PremierOil

2013 Half-Yearly Report

for the six months to 30 June 2013

PREMIER IS A LEADING FTSE 250 INDEPENDENT UPSTREAM OIL AND GAS COMPANY

OUR STRATEGY is to focus on growing the underlying value of the business through disciplined investment in high quality projects where we see the potential for attractive returns to shareholders.

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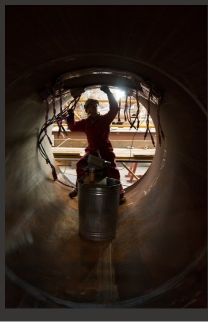
Following changes in the UK company disclosure regulations in 2008, it is not a requirement for half-yearly financial statements to be sent to shareholders. Accordingly, Premier will not be printing and distributing a 2013 Half-Yearly Report. A copy of this announcement is available for download from our website at www.premier-oil.com and hard copies can be requested by contacting the company (email: premier@premier-oil.com or telephone: +44 (0)20 7730 1111).

HIGHLIGHTS


Operational

- Production averaged 58,600 boepd (2012: 58,400 boepd) as previously announced; initial Huntington production issues addressed
- Catcher project advanced, sanction expected by year-end; significant progress on Sea Lion project and forward plans for Falkland Islands
- Six out of seven exploration wells successful, including significant oil discovery at Luno II in Norway
- Three blocks awarded in Brazil's 11th Bid Round; farm-in to UK Bagpuss/Blofeld area, potential high impact 2014 well
- Delivering on portfolio upgrade: increased stake in Bream area; disposals in Vietnam and Norway

Financial

- Record half-year financial results; continued growth in operating cash flow
- Profit before tax of US$214.6 million (2012: US$194.6 million); profit after tax of US$161.1 million (2012: US$145.8 million)
- Operating cash flow up 18 per cent at US$384.9 million (2012: US$325.5 million)

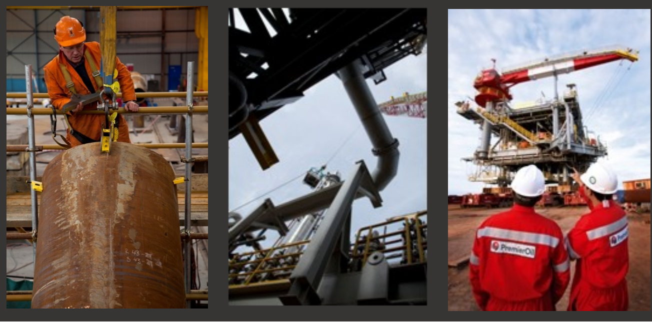
Outlook

- Full year production target (63,000 boepd) depends on Huntington field performance in 2H
- Pipeline of 2014 projects (Solan, Pelikan, Naga and Dua) in execution phase
- Six wells planned for 2H 2013 including Kuda/Singa Laut in Indonesia and Luno II appraisal in Norway; offshore Kenya programme and Lama play in Indonesia to commence late 2013 or early 2014
- Rising cash flows and strong funding position fully finance forward development spend, exploration programme and dividend plans

Simon Lockett, Chief Executive Officer, commented:

"We are well placed to continue to deliver our target growth in the underlying value of the business. We have had one of our most successful periods for exploration with six discoveries from seven wells, material additions to the portfolio and significant maturation of high impact leads and prospects. We are actively managing our portfolio to focus on our operated development projects. Despite rising costs and challenging execution timetables across the industry, we see high returns on capital and strong cash flow growth as we deliver on these valuable projects."

CHAIRMAN'S STATEMENT



A robust oil and gas price environment combined with consistent performance from our producing assets has generated strong first half financial results. Premier is also increasingly well placed to deliver the projects which will drive future value. Our pipeline of developments due on-stream in 2014 supports near term growth. Considerable progress on the Premier-operated Bream, Catcher and Sea Lion projects further underpins rising cash flows and returns to shareholders for the medium-term. Exploration success in the first half has enhanced the group's resource base and recent acreage additions have increased significantly the materiality of our portfolio for future drilling.

Average production during the first half of the year was 58,600 barrels of oil equivalent per day (boepd) (2012: 58,400 boepd). Strong reservoir performance across our portfolio was offset by the slow ramp up of production from the Huntington field in the UK and lower gas production rates from Chim Sáo in Vietnam. While important from a production perspective, the value impact of these two events is small.

The immediate focus of our development activity is on our pipeline of operated projects which are expected on-stream in 2014 and on progressing the operated Catcher and Sea Lion developments to project sanction by year-end 2013 and 2014, respectively. We are delighted to have secured operatorship of the Bream area project in Norway through successive acquisitions and we look forward to working with the new partnership group to take the project forward to sanction in the first half of next year.

We remain focused on bringing potential developments into the portfolio through exploration whilst maintaining disciplined capital spend. In this respect, the first half of 2013 has seen success across our acreage with the significant Luno II oil discovery in Norway as well as near field discoveries in Indonesia, Pakistan and the UK. We continue to focus on adding early stage exploration acreage to our portfolio for future drilling and we are delighted to have been awarded three blocks in under-explored but proven basins in Brazil's 11th Bid Round. As well as appraising our Luno II discovery, we look forward to our upcoming exploration drilling in Kenya and the follow up programme on the deeper Lama play close to our existing gas infrastructure in Indonesia. These wells will spud later this year or early in 2014. We are also pleased with the successful sale of Block 07/03 in Vietnam and PL378 in Norway as we seek to re-allocate our resources to other key projects.

Oil and gas prices continued to be strong during the period, with Brent crude oil prices trading in a range of US$96.0 per barrel (bbl) to US$119.7/bbl. The average for the period was US$107.7/bbl against US$113.7/bbl in the corresponding period last year. Operating cash flows were US$384.9 million (2012: US$325.5 million) in the first half and are expected to grow in the second half as we benefit from a full half year of Huntington production. Profit after tax for the period was US$161.1 million (2012: US$145.8 million).

We continue to place the highest priority on health, safety and environmental matters. We remain committed to operating safely, responsibly and sustainably in every part of our business. Success in these areas protects our people, our assets, our revenue and our reputation. Our health, safety and environmental management systems are key drivers to deliver this success and their certification to OHSAS 18001 and ISO 14001 demonstrates we are meeting international standards. We continue to retain this certification for our Balmoral production operations in the UK, for Anoa and Gajah Baru in Indonesia, and for our global drilling function. As of end April 2013, we retained our inclusion within the FTSE4Good Index for the tenth year in a row.

Outlook

The Board remains committed to delivering value growth to shareholders and to the prudent financing principles which underpin our strategy. We focus our resources on high quality development projects, which we continue to access through successful exploration and acquisitions, where we see the potential for high returns. The industry faces significant challenges with ageing infrastructure and rising costs in many areas. Despite this, our strategy has resulted in rising cash flows, improved returns on capital and continued growth in the underlying value of the business. Much more is to come as we execute on our future development pipeline, transforming our cash flows and financial position. We will also continue to manage our portfolio actively, to divest lower return projects and to maintain appropriate exposure to material exploration.

The first half of this year has seen us deliver significant exploration success, progress on operated developments, strong financial performance and the commencement of cash returns to shareholders. In the second half of the year, we will see material exploration activities in Indonesia and Norway, key milestones reached on our core operated projects and further growth in production, generating stronger cash flows.

Mike Welton
Chairman

OPERATIONAL REVIEW



THE FALKLAND ISLANDS

A considerable amount of work has been undertaken on the Sea Lion project in the first six months of the year. A subsea development tied back to a floating production, storage and offtake vessel (FPSO) has been confirmed as a viable scheme and a phased drilling programme selected. Initial development will start with the major part of Sea Lion in the north followed by a subsequent southern development which will access the remaining part of Sea Lion and other discoveries. Premier is targeting project sanction for the end of next year. Progress has also been made in securing a rig for an exploration campaign starting next year.

Development

On 1 November 2012, Premier formally became operator of all of the licence interests previously operated by Rockhopper, thereby becoming the operator of the Sea Lion development project. Since then, Premier's newly formed dedicated project team has been focused on evaluating the options for the development of the field.

During the half year, the project team, in collaboration with third party specialists, has progressed a comprehensive set of studies as part of the pre-FEED (front end engineering and design) phase to refine the development concept. These have included detailed work in areas such as metocean studies, FPSO design (including turret design and topsides layout), flow assurance methodologies, subsea equipment layout and installation methods, reservoir studies and well trajectories. These studies have now either been concluded or are nearing completion.

A phased approach to development drilling has been selected. It is envisaged that drilling will initially target the northern part of the field, and is estimated to recover 284 million barrels (mmbbls), with the southern area subsequently tied back to the host facilities and estimated to recover a further 110 mmbbls. The second phase of development will be optimised to incorporate any additional exploration or appraisal success. Premier is working to participate in a multi-operator exploration programme starting in the second half of 2014 which will include a well to confirm the presence of a gas cap in the west of Sea Lion.

Premier has confirmed that an FPSO is a viable host facility for the Sea Lion project, however conceptual studies have indicated that a Tension Leg Platform (TLP) with an integral drilling rig may offer significant cost savings while providing better motion characteristics and flow assurance options. Work is now ongoing to optimise the design specifications (such as capacities and construction methods) for both the FPSO and the TLP schemes and to prepare the documentation for FEED. A final decision between the two is expected to be made at the end of this year with project sanction targeted for the end of 2014. The timing for first oil will depend on the final scheme configuration.

Exploration

During the first half, Premier has continued to work closely with Rockhopper to define and mature the lead and prospect inventory within its acreage in the North Falklands Basin. As a result of this work, an exploration programme of at least three wells with multiple stacked targets is planned. The exact timings for this programme are still being firmed up in conjunction with other operators in the area.

This exploration programme will include the Zebedee well, which will test the extent of the proven F2 sequence towards the south as well as the older F3 sequence. The well, testing the gas cap on the western flank, will also test the deeper potential Chatham prospect. The results of this work will be incorporated into the planning for the Sea Lion development.

INDONESIA

The first half saw a strong performance from Natuna Sea Block A with the Anoa field capturing in excess of its contractual share of GSA1 and the Gajah Baru field achieving record production rates. The Premier-operated Anoa Phase 4, Pelikan and Naga projects will maintain Premier's future production levels in

Indonesia, commercialising an additional 350 billion cubic feet (bcf) of gas. Premier's return to exploration in Indonesia in the fourth quarter offers potential for significant further resource additions.

Production & Development

Singapore demand for Natuna gas remained robust and above take or pay levels during the first half of 2013 at 407 billion British thermal units per day (BBtud), higher than the corresponding period last year (2012 1H: 385 BBtud). This was mainly due to higher GSA2 demand which was entirely supplied by Premier-operated Gajah Baru field.

During the first six months of 2013, the Premier-operated Natuna Sea Block A sold an average of 225 BBtud (gross) (2012 1H: 231 BBtud) from its gas export facilities on Anoa (144 BBtud) and Gajah Baru (81 BBtud). The non-operated Kakap Block contributed gas production of a further 34 BBtud (gross) (2012 1H: 33 BBtud) during the first half. Gross liquids production from the Block A Anoa field averaged 2,000 barrels of oil per day (bopd) (2012 1H: 2,600 bopd) and 3,700 bopd from Kakap (2012 1H: 4,000 bopd). Overall, net production from Indonesia in the first six months was 14,100 boepd (2012 1H 14,700 boepd), on a working interest basis.

The Anoa field continued to exceed its 36.9 per cent contractual share of GSA1, delivering around 44 per cent year to date. The Anoa Phase 4 additional compression project has now been completed and field production resumed on 14 August. This project will result in an additional 200 bcf of reserves being delivered from the Anoa field into Singapore. A substantial proportion of Anoa's contractual commitments under GSA1 was covered during the Anoa Phase 4 shutdown by the nearby Gajah Baru field, which consistently achieved record production rates of in excess of 200 BBtud.

Good progress was made during the first half on the Pelikan and Naga gas projects. The two gas fields, which contain 150 bcf of reserves and will maintain the profiles of GSA1 and GSA2, will be tied into the Gajah Baru facilities. Onshore fabrication of both the Pelikan and Naga wellhead platforms is nearing completion for load out and installation in the third quarter of 2013. The planning for the development drilling campaign is also far advanced with the rig contract awarded. Drilling is planned to begin on the Pelikan platform wells after the monsoon season in the first quarter of 2014, followed by the Naga wells. First gas from both fields is expected in the second half of 2014.

On the non-operated Block A Aceh, work continued on the gas development project. All engineering, procurement, construction and installation (EPCI) bids for the facilities have been received and negotiations on a revised gas price with the end user and the Indonesian Government are nearing completion. However, the success of the Matang-1 exploration well in April has enabled the joint venture to consider the potential for an alternative development scenario based on early production from Matang. Planning of an appraisal well on the Matang discovery in line with alternative block development plans has commenced and an agreement on the preferred development plan is expected in the fourth quarter of this year.

Exploration & Appraisal

The Matang-1 exploration well on Block A Aceh was spudded in November 2012 and penetrated a gross gas column of at least 90 feet. The well was tested in May 2013 and flowed gas at commercial rates of 25 thousand standard cubic feet (mmscf)/d from the target Upper Bampo Limestone Formation. The gas has low H_2S and CO_2 content compared to gas discovered in the surrounding fields. Work is now under way to progress a follow up Matang appraisal and development drilling programme.

During the first six months of the year, Premier continued to mature the Kuda/Singa Laut prospect on the operated Tuna Block for drilling. The Kuda Laut segment, which is in Miocene sands within a four-way dip closure, is scheduled for drilling in the fourth quarter of this year. The well will then be side-tracked in early 2014 to drill the Singa Laut segment in an adjoining three-way dip structure in the lower Miocene and

Oligocene.

In 2011, Premier successfully drilled the Anoa Deep well on Natuna Sea Block A which opened up a new play concept in the fractured sandstones of the deeper Lama formation. Since then Premier has successfully mapped the Lama formation across its acreage and has matured prospects and leads in this play for follow on drilling. To date, a total of five leads and prospects have been identified across the block, including the Ratu Gajah prospect which Premier plans to spud in late 2013 or early 2014.

NORWAY

Since being awarded its first licences in Norway in December 2005, Premier has participated, through exploration success or new licence awards, in six potential development projects. Following the profitable sale of the Grosbeak discovery, Premier's focus has turned to operating the Bream area project and appraising the new Luno II discovery. Premier will also continue to fully exploit its exploration position in Norway.

Production and Development

In July, Premier announced that, in conjunction with KUFPEC Norway (KUFPEC), it had acquired a 40 per cent interest in PL407 from BG Norge AS (BG) for an aggregate consideration of $22.2 million. As a result of the transaction, Premier increased its existing 40 per cent equity interest in PL407 to 50 per cent (at an upfront cost of around $1/boe) and will assume operatorship of the Bream project in October. Premier is also operator of the adjacent PL406, which contains the Mackerel discovery and, through the sale of a 30 per cent interest in the licence to KUFPEC for a contingent consideration of $5.0 million, was able to align partnership interests across the two licences.

The joint venture partners have agreed to allow Premier to take immediate control of the Bream project. It is envisaged that the Bream development will entail three production and two water injection wells tied back to an FPSO while the Mackerel discovery will be developed as a subsea tie-back to the Bream facility. Submission of a plan of development for the Bream area is targeted for the first half of 2014 following optimisation of subsea layout, well design and FPSO contracting strategy. Premier currently estimates that the Bream and Mackerel fields contain around 50 million barrels of oil equivalent (mmboe) of 2C resources, with some further upside in the low risk Herring prospect on PL406 and through a potential third party tie-back.

Elsewhere in Norway, work continued on evaluating the development options for the non-operated Froy field with the aim of progressing the project to concept selection. Technical studies for a joint processing hub to receive production from the fields in the Froy area was completed during the first half. The results of these initial engineering and subsurface studies are now under evaluation. Meanwhile, work continued on the standalone development option with an initial focus on the Horst area of the field. A decision on whether to pursue a joint or standalone development solution is expected to be made in 2014.

Exploration and Appraisal

In April, the exploration well 16/4-6S, which was targeting the Luno II prospect on the south western flank of the Utsira High in PL359, resulted in a significant oil discovery. Premier estimates the gross resource across the Luno II structure to be in the range of 75 to 130 mmboe of which approximately 80 per cent are liquids. The operator plans to appraise the Luno II discovery later this year and further exploration potential remains on PL359.

Elsewhere in Norway, responses to an invitation to tender (ITT) for a jack-up rig to drill the Myrhauk prospect on the eastern flank of the Mandal High have been received and the well is currently expected to spud in the second half of next year. Premier further built on its position in and around the Mandal High in February when it was awarded a 20 per cent interest in PL663 in the APA 2012 licensing round. The licence contains the Skåla prospect and is located to the north of the Myrhauk prospect. The work programme comprises geological and geophysical studies followed by a drill or drop decision to be made in early 2015.

In August, Premier agreed to sell its 20 per cent interest in PL378 and PL378B, which contain the Grosbeak discovery and a possible extension to the Skarfjell discovery located in PL418 to the north, to Cairn Energy, for an upfront consideration of $16 million. This sale formed part of an ongoing programme of non-core asset disposals.

PAKISTAN

The natural decline in Premier's large mature gas fields continues to be mitigated by ongoing success in infill drilling, compression projects and the tie-in of successful exploration wells. Further potential will be tested during the remainder of the year.

Production and Development

Average production in Pakistan during the first six months was 15,300 boepd (2012 1H: 15,900 boepd). Natural production decline in some existing wells was partially offset by successful infill drilling and the tie-in of exploration and development wells in the Kadanwari, Qadirpur, Zamzama, Bhit and Badhra fields.

Production from the Qadirpur gas field averaged 3,600 boepd net to Premier (2012 1H: 3,900 boepd). Deliverability from Qadirpur remained strong with two front-end gas compressors successfully commissioned. In addition, development drilling on Qadirpur continued apace with 2 development wells (QP-48SUL and QP-49ERW) successfully completed during the period, with more planned for the remainder of the year. Demand reduced between March and June as a result of the gas buyer, SNGPL, temporarily stopping gas supply to a power plant while a commercial dispute was resolved. Gas demand has since increased back to normal levels and Qadirpur is currently producing around 3,800 boepd net to Premier.

Production from the Kadanwari gas field during the period was 2,700 boepd, 13 per cent higher than in the corresponding period last year (2012 1H: 2,400 boepd). This increase in production followed the tie-in to facilities of the successful K-29 development well in the fourth quarter of 2012. More recently, the successful K-32 exploration well, which was drilled in May, was tied in to the production facilities and commissioned in July. It is currently producing at around 15 mmscfd. This strong performance was offset by the K-27 exploration well which has been offline between April and June due to a pipeline failure. That issue has been resolved and the K-27 well is currently producing up to 45 mmscfd.

The pilot programme at Kadanwari to test the tight gas potential in the Lower Goru formation is ongoing. The third and final pilot well, K-31H, which spudded in July, is being drilled horizontally to target the higher ranked G-Sand. The results of this well are expected by the end of November.

Average production from the Zamzama gas field during the period was 5,700 boepd (2012 1H: 6,100 boepd). The decrease in production was due to natural decline from existing wells partially compensated by the good performance of the Zam-9 well, which was tied into production in February. Further development wells on Zamzama for 2014 are under consideration.

Production from the Bhit/Badhra gas fields averaged 3,300 boepd in the first half (2012 1H: 3,500 boepd). The combined production from the two fields is currently at plateau. The lower production due to the natural decline from the existing Bhit gas field wells was partially offset by higher production following the successful tie in of the Badhra B North-1 (BBN-1) exploration well which is currently producing up to 30 mmscfd. The Bhit-15 development well was tied into production in July and the Bhit-16 development well will be brought on-stream by end of the third quarter.

Exploration and Appraisal

Two exploration wells, K-32 on the Kadanwari gas field and Badhra B North-2 (BBN-2) on the Badhra gas field, were drilled in the first half of the year.

The K-32 exploration well was spudded at the end of March and discovered gas in the F-Sand, the primary target, and was successfully tested. The well was subsequently tied into the Kadanwari production facilities and came on-stream in July and is now flowing gas at around 15 mmscfd.

In September 2012, Premier made a significant gas discovery in the Kirthar Foldbelt with the BBN-1 well. The objective of the BBN-2 well, which was spudded in May 2013, was to confirm the extent of the newly discovered gas pool towards the flank of the Badhra structure. Log results across the Mughalkot formation show presence of 22 metres of net pay in the A-Sand and 7 metres of net pay in the new B-Sand intervals while strong gas shows were recorded in the Parh Limestone formation. The testing has commenced and the results will be known by early September.

Looking ahead, the Badhra South-1 Deep exploration well will be drilled later this year to test the potential of a deeper lead at the Lower Goru level. The Badhra-7 development well, which will be deepened to test the potential of the Parh Limestone, and the K-36 exploration well are planned for 2014.

MAURITANIA

Production and Development

First half working interest production from the Chinguetti field offshore Mauritania averaged 600 boepd (2012 1H: 500 boepd). On the Banda gas development, the Environmental Impact Assessment (EIA) and FEED were completed in the first half. In addition, ITT documents for major contracts, including those for drilling, production systems, umbilical and pipeline, were issued in July 2013. Gas sales negotiations and payment guarantees are planned to be completed during the second half of the year, ahead of project sanction.

Exploration and Appraisal

Following the consolidation of Premier's exploration licences offshore Mauritania in 2011, Premier has a 6.23 per cent equity interest in the production sharing contract (PSC) C-10 exploration licence. Geological studies across the licence to determine the optimum locations for the two commitment wells were completed in the first half of the year. It is expected that the first well, which will target the Tapendar prospect, will spud in the fourth quarter.

UNITED KINGDOM

Premier continued to add valuable resources to its UK North Sea portfolio during the first half with exploration successes at Bonneville and Lacewing. Nearer term, rising production from Huntington and Rochelle will underpin a significant rise in cash flows due to the company's UK tax position, while UK development activity is focused on delivering the Solan project in 2014 and on progressing Catcher development to project sanction by year-end.

Production

UK production averaged 13,400 boepd for the first half of the year (1H 2012: 13,600 boepd). 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 in the first six months of 2013, up from 82 per cent for the same period last year. The Scott and Telford fields also performed above expectations due to improved production efficiency and a successful well intervention programme.

These gains were offset by lower production from the Balmoral area due to a temporary shutdown of the Balmoral floating production vessel (FPV) in April and the shut-in of five Balmoral wells since June pending intervention. A subsea intervention campaign utilising a dive support vessel to carry out the repairs is scheduled for end of September. Production from the Brenda D3 well has also been offline since April due to a downhole valve failure and is expected to be reinstated during November.

The Huntington field achieved first oil on 12 April 2013. Initial production was restricted due to start-up problems with the gas compression system. These have now been resolved and a new power turbine was installed earlier in August to address the vibration issues associated with the second compression train. Gross production rates of around 27,000 boepd (Premier interest 40 per cent) have since been achieved. However, recent periods of calm weather have resulted in gas venting from the cargo tanks being picked up by the gas detection system at deck level. This has resulted in production being shutdown whenever the wind speed falls to below 5 knots. This issue will be resolved once the primary hydrocarbon blanketing system, which recycles gas from cargo tanks, has been commissioned in late August.

Premier received no contribution from the Kyle field during the first half. 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 are near to agreement and the field re-instatement plans are in progress.

Developments

On the non-operated Rochelle field, the West Rochelle well, which was successfully completed and tested in June, is expected to have an initial delivery capacity of 80 mmscfd and 3 thousand barrels of oil per day (kbopd) (Premier interest 15 per cent). First gas is expected late September or early October due to constraints on the Forties Pipeline System as a result of ongoing work at the Kinneil gas plant. The East Rochelle well (E2), which spudded in July, is expected to be completed and tied back to the Scott field in November, increasing production from the Rochelle field. Subsequent to period-end, Nexen has replaced Endeavour as operator of the field and abandonment operations on the E1 well have been successfully completed.

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. The campaign is scheduled for completion in mid-2014, following a planned break in activities for the winter weather. Dry Docks World Dubai is constructing the subsea storage tank, with a target to sail away from Dubai in the first quarter of 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 during the second quarter of 2014. Hook up and commissioning will then be undertaken ahead of first oil scheduled for the fourth quarter of 2014. The field is expected to produce approximately 40 million barrels gross (Premier equity 60 per cent) with an estimated initial production rate of 24,000 bopd (gross).

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 (both static and dynamic) was completed during the first half and well locations and sequence have been optimised. Bids for the well systems, Christmas trees and a heavy duty jack-up rig have been received and are under evaluation. It is envisaged that development drilling, which will entail the continuous drilling of up to 15 producers and 8 water injectors, will commence in 2015 and continue beyond first oil.

Subsea FEED for the Catcher area project was also completed in the first half and Premier expects to receive the EPCI bids for the subsea facilities in October. The funded tender process for the construction and operating contract for the FPSO was initiated in the first half with the best and final offers (BAFOs) from the three FPSO contractors received on 19 August. These bids are now being evaluated by a dedicated commercial team and a FPSO contractor will be selected ahead of project sanction which remains on track for year-end.

The Catcher area oil discoveries (Catcher, Varadero, Burgman and Carnaby) were supplemented in April, by the Bonneville discoveries which are located four kilometres south of the Burgman discovery. The Bonneville discoveries will be tied back to the Catcher area facilities post first oil.

Exploration

Premier has drilled two wells – the Bonneville exploration well and the Lacewing exploration well – in the UK Central North Sea year-to-date. Both wells have been 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 American Petroleum Institute (API) of the oils is of similar quality 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 million barrels which is 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. Post work evaluation is ongoing to ascertain whether commerciality can be established. Premier managed its capital exposure to this opportunity by farming down prior to drilling in return for a partial carry on the well.

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. Analysis of the 1981 discovery well result suggests that the Bagpuss and Blofeld prospect together could contain up to 2 billion barrels of oil in place. It is envisaged that an initial well on one of these features will spud in late 2014.

VIETNAM

Premier continues to focus on optimising production from the Chim Sáo oil field while progressing the nearby Dua development to first oil in 2014. Following the successful sale of Block 07/03, Premier's exploration activity in Vietnam is now concentrated on Block 121 where the frontier 121-CV-1X well, which was drilled earlier this year, established a working petroleum system in the basin.

Production & Development

During the first half of the year, production from the Premier-operated Chim Sáo oil field averaged 15,200 boepd net to Premier and the field continues to produce ahead of Premier's original development plans. It is hoped that higher gas production can be achieved once the power facility constraints have been addressed.

Water injection rates to maintain reservoir pressure at Chim Sáo continue to improve with a peak injection rate of 51,000 barrels of water per day achieved. Additional water injection wells to support production from the north west extension and the MDS 1 reservoir interval are planned for the first half of 2014.
The Dua oil project, which is being developed as a subsea tie-back to Chim Sáo, is now well advanced. The subsea structures and equipment to tie Dua into the FPSO have been completed; load out and installation will commence shortly. Drilling of the three production wells is planned to start in the fourth

quarter. First oil from Dua is targeted for the first half of 2014. The field, which will be able to produce around 10,000 boepd, will extend plateau production from Chim Sáo.

Exploration and appraisal

In June, the 121-CV-1X, a frontier exploration well targeting the Ca Voi prospect in Block 121, was spudded to test a syn-rift section in a four-way dip closure. The well, although not a commercial discovery, established the presence of a working petroleum system with reservoir and source rocks encountered in the primary target and thermogenic gas encountered in thin post-rift sands. The results of this well are being incorporated into Premier's understanding of the reservoir and source distribution across the block.

In July, Premier sold its 30 per cent operated interest in Block 07/03, offshore Vietnam, which contains the Cá Rồng Đỏ oil and gas discovery and the Ca Duc exploration prospect. The consideration in respect of this transaction was up to $100 million, which included an immediate cash payment of $45 million. The balance is made up of contingent payments dependent on success at the CRD-3X appraisal and Ca Duc exploration wells, as well as upon certain development milestones being reached. The CRD-3X appraisal well will spud in September. The rig will then move to drill the Ca Duc prospect. While Premier continues to provide drilling support, it will not participate in the capital cost of these two wells.

NEW COUNTRY EXPLORATION

Premier aims to add early stage exploration acreage in targeted new countries where the geology is assessed to be similar to that of the existing business units where Premier has built expertise and where an exploration success has the potential to transform the resource base of the company.

In the first half of the year, Premier was awarded three blocks – two operated blocks in the Ceara basin and one non-operated block in the Foz do Amazonas basin – in Brazil's 11th Bid Round in May. The blocks are located offshore North East Brazil in under-explored but proven deepwater basins and contain the potential to deliver material net resource to Premier. It is anticipated that 3D seismic data will be acquired across these blocks ahead of drilling three wells (two operated) within the initial five year licence terms. Premier will fund the cost of this work programme (estimated to be around $150 million) from within its planned exploration spend.

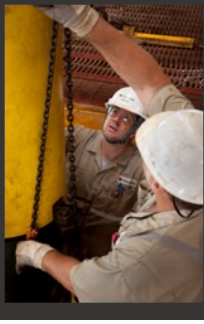
Premier also has exposure to frontier exploration acreage in selected areas of Africa and the Middle East. Premier has equity interests in two blocks offshore Kenya, Blocks L10A and L10B, which it acquired in 2011. Processing and interpretation of 2D and 3D seismic data across these two blocks continued into 2013. Premier's first well in Kenya is planned to be drilled in early 2014 to test the Miocene Carbonate play in the inboard part of the block. To date, 15 prospects and leads have been identified across this play and final prospect selection for drilling is subject to technical agreement in September. Premier estimates gross prospective resource of in excess of 1 billion barrels across its two blocks in Kenya.

In Iraq, work continues on onshore Block 12, in which Premier was awarded a non-operated 30 per cent interest in November 2012. Block 12 is an 8,000 square kilometre block in the foreland of the Zagros fold belt, up dip from producing fields. The forward plan is to reprocess the existing seismic data through 2013 and then acquire new seismic data in 2014. Subject to the interpretation of the new seismic data an exploration well will be drilled in 2015 or 2016.

In Egypt, Premier has decided to relinquish its equity share of the North Red Sea 1 licence and to withdraw from the South Darag block in the Gulf of Suez.

Premier's exploration rights in the Daora, Haouza, Mahbes, Mijek and Laguara blocks offshore the Saharawi Arab Democratic Republic (SADR) remain under force majeure, awaiting resolution of sovereignty under a United Nations mandated process.

FINANCIAL REVIEW



Income statement

Group production on a working interest basis, averaged 58,600 boepd in the first half of 2013 compared to 58,400 boepd in the first half of 2012 and 57,700 boepd for the full year 2012. This reflects continuing good underlying performance from existing producing reservoirs, the start of new production from the Huntington field in the UK in April 2013, offset by unplanned maintenance downtime notably in the UK Balmoral area.

Entitlement production for the period was 53,100 boepd (2012: 52,400 boepd).

Oil and gas prices remained both stable and strong during the first half with the Brent oil price fluctuating between US$96.0/bbl and US$119.7/bbl and averaging US$107.7/bbl (2012: US$113.7/bbl). Premier's average realised oil price for the period was US$107.2/bbl (2012: US$110.5/bbl) pre-hedges or US$108.0/bbl (2012: US$106.2/bbl) on a post-hedge basis.

Average realised gas price for Indonesian production sold into Singapore was US$17.4 per thousand standard cubic feet (mscf) (2012: US$19.6/mscf) in line with slightly lower crude oil pricing. In Pakistan, gas prices across all producing fields averaged US$4.3/mscf (2012: US$4.1/mscf). The combined effect of higher production and realised prices was to increase turnover to US$757.8 million (2012: US$744.3 million).

Cost of sales in the period was US$472.2 million (2012: US$393.9 million). Underlying operating costs were US$16.0 per barrel of oil production (boe) (2012: US$14.7/boe) reflecting unplanned maintenance costs in the Balmoral area and start-up cost on the Huntington field.

Amortisation of oil and gas properties rose from US$164.0 million to US$172.5 million or on a unit basis US$16.2/boe. Impairment charges for the period amounted to US$77.7 million on a pre-tax basis (2012: US$22.0 million). This charge related to the Balmoral area where, following a review of the longer-term plans for the life of fields in the area, it was determined that additional maintenance and operating cost expenditure is likely to be required in order to ensure that remaining reserves will be extracted.

Exploration expense and pre-licence exploration costs amounted to US$21.6 million (2012: US$92.4 million) reflecting the fact that our exploration track record in the first half has been very successful. Operating profit for the period was US$255.1 million (2012: US$245.2 million).

Finance costs and other finance expenses were US$44.6 million (2012: US$57.3 million) offset by interest revenue, finance and other gains of US$5.3 million (2012: US$0.7 million). Finance costs capitalised during the period totalled US$14.0 million (2012: US$4.6 million).

A net loss of US$1.2 million was recorded in the first half in respect of the group's outstanding derivative instruments (2012: US$6.0 million, gain). Substantially all of the group's oil and gas collar arrangements expired at 31st December 2012. Current hedging activities are limited to forward sales of oil and gas when market opportunities arise, based on pre-defined Board approved limits. Realised losses during the first half from such forward sales amounted to US$0.9 million (2012: US$38.2 million) and have been included within sales revenues. Looking forward, approximately 18 per cent of estimated future oil and gas production volumes have been sold forward for the period to end-2014 at an average price, in oil equivalent terms of US$102.0/boe.

The group had a tax charge for the period of US$53.5 million (2012: US$48.8 million). This includes overseas tax charges of US$101.2 million (2012: US$103.3 million) and UK petroleum revenue tax (PRT) of US$31.2 million (2012: US$17.7 million). These charges were offset by a deferred tax credit of US$65.6 million (2012: US$72.2 million) in respect of UK mainstream corporation tax reflecting future capital allowances (including carried forward ring-fence expenditure supplement) arising from our investing activities in the UK North Sea.

Profit after tax in the period to 30 June 2013 was US$161.1 million (2012: US$145.8 million). Basic earnings per share for the period were 30.5 cents (2012: 27.8 cents).

Cash Flow

Cash flow from operating activities amounted to US$384.9 million (2012: US$325.5 million). Adverse working capital movements amounting to US$36.8 million were driven by the specific timing of cargo sales at period end. Capital expenditure in the period (excluding acquisitions and disposals) was US$435.7 million (2012: US$318.2 million). In addition, Premier provided US$51.4 million of partner funding for the Solan project which will be recovered from additional oil production post first oil. Dividends amounting to US$40.2 million were also paid during the first half. During the period US$200.0 million was drawn from our revolving credit facilities.

Capital expenditure

	2013 Half-year $ million	2012 Half-year $ million
Fields/developments	282.9	204.2
Partner Funding	51.4	-
Exploration	147.4	111.0
Other	5.4	3.0
Total	487.1	318.2

Development spend in the first half was focused on completion of the Huntington and Rochelle fields in the UK and progressing the Solan field towards first oil in 2014. There was also an ongoing programme of investment in the Pelikan, Naga and Anoa fields in Indonesia and in the Dua project in Vietnam. Exploration spend in the first half was US$147.4 million (2012: US$111.0 million). Signature bonuses in respect of our Brazilian licence awards, amounting to US$24.0 million, were settled in August.

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 will now hold 50 per cent and assume operatorship. In addition, Premier will sell 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 align the partnership interests across the two licences and are expected to complete, following government approval, later 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 comprises 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. Two wells are expected to be drilled on the block in the second half of the year and whilst Premier continues to provide drilling support services to the new operator, it will not participate in the capital costs of these two wells.

In August, Premier announced that it had reached agreement to sell licences PL378 and PL378B in Norway to Cairn Energy for a total consideration of US$16.0 million. These licences contain the Grosbeak discovery. The transaction, which is subject to government approval, is expected to complete in the second half. As at 30 June, the assets being sold in Vietnam and Norway are held on the balance sheet

Going concern

The group monitors its capital position and its liquidity risk regularly throughout the year to ensure that it has sufficient funds to meet forecast cash requirements. Sensitivities are run to reflect latest expectations of expenditures, forecast oil and gas prices and other negative economic scenarios in order to manage the risk of funds shortfalls or covenant breaches and to ensure the group's ability to continue as a going concern.

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 half-yearly condensed 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 assets, personnel and reputation and therefore Premier 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 departments, project teams, corporate functions and business units are consolidated and amalgamated to provide an oversight of key risk factors at each level from operations through business unit management to Executive Committee and Board level.

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 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 health, safety, environment and security (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 risk areas 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 pages 52 to 53 of the 2012 Annual Report and Financial Statements.

STATEMENT OF DIRECTORS' RESPONSIBILITIES

The directors confirm that to the best of their knowledge:

a) the condensed set of financial statements has been prepared in accordance with IAS 34 – 'Interim Financial Reporting';

b) the Interim Management Report includes a fair review of the information required by DTR 4.2.7R (indication of important events during the first six months and description of principal risks and uncertainties for the remaining six months of the year); and

c) the Interim Management Report includes a fair review of the information required by DTR 4.2.8R (disclosure of related parties' transactions and changes therein).

The directors of Premier Oil plc are listed in the group's 2011 Annual Report and Financial Statements. A list of the current directors is maintained on the company's website: www.premier-oil.com.

By order of the Board

S C Lockett
Chief Executive Officer

21 August 2013

A R C Durrant
Finance Director

21 August 2013

Disclaimer

This report 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 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.

CONDENSED FINANCIAL STATEMENTS

CONDENSED CONSOLIDATED INCOME STATEMENT

	Note	Six months to 30 June 2013 Unaudited $ million	Six months to 30 June 2012 Unaudited $ million	Year to 31 December 2012 Audited $ million
Sales revenues	2	757.8	744.3	1,408.7
Cost of sales	3	(472.2)	(393.9)	(742.4)
Exploration expense		(7.7)	(77.9)	(157.7)
Pre-licence exploration costs		(13.9)	(14.5)	(29.2)
General and administration costs		(8.9)	(12.8)	(24.2)
Operating profit		255.1	245.2	455.2
Share of loss in associate		-	-	(1.9)
Interest revenue, finance and other gains	4	5.3	0.7	3.2
Finance costs and other finance expenses	4	(44.6)	(57.3)	(110.8)
(loss)/gain on derivative financial instruments		(1.2)	6.0	14.2
Profit before tax		214.6	194.6	359.9
Tax	5	(53.5)	(48.8)	(107.9)
Profit for the period/year		161.1	145.8	252.0
Earnings per share (cents):				
Basic	7	30.5	27.8	47.9
Diluted	7	29.1	26.9	46.9

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Note	Six months to 30 June 2013 Unaudited $ million	Six months to 30 June 2012 Unaudited $ million	Year to 31 December 2012 Audited $ million
Profit for the period/year		161.1	145.8	252.0
Cash flow on commodity swaps:				
Gains/(losses) arising during the period/year		15.4	8.3	(19.1)
Reclassification adjustments for losses in the period/year		0.9	25.9	39.6
		16.3	34.2	(20.5)
Tax relating to components of other comprehensive income	6	(8.1)	(12.2)	-
Cash flow hedges on interest rate and foreign exchange swaps		(4.5)	(0.5)	(4.7)
Exchange differences on translation of foreign operations		(18.0)	2.4	(15.3)
Actuarial gains on long-term employee benefit plans*		-	-	1.2
Other comprehensive income/(expense)		(5.3)	(23.9)	(41.7)
Total comprehensive income for the period/year		155.8	169.7	293.7

* Not expected to be reclassified subsequently to profit and loss account

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

CONDENSED CONSOLIDATED BALANCE SHEET

	Note	30 June 2013 Unaudited $ million	30 June 2012 Unaudited $ million	31 Dec 2012 Audited $ million
Non-current assets:				
Goodwill		240.8	188.1	240.8
Intangible exploration and evaluation assets	8	681.0	407.8	658.0
Property, plant and equipment	9	2,685.2	2,661.4	2,692.9
Investments		5.5	7.7	6.1
Long-term employee benefit plan surplus		4.8		4.2
Other receivables		55.0	3.2	2.5
Deferred tax assets	6	623.0	373.1	568.9
		4,295.3	3,641.3	4,173.4
Current assets:				
Inventories		31.7	34.5	34.6
Trade and other receivables		448.2	355.7	351.3
Tax recoverable		78.2	95.8	87.1
Derivative financial instruments		23.8	30.7	9.8
Cash and cash equivalents		182.3	290.2	187.4
Assets held for sale		97.9	-	-
		826.1	806.9	670.2
Total assets		5,157.4	4,448.2	4,843.6
Current liabilities:				
Trade and other payables		(474.8)	(431.6)	(450.0)
Current tax payable		(93.3)	(102.3)	(114.9)
Short-term borrowings		-	(16.3)	-
Provisions		(43.5)	(37.9)	(68.8)
Derivative financial instruments		(21.4)	(73.6)	(43.8)
Deferred revenue		-	(4.2)	-
Liabilities directly associated with assets held for sale		(26.1)	-	-
		(659.1)	(665.9)	(677.5)
Net current assets/(liabilities)		203.0	141.0	(7.3)
Non-current liabilities:				
Convertible bonds		(221.7)	(230.9)	(219.6)
Other long-term debt		(1,265.6)	(856.4)	(1,064.4)
Deferred tax liabilities	6	(302.9)	(256.2)	(297.1)
Long-term provisions		(618.9)	(591.1)	(613.3)
Long-term employee benefit plan deficit		(17.9)	(18.8)	(18.2)
		(2,427.0)	(1,953.4)	(2,212.6)
Total liabilities		(3,086.1)	(2,619.3)	(2,890.1)
Net assets		2,071.3	1,828.9	1,953.5
Equity and reserves:				
Share capital		110.5	110.5	110.5
Share premium account		649.5	649.0	649.2
Retained earnings		1,287.6	1,043.5	1,150.1
Other reserves		23.7	25.9	43.7
		2,071.3	1,828.9	1,953.5

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Attributable to the equity holders of the parent						
				Other reserves			
	Share capital	Share premium account	Retained earnings	Capital redemption reserve	Translation reserves	Equity reserve	Total
	$ million	$ million	$ million	$ million	$ million	$ million	$ million
At 1 January 2012	98.3	274.5	922.9	4.3	1.8	21.3	1,323.6
Issue of Ordinary Shares	11.7	374.7	-	-	-	-	386.4
Net 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 31 December 2012	110.5	649.2	1,150.1	4.3	17.1	22.3	1,953.5
Issue of Ordinary Shares	-	0.3	-	-	-	-	0.3
Net purchase of ESOP Trust shares	-	-	(12.1)	-	-	-	(12.1)
Provision for share-based payments	-	-	14.0	-	-	-	14.0
Dividend paid	-	-	(40.2)	-	-	-	(40.2)
Transfer between reserves*	-	-	2.0	-	-	(2.0)	-
Total comprehensive income	-	-	173.8	-	(18.0)	-	155.8
At 30 June 2013	110.5	649.5	1,287.6	4.3	(0.9)	20.3	2,071.3
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	374.5	-	-	-	-	386.2
Net purchase of ESOP Trust shares	-	-	(65.8)	-	-	-	(65.8)
Provision for share-based payments	-	-	15.2	-	-	-	15.2
Transfer between reserves*	-	-	3.9	-	-	(3.9)	-
Total comprehensive income	-	-	167.3	-	2.4	-	169.7
At 30 June 2012	110.5	649.0	1,043.5	4.3	4.2	17.4	1,828.9

* The transfer between reserves relates to the non-cash interest on the convertible bonds, less the amortisation of the issue costs that were charged directly against equity.

CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Note	Six months to 30 June 2013 Unaudited $ million	Six months to 30 June 2012 Unaudited $ million	Year to 31 December 2012 Audited $ million
Net cash from operating activities	*1*	384.9	325.5	808.2
Investing activities:				
Capital expenditure		(435.7)	(318.2)	(771.6)
Pre-licence exploration costs		(13.9)	(14.5)	(29.2)
Net cash inflow from acquisition of subsidiaries		-	4.6	4.6
Acquisition of oil and gas properties		-	(31.9)	(267.5)
Proceeds from disposal of oil and gas properties		-	52.7	52.4
Net cash used in investing activities		(449.6)	(307.3)	(1,011.3)
Financing activities:				
Proceeds from issuance of Ordinary Shares		0.3	0.2	0.4
Purchases of ESOP Trust shares		(12.1)	(65.8)	(89.3)
Proceeds from drawdown of bank loans		200.0	7.6	217.6
Proceeds from issuance of senior loan notes		-	235.2	235.2
Debt arrangement fees		(0.9)	(4.8)	(5.0)
Repayment of bank loans		-	(175.0)	(202.0)
Convertible bonds partial repayment/arrangement fee—new Partner funding for development project		(51.4)		(7.9)
Dividends paid		(40.2)		-
Interest paid		(35.7)	(32.3)	(65.6)
Net cash from/(used in) financing activities		60.0	(34.9)	83.4
Currency translation differences relating to cash and cash equivalents		(0.4)	(2.2)	(2.0)
Net decrease in cash and cash equivalents		(5.1	(18.9)	(121.7)
Cash and cash equivalents at the beginning of the period/year		187.4	309.1	309.1
Cash and cash equivalents at the end of the period/year	*1*	182.3	290.2	187.4

NOTES TO THE CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PREPARATION

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.

The condensed financial statements for the six months ended 30 June 2013 were authorised for issue in accordance with a resolution of the Board of Directors on 21 August 2013.

The information for the year ended 31 December 2012 contained within the condensed financial statements 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. The auditor reported on those accounts; the report was unqualified, did not draw attention to any matters by way of emphasis and did not contain any statement under section 498(2) or 498(3) of the Companies Act 2006.

The financial information contained in this report is unaudited. The condensed consolidated income statement, condensed consolidated statement of comprehensive income, condensed consolidated statement of changes in equity and the condensed consolidated cash flow statement for the six months to 30 June 2013, and the condensed consolidated balance sheet as at 30 June 2013 and related notes, have been reviewed by the auditors and their report to the company is attached.

Basis of preparation

The condensed financial statements for the six months ended 30 June 2013 have been prepared in accordance with IAS 34 – 'Interim Financial Reporting', as adopted by the European Union and with the requirements of the Disclosure and Transparency Rules issued by the Financial Services Authority. These condensed financial statements should be read in conjunction with the annual financial statements for the year ended 31 December 2012, which have been prepared in accordance with International Financial Reporting Standards as adopted by the European Union.

The condensed financial statements have been prepared on the going concern basis. Further information relating to the going concern assumption is provided in the Financial Review.

Accounting policies

The accounting policies applied in these condensed financial statements 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 condensed financial statements for the half-year ended 30 June 2013.

2. OPERATING SEGMENTS

	Six months to 30 June 2013 Unaudited $ million	Six months to 30 June 2012 Unaudited $ million	Year to 31 December 2012 Audited $ million
Revenue:			
Indonesia	154.9	153.4	305.1
Pakistan (including Mauritania)	85.3	87.7	175.2
Vietnam	259.1	229.5	509.4
United Kingdom	258.5	273.7	419.0
Total group sales revenue	757.8	744.3	1,408.7
Interest and other finance revenue	3.3	0.7	1.7
Total group revenue	761.1	745.0	1,410.4
Group operating profit/(loss):			
Indonesia	102.9	56.5	134.6
Norway	(2.5)	(3.0)	(7.7)
Pakistan (including Mauritania)	40.2	47.9	103.0
Vietnam	126.3	134.3	261.7
United Kingdom	6.4	28.8	6.7
Rest of the World	(0.6)	(0.6)	(1.9)
Unallocated*	(17.6)	(18.7)	(41.2)
Group operating profit	255.1	245.2	455.2
Share of loss in associate	-	-	(1.9)
Interest revenue, finance and other gains	5.3	0.7	3.2
Finance costs and other finance expenses	(44.6)	(57.3)	(110.8)
Loss/(gain) on derivative financial instruments	1.2	6.0	14.2
Profit before tax	214.6	194.6	359.9
Tax	(53.5)	(48.8)	(107.9)
Profit after tax	161.1	145.8	252.0
Balance sheet - Segment assets:			
Falkland Islands	262.3	1.4	242.6
Indonesia	719.8	701.6	692.2
Norway	288.9	255.1	253.5
Pakistan (including Mauritania)	132.2	140.3	140.7
Vietnam	705.2	749.7	705.2
United Kingdom**	2,814.5	2,269.6	2,594.3
Rest of the World	28.4	9.6	18.0
Unallocated*	206.1	320.9	197.1
Total assets	5,157.4	4,448.2	4,843.6

* Unallocated expenditure and assets 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 and mark to market valuations of commodity contracts.

** Includes goodwill and investments.

3. COST OF SALES

	Six months to 30 June 2013 Unaudited $ million	Six months to 30 June 2012 Unaudited $ million	Year to 31 December 2012 Audited $ million
Operating costs	170.1	155.7	342.4
Stock overlift/underlift movement	25.7	29.8	(17.1)
Royalties	22.2	20.8	44.3
Amortisation and depreciation of property, plant and equipment:			
Oil and gas properties	172.5	164.0	345.4
Other fixed assets	4.0	1.6	6.7
Impairment of oil and gas properties	77.7	22.0	20.7
	472.2	393.9	742.4

4. INTEREST REVENUE AND FINANCE COSTS

	Six months to 30 June 2013 Unaudited $ million	Six months to 30 June 2012 Unaudited $ million	Year to 31 December 2012 Audited $ million
Interest revenue, finance and other gains:			
Short-term deposits	0.2	0.3	0.5
Exchange differences and others	5.1	0.4	2.7
	5.3	0.7	3.2
Finance costs and other finance expenses:			
Bank loans and overdrafts	(16.9)	(18.9)	(35.0)
Payable in respect of convertible bonds	(5.1)	(7.9)	(15.2)
Payable in respect of senior loan notes	(15.8)	(12.7)	(28.5)
Unwinding of discount on decommissioning provision	(17.0)	(15.5)	(33.2)
Long-term debt arrangement fees	(3.8)	(3.3)	(6.6)
Exchange differences and others	-	(3.6)	(5.8)
Gross finance costs and other finance expenses	(58.6)	(61.9)	(124.3)
Finance costs capitalised during the period/year	14.0	4.6	13.5
	(44.6)	(57.3)	(110.8)

5. TAX

	Six months to 30 June 2013 Unaudited $ million	Six months to 30 June 2012 Unaudited $ million	Year to 31 December 2012 Audited $ million
Current tax:			
UK corporation tax on profits	-	-	-
UK petroleum revenue tax	28.2	14.1	83.1
Overseas tax	61.9	78.0	137.0
Adjustments in respect of prior years	(13.3)	(6.0)	(11.9)
Total current tax	76.8	86.1	208.2
Deferred tax:			
UK corporation tax	(65.6)	(68.6)	(162.2)
UK petroleum revenue tax	3.0	3.6	(6.2)
Overseas tax	39.3	27.7	68.1
Total deferred tax	(23.3)	(37.3)	(100.3)
Tax on profit on ordinary activities	53.5	48.8	(107.9)

6. DEFERRED TAX

	At 30 June 2012 Unaudited $ million	At 30 June 2011 Unaudited $ million	At 31 December 2011 Audited $ million
Deferred tax assets	373.1	373.1	568.9
Deferred tax liabilities	(256.2)	(256.2)	(297.1)
	116.9	116.9	271.8

6. DEFERRED TAX *(continued)*

	At 1 January 2013 $ million	Exchange movements $ million	Acquisitions $ million	(Charged)/ credited to income statement $ million	Charged to retained earnings $ million	At 30 June 2013 $ million
UK deferred corporation tax:						
Fixed assets and allowances	(601.6)	-	-	(65.6)	-	(667.2)
Decommissioning	252.8	-	-	(0.3)	-	252.5
Deferred petroleum revenue tax	(1.5)	-	-	1.8	-	0.3
Tax losses and allowances	861.7	-	-	130.6	-	992.3
Small field allowance	45.8	-	-	-	-	45.8
Deferred revenue	2.0	-	-	(0.9)	-	1.1
Derivative financial instruments	-	-	-	-	(8.1)	(8.1)
Total UK deferred corporation tax	559.2	-	-	65.6	(8.1)	616.7
UK deferred petroleum revenue tax*	2.3	-	-	(3.0)	-	(0.7)
Overseas deferred tax**	(289.7)	9.0	24.1	(39.3)	-	(295.9)
Total	271.8	9.0	24.1	23.3	((8.1)	320.1

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

The group's deferred tax assets at 30 June 2013 are recognised to the extent that taxable profits are expected to arise in the future against which the ring fence tax losses and allowances can be utilised. In accordance with paragraph 37 of IAS 12 - 'Income Taxes' the group re-assessed its deferred tax assets at 30 June 2013 with respect to ring fence tax losses and allowances. The corporate model used to assess whether it is appropriate to recognise all of the group's deferred tax assets was re-run, using a long-term oil price assumption of US$85/bbl in 'real' terms. The results of the corporate model concluded that it was appropriate to continue to recognise all of 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$255.0 million (2012: US$218.3 million) and current year non-UK tax losses of approximately US$7.9 million (2012: US$22.3 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.

A deferred petroleum revenue tax (PRT) asset has been recognised to the extent that it is probable that the asset will reverse when the PRT field is fully decommissioned.

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.

7. 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 period. Basic and diluted earnings per share are calculated as follows:

7. EARNINGS PER SHARE *(continued)*

	Six months to 30 June 2013 Unaudited	Six months to 30 June 2012 Unaudited	Year to 31 December 2012 Audited
Earnings ($ million):			
Earnings for the purposes of basic earnings per share being net profit attributable to owners of the company	161.1	145.8	252.0
Effect of dilutive potential Ordinary Shares:			
Interest on convertible bonds	5.1	7.6	11.2
Earnings for the purposes of diluted earnings per share	166.2	153.4	263.2
Number of shares (millions)			
Weighted average number of Ordinary Shares for the purposes of basic earnings per share	529.1	523.6	526.4
Effects of dilutive potential Ordinary Shares:			
Contingently issuable shares	41.7	46.9	35.3
Weighted average number of Ordinary Shares for the purposes of diluted earnings per share	570.8	570.5	561.7
Earnings per share (cents):			
Basic	30.5	27.8	47.9
Diluted	29.1	26.9	46.9

8. INTANGIBLE EXPLORATION AND EVALUATION (E&E) ASSETS (unaudited)

	Oil and gas properties
	Total $ million
Cost:	
At 1 January 2013	658.0
Exchange movements	(18.5)
Additions during the year	142.3
Transfer to property, plant and equipment	2.5
Exploration expense	(7.7)
Assets held for sale	(95.6)
At 30 June 2013	681.0
At 30 June 2012	407.8

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.

9. PROPERTY, PLANT AND EQUIPMENT

	Oil and gas properties $ million	Other fixed assets $ million	Total $ million
Cost:			
At 1 January 2013	4,183.2	38.5	4,221.7
Exchange movements	-	(1.4)	(1.4)
Additions during the period	244.1	5.4	249.5
Transfer (to)/from intangible E&E assets	1.8	(4.3)	(2.5)
At 30 June 2013	4,429.1	38.2	4,467.3
Amortisation and depreciation:			
At 1 January 2013	1,509.0	19.8	1,528.8
Exchange movements	-	(0.9)	(0.9)
Charge for the period	172.5	4.0	176.5
Impairment charge	77.7	-	77.7
At 30 June 2013	1,759.2	22.9	1,782.1
Net book value:			
At 31 December 2012	2,674.2	18.7	2,692.9
At 30 June 2013	2,669.9	15.3	2,685.2
At 30 June 2012	2,648.9	12.5	2,661.4

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.

The impairment charge relates to the UK Balmoral area. The impairment charge 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 2H 2013, 2014 and 2015, an US$85/bbl in 'real' terms thereafter and were discounted using a discount rate of 10.0 per cent. Assumptions involved in impairment measurement include estimates of commercial reserves and production volumes, future oil an gas prices and the level and timing of expenditures, all of which are inherently uncertain.

10. ASSETS HELD FOR SALE

On 16 July 2013, Premier announced the sale of its 100 per cent wholly owned subsidiary Premier Oil Vietnam South BV. Premier Oil Vietnam BV holds a 30 per cent operated interest in Block 07/03, offshore Vietnam, which contains the Cá Rồng Đỏ oil and gas discovery and the Ca Duc exploration prospect.

The consideration in respect to this transaction is up to US$100.0 million, of which an immediate cash payment of US$45.0 million was received in July. Further payment of up to US$10.0 million is due depending on the results of the upcoming CRD-3X appraisal well, plus US$10.0 million contingent upon the signature of a gas sales agreement relating to Cá Rồng Đỏ gas. The remaining consideration is contingent on the success at Ca Duc, and on reaching certain targets in relation to its development.

In August, Premier agreed to sell its 20 per cent interest in the Norwegian assets, PL378 and PL378B, located in the Norwegian North Sea which contains the Grosbeak discovery for an upfront consideration of US$16.0 million.

The above E&E assets have been reclassified as Assets held for Sale at 30 June 2013. Related liabilities have also been separately identified in the Balance Sheet. They are held on the balance sheet at the lower of cost and net realisable value, which led to a US$6.1 million charge in respect of the Vietnam disposal, included within exploration expense. In assessing realisable value for this disposal group, the group took into consideration its best estimate of the fair value of the US$55.0 million contingent consideration referred to above.

11. NOTES TO THE CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Six months to 30 June 2013 Unaudited $ million	Six months to 30 June 2012 Unaudited $ million	Year to 31 December 2012 Audited $ million
Profit before tax for the period/year	214.6	194.6	359.9
Adjustments for:			
Depreciation, depletion, amortisation and impairment	254.2	187.6	372.8
Exploration expense	7.7	77.9	157.7
Pre-licence exploration costs	13.9	14.5	29.2
Provision for share-based payments	4.8	3.0	10.1
Share of loss in associate			1.9
Interest revenue, finance and other gains	(5.3)	(0.7)	(3.2)
Finance costs and other finance expenses	44.6	57.3	110.8
Loss/(gain) on derivative financial instruments	1.2	(6.0)	(14.2)
Operating cash flows before movements in working capital	535.7	528.2	1,025.0
Decrease/(increase) in inventories	2.9	(6.8)	(6.8)
Increase/(decrease) in receivables	(25.0)	(31.1)	36.3
Decrease in payables	(14.7)	(24.3)	(15.1)
Cash generated by operations	498.9	466.0	1,039.4
Income taxes paid	(117.4	(141.0)	(233.1)
Interest income received	3.4	0.5	1.9
Net cash from operating activities	384.9	325.5	808.2

11. NOTES TO THE CONDENSED CONSOLIDATED CASH FLOW STATEMENT *(continued)*

Analysis of changes in net debt:

	Six months to 30 June 2013 Unaudited $ million	Six months to 30 June 2012 Unaudited $ million	Year to 31 December 2012 Audited $ million
a) Reconciliation of net cash flow to movement in net debt:			
Movement in cash and cash equivalents	(5.1)	(18.9)	(121.7)
Proceeds from drawdown of bank loans	(200.0	(7.6)	(217.6)
Proceeds from issuance of senior loan notes	-	(235.2)	(235.2)
Repayment of bank loans	-	175.0	202.0
Non-cash movements on debt and cash balances	(0.3)	(0.2)	6.1
Increase in net debt in the period/year	(205.4)	(86.9)	(366.4)
Opening net debt	(1,110.4)	(744.0)	(744.0)
Closing net debt	(1,315.8)	(830.9)	(1,110.4)
b) Analysis of net debt:			
Cash and cash equivalents	182.3	290.2	187.4
Borrowings*	(1,498.1	(1,121.1)	(1,297.8)
Total net debt	(1,315.8	(830.9)	(1,110.4)

* Borrowings consist of the short-term borrowings, 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$0.5 million (December 2012: US$0.6 million) and debt arrangement fees of US$10.2 million (December 2012: US$13.2 million).

12. FINANCIAL INSTRUMENTS

No interim dividend is proposed (2012: US$nil).

Derivative financial instruments

The group held the following financial instruments at fair value at 30 June 2013. The group has no financial instruments with fair values that are determined by reference to significant unobservable inputs i.e. those that would be classified as level 3 in the fair value hierarchy, nor have there been any transfers of assets or liabilities between levels of the fair value hierarchy. There are no non-recurring fair value measurements.

The fair values were determined from counterparties with whom the trades have been entered into. Fair value is the amount at which a financial instrument could be exchanged in an arm's length transaction, other than in a forced or liquidated sale. Where available, market values have been used to determine fair values. The estimated fair values have been determined using market information and appropriate valuation methodologies. Values recorded are as at the balance sheet date, and will not necessarily be realised. Non-interest bearing financial instruments, which include amounts receivable from customers and accounts payable are also recorded materially at fair value reflecting their short-term maturity.

Fair value of financial assets and financial liabilities

The carrying values of the financial assets and financial liabilities (excluding current assets, current liabilities and derivative financial instruments), are considered to be materially equivalent to their fair values.

12. FINANCIAL INSTRUMENTS *(continued)*

	As at 30 June 2013 Unaudited $ million	Level 1 $ million	Level 2 $ million
Financial assets:			
Oil forward sales contracts	17.1	-	17.1
Gas forward sales contracts	5.1	-	5.1
Forward foreign exchange contracts	1.6	-	1.6
Total	23.8	-	23.8

Financial liabilities:			
Gas collars	1.0	-	1.0
Interest rate swaps	13.1		13.1
Cross currency swaps	7.3	-	7.3
Total	21.4	-	21.4

* Borrowings consist of the short-term borrowings, 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$0.5 million (December 2012: US$0.6 million) and debt arrangement fees of US$10.2 million (December 2012: US$13.2 million).

13. DIVIDENDS

No interim dividend is proposed (2012: US$nil).

14. EVENTS AFTER THE BALANCE SHEET DATE

In July 2012, the group announced that it had agreed to farm-in to 60 per cent of Rockhopper Exploration plc's (Rockhopper) licence interests in the Falkland Islands, which include the Sea Lion development project. The initial payment will be US$231.0 million in cash. In addition, Premier will pay an exploration carry of up to US$48.0 million and, subject to field development plan approval, a development carry of up to US$722.0 million. These will be funded from a combination of Premier's existing cash resources and facilities and future cash flow from operations. Premier and Rockhopper have also agreed to jointly pursue exploration opportunities in the Falkland Islands and analogous plays in selected areas offshore Southern Africa. The acquisition transaction is subject to the approval of the Falkland Islands Government and is expected to complete in September 2012.

INDEPENDENT REVIEW REPORT TO PREMIER OIL PLC

We have been engaged by the company to review the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2013 which comprises the condensed consolidated income statement, the condensed consolidated statement of comprehensive income, the condensed consolidated balance sheet, the condensed consolidated statement of changes in equity, the condensed consolidated cash flow statement and related notes 1 to 14. We have read the other information contained in the half-yearly financial report and considered whether it contains any apparent misstatements or material inconsistencies with the information in the condensed set of financial statements.

This report is made solely to the company in accordance with International Standards on Review Engagements (UK and Ireland) 2410 'Review of Interim Financial Information Performed by the Independent Auditor of the Entity' issued by the Auditing Practices Board. Our work has been undertaken so that we might state to the company those matters we are required to state to it in an independent review report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company, for our review work, for this report, or for the conclusions we have formed.

Directors' responsibilities

The half-yearly financial report is the responsibility of, and has been approved by, the directors. The directors are responsible for preparing the half-yearly financial report in accordance with the Disclosure and Transparency Rules of the United Kingdom's Financial Conduct Authority.

As disclosed in note 1, the annual financial statements of the group are prepared in accordance with IFRSs as adopted by the European Union. The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with International Accounting Standard 34 -'Interim Financial Reporting', as adopted by the European Union.

Our responsibility

Our responsibility is to express to the company a conclusion on the condensed set of financial statements in the half-yearly financial report based on our review.

Scope of review

We conducted our review in accordance with International Standards on Review Engagements (UK and Ireland) 2410 'Review of Interim Financial Information Performed by the Independent Auditor of the Entity' issued by the Auditing Practices Board for use in the United Kingdom. A review of interim financial information consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing (UK and Ireland) and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Conclusion

Based on our review, nothing has come to our attention that causes us to believe that the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2013 is not prepared, in all material respects, in accordance with International Accounting Standard 34 as adopted by the European Union and the Disclosure and Transparency Rules of the United Kingdom's Financial Services Authority.

Deloitte LLP
Chartered Accountants and Statutory Auditor
London, UK

21 August 2013

WORKING INTEREST PRODUCTION BY REGION (unaudited)

	Six months to 30 June 2013 kboepd	Six months to 30 June 2012 kboepd	Year to 31 December 2012 kboepd
UK:			
Balmoral area*	2.7	5.5	4.5
Huntington	1.2	-	-
Scott/Telford	4.2	3.6	3.0
Wytch Farm	5.1	4.3	4.5
Other UK	0.2	0.2	0.1
	13.4	13.6	12.1
Indonesia:			
Natuna Sea Block A	12.1	12.6	12.3
Kakap	2.0	2.1	1.9
	14.1	14.7	14.2
Vietnam:			
Chim Sáo	15.2	13.7	15.2
	15.2	13.7	15.2
Pakistan:			
Bhit/Badhra	3.3	3.5	3.5
Kadanwari	2.7	2.4	2.6
Qadirpur	3.6	3.9	3.7
Zamzama	5.7	6.1	5.8
Mauritania:			
Chinguetti	0.6	0.5	0.6
	15.9	16.4	16.2
Total	58.6	58.4	57.7

* Includes Balmoral, Brenda, Nicol and Stirling fields.

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