD</td>
<td>USD</td>
</tr>
</tbody>
</table>

Tax at domestic rates applicable in the countries where the Group operates 10,453,621 16,046,954

Adjustments:
- Non-deductible expenses 158,424 1,136,755
- Income not subject to tax (348,768)
- Deferred tax assets not recognised 3,760,858 1,807,386
- Effect of partial tax exemption and tax relief (20,701) (21,204)
- Overprovision in respect of previous years 1,587,619 1,388,804
- Others 36,080

Tax expense recognised in profit or loss 12,758,629 18,518,399

The above reconciliation is prepared by aggregating separate reconciliations for each national jurisdiction.

The nature of expenses that is not deductible for tax purposes are mainly made up of the following items:
Deferred tax at 31 December relates to the following:

### Exploration and evaluation assets

<table>
<thead>
<tr>
<th>GROUP</th>
<th>CONSOLIDATED STATEMENT OF FINANCIAL POSITION</th>
<th>CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME</th>
</tr>
</thead>
</table>

**Deferred tax liabilities**
- Fair value adjustment on acquisition: 42,660,419
- (1,310,583)
- (1,494,614)
- Deferred tax assets
- Provisions: 750,734
- (2,226,477)
- 1,475,743
- 748,554
- Deferred tax benefit: 165,160
- (746,060)
- Net deferred tax liabilities: 41,909,685
- 41,744,525

### Oil and gas properties

<table>
<thead>
<tr>
<th>GROUP</th>
<th>NOTE</th>
<th>US$</th>
</tr>
</thead>
</table>

**Depletion, amortisation and impairment**
- At 1 January 2012: 114,203,164
- Charge for the year: 22,638,042
- At 31 December 2012 and 1 January 2013: 136,841,206
- Charge for the year: 20,056,305
- As at 31 December 2013: 156,897,511
- Net book value
- As at 31 December 2013: 834,706
- As at 31 December 2012: 287,493,592

### Other property, plant and equipment

<table>
<thead>
<tr>
<th>GROUP</th>
<th>RENOVATION</th>
<th>FURNITURE AND FITTINGS</th>
<th>OFFICE EQUIPMENT</th>
<th>COMPUTERS</th>
<th>TOTAL</th>
</tr>
</thead>
</table>

**Deferred tax at 31 December relates to the following:**

<table>
<thead>
<tr>
<th>GROUP</th>
<th>COST</th>
<th>ADDITIONS</th>
<th>EXCHANGE DIFFERENCES</th>
<th>CHARGE FOR THE YEAR</th>
<th>EXCHANGE DIFFERENCES</th>
<th>NET CARRYING AMOUNT</th>
</tr>
</thead>
</table>

**Intangible assets**

<table>
<thead>
<tr>
<th>GROUP</th>
<th>GOODWILL</th>
<th>OTHER</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>US$</td>
<td>US$</td>
<td>US$</td>
</tr>
</tbody>
</table>

**Deferred tax at 31 December relates to the following:**

<table>
<thead>
<tr>
<th>GROUP</th>
<th>COST</th>
<th>ACCUMULATED AMORTISATION AND IMPAIRMENT LOSS</th>
<th>NET CARRYING AMOUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2012</td>
<td>2013</td>
</tr>
<tr>
<td></td>
<td>US$</td>
<td>US$</td>
<td>US$</td>
</tr>
</tbody>
</table>

**Deferred tax at 31 December relates to the following:**

<table>
<thead>
<tr>
<th>GROUP</th>
<th>GOODWILL</th>
<th>OTHER</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>US$</td>
<td>US$</td>
<td>US$</td>
</tr>
</tbody>
</table>

**Deferred tax at 31 December relates to the following:**

<table>
<thead>
<tr>
<th>GROUP</th>
<th>COST</th>
<th>ACCUMULATED AMORTISATION AND IMPAIRMENT LOSS</th>
<th>NET CARRYING AMOUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2012</td>
<td>2013</td>
</tr>
<tr>
<td></td>
<td>US$</td>
<td>US$</td>
<td>US$</td>
</tr>
</tbody>
</table>

Goodwill

- Goodwill arises principally because of the following factors:
  - (a) The going concern value implicit in our ability to sustain and/or grow our business by increasing reserves and resources through new discoveries
  - (b) The ability to capture unique synergies that can be realised from managing a portfolio of both acquired and existing fields
  - (c) The requirement to recognise deferred tax assets and liabilities for the difference between the assigned values and the tax bases of assets acquired and liabilities assumed in a business combination at amounts that do not reflect fair value.

The Group offsets tax assets and liabilities if and only if it has a legally enforceable right to set off current tax assets and current tax liabilities and the deferred tax assets and deferred tax liabilities relate to income taxes levied by the same tax authority.

Deferred tax assets have not been recognised in respect of most temporary differences and tax losses as they may not be used to offset taxable profits elsewhere in the Group, they have arisen in subsidiaries that have been loss-making for some time, and there are no other tax planning opportunities or other evidence of recoverability in the near future. The use of these tax losses is subject to the agreement of the tax authorities and compliance with certain provisions of the tax legislation of the respective countries in which the companies operates.
Other intangible assets

<table>
<thead>
<tr>
<th></th>
<th>GROUP</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2012</td>
</tr>
<tr>
<td>0.75% overriding royalty interest in Concession G10/48 and G11/48</td>
<td>1,300,000</td>
<td>1,300,000</td>
</tr>
<tr>
<td>Leasehold bonus for Concession G10/48</td>
<td>269,711</td>
<td>269,711</td>
</tr>
<tr>
<td>Others</td>
<td>100,000</td>
<td>100,000</td>
</tr>
<tr>
<td></td>
<td><strong>1,669,711</strong></td>
<td><strong>1,669,711</strong></td>
</tr>
</tbody>
</table>

The Group was assigned the overriding royalty interest from the acquisition of KrisEnergy Oil and Gas (Thailand) Ltd (“KEDG”) and KrisEnergy Resources (Thailand) Ltd (“KER”). The overriding royalty interest entitles the Group rights to the revenues derived from the production and disposal of all of the oil, gas, and other minerals, in, on, under, and that may be produced and saved from Concession G10/48 and G11/48.

The useful lives of these other intangible assets are estimated to be indefinite as the exploration period of the blocks are extended every three years and cannot be reliably estimated.

Impairment testing
For impairment testing purposes, goodwill and other intangible assets acquired through business combinations has been allocated as follows:

<table>
<thead>
<tr>
<th></th>
<th>GROUP</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2012</td>
</tr>
<tr>
<td>G10/48 and G11/48 Concession</td>
<td>21,774,832</td>
<td>21,774,832</td>
</tr>
<tr>
<td>Block B9A and Block B8/12 Concession</td>
<td>13,301,576</td>
<td>13,301,576</td>
</tr>
<tr>
<td>Bulu PSC</td>
<td>7,144,606</td>
<td>7,144,606</td>
</tr>
<tr>
<td>Block 105 PSC</td>
<td>–</td>
<td>100,000</td>
</tr>
<tr>
<td></td>
<td><strong>42,221,014</strong></td>
<td><strong>42,221,014</strong></td>
</tr>
</tbody>
</table>

Estimated production volumes are based on detailed data for the fields and take into account development plans for the fields agreed by management as part of the long-term planning process. It is estimated that, if all production were to be reduced by 2% for the whole term of the contract area, this would not be sufficient to reduce the excess of recoverable amount over the carrying amounts of the individual CGUs to zero. Consequently, management believes no reasonably possible change in the production assumptions would cause the carrying amount of goodwill and/or other non-current assets to exceed their recoverable amount.

The Group generally estimates value in use for the oil exploration and production CGU using a discount cash flow model. The future cash flows are discounted to their present value using a pre-tax discount rate of 8% to 10% that reflects current market assessments of the time value of money and the risks specific to the asset.

The discount rate is derived from the Group’s weighted average cost of capital (“WACC”), with appropriate adjustments made to reflect the risks specific to the asset/CGU.

Oil prices are based on Brent future prices at the reporting date and adjusted for quality, transportation fees and regional price differences.

### Embedded derivatives

The Group issued callable bonds (Note 21), which have embedded derivatives that require bifurcation and separately recognised and accounted for at fair value with any changes to fair value credited or charge to profit or loss. The carrying value of the embedded derivatives as at 31 December 2013 amounted to US$6,137,226 (2012: US$2,864,000). The effect on profit or loss is reflected in other operating income/ (expenses) (Note 6).

### Investment securities

<table>
<thead>
<tr>
<th></th>
<th>GROUP</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2012</td>
</tr>
<tr>
<td>Available for sale investments</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unquoted equity shares, at cost</td>
<td><strong>182,057</strong></td>
<td><strong>182,057</strong></td>
</tr>
</tbody>
</table>

The recoverable amount of each field is determined on a value-in-use calculation.

The calculation of value in use of the oil exploration and production CGUs is most sensitive to the following assumptions:

- Production volumes
- Discount rates
- Crude oil prices

The Group issued callable bonds (Note 21), which have embedded derivatives that require bifurcation and separately recognised and accounted for at fair value with any changes to fair value credited or charge to profit or loss. The carrying value of the embedded derivatives as at 31 December 2013 amounted to US$6,137,226 (2012: US$2,864,000). The effect on profit or loss is reflected in other operating income/(expenses) (Note 6).

The recoverable amount of each field is determined on a value-in-use calculation.

The calculation of value in use of the oil exploration and production CGUs is most sensitive to the following assumptions:

- Production volumes
- Discount rates
- Crude oil prices

### Investment in subsidiaries

<table>
<thead>
<tr>
<th>COMPANY</th>
<th>NOTE</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>KrisEnergy Holding Company Ltd(1)</td>
<td>Investment holding</td>
<td>Singapore</td>
<td>British Virgin Islands</td>
</tr>
<tr>
<td>KrisEnergy Pte Ltd(1)(2)(3)</td>
<td>Provision of management support service</td>
<td>Singapore</td>
<td>Singapore</td>
</tr>
<tr>
<td>KrisEnergy (Management Services) Ltd (1)(2)(3)</td>
<td>Provision of offshore management support service</td>
<td>Singapore</td>
<td>British Virgin Islands</td>
</tr>
<tr>
<td>KrisEnergy Asia Ltd(1)(2)(3)</td>
<td>Investment holding</td>
<td>Singapore</td>
<td>British Virgin Islands</td>
</tr>
<tr>
<td>KrisEnergy International (Thailand) Holdings Ltd(1)(2)(3)</td>
<td>Investment holding</td>
<td>Thailand</td>
<td>British Virgin Islands</td>
</tr>
<tr>
<td>KrisEnergy (Gulf of Thailand) Ltd</td>
<td>Investment holding</td>
<td>Thailand</td>
<td>Cypman Islands</td>
</tr>
<tr>
<td>KrisEnergy Oil and Gas (Thailand) Ltd</td>
<td>Exploration and production of oil and gas</td>
<td>Thailand</td>
<td>Thailand</td>
</tr>
<tr>
<td>KrisEnergy Resources (Thailand) Ltd</td>
<td>Exploration and production of oil and gas</td>
<td>Thailand</td>
<td>Thailand</td>
</tr>
<tr>
<td>KrisEnergy Management Ltd</td>
<td>Thailand</td>
<td>Dormant</td>
<td>British Virgin Islands</td>
</tr>
<tr>
<td>KrisEnergy (Cambodia) Holding Ltd(1)</td>
<td>Investment holding</td>
<td>Cambodia</td>
<td>British Virgin Islands</td>
</tr>
<tr>
<td>KrisEnergy (Cambodia) Ltd</td>
<td>Exploration and production of oil and gas</td>
<td>Cambodia</td>
<td>Cambodia</td>
</tr>
<tr>
<td>KrisEnergy (Phu Khanh 129) Limited(1)</td>
<td>Exploration and production of oil and gas</td>
<td>Vietnam</td>
<td>British Virgin Islands</td>
</tr>
<tr>
<td>KrisEnergy (Song Hong 105) Limited(1)</td>
<td>Exploration and production of oil and gas</td>
<td>Vietnam</td>
<td>British Virgin Islands</td>
</tr>
<tr>
<td>KrisEnergy (Production) Ltd</td>
<td>Dormant</td>
<td>Singapore</td>
<td>British Virgin Islands</td>
</tr>
<tr>
<td>KrisEnergy Asia Cooperatief U.A.</td>
<td>Investment holding</td>
<td>Singapore</td>
<td>The Netherlands</td>
</tr>
<tr>
<td>KrisEnergy Asia Holdings II B.V.</td>
<td>Dormant</td>
<td>Singapore</td>
<td>The Netherlands</td>
</tr>
<tr>
<td>KrisEnergy Asia Holdings B.V.(1)</td>
<td>Investment holding</td>
<td>Singapore</td>
<td>The Netherlands</td>
</tr>
<tr>
<td>KrisEnergy (Bilah–Kambuma B.V.</td>
<td>Exploration and production of oil and gas</td>
<td>Indonesia</td>
<td>The Netherlands</td>
</tr>
<tr>
<td>KrisEnergy (Bangrapal B.V.)</td>
<td>Exploration and production of oil and gas</td>
<td>Indonesia</td>
<td>The Netherlands</td>
</tr>
<tr>
<td>KrisEnergy Kutai B.V.</td>
<td>Exploration and production of oil and gas</td>
<td>Indonesia</td>
<td>The Netherlands</td>
</tr>
<tr>
<td>KrisEnergy (Andaman II) B.V.</td>
<td>Exploration and production of oil and gas</td>
<td>Indonesia</td>
<td>The Netherlands</td>
</tr>
<tr>
<td>KrisEnergy Development Pte Ltd(1)</td>
<td>Investment holding</td>
<td>Singapore</td>
<td>Singapore</td>
</tr>
<tr>
<td>KrisEnergy Kutai B.V.</td>
<td>Exploration and production of oil and gas</td>
<td>Indonesia</td>
<td>The Netherlands</td>
</tr>
</tbody>
</table>

The financial statements include the financial statements of KrisEnergy Ltd., the subsidiaries and joint arrangements listed in the following table:

<table>
<thead>
<tr>
<th>NAME OF ENTITIES</th>
<th>PRINCIPAL ACTIVITIES</th>
<th>PRINCIPAL PLACE OF BUSINESS</th>
<th>COUNTRY OF INCORPORATION</th>
<th>% OF EQUITY INTEREST</th>
</tr>
</thead>
<tbody>
<tr>
<td>KrisEnergy (Cambodia) Holding Ltd</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KrisEnergy (Management Services) Ltd</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KrisEnergy Asia Ltd</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KrisEnergy Asia Holdings B.V.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KrisEnergy (Phu Khanh 129) Limited</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KrisEnergy (Song Hong 105) Limited</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KrisEnergy (Production) Ltd</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KrisEnergy (Development) Pte Ltd</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KrisEnergy Kutai B.V.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Inventories

#### Balance sheet:

<table>
<thead>
<tr>
<th>Description</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling supplies and materials</td>
<td>5,323,207</td>
<td>5,309,628</td>
</tr>
<tr>
<td>Crude oil</td>
<td>1,703,956</td>
<td>745,100</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>7,027,163</td>
<td>6,054,728</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inventories recognised as an expense in cost of sales</td>
<td>116,420</td>
<td>1,518,421</td>
</tr>
</tbody>
</table>

### Trade and other receivables

#### Statement of financial position

<table>
<thead>
<tr>
<th>Description</th>
<th>2013</th>
<th>2012</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Trade and other receivables</strong></td>
<td>$305,959,409</td>
<td>$164,444,400</td>
<td>$276,522,994</td>
<td>$75,150,506</td>
</tr>
<tr>
<td><strong>Trade receivables</strong></td>
<td>15,095,907</td>
<td>11,180,087</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td><strong>Refundable deposits</strong></td>
<td>5,489,566</td>
<td>282,210</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td><strong>Other receivables</strong></td>
<td>13,193,081</td>
<td>8,928,334</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td><strong>Joint operation receivables</strong></td>
<td>54,149,712</td>
<td>34,743,446</td>
<td>122,982</td>
<td>–</td>
</tr>
</tbody>
</table>

**Trade and other receivables (current):**

<table>
<thead>
<tr>
<th>Description</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Add: cash and bank balances</strong></td>
<td>251,809,697</td>
<td>129,900,954</td>
</tr>
<tr>
<td><strong>Total trade and other receivables</strong></td>
<td>$75,150,506</td>
<td>$276,522,994</td>
</tr>
</tbody>
</table>

**Trade and other receivables (non-current):**

<table>
<thead>
<tr>
<th>Description</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Joint operation receivables</strong></td>
<td>276,522,994</td>
<td>75,150,506</td>
</tr>
</tbody>
</table>

**Trade and other receivables comprise:**

<table>
<thead>
<tr>
<th>Description</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Payment on behalf of joint operation's partners</td>
<td>4,969,756</td>
<td>746,302</td>
</tr>
<tr>
<td>Proportionate share of joint operation's other receivables</td>
<td>15,163,811</td>
<td>5,905,932</td>
</tr>
<tr>
<td>Value added tax receivables</td>
<td>221,692</td>
<td>701,530</td>
</tr>
<tr>
<td>Others</td>
<td>15,899</td>
<td>99,033</td>
</tr>
<tr>
<td><strong>Value added tax receivables</strong></td>
<td>20,371,158</td>
<td>14,352,815</td>
</tr>
</tbody>
</table>

**Value added tax receivables:**

<table>
<thead>
<tr>
<th>Description</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Trade and other receivables</strong></td>
<td>54,149,712</td>
<td>34,743,446</td>
</tr>
<tr>
<td><strong>Other receivables</strong></td>
<td>54,149,712</td>
<td>34,743,446</td>
</tr>
</tbody>
</table>

**Trade and other receivables denominated in foreign currencies at 31 December are as follows:**

<table>
<thead>
<tr>
<th>Description</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Thai Baht</strong></td>
<td>182,901</td>
<td>20,679</td>
</tr>
</tbody>
</table>

At the reporting date, the Group does not have any receivables that are past due or impaired, or would otherwise be past due but not impaired.
**Other current assets**

**GROUP AND COMPANY**

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>$</td>
<td>$</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>Expenses directly attributable to proposed share issue</td>
<td>–</td>
<td>500,000</td>
<td>–</td>
<td>500,000</td>
</tr>
</tbody>
</table>

**Cash and bank balances**

**GROUP AND COMPANY**

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>$</td>
<td>$</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>Cash at banks and on hand</td>
<td>247,809,697</td>
<td>121,900,954</td>
<td>211,400,012</td>
<td>75,150,506</td>
</tr>
<tr>
<td>Short-term structured deposits</td>
<td>0</td>
<td>8,000,000</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Cash and bank balances</td>
<td>251,809,697</td>
<td>129,900,954</td>
<td>211,400,012</td>
<td>75,150,506</td>
</tr>
</tbody>
</table>

Cash at banks and on hand earn interest at floating rates based on daily bank deposit rates. Included in cash at banks and on hand is a short-term structured deposit of US$4,000,000 (2012: US$8,000,000) placed with and pledged to a bank for issuance of guarantees on behalf of KrisEnergy (Song Hong 105) Ltd and KrisEnergy (Phu Khanh 120) Ltd. These deposits have a minimum yield of 0.5% (2012: 0.5%) per annum.

**Share capital and reserve**

**GROUP AND COMPANY**

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>Issued and fully paid ordinary shares</td>
<td>1,046,154,000</td>
<td>1,307,693</td>
</tr>
</tbody>
</table>

The holders of ordinary shares are entitled to receive dividends as and when declared by the Company. All ordinary shares carry one vote per share without restrictions. The ordinary shares have a par value of US$0.00125 (2012: US$0.01) each.

**Share premium**

**GROUP AND COMPANY**

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>Issued on 19 July 2013 for cash</td>
<td>246,154,000</td>
<td>307,693</td>
</tr>
<tr>
<td>One for eight share split on 10 July 2013</td>
<td>700,000,000</td>
<td>–</td>
</tr>
<tr>
<td>Issued on 19 July 2013 for cash</td>
<td>246,154,000</td>
<td>307,693</td>
</tr>
</tbody>
</table>

**Trade and other payables**

**GROUP AND COMPANY**

<table>
<thead>
<tr>
<th>-</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>Issue expenses (12,490,098)</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>At 1 January</td>
<td>402,750,000</td>
<td>–</td>
</tr>
<tr>
<td>Increase on 4 July 2012 by way of capitalisation of amount due to holding company into new shares</td>
<td>–</td>
<td>287,930,000</td>
</tr>
<tr>
<td>Increase on 9 July 2012 for cash arising from an issuance of share capital</td>
<td>–</td>
<td>114,800,000</td>
</tr>
<tr>
<td>Increase on 19 July 2013 for cash arising from an issuance of share capital</td>
<td>212,678,368</td>
<td>–</td>
</tr>
<tr>
<td>Share issuance expense</td>
<td>(12,490,098)</td>
<td>–</td>
</tr>
<tr>
<td>At 31 December</td>
<td>602,938,278</td>
<td>402,750,000</td>
</tr>
</tbody>
</table>

**Foreign currency translation reserve**

The foreign currency translation reserve represents exchange differences arising from the translation of the financial statements of foreign subsidiaries whose functional currencies are different from that of the Group's presentation currency.

**Employee share option reserve**

Employee share option reserve represents equity-settled share options granted to employees (Note 24). The reserve is made up of the cumulative value of services received from employees recorded over the vesting period commencing from the grant date of equity-settled share options, and is reduced by the expiry or exercise of the share options.
Trade and other payables denominated in foreign currencies at 31 December are as follows:

<table>
<thead>
<tr>
<th>Currency</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thai Baht</td>
<td>376,572</td>
<td>254,971</td>
</tr>
<tr>
<td>Indonesian Rupiah</td>
<td>119,141,003</td>
<td>81,142,055</td>
</tr>
</tbody>
</table>

Other payables comprise:

<table>
<thead>
<tr>
<th>Group</th>
<th>2013</th>
<th>2012</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>US$85,000,000 Bonds:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Face value of Bonds</td>
<td>85,000,000</td>
<td>85,000,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Discount on Bonds</td>
<td>(6,545,000)</td>
<td>(6,545,000)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proceeds from issuance of Bonds</td>
<td>78,455,000</td>
<td>78,455,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Embedded derivatives at initial recognition</td>
<td>12</td>
<td>1,526,000</td>
<td>1,526,000</td>
<td></td>
</tr>
<tr>
<td>Liability component at initial recognition</td>
<td>79,981,000</td>
<td>79,981,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Add: accretion of interest on Bonds</td>
<td>2,088,515</td>
<td>1,161,055</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>82,069,515</td>
<td>81,142,055</td>
<td></td>
<td></td>
</tr>
<tr>
<td>US$35,000,000 Bonds:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Face value of Bonds</td>
<td>35,000,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Premium on Bonds</td>
<td>1,750,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proceeds from issuance of Bonds</td>
<td>36,750,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Embedded derivatives at initial recognition</td>
<td>12</td>
<td>988,528</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liability component at initial recognition</td>
<td>37,738,528</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Less: accretion of interest on Bonds</td>
<td>(667,045)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>37,071,483</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

At 31 December 2013 | 119,141,003 | 81,142,055 |

Callable bonds

KrisEnergy Holding Company Ltd ("Issuer"), a wholly owned subsidiary, issued a US$85,000,000,000 10.5% Senior Guaranteed Secured Bonds ("Bonds") due 21 July 2016 at issue price of 92.3%. Interest on the Bonds accrues at the rate of 10.5% per annum and is payable semi-annually in arrears on 21 January and 21 July in each year, commencing on 21 January 2012. The Bonds include an option for the Issuer to redeem all or a part of the Bonds at the redemption prices, giving rise to an embedded derivative that require bifurcation and it is separately recognised and accounted for at fair value (Note 12).

On 31 May 2013, the Issuer issued an additional US$35,000,000,000 Bonds under the same terms, including the same interest rate and maturity date, increasing the total principal amount of the Bonds to US$120,000,000,000. This issue was priced at 105% of the face value.

On 30 January 2014, the Issuer exercised its option to redeem the Bonds in whole, at a redemption price of 105.25% of the principal amount, and accrued interest of US$315,600.

The carrying amount of the liability component of the Bonds at reporting date is as follows:

<table>
<thead>
<tr>
<th>Group</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>US$85,000,000 Bonds:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Face value of Bonds</td>
<td>85,000,000</td>
<td>85,000,000</td>
</tr>
<tr>
<td>Discount on Bonds</td>
<td>(6,545,000)</td>
<td>(6,545,000)</td>
</tr>
<tr>
<td>Proceeds from issuance of Bonds</td>
<td>78,455,000</td>
<td>78,455,000</td>
</tr>
<tr>
<td>Embedded derivatives at initial recognition</td>
<td>12</td>
<td>1,526,000</td>
</tr>
<tr>
<td>Liability component at initial recognition</td>
<td>79,981,000</td>
<td>79,981,000</td>
</tr>
<tr>
<td>Add: accretion of interest on Bonds</td>
<td>2,088,515</td>
<td>1,161,055</td>
</tr>
<tr>
<td></td>
<td>82,069,515</td>
<td>81,142,055</td>
</tr>
<tr>
<td>US$35,000,000 Bonds:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Face value of Bonds</td>
<td>35,000,000</td>
<td></td>
</tr>
<tr>
<td>Premium on Bonds</td>
<td>1,750,000</td>
<td></td>
</tr>
<tr>
<td>Proceeds from issuance of Bonds</td>
<td>36,750,000</td>
<td></td>
</tr>
<tr>
<td>Embedded derivatives at initial recognition</td>
<td>12</td>
<td>988,528</td>
</tr>
<tr>
<td>Liability component at initial recognition</td>
<td>37,738,528</td>
<td></td>
</tr>
<tr>
<td>Less: accretion of interest on Bonds</td>
<td>(667,045)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>37,071,483</td>
<td></td>
</tr>
</tbody>
</table>

At 31 December 2013 | 119,141,003 | 81,142,055 |

Revolving credit

On 21 July 2012, the Issuer entered into a credit agreement with banks for a US$30,000,000 revolving credit facility ("Revolving Credit"). On 31 May 2013, the Issuer increased its Revolving Credit to US$42,500,000.

The Revolving Credit has an interest rate of LIBOR plus an applicable margin ranging from 4.0% to 5.0% (in increments of 0.25%), depending on the percentage of commitment utilised at the relevant time. The Revolving Credit is used to finance the Group’s working capital requirements, capital expenditure, acquisitions and payment of fees, costs and expenses related to the Bonds and Revolving Credit.

As at 31 December 2012 and 2013, there is no amount drawn down under the Revolving Credit.

The Parent Guarantor of the Bonds and Revolving Credit is the Company and the Subsidiary Guarantors are KrisEnergy Asia Cooparated U.A., KrisEnergy Ltd, KrisEnergy Glagah-Kambuna B.V., Kutai B.V., KrisEnergy Nam Con Son B.V., KrisEnergy Oil & Gas (Thailand) Ltd, KrisEnergy Resources (Thailand) Ltd, KrisEnergy Gulf of Thailand Ltd, KrisEnergy (Cambodia) Ltd, KrisEnergy (Phu Khanh 120) Ltd, and KrisEnergy (Song Hong 105) Ltd.

Please refer to Note 14 for subsidiaries that provide the above collaterals.

Provisions

Decommissioning provisions

<table>
<thead>
<tr>
<th>Group</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current</td>
<td>18,048,096</td>
<td>6,076,986</td>
</tr>
<tr>
<td>Unwinding of discount</td>
<td>399,561</td>
<td></td>
</tr>
<tr>
<td>At 31 December 2012 and 1 January 2013</td>
<td>24,524,643</td>
<td></td>
</tr>
<tr>
<td>Arising during the year</td>
<td>1,284,797</td>
<td></td>
</tr>
<tr>
<td>Write-back of unused provisions</td>
<td>(667,726)</td>
<td></td>
</tr>
<tr>
<td>Unwinding of discount</td>
<td>431,792</td>
<td></td>
</tr>
<tr>
<td>Utilisation</td>
<td>(1,832,774)</td>
<td></td>
</tr>
<tr>
<td>At 31 December 2013</td>
<td>23,741,232</td>
<td></td>
</tr>
</tbody>
</table>

Revolving credit

On 21 July 2012, the Issuer entered into a credit agreement with banks for a US$30,000,000 revolving credit facility ("Revolving Credit"). On 31 May 2013, the Issuer increased its Revolving Credit to US$42,500,000.
the producing oil and gas properties are expected to cease operations. These provisions have been created based on the Group’s internal estimates. Assumptions based on the current economic environment have been made, which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required that will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

The discount rate used in the calculation of the provision as at 31 December 2013 equalled 3.4% (2012: 3.4%) in respect of its defined benefit pension plan is as follows:

<table>
<thead>
<tr>
<th>Retirement age</th>
<th>58 years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount rate</td>
<td>9% per annum</td>
</tr>
<tr>
<td>Long-term salary increase</td>
<td>5% per annum</td>
</tr>
<tr>
<td>Expected return on plan assets</td>
<td>n.a.</td>
</tr>
<tr>
<td>Voluntary resignation</td>
<td>6% for employees before the age of 30 and linearly decrease until 0% at the age of 52</td>
</tr>
</tbody>
</table>

The cost of defined benefit pension plan and the present value of the defined benefit obligation are determined using actuarial valuations. The actuarial obligation involves making various assumptions. The principal assumptions used to determine defined benefit obligation is shown below:

<table>
<thead>
<tr>
<th>Employee benefit liability</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Group has a defined benefit pension plan for Indonesia employees. The plan is governed by the Labour Law Number 13/2003 and Collective Labour agreement in Indonesia which all local permanent employees are entitled for the plan. Salary is a basis of payment for severance and service benefits which consist of basis salary plus fixed allowance. The amount included in the consolidated statement of financial position arising from the Group’s obligation in respect of its defined benefit pension plan is as follows:</td>
</tr>
</tbody>
</table>

**GROUP**

<table>
<thead>
<tr>
<th>Present value of defined benefit obligation</th>
<th>US$</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>884,691</td>
</tr>
<tr>
<td>2012</td>
<td>–</td>
</tr>
<tr>
<td>Net liability arising from defined benefit obligation</td>
<td>US$</td>
</tr>
<tr>
<td>2013</td>
<td>884,691</td>
</tr>
<tr>
<td>2012</td>
<td>–</td>
</tr>
</tbody>
</table>

**Share-based payments**

The expenses recognised for employee services received during the year is shown in the following table:

**GROUP**

<table>
<thead>
<tr>
<th>Expense arising from cash-settled share-based payment transactions</th>
<th>US$</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>146,735</td>
</tr>
<tr>
<td>2012</td>
<td>–</td>
</tr>
<tr>
<td>Expense arising from equity-settled share-based payment transactions</td>
<td>US$</td>
</tr>
<tr>
<td>2013</td>
<td>527,847</td>
</tr>
<tr>
<td>2012</td>
<td>–</td>
</tr>
<tr>
<td>Total</td>
<td>674,582</td>
</tr>
</tbody>
</table>

**Virtual Shares Award (“VSA”)**

On 18 September 2013, the Company awarded 783,704 virtual shares to its employees under the VSA scheme. This VSA is a performance-based share incentive scheme to reward eligible employees for their continued contribution to KrisEnergy and to serve as a long-term incentive reward to motivate and retain eligible employees, with a view to align the interests of such employees with the interest of KrisEnergy and its shareholders.

The virtual share represents a cash award which is linked to KrisEnergy’s share price. No shares are actually issued or transferred to the employee who has been awarded virtual shares. The cash amount depends on KrisEnergy’s closing share price on the relevant vesting date, being 19 July 2014, 19 July 2015 and 19 July 2016, and is calculated based on the number of virtual shares vested on the relevant vesting date multiplied by the vesting share price.

The carrying amount to the liability relating to the VSA as at 31 December 2013 is US$148,735.

**Performance Share Plan (“PSP”)**

On 13 November 2013, the Company awarded 5,429,689 performance shares to its employees under the PSP scheme. The PSP is a performance based share incentive scheme to reward selected employees and directors of the Company, who have contributed to the growth and performance of the Group and for their continued support and loyalty, with a direct interest in KrisEnergy.

The shares will be awarded to the selected employees if they remain employed by KrisEnergy with a clean employment record during the relevant vesting period, being 19 July 2014, 19 July 2015 and 19 July 2016. When the shares are fully vested, the shares will be issued and allotted to an account or sub-account with the Central Depository (Pte) Limited (“CDP”) in Singapore within ten (10) business days of the vesting date.

As at 31 December 2013, the employee share option reserve for the PSP amounts to US$527,847 (Note 18).

There has been no cancellation or modification to the employee share-based payments in 2013.

The fair value of the VSA and PSP are estimated at reporting date and grant date respectively, using a Monte Carlo simulation model, taking into account the terms and conditions upon which the shares were granted. The model simulates a sophisticated random number generator of random variables based on their historical distributions. These variables are then input into a model predicting the price behaviors of the instruments, and the mean of this distribution is taken as the approximate fair value. The valuations are split into three tranches based on the vesting dates.

The following table lists the inputs to the Monte Carlo simulation model for VSA and PSP respectively.

**Commitments**

**a) Operating lease commitments**

The Group has entered into non-cancellable commercial property leases for the office operations. These operating leases have remaining lease terms of one year or more. Future minimum lease payments payable under non-cancellable operating leases as at 31 December are as follows:

**GROUP**

<table>
<thead>
<tr>
<th>Preferred</th>
<th>US$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Within one year</td>
<td>664,078</td>
</tr>
<tr>
<td>After one year but not more than five years</td>
<td>2,228,050</td>
</tr>
<tr>
<td>Total</td>
<td>2,892,128</td>
</tr>
</tbody>
</table>

**b) Capital commitments**

Certain of our joint operations have firm capital commitments where we are required to participate in minimum exploration activities. The Group’s share of the estimated minimum exploration commitments is approximately US$103,764,800 (2012: US$93,295,534).

At the reporting date, the Group’s outstanding minimum exploration commitments will fall due as follows:

**GROUP**

<table>
<thead>
<tr>
<th>Preferred</th>
<th>US$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Within one year</td>
<td>17,453,300</td>
</tr>
<tr>
<td>Within two to five years</td>
<td>83,311,500</td>
</tr>
<tr>
<td>Total</td>
<td>103,764,800</td>
</tr>
</tbody>
</table>

**Related party disclosures**

Compensation of directors and key management personnel

The remuneration of directors and other members of key management during the year was as follows:

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salaries and bonus</td>
<td>9,439,231</td>
<td>3,762,717</td>
</tr>
<tr>
<td>Central Provident fund contributions</td>
<td>67,217</td>
<td>16,317</td>
</tr>
<tr>
<td>Share-based payments</td>
<td>367,596</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td><strong>9,874,044</strong></td>
<td><strong>3,779,034</strong></td>
</tr>
</tbody>
</table>

Comprise amounts paid to:

- Directors of the Company: 3,537,338 – 2,578,112
- Other key management personnel: 6,346,726 – 1,200,922

**Fair value of financial instruments**

(a) Fair value hierarchy

The Group categorises fair value measurements using a fair value hierarchy that is dependent on the valuation inputs used as follows:

- **Level 1** – Quoted prices (unadjusted) in active markets for identical assets or liabilities that the Group can access at the measurement date
- **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), and
- **Level 3** – Unobservable inputs for the asset or liability

(b) Assets measured at fair value

The following table shows an analysis of assets measured at fair value at the end of the reporting period:

<table>
<thead>
<tr>
<th></th>
<th>GROUP</th>
<th>GROUP</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2012</td>
</tr>
<tr>
<td>Recurring fair value measurements</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Financial assets:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Embedded derivatives</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>(Note 12)</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>2012</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Financial assets:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Embedded derivatives</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>(Note 12)</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>9,874,044</td>
<td>3,779,034</td>
</tr>
</tbody>
</table>

(c) Level 2 fair value measurements

The following is a description of the valuation techniques and inputs used in the fair value measurement for assets that are categorised within Level 2 of the fair value hierarchy:

Embedded derivatives

Fair value of embedded derivatives are valued using a valuation technique with market observable inputs. The trinomial tree (lattice, i.e. Hull-White one factor Trinomial Tree (“Hull & White” model) is constructed to model the interest rates used to value the Bonds. The Hull & White Model incorporates various inputs including the short rate volatility, mean reversion and discount rate.

(d) Assets and liabilities not carried at fair value but for which fair value is disclosed

Trade and other receivables and payables and accrued operating expenses

The carrying amounts of these financial assets and liabilities are reasonable approximation of fair values due to their short-term nature.

Fair value measurements that use inputs of different hierarchy levels are categorised in its entirety in the same level of the fair value hierarchy as the lowest level input that is significant to the entire measurement.

**Financial risk management objectives and policies**

The Group is exposed to financial risks arising from its operations and the use of financial instruments. The key financial risks include credit risk, interest rate risk, and liquidity risk. It, and has been throughout the current financial year, the Group’s policy that no derivatives shall be undertaken, except for the use as hedging instruments where appropriate and cost-efficient.

The following sections provide details regarding the Group’s exposure to the above-mentioned financial risks and the objectives, policies and processes for the management of these risks.

**Credit risk**

Credit risk is the risk of loss that may arise on outstanding financial instruments should a counterparty fail to default on its obligations. The Group’s exposure to credit risk arises primarily from trade and other receivables. For other financial assets (including cash and bank balances and derivatives), the Group minimises credit risk by dealing exclusively with high credit rating counterparties.

**Exposure to credit risk**

At the end of the reporting date, the Group’s maximum exposure to credit risk is represented by:

- the carrying amount of each class of financial assets recognised in the consolidated statement of financial position
- the carrying amount of loans and borrowings recognised in the consolidated statement of financial position relating to a corporate guarantee for the Bonds

**Credit risk concentration profile**

At the reporting date, approximately 65% (2012: 46%) of the Group’s receivables arises from the Group’s working interest in Glagah Kambuna TAC, B8/32 concession, B9/A concession and Block 9 PSC.

**Financial assets that are neither past due nor impaired**

Trade and other receivables that are neither past due nor impaired are with creditworthy debtors with good payment record with the Group. Cash and cash equivalents, investment securities and derivatives are placed with or entered into with reputable financial institutions or companies with high credit ratings and no history of default.

**Financial assets that are either past due or impaired**

Information regarding financial assets that are either past due or impaired is disclosed in Note 16 (Trade and other receivables).

**Interest rate risk**

Interest rate risk is the risk that the fair value or future cash flows of the Group’s financial instrument will fluctuate because of changes in market interest rates. At 31 December 2013 and 2012, the Group has insignificant financial instruments that are exposed to interest rate risk.

**Liquidity risk**

Liquidity risk is the risk that the Group will encounter difficulty in meeting financial obligations due to shortage of funds. The Group’s exposure to liquidity risk arises primarily from mismatches of the maturities of financial assets and liabilities.
The table below summarizes the maturity profile of the Group’s financial assets and liabilities at the reporting date based on contractual undiscounted repayments obligations:

<table>
<thead>
<tr>
<th>GROUP</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ONE YEAR OR LESS</td>
<td>ONE TO FIVE YEARS</td>
</tr>
<tr>
<td></td>
<td>US$</td>
<td>US$</td>
</tr>
<tr>
<td>Financial assets:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Trade and other receivables</td>
<td>54,149,712</td>
<td>–</td>
</tr>
<tr>
<td>Cash and bank balances</td>
<td>251,809,697</td>
<td>–</td>
</tr>
<tr>
<td>Total undiscounted financial assets</td>
<td>305,959,409</td>
<td>–</td>
</tr>
<tr>
<td>Financial liabilities:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Trade and other payables</td>
<td>35,990,001</td>
<td>–</td>
</tr>
<tr>
<td>Accrued operating expenses</td>
<td>13,012,320</td>
<td>–</td>
</tr>
<tr>
<td>Loans and borrowings</td>
<td>127,348,262</td>
<td>–</td>
</tr>
<tr>
<td>Employee benefit liability</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Total undiscounted financial liabilities</td>
<td>176,350,583</td>
<td>–</td>
</tr>
<tr>
<td>Total net undiscounted financial assets/(liabilities)</td>
<td>129,608,826</td>
<td>(884,691)</td>
</tr>
</tbody>
</table>

The table below shows the contractual expiry by maturity of the Group’s contingent liabilities and commitments. The maximum amount of the corporate guarantee for the callable bonds (Note 21) is allocated to the earliest period in which the guarantee could be called.

<table>
<thead>
<tr>
<th>GROUP</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ONE YEAR OR LESS</td>
<td>ONE TO FIVE YEARS</td>
</tr>
<tr>
<td></td>
<td>US$</td>
<td>US$</td>
</tr>
<tr>
<td>Corporate guarantees</td>
<td>127,348,262</td>
<td>–</td>
</tr>
<tr>
<td>Corporate guarantees</td>
<td>–</td>
<td>116,746,808</td>
</tr>
</tbody>
</table>

**Capital management**

Capital includes debt and equity items as disclosed in the following table. The primary objective of the Group’s capital management is to ensure that it maintain a healthy capital ratios in order to support its business and maximise shareholder value.

The Group manages its capital structure and makes adjustments to it, in light of changes in economic conditions. To maintain or adjust the capital structure, the Group may adjust the dividend payment to shareholders, return capital to shareholders or issue new shares. No changes were made in the objectives, policies or processes during the year ended 31 December 2013 and 31 December 2012.

The Group monitors capital using a gearing ratio, which is net debt divided by total capital plus net debt. The Group’s policy is to keep the gearing ratio between 20% and 40%. The Group includes within net debts, trade and other payables, accrued operating expenses, loans and borrowings, and employee benefit liability less cash and cash equivalents. Capital includes equity attributable to the owners of the Company.

**Non-current assets information presented above consists of exploration and evaluation assets, oil and gas properties and intangible assets as presented in the consolidated statement of financial position.**

**Information about major customers**

The Group identifies a major customer as one who contributes to 10% or more of the total revenue. As at 31 December 2013, revenue from three major customers contributed to 19%, 60% and 13% (2012: 38%, 30% and 12%) of the total revenue respectively.

**Subsequent events**

On 30 January 2014, the outstanding principal amount of the US$120,000,000 Bonds (Note 21), which mature on 21 July 2016 has been fully redeemed by the Issuer at 105.25% of the principal amount together with the total amount of accrued interest. There are no outstanding Bonds following the redemption.

On 26 February 2014, the Group was awarded the operatorship and a 95% working interest in Sakti PSC, offshore East Java in Indonesia. The Sakti exploration block covers 4,794 sq km in the East Java Sea over the western margin of the East Java Basin, Bajwan Arch and the Muriah Trough.

On 12 March 2014, the Group was awarded a 45% non-operating working interest in shallow block SS-11, offshore Bangladesh. The SS-11 exploration block covers an area of 4,475 sq km in the Bay of Bengal over the Bengal Fan, and lies in shallow waters up to 200 metres with the furthest southwest portion extending into water depths up to 1,500 metres.

**Segment reporting**

For management purposes, the Group operates in one business segment that is exploration and production of oil and gas in Asia. Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

<table>
<thead>
<tr>
<th>GROUP</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>REVENUE</td>
<td>NON-CURRENT ASSETS</td>
</tr>
<tr>
<td></td>
<td>US$</td>
<td>US$</td>
</tr>
<tr>
<td>Bangladesh</td>
<td>1,660,915</td>
<td>43,146,839</td>
</tr>
<tr>
<td>Cambodia</td>
<td>22,849,469</td>
<td>21,797,456</td>
</tr>
<tr>
<td>Indonesia</td>
<td>4,031,510</td>
<td>60,074,002</td>
</tr>
<tr>
<td>Thailand</td>
<td>62,357,978</td>
<td>220,365,116</td>
</tr>
<tr>
<td>Vietnam</td>
<td>38,171,923</td>
<td>105,786,632</td>
</tr>
</tbody>
</table>

The consolidated financial statements for the year ended 31 December 2013 were authorised for issue in accordance with a resolution of the directors on 18 March 2014.
SHAREHOLDING STATISTICS

Total number of issued shares : 1,046,154,000
Class of Shares : Ordinary Shares of US$0.0125 par value
Voting rights : 1 vote per ordinary Share

Analysis of Shareholdings as at 12 March 2014:

<table>
<thead>
<tr>
<th>SIZE OF SHAREHOLDERS</th>
<th>NUMBER OF SHAREHOLDERS</th>
<th>% NUMBER OF SHARES</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 – 999</td>
<td>5</td>
<td>0.30</td>
<td>1,699</td>
</tr>
<tr>
<td>1,000 – 10,000</td>
<td>990</td>
<td>59.00</td>
<td>5,645,398</td>
</tr>
<tr>
<td>10,001 – 100,000</td>
<td>665</td>
<td>39.63</td>
<td>40,302,000</td>
</tr>
<tr>
<td>100,001 &amp; above</td>
<td>18</td>
<td>1.07</td>
<td>1,000,204,903</td>
</tr>
<tr>
<td>Total</td>
<td>1,678</td>
<td>100.00</td>
<td>1,046,154,000</td>
</tr>
</tbody>
</table>

Top Twenty Shareholders as at 12 March 2014:

<table>
<thead>
<tr>
<th>NO.</th>
<th>NAME OF SHAREHOLDER</th>
<th>NUMBER OF SHARES</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Merrill Lynch (S) Pte Ltd</td>
<td>479,311,568</td>
<td>45.82</td>
</tr>
<tr>
<td>2.</td>
<td>BNP Paribas Nominees Singapore Pte Ltd</td>
<td>328,536,000</td>
<td>31.40</td>
</tr>
<tr>
<td>3.</td>
<td>Citibank Nominees Singapore Pte Ltd</td>
<td>575,066,130</td>
<td>5.50</td>
</tr>
<tr>
<td>4.</td>
<td>DBS Services Pte Ltd</td>
<td>33,794,000</td>
<td>0.32</td>
</tr>
<tr>
<td>5.</td>
<td>Morgan Stanley Asia (S) Securities Pte Ltd</td>
<td>23,418,800</td>
<td>2.24</td>
</tr>
<tr>
<td>6.</td>
<td>Raffles Institute (Pte) Ltd</td>
<td>22,358,464</td>
<td>2.14</td>
</tr>
<tr>
<td>7.</td>
<td>HSBC (Singapore) Nominees Pte Ltd</td>
<td>15,017,050</td>
<td>1.44</td>
</tr>
<tr>
<td>8.</td>
<td>DBS Nominees Pte Ltd</td>
<td>9,212,883</td>
<td>0.88</td>
</tr>
<tr>
<td>9.</td>
<td>BNP Paribas Securities Services</td>
<td>7,555,000</td>
<td>0.72</td>
</tr>
<tr>
<td>10.</td>
<td>United Overseas Bank Nominees Pte Ltd</td>
<td>6,034,000</td>
<td>0.58</td>
</tr>
<tr>
<td>11.</td>
<td>OCBC Securities Private Ltd</td>
<td>5,177,000</td>
<td>0.50</td>
</tr>
<tr>
<td>12.</td>
<td>UOB Kay Hian Pte Ltd</td>
<td>3,156,000</td>
<td>0.30</td>
</tr>
<tr>
<td>13.</td>
<td>Lim Chye Hai (Lin Cahai)</td>
<td>2,028,000</td>
<td>0.19</td>
</tr>
<tr>
<td>14.</td>
<td>DB Nominees (S) Pte Ltd</td>
<td>1,625,000</td>
<td>0.16</td>
</tr>
<tr>
<td>15.</td>
<td>Radika Investments L.P.</td>
<td>1,815,008</td>
<td>0.15</td>
</tr>
<tr>
<td>16.</td>
<td>DBS Vickers Securities (S) Pte Ltd</td>
<td>1,510,000</td>
<td>0.14</td>
</tr>
<tr>
<td>17.</td>
<td>Maybank Kim Eng Securities Pte Ltd</td>
<td>1,237,000</td>
<td>0.12</td>
</tr>
<tr>
<td>18.</td>
<td>Bank of Singapore Nominees Pte Ltd</td>
<td>1,123,000</td>
<td>0.11</td>
</tr>
<tr>
<td>19.</td>
<td>Lee Yuan Shih</td>
<td>1,000,000</td>
<td>0.10</td>
</tr>
<tr>
<td>20.</td>
<td>CIMB Securities (S) Pte Ltd</td>
<td>994,000</td>
<td>0.10</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>1,002,198,903</td>
<td>95.81</td>
</tr>
</tbody>
</table>

Substantial Shareholders as at 12 March 2014:

<table>
<thead>
<tr>
<th>HOLDINGS REGISTERED IN NAME OF SUBSTANTIAL SHAREHOLDERS OR NOMINEES</th>
<th>HOLDINGS IN WHICH SUBSTANTIAL SHAREHOLDERS ARE DEEMED TO HAVE AN INTEREST IN</th>
<th>TOTAL SHAREHOLDING</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO. OF SHARES</td>
<td>%</td>
<td>NO. OF SHARES</td>
</tr>
<tr>
<td>KrisEnergy Holdings Ltd</td>
<td>473,206,568</td>
<td>45.23</td>
</tr>
<tr>
<td>First Reserve Fund XI P.L.P.</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>First Reserve GP XII P.L.P.</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>First Reserve GP XII Limited</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>William Macaluso</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Devan International Limited</td>
<td>328,536,000</td>
<td>31.40</td>
</tr>
<tr>
<td>AX, Morgan Stanley Asia (S) Securities Pte Ltd</td>
<td>23,418,800</td>
<td>2.24</td>
</tr>
<tr>
<td>AX, DBS Vickers Securities (S) Pte Ltd</td>
<td>1,510,000</td>
<td>0.14</td>
</tr>
<tr>
<td>AX, Maybank Kim Eng Securities Pte Ltd</td>
<td>1,237,000</td>
<td>0.12</td>
</tr>
<tr>
<td>AX, Bank of Singapore Nominees Pte Ltd</td>
<td>1,123,000</td>
<td>0.11</td>
</tr>
<tr>
<td>AX, Lee Yuan Shih</td>
<td>1,000,000</td>
<td>0.10</td>
</tr>
<tr>
<td>AX, CIMB Securities (S) Pte Ltd</td>
<td>994,000</td>
<td>0.10</td>
</tr>
</tbody>
</table>

NOTES:

1. First Reserve Fund XI P.L.P. (“FRXI”), First Reserve GP XII P.L.P. (“FRXGII”), First Reserve GP XII Limited (“FRXII”), and William Macaluso are deemed under Section 4 of the Securities and Futures Act, Chapter 289 of Singapore (“SFA”) to have an interest in the Shares held by KrisEnergy Holdings Ltd. (“KESL”).
2. The ordinary shares of KESL are held by FRXI (86.3 per cent.) and FRXII-A Parallel Vehicle P.L.P (“FRX-A1”) (1.7 per cent.).
3. KESL is a wholly owned subsidiary of KCL.
4. FRXII is managed by FR GP XII Limited.
5. William Macaluso has the ability to appoint directors of FR GP XII Limited.

Public Shareholders
Based on the information available to our Company as at 12 March 2014, approximately 16.70% of the issued shares of our Company is held by the public and therefore, pursuant to Rules 1007 and 723 of the Listing Manual of the Singapore Exchange Securities Trading Limited, it is confirmed that at least 10% of the ordinary shares of our Company is at all times held by the public.

Treasury Shares
As at 12 March 2014, the Company does not hold any treasury shares.
January 22, 2014

Board of Directors
KrisEnergy Ltd
83 Clemenceau Avenue
10-05, UE Square, Shell House
Singapore 239920

Gentlemen:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future reserves, as of December 31, 2013, to the KrisEnergy Ltd (KrisEnergy) interest in certain oil and gas properties located in Blocks B8/B2 and B9A and Nang Yai Field, offshore Thailand, and Banggaree Field, onshore Bangladesh. Also as requested, we have estimated the development pending contingent resources and cash flow to the KrisEnergy interest, as of December 31, 2013, for certain discoveries located offshore Thailand, Indonesia, and Cambodia and the development unclassified contingent resources to the KrisEnergy working interest, as of December 31, 2013, for certain other discoveries located offshore Thailand, Indonesia, and Cambodia and onshore Bangladesh. We completed our evaluation on or about the date of this letter. This report has been prepared using price and cost parameters specified by KrisEnergy, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (S$).

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2007 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be evaluated without extensive consideration of these factors. Definitions are presented immediately following this letter. The tables following the definitions set forth our estimates of reserves and contingent resources, by category, to the KrisEnergy interest for each asset area.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

We estimate the gross (100 percent) reserves and working interest reserves and future net revenue to the KrisEnergy interest in these properties, as of December 31, 2013, to be:

<table>
<thead>
<tr>
<th>Category</th>
<th>Gross (100 Percent) Reserves</th>
<th>Working Interest Reserves</th>
<th>Future Net Revenuea (S$)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oil (MMBBL)</td>
<td>Gas (MMCFG)</td>
<td>Total</td>
</tr>
<tr>
<td></td>
<td>Present Worth At 10%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proved Developed Producing</td>
<td>18,557.0</td>
<td>164,844.2</td>
<td>393.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>13,794.5</td>
</tr>
<tr>
<td>Proved Developed Non-Producing</td>
<td>55.7</td>
<td>201.0</td>
<td>2.6</td>
</tr>
<tr>
<td>Proved Undeveloped</td>
<td>21,644.6</td>
<td>66,039.9</td>
<td>2,840.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>66,456.2</td>
</tr>
<tr>
<td>Proved (P)</td>
<td>40,107.2</td>
<td>254,134.8</td>
<td>3,998.8</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>100,539.8</td>
</tr>
<tr>
<td>Probable</td>
<td>111,128.1</td>
<td>897,298.6</td>
<td>6,301.1</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>269,286.6</td>
</tr>
<tr>
<td>Proved + Probable (2P)</td>
<td>151,235.3</td>
<td>1,151,143.4</td>
<td>9,900.8</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>369,826.4</td>
</tr>
<tr>
<td>Possible</td>
<td>39,929.7</td>
<td>346,046.0</td>
<td>3,333.9</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>159,819.3</td>
</tr>
<tr>
<td>Proved + Probable + Possible (3P)</td>
<td>191,163.9</td>
<td>1,498,379.4</td>
<td>13,234.7</td>
</tr>
</tbody>
</table>

a) Future net revenue is after deductions for royalties and KrisEnergy’s share of future capital costs, abandonment costs, operating expenses, special remuneration benefit, and income taxes.

The oil volumes shown include crude oil and condensate. Gas volumes are expressed in millions of cubic feet (MMCFG) at standard temperature and pressure bases.

The estimates of reserves shown in this report are for proved, probable, and possible reserves. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue for the reserves is KrisEnergy’s share of the gross (100 percent) revenue from the properties after deductions for royalties. Future net revenue is after additional deductions for KrisEnergy’s share of future capital costs, abandonment costs, operating expenses, special remuneration benefit, and income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the KrisEnergy interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on KrisEnergy receiving its net revenue interest share of estimated future gross production.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. The discoveries assessed in this report have been subclassified as development pending or development unclassified. The 2007 PRMS defines a development pending discovery as a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future and a development unclassified discovery as a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The contingent resources shown in this report are contingent upon one or more of the following: (1) commitment of the license partners to develop the resources, (2) submission and approval of a Plan 4900 TRANQU sill TOWER - 1601 ELM STREET - DALLAS, Texas 75201-4754 - PH: 214-569-5451 - FAX: 214-569-5411 1221 LAMAR STREET, SUITE 7000-FOR R I S T O N A , Texas 77010-2072 - PH: 713-654-4852 - FAX: 713-654-4801 nsa@msai-petro.com netherlands. sewell.com
of Development (POD), Production Area Application (PAA), or Production Permit Application (PPA), (3) completion of a gas sales agreement, and (4) collection of additional technical data, to be collected through delineation wells and flow tests, to establish commercial viability. The costs required to resolve these contingencies have not been included in this report; estimates of cash flow are based on the assumption that applicable contingencies will be successfully addressed. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been averted to account for the possibility that the contingencies are not successfully addressed. This report does not include economic analysis for the development unclassified contingent resources. Because of the early stage of development of these projects, we did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

We estimate the gross (100 percent) contingent resources and working interest contingent resources and net contingent cash flow to the KrisEnergy interest in these discoveries, as of December 31, 2013, to be

<table>
<thead>
<tr>
<th>Subclassification/Category</th>
<th>Gross (100 Percent)</th>
<th>Working Interest</th>
<th>Net Contingent Cash Flow</th>
<th>Discounted At 10%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oil (MMBL)</td>
<td>Gas (MMCF)</td>
<td>Oil (MMBL)</td>
<td>Gas (MMCF)</td>
</tr>
<tr>
<td>Development Pending</td>
<td>8,600.0</td>
<td>307,782.5</td>
<td>2,273.8</td>
<td>130,807.6</td>
</tr>
<tr>
<td>Low Estimate (1C)</td>
<td>8,600.0</td>
<td>307,782.5</td>
<td>2,273.8</td>
<td>130,807.6</td>
</tr>
<tr>
<td>Best Estimate (2C)</td>
<td>35,538.2</td>
<td>454,169.9</td>
<td>9,922.4</td>
<td>203,870.1</td>
</tr>
<tr>
<td>High Estimate (3C)</td>
<td>64,999.5</td>
<td>585,061.1</td>
<td>17,031.4</td>
<td>260,762.2</td>
</tr>
<tr>
<td>Development Unclassified(1)</td>
<td>1,999.4</td>
<td>11,002.4</td>
<td>400.0</td>
<td>2,931.5</td>
</tr>
<tr>
<td>Low Estimate (1C)</td>
<td>3,055.7</td>
<td>153,032.4</td>
<td>881.6</td>
<td>59,162.9</td>
</tr>
<tr>
<td>High Estimate (3C)</td>
<td>27,861.6</td>
<td>310,840.7</td>
<td>6,426.7</td>
<td>111,551.6</td>
</tr>
</tbody>
</table>

Note: Contingent resources are the arithmetic sum of multiple probability distributions.

(1) Net contingent cash flow is after deductions for royalties and KrisEnergy’s share of future capital costs, abandonment costs, operating expenses, cost reimbursements associated with local participation, head office overhead, production bonus payments, special remuneration benefit, and income taxes.

10 percent to indicate the effect of time on the value of money; the contingent cash flow, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

ECONOMIC PARAMETERS

As requested, this report has been prepared using oil and gas price parameters specified by KrisEnergy. Oil prices for the reserves and development pending contingent resources are based on the December 31, 2013, EIA Europe Brent Spot Price (FOB) of $109.95 per barrel and are adjusted by field area for quality, transportation fees, and regional price differentials. Oil prices are held constant throughout the lives of the properties. Gas prices for Block B8/32 and Block B6A reserves are based on the Tantawan Gas Sales Agreement price of $5.788 per MM BTU and are adjusted by field area for energy content. The gas price for Bangora Field reserves is the contract price of $2.516 per MCF. Gas prices for Block B8/32, Block B6A, and Bangora Field reserves are held constant throughout the lives of the properties.

Gas prices for the development pending contingent resources are based on recent gas contracts in similar areas. The gas price used for Lengo and East Lengo Fields is $6.500 per MM BTU, which is then adjusted for energy content. The gas price used for Kutai Field is $9.000 per MM BTU, which is then adjusted for energy content. Gas prices for the development pending contingent resources are escalated 3 percent per year from the year of first production throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of and budgets prepared by the operators of the properties, as provided by KrisEnergy. These costs include the per-well overhead expenses allowed under concession agreements along with estimates of costs to be incurred at and below the field level. Headquarters general and administrative overhead expenses of KrisEnergy are included to the extent that they are covered under concession agreements for the operated properties. As requested, operating costs are not escalated for inflation.

Capital costs used in this report were provided by KrisEnergy and are based on budgeted expenditures and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are KrisEnergy’s estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are not escalated for inflation.

GENERAL INFORMATION

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves and contingent resources have been estimated. For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. Based on the information used in our analyses, it is our opinion that a field visit was not required and would not materially affect our evaluation. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves and contingent resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. Our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future
production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales prices, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves and contingent resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analog, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2007 PRMS definitions and guidelines. The contingent resources and a portion of the reserves shown in this report are for undeveloped locations; such volumes are based on estimates of reserve volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from KrisEnergy, other interest owners, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical personnel responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2099

By
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By
Allen E. Evans, Jr., P.G.
Senior Vice President

By
Philip S. (Scott) Frost, P.E.
Vice President

Date Signed: January 22, 2013

PSF: TDL

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth’s crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

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

1.1 Petroleum Resources Classification Framework

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

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

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

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

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

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

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir recovery (see Production Measurement, section 3.2).

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

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

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

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

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

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

Estimated Ultimate Recovery (EUR) is a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

Definitions - Page 2 of 10

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

1.2 Project-Based Resources Evaluations

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

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

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

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

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

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

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see Definitions - Page 3 of 10

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Commercial Evaluations, section 3.1. “Conditions” include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

### 2.0 Classification and Categorization Guidelines

#### 2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

##### 2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially movable hydrocarbons.

In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

##### 2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.
PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Class/Sub-Class | Definition | Guidelines
--- | --- | ---
Reserves | Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While a 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are defined at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reserve as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests. | All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way. All this must be substantiated by any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditure must be included in the reporting entity's current or following year's approved budget.

Contingent Resources | Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources may include, for example, projects for which there are current technical, regulatory, or financial uncertainties, or where development is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. | The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Development Pending | A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The project “decision gate” is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production. | In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity’s assumptions of future prices, costs, etc. (“forecast cases”) and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There would be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Otherwise such approval/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class).

Development Unclassified or on Hold | A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project “decision gate” is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies. | The project “decision gate” is the decision to whether proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS
Excerpted from the Petroleum Resources Management System Approved by the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Class/Sub-Class | Definition | Guidelines
--- | --- | ---
**Development Not Viable** | A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. | The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or economic conditions. The project “decision gate” is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

Prospective Resources | Those quantities of oil and gas which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. | Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect | A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. | Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under commercial development programs.

Lead | A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. | Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Pilot | A project associated with a prospective field of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. | Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to develop specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

### Table 2: Reserves Status Definitions and Guidelines

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

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

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

### Table 3: Reserves Category Definitions and Guidelines

| Category | Definition | Guidelines
| --- | --- | ---
**Proved Reserves** | Proved Reserves are those quantities of oil and gas 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, these should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any; and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved reserves in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define field contours for Proved reserves (see “2001 Supplemental Guidelines” Chapter 8).

Reserves in undeveloped locations may be classified as Proved provided that:

- The locations are in undeveloped areas of the reservoir that can be judged with reasonable certainty to be commercially productive.
- Interpreted geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reserves should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

It is equally likely that actual remaining recoveries will be greater than or less than the sum of the estimated Proved Plus Probable Reserves (P2). 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 P2 estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria.

Probable Reserves also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.
## PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System approved by the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

<table>
<thead>
<tr>
<th>Category</th>
<th>Definition</th>
<th>Guidelines</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Possible Reserves</strong></td>
<td>Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.</td>
<td>The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretation of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.</td>
</tr>
<tr>
<td><strong>Probable and Possible Reserves</strong></td>
<td>(See above for separate criteria for Probable Reserves and Possible Reserves.)</td>
<td>The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly or indirectly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible and in some cases, Probable Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major potentially sealing faults until this reservoir is penetrated and evaluated as commercially producible. Justification for assigning reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a higher known oil (WHO) elevation and there exists the potential for an associated gas cap, proved oil reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible and/or based on reservoir fluid properties and pressure gradient interpretations.</td>
</tr>
</tbody>
</table>

The 2007 Petroleum Resources Management System can be viewed at its entirety at [http://www.aip.org/energy-appraisalindustry/reserves/perms.htm](http://www.aip.org/energy-appraisalindustry/reserves/perms.htm)

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### Definitions - Page 10 of 10

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.
## Offshore Thailand

<table>
<thead>
<tr>
<th>Country/Asset/Category</th>
<th>Gross Contingent Resources (bbl)</th>
<th>Working Interest</th>
<th>Net Contingent Resources (bbl)</th>
<th>Net Contingent Cash Flow (MM$)</th>
<th>Total Un undeveloped</th>
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<tr>
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<td>1,411.1</td>
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## Offshore Indonesia

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<tr>
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NOTICE OF ANNUAL GENERAL MEETING

The initial public offering of KrisEnergy Ltd. was sponsored by CLSA Singapore Pte Ltd and Merrill Lynch (Singapore) Pte. Ltd. (the “Joint Issue Managers, Global Coordinators, Bookrunners and Underwriters”). The Joint Issue Managers, Global Coordinators, Bookrunners and Underwriters assume no responsibility for the contents of this Notice.

KrisEnergy Ltd.
Company Registration Number: 231886
Incorporated in the Cayman Islands on 5 October 2009

NOTICE IS HEREBY GIVEN that the First Annual General Meeting of KRISENERGY LTD. (the “Company”) will be held at Phoenix II, Level 6, Hotel Novotel Singapore, 177A River Valley Road, Singapore 179031 on 24 April 2014 at 10.00 a.m. to transact the following business:

A

ORDINARY BUSINESS

1. To receive and adopt the Directors’ Report and the Audited Financial Statements for the financial year ended 31 December 2013 and the Auditor’s Report thereon. (See Explanatory Note 1.)

2. To re-elect Mr. Brooks Michael Shughart, a Director retiring pursuant to Article 125 of the Company’s Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. (See Explanatory Note 1.)

3. To re-elect Mr. Choo Chiau Beng, a Director retiring pursuant to Article 125 of the Company’s Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. (See Explanatory Note 1.)

4. To re-elect Mr. Koh Tjiong Lu John, a Director retiring pursuant to Article 125 of the Company’s Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. (See Explanatory Note 1.)

5. To re-elect Mr. Keith Gordon Cameron, a Director retiring pursuant to Article 125 of the Company’s Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. (See Explanatory Note 1.)

6. To approve the sum of US$895,000 (S$1,377,148) to be paid to all non-executive Directors as Directors’ fees for the financial year ended 31 December 2013. (2012: US$101,000 (S$152,723)) (See Explanatory Note 2.)

7. To re-appoint Ernst & Young LLP as Auditors of the Company and to authorise the Directors to fix their remuneration. (See Explanatory Note 2.)

B

SPECIAL BUSINESS

8. That pursuant to Rule 8.06 of the Listing Manual of the Singapore Securities Trading Limited (“SGX-ST”), authority be and is hereby given to the Directors of the Company to:

(i) issue shares in the capital of the Company (the “Shares”) (whether by way of rights, bonus or otherwise); and

(ii) make or grant offers, agreements or options (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 instruments convertible into Shares, at any time and upon such terms and conditions and for such purposes and to such person(s) as the Directors may in their absolute discretion deem fit; and

(whilst subject to the authority conferred by this Resolution may have ceased to be in force)

(iii) issue Shares in pursuance of any Instrument made or granted by the Directors while this Resolution was in force;

provided that:

(a) the aggregate number of Shares to be issued pursuant to this Resolution (including new Shares to be issued in pursuance of Instruments made or granted pursuant to this Resolution) shall not exceed 5.0 per cent. of the issued share capital of the Company excluding treasury shares (as calculated in accordance with sub-paragraph (b) below); or

(b) any subsequent bonus issue, consolidation or subdivision of Shares;

(c) in exercising the authority conferred by this Resolution, the Company shall comply with the provisions of the Listing Manual of the SGX-ST for the time being in force (unless such compliance has been waived by the SGX-ST and the Articles of Association for the time being of the Company); and

(ii) (i) any issue or grant of shares, share options or warrants, debentures or other instruments convertible into Shares, which are outstanding or subsisting at the time this Resolution is passed; and

(iii) the aggregate number of Shares to be issued pursuant to the KrisEnergy Employee Share Option Scheme and the KrisEnergy Performance Share Plan shall not exceed 15.0 per cent. of the issued share capital of the Company excluding treasury shares (as calculated in accordance with sub-paragraph (b) below); or

(d) (i) to issue and/or to grant awards in accordance with the provisions of the KrisEnergy Employee Share Option Scheme and/or the KrisEnergy Performance Share Plan; and

(ii) the aggregate number of ordinary shares in the capital of the Company as may be required to be issued pursuant to the exercise of options under the KrisEnergy Employee Share Option Scheme and/or the KrisEnergy Performance Share Plan shall not exceed 15.0 per cent. of the issued share capital of the Company from time to time.

(See Explanatory Note 4.)

9. That approval be and is hereby given to the Directors to:

(i) offer and grant options in accordance with the provisions of the KrisEnergy Employee Share Option Scheme and/or to grant awards in accordance with the provisions of the KrisEnergy Performance Share Plan; and

(ii) 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 paragraph (i) above, the percentage of issued share capital shall be based on the issued share capital of the Company excluding treasury shares at the time this Resolution is passed, after adjusting for:

(a) 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 this Resolution is passed; and

(b) any subsequent bonus issue, consolidation or subdivision of Shares;

(See Explanatory Note 3.)

10. To transact any other business as may properly be transacted at an Annual General Meeting.

By Order of the Board

KELVIN TANG / JENNIFER LEE
Joint Company Secretaries

3 April 2014, Singapore
NOTICE OF ANNUAL GENERAL MEETING

NOTES:
1. This notice to the shareholders will be sent by post at least 48 hours prior to the time of the Annual General Meeting.
2. Depositors. Under the Articles, unless The Central Depository (Pte) Limited (“CDP”) specifies otherwise in a written notice to the Company, CDP is deemed to have appointed as CDP’s proxy to vote on behalf of CDP at the Annual General Meeting each of the persons (who are individual holding shares in the capital of the Company) whose names are entered in the Depository Register (as defined in Section 130A of the Companies Act, Chapter 50) at Singapore (“Depositor”), whose names are shown in the records of CDP as at a time not earlier than 48 hours prior to the time of the Annual General Meeting supplied to CDP by the Company, and such appointment will remain in force until the meeting of the Company called for the purpose of determining the aggregate number of Shares that may be issued pursuant to Resolution 8 (including new Shares to be issued in pursuance of Instruments made or granted pursuant to Resolution 8) shall not exceed 50.0% of the issued share capital of the Company excluding treasury shares, with a sub-limit of 10.0% per cent. of the issued share capital of the Company from time to time.

3. Members. The Directors have fixed 22 April 2014 as the record date for determining those members who are entitled to attend and vote at the Annual General Meeting. A member of the Company (other than CDP) entitled to attend and vote at the Annual General Meeting who is the holder of two or more shares is entitled to appoint not more than two proxies to attend and vote at the Annual General Meeting. A member of the Company (other than CDP) entitled to attend and vote as proxy or proxies of CDP at the Annual General Meeting each of the persons (who are individuals) holding shares in the capital of the Company from time to time.

4. Deposit of Instrument of Proxy. The instrument appointing a proxy or proxies (together with the power of attorney, if any, under which it is signed or certified copy of the same) must be delivered to the Office of R & C Services Private Limited at 112 Robinson Road #05-01, Singapore 068902 at least 48 hours before the time appointed for holding the Annual General Meeting.

EXPLANATORY NOTES:

Resolutions 2 to 5
1. Detailed information on these Directors can be found in the section entitled “Board of Directors” of the Company’s Annual Report.

(a) Mr. Brooks Michael, Shughart upon re-election as a Director of the Company, will remain as a member of the Audit Committee and Remuneration Committee. He is a non-executive Director appointed by our indirect controlling shareholder, First Reserve Management L.P. and its affiliated funds. He is considered non-independent and is a non-executive Director.

(b) Mr. Chin Chiau Beng, upon re-election as a Director of the Company, will remain as a member of the Remuneration Committee. He is a non-executive Director appointed by an indirect controlling shareholder, Haplo Corporation Ltd. He is considered non-independent and is a non-executive Director.

(c) Mr. Hieh Ting Lou, upon re-election as a Director of the Company, will remain as the Chairman of the Audit Committee and a member of the Remuneration Committee and Nominating Committee, and is considered independent.

(d) Mr. Keith Gordon Cameron is considered non-independent and is an executive Director.

Resolution 6
2. The Company commenced paying Directors’ fees to all non-executive Directors on listing on 10 July 2013.

Resolution 7
3. Resolution 7 is to empower the Directors to issue shares in the capital of the Company and/or to make or grant Instruments (as defined in Resolution 8) to the purpose of determining the aggregate number of Shares that may be issued pursuant to Resolution 8 (including new Shares to be issued in pursuance of Instruments made or granted pursuant to Resolution 8) shall not exceed 50.0% of the issued share capital of the Company excluding treasury shares, with a sub-limit of 10.0% per cent. of the issued share capital of the Company from time to time.

Resolution 9
4. Resolution 9 is to empower the Directors to offer and grant options and/or grant awards and issue ordinary shares in the capital of the Company pursuant to the KrisEnergy Employee Share Option Scheme and the KrisEnergy Performance Share Plan (as amended) and/or the KrisEnergy Performance Share Plan as limited to 10.0% per cent. of the issued share capital of the Company from time to time.
This glossary contains explanations and definitions of certain terms used in this annual report in connection with our business. The terms and their assigned meaning may not correspond to standard industry or common meaning or usage of these terms.

1C: Low estimate scenario of contingent resources.
1P: Equivalent to proved reserves; denotes low estimate scenario of reserves.
2016 Notes: Senior guaranteed secured bonds due in July 2016
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.
basin: Areas where sedimentary rocks have accumulated over time, which are regarded as good prospects for oil and gas exploration.
bbl: Barrel.
bcf: Billion cubic feet.
Block 10B: Block 105-110/04.
BMS: Business Management System.
bre: Barrel of oil equivalent.
bopd: Barrels of oil per day.
BP: Business Management System.
CNPA: Cambodian National Petroleum Authority.
contingent resources: Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.
contract area: A specified geographic area that is the subject of an agreement with the host government pursuant to which an operator and its partners provide financing and technical expertise to conduct exploration, development and production operations.
CSR: Corporate Social Responsibility.
DDA: Depreciation, depletion and amortisation.
development pending: The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing a basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable timeframe. Disappoinking appraisal/evaluation results could lead to a re-classification of the project to “On Hold” or “Not Viable” status.
development unclarified: A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal and/or evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay.
discovery: One petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploration wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially movable hydrocarbons. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in place volume demonstrated by the well(s) and for evaluating the potential for economic recovery.
DST: Drill stem test.
E&P: Exploration and production.
EBITDA: Earnings before income tax, depreciation, amortisation, impairment and exploration.
Eni: Eni SpA and its subsidiaries.
EIA: Environmental Impact Assessment.
EPCIC: Engineering, procurement, construction, installation and commissioning.
Executive Director: A Director of our Group who performs an executive function.
farm-in/farm-out: Process where the owner of an interest in a contract area invites third parties to participate in and assume some of the risks of developing the contract area.
FID: Final investment decision. The decision by a joint venture to commence development of the relevant field pursuant to the relevant approved P&A, PPA, plan of development or development plans, as the case may be.
field: An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structure feature and/or stratigraphic condition.
First Reserve: First Reserve Management L.P., together with its affiliated funds.
FSO: Floating storage and offshore loading vessel.
FWhp: Flowing wellhead pressure.
geology: The scientific study of the origin, history and structure of the Earth (adj. geological).
geophysics: Matters concerning the physics of the Earth and its environment, including the physics of fields such as meteorology, oceanography and seismology. In oil and gas exploration, this refers to geophysical methods of imaging the subsurface such as gravity, magnetic and seismic (adj. geophysical).
IPO: Initial public offering.
Kepkel: Kepkel Corporation Limited.
km: Kilometre.
leads: A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.
mcf: Thousand cubic feet.
MDT: Modular dynamic tester.
mmb: Million barrels of oil.
mmbce: Million barrels of oil equivalent.
mmdc: Million cubic feet.
mmdfe: Million cubic feet per day.
MS-Awards: Shares awarded under the KrisEnergy PSP to certain Senior Management personnel on 19 July 2013 comprising 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied, subject to certain performance conditions being met and other terms and conditions.
Mubadala: Mubadala Development Corporation and its subsidiaries.
Mubaz: Mubadala Development Corporation and its subsidiaries.
Non-executive Director: A Director of our Group who is not an Executive Director (including an Independent Director).
P&A: Production Area Application.
play: A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.
possible reserves: Those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than probable reserves.
PAA: Production Permit Application.
probable reserves: Those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than proved reserves but more certain to be recovered than possible reserves.
prospect: A project associated with a potential accumulation that is sufficiently well defined to represent a viable exploration drilling target.
prospective resources: Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
proved reserves: 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.
PSC: Production sharing contract, which is an agreement with the relevant host government, which outlines the fiscal terms for exploring, developing and producing oil and gas within a specified contract area.
psp: Pounds per square inch.
QPR: Qualified person’s report.
reserves: Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.
resources: All quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced.
sq km: Square kilometre.
tcf: Trillion cubic feet.
TAC: Technical Assistance Contract.
TULLow Bangladesh: Tullow Bangladesh Ltd.
working interest: Percentage ownership in a joint operation associated with revenue and costs. 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.
KRISENERGY REGIONAL OFFICES

BANGLADESH
House-17
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Dhaka 1212
Bangladesh

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Talavera Office Park
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Cilandak
Jakarta 12430

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#10-05, UE Square
Singapore 239920

THAILAND
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No. 173/16 South Sathorn Road
Thungmahamek Sathorn
Bangkok 10120

VIETNAM
19F, Bitexco Financial Tower,
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Ho Chi Minh City