PremierOil

Annual Results for the year ended 31 December 2013

Press Release

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Premier is a leading FTSE 250 independent exploration and production company with oil and gas interests in the North Sea, South East Asia, Pakistan and the Falkland Islands. Our strategic focus is to grow shareholder value through investment in high quality projects within a disciplined financial framework. We seek to maintain the highest standards of corporate responsibility.

Highlights

- 2013 production of 58.2 kboepd (2012: 57.7 kboepd); average production of 69 kboepd in December
- Strong underlying profitability: profit after tax of US$234.0 million (2012: US$252.0 million) after impairment charges of US$67.9 million (post-tax)
- Operating cash flow of US$832.6 million (2012: US$808.2 million)
- Catcher development approval expected shortly; Solan first oil targeted for Q4 2014; Bream and Sea Lion progressing to sanction decision
- Six discoveries from seven exploration wells adding around 40 mmboe of reserves and resources; finding costs of US$5.3/boe pre-tax
- 13 firm exploration and appraisal wells planned for 2014 targeting 140 mmboe of unrisked resources
- Recommended dividend payment of 5 pence per share (2012: 5 pence)
- Board has approved share buyback programme of up to £75 million

Simon Lockett (Chief Executive), commented:

"Premier is well financed, strongly profitable and has rapidly growing cash flows. Production year-to-date is ahead of plan. Cash flows will be invested in high quality projects or returned to shareholders. Our focused exploration programme offers exposure to material wells in proven basins."

Mike Welton, Chairman — Simon Lockett, Chief Executive

27 February 2014

ENQUIRIES

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Simon Lockett

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A presentation to analysts and investors will be held at 10.30am today at the offices of Premier Oil's Falkland Islands Business Unit, 157-197 Buckingham Palace Road, London SW1W 9SP. A live webcast of this presentation will be available via Premier's website at www.premier-oil.com.

Disclaimer

This results announcement contains certain forward-looking statements that are subject to the usual risk factors and uncertainties associated with the oil and gas exploration and production business. Whilst the group believes the expectations reflected herein to be reasonable in light of the information available to it at this time, the actual outcome may be materially different owing to factors beyond the group's control or otherwise within the group's control but where, for example, the group decides on a change of plan or strategy. Accordingly, no reliance may be placed on the figures contained in such forward-looking statements.

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CHAIRMAN'S STATEMENT

The industry context

The global economy showed tentative signs of recovery during 2013. Energy demand grew modestly whilst commodity prices remained broadly stable for the third year running. Costs have risen in certain areas of the oil services sector and governments around the world continue to seek to extract higher fiscal take from the industry. This has led investors to question the return on capital across the sector. Nonetheless discerning investments in good quality projects still deliver good returns. Debt capital markets remain liquid and offer ready access to conservatively-managed companies with strong balance sheets.

Premier's performance

Premier continues to generate strong profit, rising cash flows and a healthy return on capital. 2013 also saw a much improved year of exploration, and an increase in our reserves and resources to 794 mmboe (2012: 773 mmboe). We strive to ensure that return on capital is maximised and that our financial strength and investment profile are balanced.

I wrote in my 2012 statement that with the Huntington field on-stream, production would rise to a run rate of around 75 thousand barrels of oil equivalent per day (kboepd). It has been frustrating that, despite new production during the year, the portfolio also suffered from some operational issues which were largely beyond the company's control. Save for a short period towards the end of the year we did not exceed our target. The specific issues we faced however have been resolved, we have learned the lesson of not planning for the unexpected and have adjusted our expectations accordingly for the future.

We now look forward to the future production growth that our portfolio is capable of delivering and anticipate excellent rates of return from our key new projects. Four fields are due on-stream in 2014 and solid progress was made during the year on our longer-term developments - Catcher, Bream and Sea Lion. The Solan field is scheduled to come on-stream in the fourth quarter of this year, we expect to pass final government sanction on Catcher shortly, and to be close to sanction on Sea Lion by the end of the year.

Our exploration programme in 2013 was successful with six discoveries out of seven wells drilled. The Luno II discovery in Norway is of particular note, with follow-on drilling expected in 2014. We also had success with near-field discoveries in Indonesia, Pakistan and the UK. We were pleased to be awarded three blocks in Brazil in the 11th Licensing Round which are in proven plays, but relatively under-explored, and we continue to seek early stage exploration acreage to add to the portfolio. In 2014 and 2015 we particularly look forward to the results of our drilling in Indonesia, Norway, Kenya, and a four-well programme in the Falkland Islands.

Rationalisation of the portfolio has become a key focus for Premier this year. During 2013 we realised value for undeveloped assets in Norway and Vietnam and this programme will continue into 2014. The group also raised some US$700 million of new debt financing in the fourth quarter on very favourable terms and we go into a re-financing of our main bank facility later this year in a strong position. The combination of options in our asset portfolio and continuing access to debt capital markets gives us significant flexibility to manage our financial position on a prudent basis.

Health, safety and environmental matters continue to be of paramount importance to us. Our production operations management systems at Balmoral in the UK, and at Anoa and Gajah Baru in Indonesia retained their OHSAS 18001 and ISO 14001 certifications, as did our worldwide drilling management systems. We reiterate our commitment to protecting our people, our assets, our revenues and our reputation through maintaining the highest possible standards. We continue to be a member of the FTSE4Good Index in recognition of our health, safety, environmental and social performance.

Future plans

In 12 months time I intend to be able to report further continued progress across the portfolio: growth in operating cash flow; start-up of the Pelikan, Naga, Dua and Solan fields as planned; sanction of the Catcher project and commencement of facility construction; significant progress in the front end engineering and design (FEED) studies for Sea Lion; realisation of value from our disposal programme; further success in our exploration drilling endeavours; the addition of acreage to the portfolio and that our health, safety and environment (HSE) record is acceptable to us and our regulators. Members of the Board, including the non-executives, have had frequent direct contact with our leading shareholders during the last few months and I am confident that the plans we have in place are strongly supported.

Board personnel

An immediate priority for the Board is the recruitment of a Chief Executive Officer following the announcement in February 2014 of Simon Lockett's intention to step down from the position. We are grateful to Simon for agreeing to ensure a smooth transition by remaining in post until a successor is appointed and we thank him for devoting so much energy, dedication and spirit to the role. During Simon's tenure the business has grown significantly in production, reserves and resources and operating cash flow and we wish him well in future endeavours.

In July, we were very sad to announce the death of Professor David Roberts. He had contributed enormously to the Board during his seven years with us, by application of his extensive industry experience and knowledge. Professor Roberts' passing deprived the Board particularly of expertise and skills in the field of exploration. In January 2014 we were able to announce the expected addition to the Board in May of David Bamford, who brings considerable experience in technical and exploration roles at operational and Board-level. We also announced the arrival of Anne Marie Cannon as a new Non-Executive Director. Anne Marie brings over 30 years experience in senior and Board-level roles as an adviser and executive in the sector. We welcome both David and Anne Marie to the Board.

Shareholder returns

Our objective remains to deliver consistent, measurable capital growth to our shareholders, with exposure to additional returns from a disciplined investment in exploration. Premier's share price fell by seven per cent overall during the year which although disappointing represented an outperformance relative to many of our peers. Over the five years prior to the end of 2013 the overall return to shareholders stands at 58 per cent. We are of course keen to see this performance improve going forward.

In 2012, our confidence in our growing cash flows was reflected in the proposed dividend which was approved at the Annual General Meeting (AGM) in June 2013. We said at the time that future payouts would depend on the progression of cash flows over time and our capital requirements for our projects. I am pleased that the Board is again proposing a dividend for 2013, of 5 pence per share, to be approved by shareholders at the May 2014 AGM. We are also intending to initiate a share buyback programme, reflecting the significant gap between our share price and underlying asset value. This programme will be reviewed on a quarterly basis by the Board.

On behalf of the Board as well as myself, I would like to express my appreciation of the continued hard work and dedication of Premier's staff, all of whom are also shareholders and share the disappointment of a depressed share price that does not reflect the underlying value of the company, but who continue to inspire us with their enthusiasm and commitment.

Mike Welton
Chairman

CHIEF EXECUTIVE'S REVIEW

Strategy and Business Model

Our strategic focus is to grow shareholder value through investment in high quality oil and gas projects within a disciplined financial framework. We seek to maintain the highest standards of corporate responsibility.

We look to identify and develop projects where we can realise superior returns. We have a track record of robust returns on investment.

Through recent successful developments such as Chim Sáo in Vietnam and Gajah Baru in Indonesia, we have grown the confidence and capability to take on complex operated development projects, typically offshore and utilising floating production systems. As our asset portfolio has grown we are developing the project execution and production operations skills to ensure that our projects can be delivered successfully and in a cost effective manner.

To underpin the longer term value of the business we explore for oil and gas in both our historical areas of operation and in emerging basins that offer the potential for material upside. We target basins with rift and frontal fold belt structures in which we can draw on the expertise we have gained finding oil and gas in these types of basins in Indonesia, the North Sea and Pakistan.

Our disciplined financial framework is designed to maintain a sound balance sheet and strong funding position. We plan our business on a conservative base oil price (currently US$85 real), ensuring that we maintain adequate covenant headroom and gearing levels that are well within a Board guideline maximum of 50%. We continually seek to high grade our asset portfolio including disposing of assets that are no longer core and by selectively making acquisitions where we believe our position is advantaged. Through this approach to portfolio management we can focus the efforts of our people, drive cash flow growth, and manage our risk exposure.

Our combination of strong cash generation and conservative financing approach means that we benefit from excellent access to a variety of debt markets and continuing appetite from debt investors.

In summary, we are pleased to continue to offer our shareholders the opportunity to benefit from sustained distributions, value growth within a disciplined financial framework, and the potential for upside from selective exposure to the most promising exploration plays.

Our operations

In 2013 we saw good performance across the portfolio, offset by some significant operational issues which held back short-term growth.

Production (boepd)	Working interest		Entitlement	
	2013	2012	2013	2012
Indonesia	13,700	14,200	8,800	8,800
Pakistan	14,900	15,600	14,900	15,600
Mauritania	600	600	400	500
UK	14,900	12,100	14,900	12,100
Vietnam	14,100	15,200	13,400	14,600
Total	58,200	57,700	52,400	51,600

In the UK, good production continued from the Wytch Farm, Scott and Telford fields. Production from the Balmoral area was impacted by a temporary shutdown of the facility and the shut-in of five wells on the Balmoral field for maintenance. The non-operated Huntington field began producing in April, but was restricted due to start-up problems with the gas compression system, issues with the gas detection system and operational issues on the gas export pipeline. These issues have been resolved and Huntington achieved rates of up to 35 kboepd (gross) from December onwards. The Rochelle field was brought on-stream in October following earlier storm damage to the East Rochelle well. The Kyle field continues to await re-instatement of the production facilities scheduled for September 2014.

The Premier-operated Chim Sáo field in Vietnam produced strongly for the first half of the year. Gas export was interrupted in August following third party damage to the pipeline forcing a curtailment of oil production. The pipeline was rapidly repaired and production returned to normal levels in November. Demand for Premier’s Indonesian gas in the Singapore market remained buoyant and our Anoa and Gajah Baru platforms achieved record rates of production. The contractual share for the Natuna Sea Block A was again increased and overall Premier-operated facilities contributed 52 per cent of the gas delivered to Singapore through the West Natuna Transportation System (WNTS) pipeline.

In Pakistan, production fell as expected as natural field decline at the Zamzama, Bhit and Qadirpur fields was partially offset by increased production at Kadanwari.

Material progress was made on our development projects during 2013. In Indonesia, fabrication and installation of the Pelikan and Naga facilities were completed. Development drilling will start in the second quarter of 2014 and first gas from both is expected in the second half. In Vietnam, the subsea structures and other equipment for tying Dua back to the Chim Sáo floating production, storage and offtake vessel (FPSO) were completed and installed and first oil is planned for mid-2014, following the development drilling programme.

In the UK, the construction of the jacket, topsides and tank for the Solan project continued during 2013. To achieve the target of first oil in the fourth quarter of this year, it will be necessary to complete the installation during the available summer weather window in the West of Shetlands. The Catcher project reached the point of sanction and contract award, both of which are imminent. In the Falkland Islands, the Sea Lion project passed through concept selection at the end of the year and is now entering the FEED phase.

Premier had a strong year of exploration drilling with six discoveries out of seven wells. We were particularly pleased with the results from the Luno II well in Norway, and we also had near-field discoveries in Indonesia, Pakistan and the UK. We continued to pursue acreage in under-explored areas and were delighted with the award of three blocks in proven basins in Brazil's 11th Licensing Round. 13 firm wells are planned for our 2014 exploration programme and we are particularly looking forward to results from drilling in Indonesia in the first half of the year, with campaigns in Norway and the Falkland Islands to follow.

During 2013 we divested our equity interests in Block 07/03 in Vietnam (containing the Cá Rồng Đỏ discovery that we made in 2009) and in Licence PL378 in Norway (containing the Grosbeak discovery that we made in 2009). We also relinquished various exploration licences in the UK North Sea, so as to be better able to focus our capital on our best prospects. We will continue our programme of asset disposals during 2014.

As at 31 December 2013 proven and probable (2P) reserves, on a working interest basis, were 259 mmboe (2012: 292 mmboe). Increased resource estimates in the Falkland Islands, and discoveries at Luno II in Norway and Matang in Indonesia have boosted resources so we ended the year with 794 mmboe, up from 773 mmboe one year earlier.

	Proven and probable (2P) reserves (mmboe)	**2P reserves and 2C contingent resources (mmboe)**
1 January 2013	292	773
Production	(21)	(21)
Net additions, revisions and disposals	(12)	42
31 December 2013	259	794

BUSINESS UNIT REVIEWS

THE FALKLAND ISLANDS

Extensive conceptual engineering and design work was undertaken on the Sea Lion project throughout the year. A revised development scheme involving a tension leg platform (TLP) development was found to offer a number of advantages over the previous new build FPSO scheme and the TLP scheme was chosen to be progressed through front end engineering design (FEED) during 2014. Premier is targeting project sanction for the first phase of the development in Q2 2015. Plans for an exploration campaign, now expected to commence in early 2015, were progressed on the basis of a rig share with other operators in the Falkland Islands.

Development

During the year the project team, in conjunction with consulting engineering companies, progressed a comprehensive set of studies as part of the concept selection phase to define the development plan. These studies included detailed work in areas such as metocean studies, facilities design (including turret design and topsides layout), flow assurance methodologies, subsea equipment layout and installation methods, reservoir studies and drilling trajectories.

A phased approach to development was selected. It is envisaged that an initial northern development recovering 293 million barrels (mmbbls) from Sea Lion using 32 wells, will be followed by a southern area development tied back to the host facilities to recover the remaining reserves. The second phase of development will be optimised to incorporate any additional exploration or appraisal success.

A development concept involving a TLP with an integral drilling rig was selected as it offers a more robust and lower cost development scheme than a new build FPSO-based scheme. Work is now ongoing to optimise the design specifications for the TLP scheme and to prepare the documentation for FEED which is expected to begin in the second quarter of 2014. A draft field development plan (FDP) will be submitted by the end of 2014 and project sanction is expected in Q2 2015.

Given Premier's current 60 per cent level of equity in the development, a decision has been taken to seek a suitable partner for the project.

Exploration

The prospect inventory has been matured in collaboration with partners, resulting in a planned exploration programme of at least four wells with multiple stacked targets. The programme will include a well to confirm the presence of a gas cap in the west of Sea Lion. Premier is working to participate in a multi-operator drilling programme starting in 2015. A rig tender has been issued to the market and bids are being evaluated.

In October, Premier and Rockhopper announced they had signed a Heads of Agreement with Falkland Oil and Gas Ltd (FOGL) to farm-in to licences PL004a and PL004c, which are adjacent to the Sea Lion development. The transaction, which is expected to complete imminently, will result in the increase of Premier's equity in both licences to 36 per cent and assumption of operatorship.

INDONESIA

In 2013 Premier continued to increase gas deliverability from its Natuna Sea facilities following the successful completion of the Anoa Phase 4 compression project. The Pelikan and Naga projects were progressed towards first gas in 2014. Exploration planning work also continued in preparation for the arrival of two drilling rigs in the first quarter of 2014. One rig will be devoted to drilling on the Natuna Sea Block A Production Sharing Contract (PSC) and the second will drill two exploration wells on the Tuna PSC.

Production and development

Singapore demand remained robust during the year, despite the arrival of LNG imports, at well above minimum contract volumes. The Premier-operated Natuna Sea Block A sold an average of 208 billion British thermal units per day (BBtud) (gross) (2012: 217 BBtud) from its gas export facilities. The non-operated Kakap Block contributed gas sales of a further 34 BBtud (gross) (2012: 33 BBtud). Gross liquids production from the Block A Anoa field averaged 1,700 barrels of oil per day (bopd) (2012: 2,400 bopd) and 3,700 bopd from Kakap (2012: 3,500 bopd). Overall, net production from Indonesia in 2013, on a working interest basis, was 13,700 barrels of oil equivalent per day (boepd) (2012: 14,200 boepd) and Premier-operated facilities provided the majority (52 per cent) of the gas supplied to Singapore through the WNTS pipeline.

Despite a necessary shutdown for the final completion of Anoa Phase 4, production performance for the year remained strong. The Anoa field averaged 126 BBtud (gross) (2012: 144 BBtud) capturing 39.9 per cent of Gas Sales Agreement (GSA) 1 supply against a contractual share of 36.9 per cent. The contractual share for Natuna Sea Block A for 2014 has now been increased to 39.4 per cent of GSA1. Sales from Gajah Baru, which are dedicated to GSA2, averaged 81 BBtud (gross) (2012: 72 BBtud). Both the Gajah Baru and Anoa platforms each achieved record peak production rates in excess of 200 BBtud.

The fabrication and installation of the Pelikan and Naga projects progressed well during the year. The two gas fields will maintain the profiles of GSA1 and GSA2 with 150 billion cubic feet (bcf) of reserves. Onshore fabrication of both the Pelikan and Naga wellhead platforms was completed on time and within budget and the facilities were loaded out and installed in the third quarter. Planning for the development drilling campaign is now far advanced. First gas from both fields is expected in the second half of 2014.

The Phase 4 brownfield project to upgrade the Anoa gas production facility and add 15 per cent export capacity was successfully completed, tested and brought into service within budget in the third quarter. Over its service life this compression project will deliver up to 200 bcf of reserves from the Anoa field into Singapore.

On the non-operated Block A Aceh, the operator continued to progress the gas development project. All EPCI bids for the facilities are now in place and an in-principle agreement reached on a revised gas price with the end user and the Indonesian government. The success of the Matang-1 well, which discovered gas in April 2013, caused the joint venture to consider the potential for alternative development scenarios. Premier will seek to dispose of its interest in Block A Aceh in 2014.

Exploration and appraisal

In 2012 the Anoa WL-5X exploration well flowed 17 million standard cubic feet per day (mmscfd) of gas from the deep fractured sands of the Lama Formation beneath the Anoa field on Natuna Sea Block A. The well opened up a new play in the West Natuna area and in 2013 a number of Lama formation prospects have been developed. Premier plans to drill the first of these prospects with the Ratu Gajah exploration well which will spud in the first quarter of 2014. Anoa WL-5X will be followed up in late 2014 or early 2015 with the nearby Anoa West-1 Lama appraisal/development well. Premier continues to mature additional Lama prospects in the area for drilling in 2015 and beyond.

The Matang-1 exploration well on Block A Aceh reached total depth on 21 March 2013 and penetrated over 90 feet into a gas accumulation at the top of the Bampo Limestone formation. The well was subsequently tested and flowed gas at commercial rates of 25 mmscfd. The gas is relatively sweet and lean compared to the gas found in the surrounding fields in Block A Aceh. The gross resource estimate for the Matang structure remains in line with the pre-drill estimate of 100 to 400 bcf. The joint venture is currently planning an appraisal well on Matang in 2015.

In 2013 Premier prepared for oil exploration drilling in Kuda Laut and Singa Laut, two adjacent prospects in the Premier-operated Tuna PSC. The Kuda Laut-1 well, which will drill through Miocene sands within a four-way dip closure, is scheduled to spud in the first quarter of 2014. The well will then be side-tracked to Singa Laut to drill an adjoining three-way dip closed structure with sandstone reservoirs in both the lower Miocene and Oligocene sections.

NORWAY

Premier continued to progress the development of the Bream project towards sanction following the transfer of operatorship. The company also continued to build on its position on the emerging Mandal High play through the award of two operated licences in the Award in Pre-defined Areas (APA) 2013 Licensing Round. Prospect maturation of the Myrhauk well, which will be Premier's first test of the play, is progressing to schedule and drilling is expected to commence late this year, or early next year.

Development

Commercialising and gaining control of the Bream project was a key focus during 2013, with Premier taking over operatorship of the field development via the purchase of an additional 10 per cent equity in Licence PL407 in July. A second parallel transaction was also agreed which facilitated equity alignment between PL407 and the adjacent Premier-operated PL406, which contains the Mackerel discovery. The equity alignment of these two joint ventures simplifies the development of Bream and the tie-back of the Mackerel field as a single integrated project. The transactions were completed and operatorship formally transferred in December.

A formal concept selection decision will now take place during the first quarter of 2014 and an investment decision is planned for late 2014, or early 2015.

The Bream development concept is planned to be an FPSO with subsea production and water injection wells. The Mackerel development will be a 17km subsea tie-back to the Bream facilities. An exploration well on the adjacent Herring prospect is planned during the development phase and, if successful, would contribute additional resources to the overall project.

Work continued on the non-operated Frøy field to identify a viable development concept. Technical studies for a joint processing hub involving other fields in the area were completed during the first half of the year. Commercial discussions with other field owners and further subsurface and facilities studies continue regarding identified options.

Exploration

A significant discovery was made by the Luno II well on Licence PL359 in May 2013. The production test achieved an average flow rate of 2,044 bopd of good quality (36 degrees API) crude oil through a 48/64 inch choke, with a gas to oil ratio of 1,012 standard cubic feet per barrel. The discovery will be appraised in 2014.

Premier continued to mature its operated position in and around the Mandal High area. A site survey was obtained and a drilling rig contracted for the Myrhauk prospect with a spud date planned for the end of 2014. Building on regional knowledge and extensive datasets covering the Mandal High, Premier applied for, and was awarded, two new operated licences (PL725 and PL726) under the APA 2013 Licensing Round. The two new blocks are an eastern extension of the Upper and Middle Jurassic Mandal High plays and contain large stratigraphic traps that will be further evaluated using re-processed seismic data. Both blocks were secured on a two-year drill or drop option.

As part of Premier's ongoing portfolio management, licences PL378 and PL378B, which contain the Grosbeak discovery and a potential extension of the Scarfjell discovery, were sold to Capricorn Norge, a wholly-owned subsidiary of Cairn Energy plc, for US$16 million in cash, at a profit of US$9.4 million.

PAKISTAN

In Pakistan, Premier had its eighth consecutive exploration and appraisal success in 2013 which, in conjunction with a successful infill and step-out programme, continued to slow the natural decline of our producing fields. Five near-field exploration and appraisal wells are planned to be drilled in 2014.

Production and development

Average production in Pakistan during 2013 was 14,900 boepd net to Premier, around five per cent lower than in 2012 (15,600 boepd). Annual production uptime for the fields was 96 per cent.

Production from the Qadirpur gas field averaged 3,600 boepd net to Premier in 2013, a four per cent decline on the field's 2012 production (3,700 boepd). This was due in part to the natural decline of the field but also the shutdown of a power plant which resulted in increased flare gas and process losses. In a bid to maintain current production levels, two new large centrifugal compressors have been commissioned.

Production from the Kadanwari gas field averaged 2,900 boepd net to Premier during 2013, 11 per cent higher than 2012 (2,600 boepd). This year-on-year growth was a result of the successful restoration of the K-27 well, a full-year of production from the K-29 development well, which was tied-in to production at the end of 2012, and the K-32 well which came on-stream in July 2013.

The Zamzama gas field produced 5,100 boepd net to Premier during 2013 (2012: 5,800 boepd) as the field entered a phase of natural decline. The Zam-9 well was successfully tied-in at the end of January 2013. The field is currently producing around 4,000 boepd net to Premier.

Production from Bhit/Badhra gas fields averaged 3,300 boepd net to Premier during 2013, representing a seven per cent decline year-on-year (2012: 3,500 boepd), primarily driven by the natural decline in the Bhit gas field. This decline was partially offset by higher production from the new Badhra Area B wells, and two subsequent development wells are planned in 2014. A compressor reconfiguration project is being considered to improve ultimate recovery and would consist of installing new compressors at Bhit and the relocation of up to three existing Bhit compressors to Badhra to maximise well deliverability.

Development of the Zarghun South gas field, in which Premier holds a 3.75 per cent working interest, continued through 2013. The laying of the gas pipeline is nearing completion and first gas remains on track for the third quarter of 2014 with an expected initial run rate of 20 mmscfd. All costs continue to be carried by the operator.

Exploration and appraisal

In March Premier made a discovery with the K-32 well which was subsequently tied into the Kadanwari production facilities. The same play has also been found to extend into the recently drilled K-35 development well. The third tight gas pilot well, K-31H, was drilled horizontally into the targeted G-Sand, where six hydraulic fractures were carried out. Initial flow rates were encouraging and final tie-in is expected shortly. An exploration programme of two wells is scheduled for 2014, including the K-36 well which is currently drilling.

In May 2013 the BBN-2 well was spudded and the appraisal of the two new Mughalkot sand levels was successfully completed in October. The production test of the new sands achieved a commingled flow rate of 30 mmscfd through a 181/64 inch choke. In addition, gas has also flowed to surface from Parh Limestone in an open-hole test. Development of this gas will be carried out after a field study.

MAURITANIA

The Chinguetti field continues to generate positive cash flow, and exploration drilling in the area resumed in the fourth quarter of the year.

Production and development

In Mauritania, 2013 working interest production from the Chinguetti field averaged 600 bopd (2012: 600 bopd).

The execution phase of the Banda development is proceeding following approval by the Government of Mauritania of the FDP. Gas sales negotiations and arrangement of payment guarantees with prospective buyers are underway and bids for major components including the subsea production system, umbilical, pipeline and process plant have been received and are under evaluation. Project approval is expected by the second quarter of 2014.

Subsurface studies of Tevet were completed in May 2013 and a conditional declaration of commerciality was submitted to the government of Mauritania to develop, subject to market availability, the Tevet gas reserves (69 bcf gross) through the Banda facilities.

Exploration

The Tapendar-1 well on licence PSC C-10, targeting the untapped deeper cretaceous potential, is expected to spud imminently.

UNITED KINGDOM

Rising production from two new fields, Huntington and Rochelle, underpinned a strong rise in cash flows for the UK business unit. Development activity continues to focus on delivering the Solan project in the fourth quarter of 2014 and on progressing the Catcher development to project sanction. Premier also continued to add valuable resources to its UK North Sea portfolio from near-field exploration success at Bonneville.

Production

Production from Premier's UK fields increased to 14,900 boepd, compared to 12,100 boepd during 2012.

Strong production was achieved from the Wytch Farm field as a result of two new Frome wells being brought on-stream, the successful completion of several well workovers and the re-start of water injection at Furzey Island. Operating efficiency from Wytch Farm also improved, averaging 87 per cent, up from 82 per cent for the same period last year. The Scott and Telford fields also performed above expectations due to improved operating efficiency and a successful well intervention programme.

Production from the Balmoral area was lower due to a temporary shutdown of the Balmoral floating production vessel (FPV) in April and the temporary shut in of five Balmoral wells, the Stirling 20z well and the Brenda D3 well. In October, a diving support vessel was utilised for a successful repair of the subsea template to enable production to re-start from Stirling 20z and two Balmoral wells (B3 and B5). A successful workover utilising a well intervention vessel enabled Brenda D3 to re-start in early December. Further well maintenance is planned for the second quarter of 2014.

The Kyle field remained shut in during the year. The Banff FPSO, which handles Kyle production, was damaged during exceptionally bad weather at the end of 2011. Since then it has been off location while repairs are undertaken. Property damage and business interruption insurance claims have been settled to the value of US$55 million and the field reinstatement project has been sanctioned for production, expected to restart in the third quarter of 2014.

The non-operated Huntington development was successfully completed in April and production commenced via the Voyager Spirit FPSO. Initial production was restricted following start-up issues with the gas compression system and subsequent concerns with gas venting. Both of these issues have since been resolved. A new power turbine was installed in August to address the vibration issues associated with the second compression train and the primary hydrocarbon blanketing system, which recycles gas from cargo tanks, was fully commissioned in August. However, production remained below capacity in the fourth quarter due to a gas export restriction imposed by the CATS gas export system operator. The restrictions were progressively lifted from November onwards and the field achieved a run rate of 35 kboepd (gross) in December.

On the non-operated Rochelle field, the West Rochelle well was successfully completed and tested in June. It was tied back to the Scott platform and commenced production in October. Rochelle achieved a peak daily spot production rate of 2,438 boepd (net to Premier) from the West Rochelle single producer. The second and final production well, E2, was successfully tied back to the Scott platform in January. During the restart of production a subsea construction isolation valve failed to open, preventing start-up and production from both East and West Rochelle wells. A diving support vessel is currently in the field, has opened the valve and production is expected to start imminently.

Development

The Premier-operated Solan project, West of Shetland, is now well into the execution phase. Drilling of the four wells – two producers and two water injectors – commenced in April. Drilling operations have been suspended as planned between November and March during the severe winter period and the rig sublet elsewhere. A subsea storage tank is under construction in Dubai, with a target to sail away in mid-2014. Meanwhile construction of the topsides and jackets is progressing at Burntisland Fabricators in Fife to meet sail away and installation by the Thialf Heerema vessel in mid-2014. Hook up and commissioning is planned to be undertaken prior to the end of the summer weather window West of Shetlands ahead of first oil, scheduled for the fourth quarter of 2014. The field is expected to produce approximately 40 million barrels (mmbbls) gross (Premier equity 60 per cent) with an estimated initial production rate of 24,000 boepd (gross) following ramp up.

Considerable progress has been achieved on the Premier-operated Catcher area project since the development concept (a subsea tie-back of the Catcher, Varadero and Burgman fields to a FPSO) was agreed in December 2012. Reservoir modelling has been completed and well locations and sequence have also been optimised. Tenders for the well systems, Christmas trees and a heavy duty jack-up rig were received in July and August and have been fully evaluated. It is envisaged that development drilling, which will entail the continuous drilling of up to 14 producers and eight water injectors, will commence in 2015 and continue beyond first oil. Subsea FEED for the Catcher area project has also been completed. Premier received the EPCI bids for the subsea facilities in October and bid evaluation is on schedule to meet the April 2014 target date for contract award. The funded tender process for the construction and operating contract for the FPSO is near to completion with final offers from the three FPSO contractors evaluated by a dedicated commercial team and a preferred bidder identified. A draft development work programme and budget has been issued to partners and the FDP submitted to DECC, initiating the process to target sanction in the second quarter of 2014. Capital expenditure for the field is estimated at US$2.2 billion including 30 per cent allowances and contingencies. Gross reserves under the initial development scheme are 92 mmboe. The development scheme makes provision for the tie-back of additional discoveries in the future.

Exploration

Premier drilled two wells – the Bonneville exploration well and the Lacewing exploration well – in the UK Central North Sea in 2013. Both wells were plugged and abandoned as hydrocarbon discoveries.

The Bonneville well (28/9a-6) and its sidetrack (28/9a-6z), which were drilled in April, discovered oil in excellent quality reservoirs with average porosities of approximately 30 per cent. Initial sampling indicated that the oil quality is similar to that established at the nearby Burgman discovery which was 25 degrees API. The estimated oil in place from the Bonneville discoveries is approximately 30 mmbbls, in line with pre-drill predictions.

The high pressure, high temperature Lacewing exploration well (23/22b-6Z), which spudded in June, encountered a gas column in excess of 100 feet in the Triassic reservoir. Premier managed its capital exposure to this opportunity by farming down prior to drilling in return for a partial carry on the well.

Premier continued its portfolio upgrading through the relinquishment of a number of exploration licences in the UK North Sea during the first six months of the year. This included selective acreage in the Moray Firth and exploration licences to the West of the Orkney Islands.

In August 2013, Premier successfully farmed in for a 37.5 per cent interest in blocks 13/24c and 13/25, which contain the Bagpuss and Blofeld prospects. The prospects, which Premier evaluates to be heavy oil targets, are located on the Halibut Horst which is a well-defined basement high within the Moray Firth. A well was drilled in 1981 on the Bagpuss prospect. Internal subsequent analysis of the well result suggests that the Bagpuss and Blofeld prospect together could contain around 1 billion barrels of oil in place. It is envisaged that an initial well on one of these features will spud in 2015.

VIETNAM

Chim Sáo continues to produce well and recently achieved the milestones of US$2 billion of oil revenues and 20 mmbbls of production, just over two years after first oil. To improve further the operational efficiency of Chim Sáo a number of field upgrades are being undertaken. Simultaneously the Dua project continues to progress with first oil expected later this year.

Production and development

Production from the Chim Sáo oil field in Block 12W averaged 12,500 bopd and 7,700 mmscf/d of gas net to Premier in 2013. Following damage to the gas export pipeline by a third party in late August, oil production was cut to reduce gas being flared. The pipeline was reinstated for gas export in November and production has since returned to above 30,000 boepd (gross). The costs of repair are the subject of an insurance claim.

Significant upgrades are being made to the Chim Sáo FPSO to improve the reliability of power generation and to increase the number of the offshore workforce, both critical to improving operational efficiency.

The Dua development project, which is a subsea tie-back to Chim Sáo, continued with subsea equipment now installed at Dua and tied back to the FPSO via flowlines and umbilicals. Drilling of the three Dua production wells commenced in February 2014 following the completion of the new-build West Telesto drilling unit. First oil from Dua is targeted for mid-2014. The field is expected to extend plateau production from Block 12W.

Exploration and appraisal

In the Phu Khan Basin offshore east Vietnam, Premier participated in the frontier exploration well 121-CV-1X, on Block 121. The well, which was plugged and abandoned in July, penetrated water bearing sandstones in the primary Pre-Miocene objective and proved an active petroleum system by penetrating two thin thermogenic gas bearing sands within the Miocene section. Coals with source potential were encountered within the Oligocene section. The results of the well are being integrated with existing seismic data. Further 2D seismic is planned for 2014.

In mid-July Premier sold 100 per cent of the shares in its wholly owned subsidiary Premier Oil Vietnam South BV (POVS) for a consideration of up to US$100 million. POVS held a 30 per cent operated interest in Block 07/03 offshore Vietnam, which contains the Cá Rồng Đỏ (CRD) oil and gas discovery and the Ca Duc (Silver Sillago) exploration prospect. The transaction included an immediate cash payment of US$45 million and a subsequent cash payment of US$55 million dependent on subsequent milestones being achieved.

NEW COUNTRY ENTRY - EXPLORATION

Premier continued to capture high impact emerging plays in both deepwater Atlantic Margin and rift basin geological settings through the award of two operated blocks in the Ceará rift basin, and a non-operated block in the highly contested Foz do Amazonas Basin in the Brazilian 11th Licensing Round 2013. Also, consistent with Premier's strategy of leveraging learnings from its rift basin exploration success, the group entered into a licence in the onshore Southern Anza rift basin in Kenya.

In August 2013, Premier secured 50 per cent operated equity in two licences totalling 1,270 km^2, in the offshore Ceará Basin in Northern Brazil. The Ceará Basin is a Cretaceous rift basin with proven source and reservoir rocks extending out into the deepwater setting. Premier has committed to drilling two wells in CE-M-717 before August 2018. Both Ceará licences also carry commitments to acquire 3D seismic over the entire licence areas. Premier's work programme in Brazil consists of 3D seismic acquisition planned for late 2014, with a view to drilling the first well in 2016. Premier was also awarded a 35 per cent non-operated equity in licence FZA-M-90 in the deepwater Foz do Amazonas Basin. This licence contains a potential high impact Cretaceous exploration play, proven across the border in French Guiana. Premier opened a Brazil office in early 2014, which will be staffed for executing the forward drilling programmes.

The rift system in Kenya is one of the few remaining under-explored onshore, conventional oil plays. In 2013 Premier secured a 55 per cent non-operated equity in onshore Kenya Licence 2B, in the Southern Anza Basin. The Anza Basin is a Cretaceous to recent Rift Basin, analogous to the prolific East Africa Rift Systems such as the Lokichar Tertiary Rift Basin which contains several recent oil discoveries. Approximately 100km of 2D seismic will be acquired in early 2014 and Premier is committed to drilling a well in late 2014 or early 2015. Elsewhere in Kenya, Premier relinquished its non-operated 20 per cent interest in offshore Licence 10A, as the identified prospectivity did not satisfy internal threshold criteria on a risked basis. Premier continues to retain a 25 per cent equity in adjacent offshore Block 10B, for which a drill decision will be made in May 2014.

In November 2012, Premier was awarded a 30 per cent non-operated interest in Block 12 in Iraq. Block 12 lies in an under-explored part of one of the world's most prolific oil and gas basins. This is an 8,000km^2 licence in the foreland basin of the Zagros fold belt, updip from producing fields. Premier has significant exploration experience of foreland basins via its established history in Pakistan. Over the course of the year, the 2014 work programme and budget was approved by the Iraqi ministry of oil and gas and a tender process for 2D and 3D seismic was initiated.

Premier's exploration rights in the Daora, Haouza, Mahbes, Mijek and Laguara blocks offshore the Saharawi Arab Democratic Republic (SADR) still remain under force majeure, awaiting resolution of sovereignty under a United Nations mandate process. In Egypt, Premier continues the relinquishment process for the North Red Sea-1 licence

FINANCIAL REVIEW

Economic background

The stability in oil prices continued for a third year running, averaging US$108.7/barrel (bbl) against US$111/bbl for the previous two years, and trading in a range of US$119.0/bbl to US$96.8/bbl. Premier's portfolio of crudes traded at a weighted average of US$2.6/bbl premium to Brent, as we continue to realise favourable prices for our Chim Sáo crude in the Asian markets. Premier's average realisations for the year were US$109.0/bbl (2012: US$111.4/bbl) after taking into account timings of actual liftings and export duties paid in Vietnam. Post hedging, realised prices marginally increased to US$109.1/bbl (2012: US$107.5/bbl).

Average gas prices for the group were US$8.32 per thousand standard cubic feet (mscf) (2012: US$8.34/mscf). Gas prices in Singapore, linked to High Sulphur Fuel Oil (HSFO) pricing and in turn, therefore, linked to crude oil pricing, averaged US$17.1/mscf (2012: US$18.7/mscf). The average price for Pakistan gas (where only a portion of the contract formulae is linked to energy prices) was US$4.4/mscf (2012: US$4.3/mscf).

Income statement

Production in 2013 averaged 58.2 kboepd (2012: 57.7 kboepd) on a working interest basis. On an entitlement basis, which under the terms of our PSCs allows for additional government take at higher oil prices, production was 52.4 kboepd (2012: 51.6 kboepd). Working interest gas production averaged 174 mmscfd (2012: 180 mmscfd) or approximately 52 per cent of total production.

Total sales revenue from all operations reached a new record level of US$1.5 billion (2012: US$1.4 billion), driven by higher production and the stable oil prices. Cost of sales rose to US$1,034.8 million (2012: US$742.4 million). Operating costs amounted to US$418.9 million (2012: US$342.4 million). Significant items included new field costs in respect of the Huntington field in the UK and costs relating to the gas pipeline repair in Vietnam. Unit operating costs were US$19.7 per barrel of oil equivalent (boe) (2012:US$16.2/boe). Underlying unit amortisation (excluding impairment) rose to US$17.7/boe (2012: US$16.4/boe) mainly reflecting commencement of production from the Huntington field in the UK, which has a higher amortisation charge per boe compared to the group average. Impairment charges for the year which related to the Balmoral area amounted to US$178.7 million (2012: US$20.7 million) on a pre-tax basis (US$67.9 million, post-tax). This followed a review of the longer-term plans for the life of the fields in this area, where it was determined that additional maintenance and operating cost expenditure is likely to be required in order to ensure that additional reserves will be extracted. At year-end, decommissioning costs were also updated based on latest estimates of drilling costs and time estimates to abandon the fields. A reforecast of decommissioning costs has also resulted in a credit to the income statement of US$15.3 million related to Fife area abandonment activities.

Exploration expense and pre-licence expenditure costs amounted to US$106.2 million (2012: US$157.7 million) and US$30.1 million (2012: US$29.2 million) respectively. This includes the write-off relating to the Ca Voi well in Vietnam, the exit from the Blåbaer discovery in Norway, and the relinquishment of various exploration licences in the UK as part of Premier's portfolio management programme. Net administrative costs were US$20.2 million (2012: US$24.2 million).

Operating profits were US$352.0 million (2012: US$455.2 million), the reduction mainly attributable to impairment charges described above. Operating profits include credits from receipts for business interruption insurance on the Kyle field of US$36.9 million, recorded as other income. Finance costs and other charges, net of interest revenue and other gains, were US$65.4 million (2012: US$107.6 million). While financial charges, net of capitalised borrowing costs, remained at similar levels, gains on sterling forward purchase contracts and interest income from partner funding on the Solan field development, were significantly higher at US$33.0 million. The charge for the unwinding of the discounted decommissioning provision increased to US$36.4 million (2012: US$33.2 million) reflecting increased provisions for future decommissioning as industry cost estimates rise.

Pre-tax profits were US$285.4 million (2012: US$359.9 million). The group tax charge for 2013 is US$51.4 million, an effective tax rate of 18 per cent of pre-tax profits. The group's theoretical tax rate is close to 50 per cent, which includes a higher taxation rate in the UK being offset by lower rates in Vietnam and Pakistan. The 2013 group tax charge is reduced as a result of a deferred tax credit in the UK, mainly arising from the Ring Fence Expenditure Supplement allowance. The group has an estimated US$2.3 billion of carried forward UK corporation tax allowances, which will be utilised against UK ring fence profits over time, and are therefore reflected in the deferred tax asset position at the year-end.

Profit after tax is US$234.0 million (2012: US$252.0 million) resulting in a basic earnings per share of 44.2 cents (2012: 47.9 cents).

Dividend and buyback

The Board is proposing a dividend of 5 pence per share (2012: 5 pence per share). This dividend is subject to shareholder approval at the AGM, to be held in London on 14 May 2014. If approved, the dividend will be paid on 21 May 2014 to shareholders on the register as of 22 April 2014. A dividend re-investment plan (DRIP) is available to shareholders on the UK register who would prefer to invest their dividends in the shares of the company. The last date to elect for the DRIP in respect of this dividend is 26 April 2014.

The Board has approved a share buyback programme of up to £75.0 million, the maximum currently permitted under the group's banking facilities. This programme will be executed by the group's brokers in accordance with a series of parameters set by the Board including the level of share price relative to underlying asset value. The board will review the programme on a quarterly basis.

Cash flow

(US$ million)	**2013**	2012
Operating cash flows	**832.6**	808.2
Less: Pre-licence exploration costs	**(30.1)**	(29.2)
Cash flows from operating activities	**802.5**	779.0

Cash flows from operating activities was US$802.5 million (2012: US$779.0 million) after accounting for tax payments of US$228.3 million (2012: US$233.1 million) and pre-licence costs of US$30.1 million (2012: US$29.2 million). The higher cash flow mainly reflects commencement of production from the Huntington field in the UK.

Capital expenditure in 2013 totalled US$878.0 million (2012: US$771.6 million).

Capital expenditure (US$ million)	**2013**	2012
Fields/development projects	**603.7**	569.0
Exploration and evaluation	**260.5**	187.1
Other	**13.8**	15.5
Total	**878.0**	771.6

The principal development projects were the Solan, Huntington and Rochelle fields in the UK, the Naga and Pelikan fields in Indonesia and the Dua field in Vietnam. In addition, US$185.9 million funding support was provided to our partner in the Solan project. Repayment of this loan will commence once the project achieves first oil.

Exploration and evaluation spend includes costs principally related to the exploration drilling and pre-development activities in the UK, Vietnam, the Falkland Islands, Norway and Brazil.

Acquisitions and disposals

In July, Premier announced that it had agreed to acquire an additional 10 per cent interest in Licence PL407 in Norway for a consideration of US$5.5 million. PL407 contains the Bream field where Premier now holds a 50 per cent interest and is also the operator. In addition, Premier sold 30 per cent of the adjacent Licence PL406 containing the Mackerel discovery for a consideration of US$5.0 million, contingent upon a project development approval in the area. These two transactions aligned the partnership interests across the two licences and were completed following government approval in the year.

Also in July, Premier completed the sale of its 30 per cent operated interest in Block 07/03 offshore Vietnam. The consideration for the sale comprised upfront cash of US$45.0 million with additional contingent payments of US$55.0 million dependent on future exploration appraisal and development milestones on the block.

In August, Premier reached agreement to sell licences PL378 and PL378B in Norway for a total consideration of US$16.0 million. These licences contained the Grosbeak discovery. The transaction was completed during the year.

Balance sheet position

Net debt at 31 December 2013 amounted to US$1,452.9 million (2012: US$1,110.4 million), with cash resources of US$448.9 million (2012: US$187.4 million).

Net debt (US$ million)	**2013**	2012
Cash and cash equivalents	**448.9**	187.4
Convertible bonds	**(224.2)**	(220.2)
Other debt*	**(1,677.6)**	(1,077.6)
Total net debt	**(1,452.9)**	(1,110.4)

* Other debt includes €120.0 million of long-term senior notes, which are valued at year-end US$1.38:€ spot rate. These will be redeemed at an average of US$1.39:€ due to cross currency swap arrangements. It also included £250.0 million of UK retail bond and long-term bank financing which are valued at year-end US$1.66:£ spot rate. These will be redeemed at an average of US$1.64:£ due to cross currency swap arrangements.

During the fourth quarter, the group took advantage of favourable debt market conditions and historically low interest rates to raise new debt of over US$700 million, the proceeds of which were utilised for general corporate purposes including the repayment of existing bank debt. This new debt consisted of long-term senior notes, long-term bank loans and a retail bond. Maturities are between 2017 and 2020 with an average current cost of 3.4 per cent.

The group's principal bank facilities amounting to US$1.5 billion mature in the first half of 2015. As at 31 December drawn letters of credit under the facilities were US$328 million and there were no drawings under the cash facility. Cash and undrawn facilities, including letter of credit facilities, were approximately US$1.6 billion at 31 December.

Financial risk management

Commodity prices

The Board's commodity pricing and hedging policy continues to be to lock in oil and gas prices for a proportion of expected future production at a level which ensures that investment programmes for sanctioned projects are adequately funded. Where investment requirements are well covered by cash flows without hedging, it is recognised that there may be an advantage, in periods of strong commodity prices, in locking in a portion of forward production at favourable prices on a rolling forward 12-18 month basis.

At year-end, 4.4 mmbbls of Dated Brent oil were hedged through forward sales for 2014 at an average price of US$103.9/bbl. This volume represents approximately 40 per cent of the group's expected liquids entitlement production in 2014. 192,000 metric tonnes (mt) of HSFO, which drives our gas contract pricing in Singapore, has been sold forward for 2014 at an average price of US$611/mt. These hedges cover approximately 32 per cent of our expected Indonesian gas entitlement production for 2014.

During 2013, forward oil sales of 3.2 mmbbls, and fuel oil collars and forward sales for 144,000 mt expired at a net cost of US$0.8 million (2012: US$60.7 million) which has been offset against sales revenue.

Foreign exchange

Premier's functional and reporting currency is US dollars. Exchange rate exposures relate only to local currency receipts, and expenditures within individual business units. Local currency needs are acquired on a short-term basis. At the year end, the group recorded a mark-to-market gain of US$13.1 million on its outstanding foreign exchange contracts (2012: US$1.5 million). In 2013, the group issued £150.0 million bonds, €20.0 million long-term senior loan notes and £100.0 million term loan which have been hedged under cross currency swaps in US dollars at average fixed rates of US$1.64:£ and US$1.34:€.

Interest rates

The group has various financing instruments including senior notes, convertible bonds, UK retail bonds, term loans and revolving credit facilities. 73 per cent of total borrowings is fixed or has been fixed using the interest rate swap markets. On average, therefore, the cost of drawn funds for the year was 4.7 per cent. Mark-to-market credits on interest rate swaps amounted to US$6.4 million (2012: charge of US$2.5 million), which are recorded as movements in other comprehensive income.

Cash balances are invested in short-term bank deposits and AAA rated liquidity funds, subject to Board approved limits and with a view to spreading counterparty risks.

Insurance

The group undertakes a significant insurance programme to reduce the potential impact of physical risks associated with its exploration, development and production activities. Business interruption cover is purchased for a proportion of the cash flow from producing fields for a maximum period of 18 months. As previously reported, following exceptionally bad weather in December 2011, the Banff FPSO – which handled Kyle production – lost its anchors and the risers were severely damaged, stopping Kyle production. A claim for business interruption insurance and property damage was negotiated with the underwriters and settled during 2013, the monies received in total amounting to US$55.0 million were offset against the capital expenditure to redevelop the field (US$18.1 million) or credited to the income statement as business interruption income (US$36.9 million).

Going concern

The group monitors its capital position and its liquidity risk regularly throughout the year to ensure it has sufficient funds to meet forecast cash requirements. Sensitivities are run to reflect the latest expectations of expenditures, forecast oil and gas prices, and other negative economic scenarios. This is done to manage the risk of funds shortfalls or covenant breaches and to ensure the group's ability to continue as a going concern. The group will refinance a significant portion of its financing facilities and letter of credit facilities expiring in March and April 2015 and it has commenced discussions with its relationship banks with this in mind. Based on our understanding of the bank market appetite and financial position of the company, the Board feels confident that the group will be able to refinance its maturing facilities on reasonable terms.

Despite economic volatility, the directors consider that the expected operating cash flows of the group and the headroom provided by the available borrowing facilities give them confidence that the group has adequate resources to continue as a going concern. As a result, they continue to adopt the going concern basis in preparing the 2013 Annual Report and Financial Statements.

Business risks

Premier's business may be impacted by various risks leading to failure to achieve strategic targets for growth, loss of financial standing, cash flow and earnings, and reputation. Not all of these risks are wholly within the company's control and the company may be affected by risks which are not yet manifest or reasonably foreseeable.

Effective risk management is critical to achieving our strategic objectives and protecting our personnel, assets, the communities where we operate and with whom we interact and our reputation. Premier therefore has a comprehensive approach to risk management.

A critical part of the risk management process is to assess the impact and likelihood of risks occurring so that appropriate mitigation plans can be developed and implemented. Risk severity matrices are developed across Premier's business to facilitate assessment of risk. The specific risks identified by project and asset teams, business units and corporate functions are consolidated and amalgamated to provide an oversight of key risk factors at each level, from operations through business unit management to the Executive Committee and the Board.

For all the known risks facing the business, Premier attempts to minimise the likelihood and mitigate the impact. According to the nature of the risk, Premier may elect to take or tolerate risk, treat risk with controls and mitigating actions, transfer risk to third parties, or terminate risk by ceasing particular activities or operations. Premier has a zero tolerance to financial fraud or ethics non-compliance, and ensures that HSES risks are managed to levels that are as low as reasonably practicable, whilst managing exploration and development risks on a portfolio basis.

The group has identified its principal risks for the next 12 months as being:

- Health, safety, environment and security (HSES);
- Production and development delivery;
- Exploration success and reserves addition;
- Host government – political and fiscal risks;
- Commodity price volatility;
- Organisational capability;
- Joint venture partner alignment; and
- Financial discipline and governance.

Further information detailing the way in which these risks are mitigated is provided on the company's website (www.premier-oil.com).

CONSOLIDATED INCOME STATEMENT

For the year ended 31 December 2013

	2013 $ million	2012 $ million
Sales revenues	**1,501.0**	1,408.7
Other operating income	**38.7**	-
Cost of sales	**(1,034.8)**	(742.4)
Exploration expense	**(106.2)**	(157.7)
Pre-licence exploration costs	**(30.1)**	(29.2)
Profit on disposal of exploration and evaluation assets	**3.6**	-
General and administration costs	**(20.2)**	(24.2)
Operating profit	**352.0**	455.2
Share of loss in associate	**-**	(1.9)
Interest revenue, finance and other gains	**33.0**	3.2
Finance costs, other finance expenses and losses	**(98.4)**	(110.8)
(Loss)/gain on commodity derivative financial instruments	**(1.2)**	14.2
Profit before tax	**285.4**	359.9
Tax	**(51.4)**	(107.9)
Profit after tax	**234.0**	252.0
Earnings per share (cents):		
Basic	**44.2**	47.9
Diluted	**43.2**	46.9

The results relate entirely to continuing operations.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the year ended 31 December 2013

	2013 $ million	2012 $ million
Profit for the year	**234.0**	252.0
Cash flow hedges on commodity swaps:		
Losses arising during the year	**(25.0)**	(19.1)
Less: reclassification adjustments for losses in the year	**0.8**	39.6
	(24.2)	20.5
Tax relating to components of other comprehensive income	**13.9**	-
Cash flow hedges on interest rate and foreign exchange swaps	**(0.8)**	4.7
Exchange differences on translation of foreign operations	**(17.5)**	15.3
Actuarial (losses)/gains on long-term employee benefit plans	**(6.5)**	1.2
Other comprehensive (expense)/income	**(35.1)**	41.7
Total comprehensive income for the year	**198.9**	293.7

All comprehensive income is attributable to the equity holders of the parent.

CONSOLIDATED BALANCE SHEET

As at 31 December 2013

	2013 $ million	2012 $ million
Non-current assets:		
Intangible exploration and evaluation assets	**701.0**	658.0
Property, plant and equipment	**2,885.9**	2,692.9
Goodwill	**240.8**	240.8
Investment in associate	**6.2**	6.1
Long-term employee benefit plan surplus	**1.0**	4.2
Long-term receivables	**198.1**	2.5
Deferred tax assets	**762.4**	568.9
	4,795.4	4,173.4
Current assets:		
Inventories	**49.5**	34.6
Trade and other receivables	**421.8**	351.3
Tax recoverable	**82.4**	87.1
Derivative financial instruments	**15.9**	9.8
Cash and cash equivalents	**448.9**	187.4
	1,018.5	670.2
Total assets	**5,813.9**	4,843.6
Current liabilities:		
Trade and other payables	**(512.4)**	(450.0)
Current tax payable	**(92.0)**	(114.9)
Provisions	**(13.1)**	(68.8)
Derivative financial instruments	**(38.3)**	(43.8)
	(655.8)	(677.5)
Net current assets/(liabilities)	**362.7**	(7.3)
Non-current liabilities:		
Convertible bonds	**(223.8)**	(219.6)
Other long-term debt	**(1,665.4)**	(1,064.4)
Deferred tax liabilities	**(306.8)**	(297.1)
Long-term provisions – decommissioning	**(824.6)**	(613.3)
Long-term employee benefit plan deficit	**(13.1)**	(18.2)
	(3,033.7)	(2,212.6)
Total liabilities	**(3,689.5)**	(2,890.1)
Net assets	**2,124.4**	1,953.5
Equity and reserves:		
Share capital	**110.5**	110.5
Share premium account*	**275.3**	274.9
Merger reserve*	**374.3**	374.3
Retained earnings	**1,342.1**	1,150.1
Other reserves	**22.2**	43.7
	2,124.4	1,953.5

*2012 comparatives have been restated - see consolidated statement of changes in equity.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the year ended 31 December 2013

		Attributable to the equity holders of the parent						
					Other reserves			
	Share capital $ million	Share premium account $ million	Retained earnings $ million	Merger reserve $ million	Capital redemption reserve $ million	Translation reserves $ million	Equity reserve $ million	Total $ million
At 1 January 2012	98.8	274.5	922.9	-	4.3	1.8	21.3	1,323.6
Issue of Ordinary Shares	11.7	374.7	-	-	-	-	-	386.4
Purchase of ESOP Trust shares	-	-	(89.3)	-	-	-	-	(89.3)
Provision for share-based payments	-	-	30.5	-	-	-	-	30.5
Incremental equity component of new convertible bonds	-	-	-	-	-	-	8.6	8.6
Transfer between reserves	-	-	7.6	-	-	-	(7.6)	-
Total comprehensive income	-	-	278.4	-		15.3	-	293.7
At 1 January 2013 as previously reported	110.5	649.2	1,150.1	-	4.3	17.1	22.3	1,953.5
Restatement of reserves	-	(374.3)	-	374.3	-	-	-	-
At 1 January 2013 (restated)	110.5	274.9	1,150.1	374.3	4.3	17.1	22.3	1,953.5
Issue of Ordinary Shares	-	0.4	-	-	-	-	-	0.4
Purchase of ESOP Trust shares	-	-	(12.8)	-	-	-	-	(12.8)
Provision for share-based payments	-	-	24.6	-	-	-	-	24.6
Transfer between reserves	-	-	4.0	-	-	-	(4.0)	-
Dividends paid	-	-	(40.2)	-	-	-	-	(40.2)
Total comprehensive income	-	-	216.4	-	-	(17.5)	-	198.9
At 31 December 2013	**110.5**	**275.3**	**1,342.1**	**374.3**	**4.3**	**(0.4)**	**18.3**	**2,124.4**

CONSOLIDATED CASH FLOW STATEMENT

For the year ended 31 December 2013

	2013	2012
	$ million	$ million
Net cash from operating activities	**802.5**	779.0
Investing activities:		
Capital expenditure	**(878.0)**	(771.6)
Net cash inflow from acquisition of subsidiaries	**-**	4.6
Disposal of oil and gas properties	**61.0**	52.4
Acquisition of oil and gas properties	**-**	(267.5)
Loan to joint venture partner	**(185.9)**	-
Net cash used in investing activities	**(1,002.9)**	(982.1)
Financing activities:		
Proceeds from issuance of Ordinary Shares	**0.4**	0.4
Purchase of ESOP Trust shares	**(12.8)**	(89.3)
Proceeds from drawdown of long-term bank loans	**384.1**	217.6
Proceeds from issuance of senior loan notes	**156.7**	235.2
Proceeds from issuance of retail bonds	**245.8**	-
Debt arrangement fees	**(7.1)**	(5.0)
Repayment of long-term bank loans	**(200.0)**	(202.0)
Convertible bonds partial repayment/arrangement fee for new bonds	**-**	(7.9)
Dividends paid	**(40.2)**	-
Interest paid	**(71.1)**	(65.6)
Net cash from financing activities	**455.8**	83.4
Currency translation differences relating to cash and cash equivalents	**6.1**	(2.0)
Net increase/(decrease) in cash and cash equivalents	**261.5**	(121.7)
Cash and cash equivalents at the beginning of the year	**187.4**	309.1
Cash and cash equivalents at the end of the year	**448.9**	187.4

NOTES TO THE PRELIMINARY FINANCIAL STATEMENTS

For the year ended 31 December 2013

1 General information

Premier Oil plc is a limited liability company incorporated in Scotland and listed on the London Stock Exchange. The address of the registered office is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh, EH1 2EN, United Kingdom. This preliminary announcement was authorised for issue in accordance with a resolution of the Board of Directors on 25 February 2014.

The financial information for the year ended 31 December 2013 set out in this announcement does not constitute statutory accounts within the meaning of section 434 of the Companies Act 2006. Statutory accounts for the year ended 31 December 2012 were approved by the Board of Directors on 20 March 2013 and delivered to the Registrar of Companies and those for 2013 will be delivered following the company's Annual General Meeting (AGM). The auditor has reported on these accounts; the reports were unqualified, did not include a reference to any matters to which the auditor drew attention by way of emphasis of matter and did not contain statements under section 498(2) or 498(3) of the Companies Act 2006.

Basis of preparation

The financial information has been prepared in accordance with the recognition and measurement criteria of International Financial Reporting Standards (IFRS) adopted for use in the European Union. However, this announcement does not itself contain sufficient information to comply with IFRS. The company will publish full financial statements that comply with IFRS in April 2014.

The financial information has been prepared under the historical cost convention except for the revaluation of financial instruments and certain oil and gas properties at the transition date to IFRS. These financial statements are presented in US dollars since that is the currency in which the majority of the group's transactions are denominated.

Accounting policies

The accounting policies applied in this announcement are consistent with those of the annual financial statements for the year ended 31 December 2012, as described in those annual financial statements. A number of amendments to existing standards and interpretations were applicable from 1 January 2013. The adoption of these amendments did not have a material impact on the group's financial statements for the year ended 31 December 2013.

2 Operating segments

The group's operations are located and managed in seven business units; namely the Falklands Islands, Indonesia, Norway, Pakistan (including Mauritania), the United Kingdom, Vietnam and the Rest of the World. Some of the business units currently do not generate revenue or have any material operating income.

The group is only engaged in one business of upstream oil and gas exploration and production, therefore all information is being presented for geographical segments.

	2013	2012
	$ million	$ million
Revenue:		
Indonesia	**295.9**	305.1
Pakistan (including Mauritania)	**165.4**	175.2
Vietnam	**468.2**	509.4
United Kingdom	**571.5**	419.0
Total group sales revenue	**1,501.0**	1,408.7
Other income – United Kingdom	**38.7**	-
Interest and other finance revenue	**10.9**	1.7
Total group revenue	**1,550.6**	1,410.4
Group operating profit/(loss):		
Indonesia	**187.0**	134.6
Norway	**(26.5)**	(7.7)
Pakistan (including Mauritania)	**84.0**	103.0
Vietnam	**195.9**	261.7
United Kingdom	**(31.5)**	6.7
Rest of the world	**(8.7)**	(1.9)
Unallocated	**(48.2)**	(41.2)
Group operating profit	**352.0**	455.2
Share of loss in associate	**-**	(1.9)
Interest revenue, finance and other gains	**33.0**	3.2
Finance costs and other finance expenses	**(98.4)**	(110.8)
(Charge)/gain on derivative financial instruments	**(1.2)**	14.2
Profit before tax	**285.4**	359.9
Tax	**(51.4)**	(107.9)
Profit after tax	**234.0**	252.0
Balance sheet		
Segment assets:		
Falkland Islands	**297.2**	242.6
Indonesia	**731.5**	692.2
Norway	**231.3**	253.5
Pakistan (including Mauritania)	**117.4**	140.7
Vietnam	**648.5**	705.2
United Kingdom	**3,260.4**	2,594.3
Rest of the world	**62.8**	18.0
Unallocated*	**464.8**	197.1
Total assets	**5,813.9**	4,843.6

2 Operating segments *(continued)*

	2013 $ million	2012 $ million
Liabilities:		
Falkland Islands	**(14.6)**	(3.3)
Indonesia	**(296.3)**	(326.0)
Norway	**(83.9)**	(111.9)
Pakistan (including Mauritania)	**(88.4)**	(103.3)
Vietnam	**(316.9)**	(196.9)
United Kingdom	**(948.1)**	(801.4)
Rest of the world	**(14.0)**	(19.4)
Unallocated*	**(1,927.3)**	(1,327.9)
Total liabilities	**(3,689.5)**	(2,890.1)
Other information		
Capital additions and acquisitions:		
Falkland Islands	**54.0**	242.4
Indonesia	**101.0**	94.0
Norway	**49.9**	65.2
Pakistan (including Mauritania)	**33.8**	28.3
Vietnam	**121.9**	133.1
United Kingdom	**615.4**	720.3
Rest of the world	**47.5**	13.7
Total capital additions and acquisitions	**1,023.5**	1,297.0
Depreciation, depletion, amortisation and impairment:		
Indonesia	**57.1**	72.2
Pakistan (including Mauritania)	**42.5**	27.3
Vietnam	**117.1**	149.7
United Kingdom	**344.8**	122.9
Rest of the world	**1.0**	0.7
Total depreciation, depletion, amortisation and impairment	**562.5**	372.8

* Unallocated expenditure, assets and liabilities include amounts of a corporate nature and not specifically attributable to a geographical segment. These items include corporate general and administration costs, pre-licence exploration costs, cash and cash equivalents, mark-to-market valuations of commodity contracts and interest rate swaps, convertible bonds and other short-term and long-term debt.

3 Cost of sales

	2013 $ million	2012 $ million
Operating costs	418.9	342.4
Stock overlift/underlift movement	9.8	(17.1)
Royalties	43.6	44.3
Amortisation and depreciation of property, plant and equipment:		
Oil and gas properties	375.0	345.4
Other fixed assets	8.8	6.7
Impairment charge on oil and gas properties	178.7	20.7
	1,034.8	742.4

4 Tax

	2013 $ million	2012 $ million
Current tax:		
UK corporation tax on profits	**(12.1)**	-
UK petroleum revenue tax	**100.9**	83.1
Overseas tax	**122.7**	137.0
Adjustments in respect of prior years	**(22.3)**	(11.9)
Total current tax	**189.2**	208.2
Deferred tax:		
UK corporation tax	**(180.5)**	(162.2)
UK petroleum revenue tax	**(6.4)**	(6.2)
Overseas tax	**49.1**	68.1
Total deferred tax	**(137.8)**	(100.3)
Tax on profit on ordinary activities	**51.4**	107.9

5 Deferred tax

	2013 $ million	2012 $ million
Deferred tax assets	**762.4**	**568.9**
Deferred tax liabilities	**(306.8)**	**(297.1)**
	455.6	**271.8**

	At 1 January 2013 $ million	Exchange movements $ million	Disposal of asset $ million	(Charged)/ credited to income statement $ million	Credited to retained earnings $ million	At 31 December 2013 $ million
UK deferred corporation tax:						
Fixed assets and allowances	(601.6)	-	-	(226.6)	-	(828.2)
Decommissioning	252.8	-	-	68.9	-	321.7
Deferred petroleum revenue tax	(1.5)	-	-	(3.9)	-	(5.4)
Tax losses and allowances	861.7	-	-	342.1	-	1,203.8
Small field allowance	45.8	-	-	2.0	-	47.8
Deferred revenue	2.0	-	-	(2.0)	-	-
Derivative financial instruments	-	-	-	-	13.9	13.9
Total UK deferred corporation tax	**559.2**	**-**	**-**	**180.5**	**13.9**	**753.6**
UK deferred petroleum revenue tax[1]	**2.3**	**-**	**-**	**6.4**	**-**	**8.7**
Overseas deferred tax[2]	**(289.7)**	**8.1**	**24.0**	**(49.1)**	**-**	**(306.7)**
Total	**271.8**	**8.1**	**24.0**	**137.8**	**13.9**	**455.6**

1 The UK deferred petroleum revenue tax relates mainly to temporary differences associated with decommissioning provisions.
2 The overseas deferred tax relates mainly to temporary differences associated with fixed asset balances.

The group's unutilised tax losses and allowances at 31 December 2013 are recognised to the extent that taxable profits are expected to arise in the future against which the tax losses and allowances can be utilised. In accordance with paragraph 37 of IAS 12 - 'Income Taxes' the group re-assessed its unrecognised deferred tax assets at 31 December 2013 with respect to ring fence tax losses and allowances. The corporate model used to determine the recognition of deferred tax assets was re-run, using an oil price assumption of Dated Brent forward curve in 2014 and 2015, and US$85/bbl in 'real' terms thereafter. The results of the corporate model concluded that it was appropriate to recognise the group's UK ring fence deferred tax assets in respect of tax losses and allowances in full.

In addition to the above, there are non-ring fence UK tax losses of approximately US$321.1 million (2012: US$327.6 million) and current year non-UK tax losses of US$14.3 million (2012: US$26.9 million) for which a deferred tax asset has not been recognised.

None of the UK tax losses (ring fence and non-ring fence) have a fixed expiry date for tax purposes.

No deferred tax has been provided on unremitted earnings of overseas subsidiaries, following a change in UK tax legislation in 2009 which exempted foreign dividends from the scope of UK corporation tax where certain conditions are satisfied.

6 Earnings per share

The calculation of basic earnings per share is based on the profit after tax and on the weighted average number of Ordinary Shares in issue during the year.

Basic and diluted earnings per share are calculated as follows:

	Profit after tax		Weighted average number of shares		Earnings per share	
	2013	2012	**2013**	2012	**2013**	2012
	$ million	$ million	**million**	million	**cents**	cents
Basic	**234.0**	252.0	**529.2**	526.4	**44.2**	47.9
Contingently issuable shares	**10.3**	11.2	**36.0**	35.3	*	*
Diluted	**244.3**	263.2	**565.2**	561.7	**43.2**	46.9

* The inclusion of the contingently issuable shares in the 2013 and 2012 calculations produces diluted earnings per share. At 31 December 2013, 35,526,646 (2012: 35,035,495) potential Ordinary Shares in the company that are underlying the company's convertible bonds and that may dilute earnings per share in the future have been included in the calculation of diluted earnings per share.

7 Intangible exploration and evaluation (E&E) assets

Oil and gas properties	Total $ million
Cost:	
At 1 January 2012	315.5
Exchange movements	11.0
Acquisitions	322.3
Additions during the year	213.5
Transfer to property, plant and equipment	(46.6)
Exploration expense	(157.7)
At 31 December 2012	658.0
Exchange movements	(17.3)
Additions during the year	266.9
Disposals	(101.3)
Transfer from property, plant and equipment	0.9
Exploration expense	(106.2)
At 31 December 2013	**701.0**

The amounts for intangible E&E assets represent costs incurred on active exploration projects. These amounts are written off to the income statement as exploration expense unless commercial reserves are established or the determination process is not completed and there are no indications of impairment. The outcome of ongoing exploration, and therefore whether the carrying value of E&E assets will ultimately be recovered, is inherently uncertain.

8 Property, plant and equipment

	Oil and gas properties $ million	Other fixed assets $ million	Total $ million
Cost:			
At 1 January 2012	3,390.9	22.4	3,413.3
Exchange movements	-	0.7	0.7
Acquisitions*	150.5	-	150.5
Additions during the year**	595.2	15.5	610.7
Disposals	-	(0.1)	(0.1)
Transfer from intangible E&E assets	46.6	-	46.6
At 31 December 2012	4,183.2	38.5	4,221.7
Additions during the year**	742.8	13.8	756.6
Transfer from/(to) intangible E&E assets	3.3	(4.3)	(1.0)
At 31 December 2013	**4,929.3**	**48.0**	**4,977.3**
Amortisation and depreciation:			
At 1 January 2012	1,142.9	12.6	1,155.5
Exchange movements	-	0.6	0.6
Charge for the year	345.4	6.7	352.1
Impairment charge	20.7	-	20.7
Disposals	-	(0.1)	(0.1)
At 31 December 2012	1,509.0	19.8	1,528.8
Exchange movements	-	0.1	0.1
Charge for the year	375.0	8.8	383.8
Impairment charge	178.7	-	178.7
Disposals	-	-	-
At 31 December 2013	**2,062.7**	**28.7**	**2,091.4**
Net book value:			
At 31 December 2012	2,674.2	18.7	2,692.9
At 31 December 2013	**2,866.6**	**19.3**	**2,885.9**

* Acquisitions in the prior year mainly relate to the acquisition of EnCore Oil plc.

** Finance costs that have been capitalised within oil and gas properties during the year total US$25.6 million (2012: US$13.5 million), at a weighted average interest rate of 4.70 per cent (2012: 5.21 per cent).

Other fixed assets include items such as leasehold improvements, motor vehicles and office equipment.

Amortisation and depreciation of oil and gas properties is calculated on a unit-of-production basis, using the ratio of oil and gas production in the period to the estimated quantities of proved and probable reserves on an entitlement basis at the end of the period plus production in the period, on a field-by-field basis. Proved and probable reserve estimates are based on a number of underlying assumptions including oil and gas prices, future costs, oil and gas in place and reservoir performance, which are inherently uncertain. Management uses established industry techniques to generate its estimates and regularly references its estimates against those of joint venture partners or external consultants. However, the amount of reserves that will ultimately be recovered from any field cannot be known with certainty until the end of the field's life.

8 Property, plant and equipment *continued*

The impairment charge relates to the UK Balmoral Area. The impairment charge of US$178.7 million was calculated by comparing the future discounted cash flows expected to be derived from production of commercial reserves (the value-in-use) against the carrying value of the asset. The future cash flows were estimated using an oil price assumption equal to the Dated Brent forward curve in 2014 and 2015, and US$85/bbl in 'real' terms thereafter and were discounted using a pre-tax discount rate of 10.0 per cent. Assumptions involved in impairment measurement include estimates of commercial reserves and production volumes, future oil and gas prices and the level and timing of expenditures, all of which are inherently uncertain. At 30 June, based on a review of the longer-term plans for the life of the fields in the area, it was determined that additional maintenance and operating cost expenditure is likely to be required in order to ensure that additional reserves will be extracted. At year-end, decommissioning costs were also revised and updated based on latest estimates of drilling costs and time estimates to abandon the fields.

9 Notes to the cash flow statement

	2013 **$ million**	2012 $ million
Profit before tax for the year	**285.4**	359.9
Adjustments for:		
Depreciation, depletion, amortisation and impairment	**562.5**	372.8
Exploration expense	**106.2**	157.7
Provision for share-based payments	**7.9**	10.1
Share of loss in associate	**-**	1.9
Interest revenue and finance gains	**(33.0)**	(3.2)
Finance costs and other finance expenses	**98.4**	110.8
Other gains and losses	**(3.6)**	-
Loss/(gain) on derivative financial instruments	**1.2**	(14.2)
Operating cash flows before movements in working capital	**1,025.0**	995.8
Increase in inventories	**(14.9)**	(6.8)
Decrease/(increase) in receivables	**45.1**	36.3
(Decrease)/increase in payables	**(28.9)**	(15.1)
Cash generated by operations	**1,026.3**	1,010.2
Income taxes paid	**(228.3)**	(233.1)
Interest income received	**4.5**	1.9
Net cash from operating activities	**802.5**	779.0

9 Notes to the cash flow statement *continued*

Analysis of changes in net debt:

	2013 $ million	2012 $ million
a) Reconciliation of net cash flow to movement in net debt:		
Movement in cash and cash equivalents	**261.5**	(121.7)
Proceeds from drawdown of long-term bank loans	**(384.1)**	(217.6)
Proceeds from issuance of senior loan notes	**(156.7)**	(235.2)
Proceeds from issuance of retail bonds	**(245.8)**	-
Repayment of long-term bank loans	**200.0**	202.0
Non-cash movements on debt and cash balances	**(17.4)**	6.1
Increase in net debt in the year	**(342.5)**	(366.4)
Opening net debt	**(1,110.4)**	(744.0)
Closing net debt	**(1,452.9)**	(1,110.4)

b) Analysis of net debt:		
Cash and cash equivalents	**448.9**	187.4
Borrowings*	**(1,901.8)**	(1,297.8)
Total net debt	**(1,452.9)**	(1,110.4)

* Borrowings consist of the short-term borrowings, the convertible bonds and the other long-term debt. The carrying values of the convertible bonds and the other long-term debt on the balance sheet are stated net of the unamortised portion of the issue costs of US$0.4 million (2012: US$0.6 million) and debt arrangement fees of US$12.2 million (2012: US$13.2 million) respectively.

10 Dividends

The Board is proposing a dividend of 5 pence per share (2012: 5 pence per share). This dividend is subject to shareholder approval at the Annual General Meeting to be held in London on 14 May 2014. If approved, the dividend will be paid on 21 May 2014 to shareholders on the register as of 22 April 2014.

The following is the dividend timetable for shareholders' information:

27 February 2014:	Declaration of final dividend
16 April 2014:	Ex-dividend date
22 April 2014:	Record date
14 May 2014:	AGM
21 May 2014:	Dividend payment date

11 External audit

This preliminary announcement is consistent with the audited financial statements of the group for the year-ended 31 December 2013.

12 Publication of financial statements

A full set of financial statements will be published on or before 7 April 2014. Copies will be available by this date at the company's head office, 23 Lower Belgrave Street, London SW1W 0NR, and on the company's website (www.premier-oil.com).

13 Annual General Meeting

The Annual General Meeting will be held at Institute of Directors, 116 Pall Mall, London SW1Y 5ED on Wednesday 14 May 2014 at 11.00am.

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Working interest reserves at 31 December 2013

	Working interest basis												
	Indonesia		Mauritania		Pakistan		UK		Vietnam		TOTAL		
	Oil and NGLs mmbbls	Gas bcf	Oil and NGLs mmbbls	Gas bcf	Oil and NGLs mmbbls	Gas bcf	Oil and NGLs mmbbls	Gas bcf	Oil and NGLs mmbbls	Gas bcf	**Oil and NGLs mmbbls**	**Gas[4] bcf**	**Oil, NGLs and gas Mmboe**
Group proved plus probable reserves:													
At 1 January 2013	5.0	496.8	0.6	0.7	0.7	211.0	112.8	60.3	28.7	37.6	**147.8**	**806.4**	**291.9**
Revisions[1]	1.1	(36.1)	-	(0.7)	(0.3)	(33.0)	1.1	1.1	1.1	4.8	**3.0**	**(63.9)**	**(12.8)**
Discoveries and extensions[2]	-	-	-	-	-	0.3	-	-	-	-	**-**	**0.3**	**0.1**
Acquisitions and divestments[3]	-	-	-	-	-	-	1.4	0.1	-	-	**1.4**	**0.1**	**1.4**
Production	(0.4)	(25.3)	(0.2)	-	(0.1)	(34.0)	(5.0)	(2.4)	(4.6)	(2.8)	**(10.3)**	**(64.5)**	**(21.2)**
At 31 December 2013	**5.7**	**435.4**	**0.4**	**-**	**0.3**	**144.3**	**110.3**	**59.1**	**25.2**	**39.6**	**141.9**	**678.4**	**259.4**
Total group developed and undeveloped reserves:													
Proved on production	1.1	115.5	0.2	-	0.2	89.1	21.7	18.0	15.8	11.6	**39.0**	**234.2**	**80.2**
Proved approved/justified for development	2.6	186.5	-	-	-	14.1	44.7	21.3	4.0	15.6	**51.3**	**237.5**	**89.8**
Probable on production	0.6	57.6	0.2	-	0.1	33.8	10.3	12.2	4.3	8.6	**15.5**	**112.2**	**35.7**
Probable approved/justified for development	1.4	75.8	-	-	-	7.3	33.6	7.6	1.1	3.8	**36.1**	**94.5**	**53.7**
At 31 December 2013	**5.7**	**435.4**	**0.4**	**-**	**0.3**	**144.3**	**110.3**	**59.1**	**25.2**	**39.6**	**141.9**	**678.4**	**259.4**

Notes:

1 Includes re-evaluation of reserves at Anoa, Gaja Baru, Gaja Puteri, Bison (West Natuna Block A, Indonesia), Alur Rambong and Alur Siwah (Block A Aceh, Indonesia), Zamzama (Pakistan), Chim Sáo (Vietnam) and Catcher Area (UK). Reserves from Caledonia field have been re-classified as contingent resources.

2 Includes reserves discovered at Kadanwari and Badhra (Pakistan). Discoveries at Bonneville and Lacewing (UK), Luno II (Norway) and Matang (Indonesia) are currently classified as contingent resources and do not appear in this table.

3 Includes a minor change in net equity on Solan. Falkland Islands assets and changes to the working interests in the Bream Area in Norway remain as contingent resources and do not appear in this table.

4 Proved plus probable gas reserves include 75 bcf fuel gas.

Premier Oil plc categorises petroleum resources in accordance with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System (SPE PRMS).

Proved and probable reserves are based on operator, third party reports and internal estimates and are defined in accordance with the Statement of Recommended Practice (SORP) issued by the Oil Industry Accounting Committee (OIAC), dated July 2001.

The group provides for amortisation of costs relating to evaluated properties based on direct interests on an entitlement basis, which incorporates the terms of the PSCs in Indonesia, Vietnam and Mauritania. On an entitlement basis reserves were 230.9 mmboe as at 31 December 2013 (2012: 255.5 mmboe). This was calculated at year-end 2013 using an oil price assumption equal to US$108.8 in 2014, US$102.8 in 2015 and US$85/bbl in 'real' terms thereafter (2012: Dated Brent forward curve in 2013 and 2014 and US$85/bbl in 'real' terms thereafter).