Half-Yearly Results for the six months to 30 June 2016

Press Release

Tony Durrant, Chief Executive, commented:

"Delivery of a step change in production levels and a leaner operating cost base has addressed the lower commodity price environment. Full year production guidance is now increased, which will drive free cash flow generation. We have made substantial progress with our lending group on the principal terms of a refinancing. Our project portfolio has been expanded, positioning Premier for future growth at lower cost."

Entering new phase

- Moving to positive cash flow following a period of substantial investment
- E.On UK acquisition brings portfolio and financial benefits
- Full year production guidance raised to 68-73 kboepd
- Cost base reset
- Progress being made with lending group to amend financial covenants and to revise debt maturities

Strong operational performance

- Production averaged 61.0 kboepd (2015 H1: 60.4 kboepd)
- 93 per cent production efficiency
- Recent record production rates above 95 kboepd
- Solan on-stream

Solid financial performance

- Profit after tax of US$167.1 million, including E.On negative goodwill credit of US$106.9 million (2015 H1: loss of US$375.2 million)
- Operating cash flow of US$108.7 million (2015 H1: US$513.0 million)
- H1 operating costs of US$16.5/boe, 14 per cent below budget
- Weaker sterling exchange rate positively impacts forward opex, capex and debt
- Net debt slightly lower on end Q1 position at US$2.63 billion (31 December 2015: US$2.2 billion)

Future growth

- Catcher on schedule for 2017 first oil, capex 20 per cent lower than at sanction
- High return infill drilling in UK and Asia
- New development projects benefitting from improved economics
- Exploration prospects in Mexico, Brazil and UK Southern Gas Basin

ENQUIRIES

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Half-Yearly Results for the six months to 30 June 2016

A presentation to analysts will be held at 9.30am today at the offices of Premier Oil, 23 Lower Belgrave Street, London SW1W 0NR and will be webcast live on the company's website at www.premier-oil.com. A copy of this announcement is available for download from our website at www.premier-oil.com.

Half-Yearly Results for the six months to 30 June 2016

This announcement has been determined to contain inside information

CHAIRMAN'S STATEMENT

Industry context

Volatility in the oil markets persisted into the first half of 2016. Brent dropped to US$26/bbl in January but subsequently almost doubled to close the period at US$48/bbl. Post period end, the price of Brent weakened, driven primarily by a strengthening US dollar and fears that a product oversupply could delay any further crude price recovery. Nonetheless, sentiment has become more positive with consensus expectations of a rebalanced market and higher prices during the second half of 2016 and 2017. Against this backdrop, we remain focussed on maximising value from existing production and sanctioned projects whilst maintaining asset integrity and controlling operating costs.

Premier's performance

Operationally Premier has performed strongly. Production for the period averaged 61.0 kboepd. This was due to high production efficiency across the Group and, in particular, outperformance from the Huntington field, where we have increased our interest and managed reservoir decline. Record Group production rates of over 95 kboepd were achieved post period end which is a testament to the skill and focus of our production and development teams in what has been a challenging environment.

At the same time as increasing our production, we have continued to secure sustainable savings in our underlying operating costs, by implementing more efficient working practices and removing costs from our supply chain. A number of collaboration initiatives with other operators should lead to further cost reductions being realised over time.

During the first half the Solan field, which has been a challenging project since sanction, came on-stream and the field is now set to produce at plateau rates. With low operating costs and our tax advantaged position in the UK, the field generates important cash flows for the Group. These will be prioritised towards reducing debt and completing the Catcher project, which underpins further growth in our production profile. The Catcher project is our only significant capital commitment going forward and our team has continued to secure material savings with latest capital expenditure forecasts 20 per cent below the original sanctioned estimates.

We have preserved considerable optionality within our portfolio to maintain and grow our production beyond current firm plans. Our unsanctioned projects range from low cost, high return infill drilling programmes in the UK North Sea and Asia to incremental developments to backfill our gas contracts in Asia and new projects such as Tolmount in the Southern Gas Basin, Tuna in Indonesia and Sea Lion in the Falkland Islands. Premier also has the potential for material value creation in future years through its exploration acreage in Mexico, Brazil and tight gas plays in the UK Southern Gas Basin. We intend to only sanction those projects which deliver clear value for our shareholders and where our exposure is appropriate given our funding position and capital structure.

The most significant opportunity to realise capital expenditure savings exists in our unsanctioned projects where we have yet to commit to firm contracts. It is here that we can look to capitalise on weak order backlogs and innovative contractual arrangements driven by the current commodity background. FEED on the Sea Lion project is progressing well in this respect with material cost reductions identified to further lower the breakeven oil price of the project. Meanwhile, our team is working hard to progress the development concept for the UK Tolmount gas field which, even in a low gas price environment, will deliver a high return and significant value. The opportunity of course is to secure lower costs for these pre-development projects at the bottom of the cycle and to bring them on-stream in a rising oil and gas price environment.

We continue to manage our portfolio actively and to focus on those core areas where we have a strategic or operational advantage. The acquisition of E.ON's UK North Sea assets was consistent with this strategy: it has enhanced our UK asset base, created considerable operating and cost synergies with our existing UK business and accelerates the use of our UK tax losses. It is a reflection of the hard work and skill of the Premier team that we were able to complete this acquisition when the oil price was at a cyclical low and thereby building on our proven track record of adding long term value through acquisitions.

I noted in February that, if low oil prices persisted, then a further relaxation of our main financing covenants would be required, which we would take pre-emptive action to address. We are currently in discussions with our lending group in respect of amending financial covenants and resetting debt maturities. Given the unsecured nature of our debt arrangements and the number of parties involved it is not surprising that negotiations will take time to conclude but I am encouraged by the progress that has been made to date. In the meantime, we have been receiving deferrals in respect of tests to our financial covenants and expect further deferrals to be forthcoming until the process is completed. Debt reduction remains a priority for the Company going forward. Increasing production levels coupled with reducing capital commitments mean that we expect to deliver that from the fourth quarter onwards.

Health, safety and environmental (HSE) matters continue to be of paramount importance to us and, critically in the current environment, we will not compromise on the integrity and safety of our people and our operations. We continue to set ourselves challenging HSE targets to drive continuous improvement in all these areas and our HSE performance, as measured against our Group aggregated HSE target, improved in the first six months of the year. In addition, all of our production and drilling operations retain their OHSAS 18001 and ISO 14001 certifications. To reinforce the Company's HSE policy commitments with our operating teams, our executive management have committed to a structured programme of HSE-focused visits to our facilities throughout 2016.

In summary, during the first half, production commenced from the Solan field, the acquisition of the E.ON UK portfolio was completed and our legacy production assets delivered a robust performance. We have also continued to capture sustainable savings both in our operating costs and our capital expenditure. Good progress has also been made with our lending groups to refinance our debt portfolio, amend our covenants and to extend maturities to ensure that we have the financial flexibility to deliver the Catcher project to completion.

Board changes

In light of both planned retirements and the current price environment, the Board determined that a reduction in the number of non-executive members was appropriate. Accordingly, David Bamford and Michel Romieu agreed to stand down from the Board with effect from the AGM on 11 May 2016. I would like to thank them for their significant contribution to the Board and wish them well for the future. It is anticipated that David Lindsell will retire after more than nine years of service at the Company's 2017 Annual General Meeting.

I am delighted to welcome Iain Macdonald, formerly Deputy Group CFO for BP, to the Board. Iain will take over the role of Chairman of the Audit and Risk Committee upon David's retirement.

I would also like to thank Neil Hawkings who has been an Executive Director for over ten years and who has retired from the Board. We are delighted, however, to retain Neil's services on key projects where his knowledge and experience are most valuable.

Outlook

We now look forward to a rising production profile delivered from a leaner operating cost base and with significantly lower committed capital expenditure. The second half of the year will see Premier transition from a period of heavy investment to one where at oil prices above $45/bbl we can generate free cash flow. Our priority for that cash flow is to deleverage our balance sheet while continuing to ensure the integrity of our assets and to deliver our Catcher project. We will invest in new development projects within a strict disciplined framework such that we are in a position to execute those projects which deliver the highest value for our stakeholders.

Mike Welton
Chairman

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OPERATIONAL REVIEW

GROUP PRODUCTION

Group production for the first half averaged 61.0 kboepd (2015 H1: 60.4 kboepd) with record rates of over 95 kboepd achieved post period end. This was driven by high production efficiency from our existing assets, outperformance from the newly acquired E.ON UK portfolio and new production from the Solan field. As a result of this robust production performance, Premier has revised upwards its production guidance for the full year to 68-73kboepd.

kboepd	2016 H1	2015 H1
Indonesia	13.8	13.2
Pakistan & Mauritania	8.3	10.7
UK	22.2	16.9
Vietnam	16.7	19.6
Total	**61.0**	**60.4**

INDONESIA

Production from Indonesia averaged 13.8 kboepd, up five per cent on the prior period driven by increased market share within Premier's principal gas sales agreement (GSA1), strong Singapore demand for gas deliveries under GSA2 and higher liquids production from the Anoa field following well intervention work.

Production & Development

Production from Indonesia in the first six months was 13.8 kboepd (2015 H1: 13.2 kboepd). The Premier operated Natuna Sea Block A delivered 12.5 kboepd while production from the non-operated Kakap field averaged 1.3 kboepd.

Singapore demand for gas sold under GSA1 remained robust, averaging 297 BBtud (2015 H1: 312 BBtud). Premier's Anoa and Pelikan fields delivered 131 BBtud (2015 H1: 133 BBtud) and accounted for 44 per cent of GAS1 deliveries (2015 H1: 43 per cent), against a contractual share of 40.9 per cent. Sales of Gajah Baru and Naga gas dedicated to GSA2 averaged 96 BBtud (2015 H1: 70 BBtud), up 33 per cent on the prior period, representing 100 per cent nomination delivery by Premier. There were no deliveries from Gajah Baru and Naga under the Domestic Swap Agreement (DSA) in the first half. Delivery is expected to resume in the third quarter following an extension of the DSA to end December 2016.

Gas sales from the non-operated Kakap field averaged 19 BBtud (gross) (2015 H1: 26 BBtud) over the period. Gross liquids production from the Kakap field averaged 3.0 kbopd (2015 H1: 3.7 kbopd) reflecting natural decline, while gross liquids production from the Anoa field averaged 1.5 kbopd (2015 H1: 1.4 kbopd), up on the prior period due to successful well intervention work.

The next generation of developments in Natuna Sea Block A to backfill our existing Singapore and domestic market contracts continue to progress. FEED has been completed on the Bison, Iguana and Gajah Puteri projects and a final investment decision on these projects is targeted for early 2017. Premier has also identified several infill drilling candidates at Gajah Baru and is in the early stages of evaluating other incremental developments, including the deeper Lama play discoveries and water handling and gas compressor reconfiguration projects at both Anoa and Gajah Baru.

Evaluation of potential development scenarios for the 2014 Kuda and Singa Laut discoveries on the Premier operated Tuna Block is ongoing and an application has been made to the regulator to extend the exploration period of the licence for an additional two years.

VIETNAM

A robust production performance, combined with substantially reduced operating costs, resulted in the Vietnam business generating strong operating cash flows over the period.

Production

Production from the Premier-operated Block 12W, which contains the Chim Sáo and Dua fields, averaged 16.7 kboepd (2015 H1: 19.6 kboepd) net to Premier over the period, in line with expectations. Production efficiency at Block 12W remained high at 90 per cent over the period with good reservoir performance. The fall in production compared to the prior corresponding period reflects natural decline from the existing wells. However, a number of successful well stimulations were carried out during the period and further well stimulations are planned to help offset natural decline. Premier has also identified two infill drilling candidates on Block 12W to add incremental production from 2017 onwards.

Unit operating costs for the period have been maintained at $9/boe, despite the lower production. This reflects further cost savings realised through renegotiation of vessel and helicopter contracts as well as lower fuel and insurance costs. In addition Premier, in its capacity as Block 12W operator, is in advanced discussions with PetroFirst regarding revision of the FPSO charter party, including reductions in the cost of the lease rate. Final documentation and government approvals are expected to be completed during the third quarter. This will further reduce operating costs going forward.

UNITED KINGDOM

The UK business delivered a strong production performance from its existing asset base whilst securing significant operating cost reductions. The acquisition of E.ON UK completed on 28 April 2016 and asset performance from that portfolio has exceeded expectations. This, together with new Solan production, will see production from the UK increase to over 50 kboepd in the second half, generating material cash flow for the Company. With Solan on stream, the focus of the development activity now turns to the delivery of the Catcher project in 2017.

Production

Production from Premier's UK fields averaged 22.2 kboepd (2015 H1: 16.9 kboepd), up 31 per cent on the prior period. This higher production was driven by the new contribution from the E.ON UK assets from 29 April, high production efficiency across the portfolio of 87 per cent and strong performance from the Huntington field. Production in the second half of the year will benefit from the ramp up of Solan and a full contribution from the E.ON UK portfolio.

The operated Huntington field outperformed over the period, producing at consistent rates of 14 kboepd (gross) prior to summer maintenance restrictions. This was as a result of high uptime and positive reservoir management offsetting the impact of natural decline.

Production from the non-operated Elgin Franklin area, which was acquired as part of the E.ON UK acquisition, has been strong. Post period end, the field has delivered rates of over 130 kboepd gross (Premier 5.2 per cent), levels not seen since 2011. This has been driven by a successful on-going well intervention and infill drilling programme. Separately, the non-operated Glenelg field (Premier 18.57 per cent), a satellite field within the Elgin-Franklin area, came back on-stream at the end of May following a successful well workover of the G10 well and has been producing over 20 kboepd (gross).

Production from the non-operated Kyle field performed as anticipated delivering 1.8 kboepd (2015: 1.8 kboepd) while production from the Premier-operated Balmoral area averaged 1.7 kboepd (2014: 3.4 kboepd), impacted by a commercial disagreement between partners at the start of the year resulting in a temporary shutdown of production.

Production from the non-operated Wytch Farm field averaged 5.1 kboepd for the first six months of the year (2015 H1: 5.4 kboepd), benefitting from the well maintenance work carried out in the second half of 2015. Production from the operated Babbage field, which was acquired as part of the E.ON UK acquisition, also exceeded expectations. The field is currently producing over 3 kboepd net to Premier as a result of continued high demand for the field's gas coupled with high uptime at the onshore facility. Planning is underway to complete transition of the Babbage platform to being unmanned. This should result in considerably reduced operating costs.

First oil from the Solan field was achieved on 12 April. Premier subsequently carried out a planned production shut down focused on the final commissioning of the topsides, taking advantage of the availability of the flotel utilised for pre-first oil hook up and commissioning. Production from the Solan field recommenced on 22 June and the first tanker offload from the subsea oil storage tank was successfully undertaken at the end of July with a cargo size of over 250,000 barrels of oil. Drilling activities on the second production well (P2Y) have been completed and the well was tied in by DSV during August. Production from the second well is expected to start later today (18 August) and, together with production from the first well which is producing at 14 kboepd, the field is expected to reach plateau rates of 20-25 kboepd within the next few days. Solan's untaxed production will generate material cash flow with operating costs of less than US$10/bbl while the field is on plateau production.

UK unit operating costs for the period were US$31/boe (2015 H1: US$29/boe), driven by natural decline from Premier's UK legacy assets and higher equity in the Huntington field offset by cost reductions, particularly at Balmoral and Wytch Farm. Going forward, UK unit operating costs are expected to reduce significantly towards $20/boe with new production from the Solan field and as Premier benefits from a full contribution from the lower opex Elgin-Franklin field.

Developments

The Premier-operated Catcher project remains on schedule to deliver first oil in 2017. Significant cost savings have been realised against the original development budget with total project capex now forecast at US$1.8bn, a reduction of 20 per cent. The 2016 subsea installation campaign is ahead of plan with the bundles, towhead, midwater arches and gas export pipeline along with the buoy and mooring system for the FPSO installed. The buoy has also been ballasted down, thereby completing the most weather-sensitive part of this phase. Post period end eight of the nine risers were installed and hung off the buoy and the first umbilical connected. Support vessels are currently in field completing the installation of the last riser and the remaining two umbilicals.

Drilling activities have continued to yield very positive results. All six wells drilled to date have met or exceeded pre-drill predictions for reservoir quality while flow rates have been at or above prognosis. The drilling programme also remains significantly below the original cost budget. During the period production wells CCP3 and CTP1 on the Catcher template and BP3 and BP5 on the Burgman template were completed. The rig is now preparing to move to the Varadero template to commence operations. Work continues to assess the possibility of reducing the overall well count reducing costs without impacting production delivery. Fabrication of the FPSO hull and topsides continued in Asia in the first half of 2016. The Stern Terra Block and Forward Terra Block were delivered to the Keppel yard in Singapore in June and July, respectively. The hull mating operation was carried out successfully and the welding of the two blocks completed. Fabrication of the topside modules at the DynaMac and AOS yards in Singapore and the Profab yard in Batam continues to progress with first module lift targeted for September. The sail-away date of the FPSO from Singapore for a 2017 field start up remains on track.

Work is ongoing on the Tolmount gas field development in the Southern Gas Basin in which Premier acquired a 50 per cent operated interest through its acquisition of E.ON UK in April. Premier is progressing a number of options for the initial phase of the development which will target the main Tolmount structure. Concept selection is targeted for the second half of the year with a view to taking a final investment decision in 2017. Further upside at Tolmount includes the subsequent development of Tolmount East and the potential for further gas production utilising the Tolmount infrastructure from both Premier's and third party discoveries and prospects nearby.

Exploration

The Ensco 100 rig spudded the Laverda/Slough prospect, near the Catcher area in the UK North Sea, in April. This commitment well encountered 13 feet of net oil bearing Tay sands at Laverda, in line with pre-drill expectations, but did not encounter any indications of hydrocarbons in the deeper, high risk Slough prospect. The well was subsequently plugged and abandoned.

The Ocean Valiant rig spudded the Bagpuss prospect in the Outer Moray Firth in July. The well encountered 41 feet of hydrocarbon-bearing sands within a 68 feet hydrocarbon column, in line with pre-drill estimates. The sands have between 25 per cent and 33 per cent porosity and indications are that the oil is heavy. The well has been plugged and abandoned.

As a result of the E.ON UK acquisition, Premier has a carried five per cent interest in the Ravenspurn North Deep well to be drilled later this year. This well has the potential to open up a significant new tight gas play within the Southern Gas Basin which, if successful, will provide material follow-on opportunities for Premier within its existing portfolio. It also has the potential to defer the abandonment date of the Ravenspurn North facilities. Premier also acquired ten greenfield and six near-field exploration licences, close to either the Babbage or Tolmount areas, through the E.ON acquisition. Premier's exploration focus is on high-grading and maturing this acreage within the lightly explored tight gas plays in the area. Away from the Southern Gas Basin, Premier has relinquished six UK exploration licences with a further eight targeted for divestment, a saving of approximately US$2 million per year in licence costs alone.

PAKISTAN

Premier's Pakistan business has continued to generate positive and stable net cash flows for the Group. During the first six months of the year, the average realised gas price was US$3.1/mscf while operating costs remained low at US$0.52/mscf.

Production and Development

Production in Pakistan averaged 7.9 kboepd (2015 H1: 10.3 kboepd), from Premier's six non-operated producing gas fields. The fall in production reflects natural decline in all of the gas fields, partially offset by a successful well intervention campaign at the Zamzama field.

Production from the Zamzama gas field exceeded expectations over the period, averaging 1.9 kboepd (2015 H1: 2.2 kboepd), with the well intervention campaign yielding better than anticipated results and helping to arrest the decline rate of this field.

Production from the Qadirpur, Bhit/Badhra and Zarghun South gas fields was in line with expectations averaging 2.6 kboepd (2015 H1: 2.8 kboepd), 2.4 kboepd (2015 H1: 3.3 kboepd) and 63 boepd (2015 H1: 86 boepd) respectively.

Portfolio management
Premier has agreed terms with a preferred bidder for the sale of its Pakistan business. Completion of the transaction remains subject to the purchaser putting in place the necessary funding arrangements.

MAURITANIA
Production and development
Production from the Chinguetti field averaged 356 barrels bopd (2015 H1: 400 bopd) net to Premier during the first six months of the year. In view of the low oil price and resulting marginal cash flows, the joint venture partners are targeting cessation of production from the field by year-end. To this end, the operator submitted the Abandonment and Decommissioning Plan to the Government of Mauritania on 29 June.

FALKLAND ISLANDS
In the Falkland Islands, FEED on the Premier operated Sea Lion Phase 1 project is progressing well and identified cost reductions have lowered the current break-even oil price estimate for the project to $45/bbl.

Development
In January, Premier commenced FEED on its operated Sea Lion Phase 1 project, which comprises the development of the reserves in the north-east and north-west of Sea Lion oilfield in licence PL032. FEED contracts were awarded to a group of world-class contractors comprising SBM Offshore for the FPSO, Subsea 7 for the subsea installation, NOV for the flexible flowlines and One Subsea for the subsea production system. The four contractors are working collaboratively with Premier to optimise the facilities design and installation methodology and to reduce project costs.

Engagement with the drilling and logistics services markets is progressing well, with alternative commercial models being discussed and cost estimates reducing. Tender packages for these services are expected to be prepared by year end.

Current estimated capex to first oil is now US$1.5 billion while current project breakeven price estimate has reduced to US$45/bbl. Further cost reductions are being targeted.

The Falkland Islands Government (FIG) has confirmed to Premier that it has secured approval from the Secretary of State for an extension to the Sea Lion Discovery Area licence to April 2020. Premier continues to work closely with FIG in progressing the project to a final investment decision, subject to securing acceptable project economics and the conclusion of a successful farm down process.

Exploration
In January 2016, Premier completed its exploration programme in the North Falklands Basin with the successful re-drill of the Isobel Deep well. The well confirmed the oil discovery encountered in the original Isobel Deep well and, in addition, discovered new hydrocarbons in additional sandstones.

NEW COUNTRY ENTRY - EXPLORATION
Premier has rebalanced its exploration portfolio away from traditional but now mature areas towards under-explored but proven hydrocarbon basins that have the potential to transform the company's resource base and to develop into new business units.

Mexico
Premier was awarded a non-operated 10 per cent interest in Blocks 2 and 7 at no upfront cost in July 2015 and is carried on each of the blocks up to the point of the first well. The Blocks, located in the shallow water Sureste Basin, a proven and prolific hydrocarbon province in the Gulf of Mexico, contain numerous leads in established and emerging plays. Existing 3D seismic has been reprocessed across the two blocks and is on track for delivery in Q3 this year. This data will be used to confirm final drilling candidates with the first exploration well expected to spud on Block 7 in 2017 and Block 2 in 2018. It is

anticipated that the joint venture will go out to tender for a moored, semi-submersible rig for Block 7 in Q4 2016. Premier has the option to increase its interest in the blocks up to 25 per cent prior to drilling in payment for past costs.

Brazil

The multi-client seismic survey across Premier's acreage in the Ceará Basin, our top ranked basin in Brazil, was successfully completed in early 2016. Premier has subsequently received fast-track and final PSTM data and fast-track PSDM data across both its operated CE-M-665 and CE-M-717 concessions as well as across its non-operated CE-M-661 and data interpretation is underway. The final PSDM seismic product is on track to be delivered in Q1 2017. To date, several promising plays have been identified and final data will be used to identify drilling targets. Meanwhile, we are working with other operators to evaluate rig sharing options as well as the possibility of shared onshore services. Simultaneously, along with other operators, Premier is seeking licence extensions from the government such that the Company has sufficient time to conclude such a rig sharing agreement and to drill our wells prior to licence expiry.

In the Foz do Amazonas Basin where Premier holds a 35 per cent non-operated interest in block FZA-M-90, interpretation of the new 3D seismic data has been completed and is being evaluated by the joint venture partnership.

Portfolio management

During the period, Premier exited its licence position in the Saharawi Arab Democratic Republic and is in the process of finalising its exit from its Iraq licence.

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FINANCIAL REVIEW

Financial overview

Following the sharp fall in crude oil prices in 2015, prices continued to fall in the opening months of 2016 before stabilising and recovering to improved levels by 30 June 2016. Brent crude opened the year at US$35.7/bbl and, after dropping to US$26/bbl in January 2016, increased to US$48.4/bbl at 30 June 2016. The average for 2016 H1 was US$39.8/bbl against US$57.8/bbl for the prior half year.

Against this economic backdrop our production averaged 61.0 kboepd, (2015 H1: 60.4 kboepd), resulting in revenue of US$393.8 million compared with US$577.0 million in 2015 H1. Revenue for the period includes US$54.8 million (2015 H1: US$145.0 million) for forward sales of oil and gas which have settled in the year.

EBITDAX for the period was US$182.2 million compared to US$446.7 million for 2015 H1 (as previously reported). The lower EBITDAX is mainly due to lower oil prices realised during the period.

Business performance	**2016 Half-year $ million**	**2015 Half-year $ million**
Operating profit / (loss)	197.0	(167.0)
Amortisation and depreciation	156.8	176.1
Impairment charge on oil and gas properties	-	385.3
Reduction in decommissioning estimates	(100.8)	-
Exploration expense and pre-licence costs	14.5	52.3
Acquisition of subsidiaries:		
- Excess of fair value over consideration	(106.9)	-
- Costs of the acquisition	5.6	-
- Settlement provision for E.On acquisition	16.0	-
EBITDAX	**182.2**	**446.7**

Net debt at 30 June 2016 amounted to US$2,634.6 million (31 December 2015: US$2,242.2 million), with cash resources of US$207.7 million (31 December 2015: US$401.3 million).

	2016 Half-year $ million	2015 Half-year $ million	2015 Year-end $ million
Cash and cash equivalents	**207.7**	372.4	401.3
Convertible bonds	**(235.2)**	(230.3)	(232.9)
Other long-term debt	**(2,607.1)**	(2,234.6)	(2,410.6)
Net debt	**(2,634.6)**	(2,092.5)	(2,242.2)

Long-term borrowings consist of convertible bonds, UK retail bonds, senior loan notes and bank debt.

Premier's principal financing facilities include a leverage cover ratio and an interest cover ratio, that are measured every six months for the previous 12 month period. Under the current financial agreements, the leverage cover ratio is 4.75 times for the 12 month period to 30 June 2016 and 31 December 2016, whilst the interest cover ratio is 3 times for the same testing periods.

Premier is currently in negotiations with its lending group to modify the terms of its existing financial facilities. As part of these negotiations the testing of the 30 June 2016 financial covenants has been waived, and replaced with a test for the 12 month period ending 31 August 2016. Good progress is being made with the company's lending group over amendments to the medium term covenant profile and resetting of debt maturities. Premier expects negotiations to conclude and revised agreements to be implemented during H2 2016. Further deferral of the covenant test date will be sought if required during this period.

Premier retained significant cash and undrawn facilities of c.US$800 million at 30 June 2016.

Acquisition of E.On's UK North Sea assets

In April 2016 Premier completed the acquisition of E.ON's UK North Sea assets for cash consideration of US$135.0 million. The acquisition has been accounted for as a business combination under the requirements of IFRS 3 Business Combinations and the assets and liabilities acquired have been fair valued on the date of completion utilising Premier's corporate assumptions for oil and gas prices, reserves estimates and discount rates. The fair value of the net assets acquired was US$241.9 million resulting in an excess of fair value over consideration of US$106.9 million recorded as a credit in the income statement. Separately, costs related to the acquisition of US$21.6 million have been recognised in the period. This is made up acquisition costs of US$5.6 million and the recognition of a settlement provision of US$16.0 million in respect of employee costs.

Results for the E.On assets acquired have been consolidated into the Premier group results from the date of completion, which has resulted in an increase to Premier's group revenue of US$44.2 million and an increase in Premier's group profit before tax of US$5.0 million.

Income statement

<u>Production and revenue</u>

Group production on a working interest basis averaged 61.0 kboepd for the period compared to 60.4 kboepd in 2015 H1. This was driven by high operating efficiency, better than predicted reservoir performance on certain fields and a contribution from the E.On portfolio from the acquisition date. These were offset by natural decline in the portfolio. Entitlement production for the period was 57.0 kboepd (2015 H1: 55.7 kboepd). Post hedging, Premier realised an average price for the period of US$48.6/bbl (2015 H1: US$83.7/bbl) vs a Brent average price of US$39.8/bbl (2015 H1: US$57.8/bbl).

Gas prices in Singapore, linked to high sulphur fuel oil (HSFO) pricing and in turn, therefore, linked to crude oil pricing, averaged US$5.8/mscf (2015 H1: US$12.3/mscf) post hedging. The average price for Pakistan gas (where only a portion of the contract formulae is linked to energy prices) was US$3.1/mscf (2015 H1: US$4.4/mscf).

Total sales revenue from all operations fell to US$393.8 million (2015 H1: US$577.0 million), due to the fall in average realised prices and lower volumes of hedged production realised in the period.

<u>Operating costs</u>

Cost of sales comprise cost of operations, changes in lifting positions, inventory movement, royalties and amortisation and depreciation of property plant and equipment ("PP&E"). Cost of sales for the group was US$355.2 million for 2016 H1, compared to US$298.8 million for 2015 H1.

Operating costs	**2016 Half-year $ million**	**2015 Half-year $ million**
Cost of operations (US$ million)	183.7	149.8
Unit cost of operations (US$ per barrel)	16.5	13.8
Amortisation of oil and gas properties (US$ million)	152.8	170.6
Unit amortisation rate (US$ per barrel)	13.7	15.7

The increase in absolute operating costs on the prior period reflects the operating costs associated with the E.ON UK assets, the start-up of the Solan field and the Company's higher equity interest in the Huntington field partially offset by further savings in underlying opex from contract renegotiations and operational efficiencies across the Company's asset base. Underlying unit amortisation fell to US$13.7/boe (2015 H1: US$15.7/boe).

Revision in decommissioning estimates

The weakness in GBP:USD exchange rate at 30 June has been the principal cause of a US$100.8 million gain being credited to the Income statement in respect of revised decommissioning estimates. Whilst any positive foreign exchange revision would generally have been credited to the decommissioning asset in the balance sheet, the majority relates to late life UK assets which have previously been fully provided for. As such, this revision has been taken as a credit to the Income Statement in the period.

Exploration expenditure and pre-licence costs

Exploration expense and pre-licence expenditure costs amounted to US$14.5 million (2015 H1: US$51.5 million). This predominantly relates to the write off of the Laverda and Slough prospects in the UK. After recognition of these expenditures, the exploration and evaluation asset remaining on the balance sheet at 30 June 2016, including goodwill attributable to the Catcher asset, is US$1,169.8 million (31 December 2015: US$990.5 million) with the increase driven primarily by the acquisition of the Tolmount asset as part of the E.On portfolio.

General and Administrative Expenses

Net G&A costs have increased for H1 2016 to US$13.4 million (2015 H1: US$8.4 million) due to the inclusion of E.On's unallocated G&A for the two month period since the completion of the acquisition. Underlying G&A, without the acquisition, would have fallen period on period. Unallocated G&A is expected to fall in the second half of the year, following the integration of E.On's assets into Premier's UK business unit with effect from 1 July 2016.

Finance gains and charges

Interest revenue and finance gains reduced to US$10.3 million from US$47.4 million in 2015 H1. The principal reason for this reduction is the fall in accrued interest receivable from the former JV partner in the Solan development following the acquisition of the JV partner interest in Solan in May 2015. Gross finance costs, before interest capitalisation, which include the unwinding of the discount on decommissioning, of US$122.1 million were broadly consistent with costs of US$120.1 million in 2015 H1. Interest costs continue to be capitalised for the Catcher development but ceased on the Solan development from the achievement of first oil.

Taxation

The group has a current tax charge for the period of US$12.3 million (2015 H1: US$61.7 million) and a non-cash deferred tax credit for the period of US$75.4 million (2015 H1: charge of US$98.8 million) which results in a total tax credit for the period of US$63.1 million (2015 H1: charge of US$160.5 million).

The negative effective tax rate for the period is a result of the recognition of UK tax losses and allowances in the period, driven by anticipated future profitability from the acquisition of E.ON's UK North Sea assets.

The effects of the UK Supplementary Charge to Tax rate reduction from 20 per cent to 10 per cent from 1 January 2016 on opening deferred tax balances (charge of US$183.9 million) has not been included in the tax charge for the period as the legislation enacting the rate reduction is not expected to be substantially enacted until September 2016.

Profit after tax

Profit after tax is US$167.1 million (2015 H1: loss of US$375.2 million) resulting in a basic profit per share of 33.9 cents (2015 H1: loss of 73.5 cents).

Cash flow

Cash flow from operating activities was US$108.7 million (2015 H1: US$513.0 million) after accounting for tax payments of US$37.0 million (2015 H1: US$58.0 million).

Capital expenditure in the period to 30 June 2016 totalled US$318.3 million (2015 H1: US$517.6 million).

Capital expenditure (US$ million)	**2016 Half-year $ million**	**2015 Half-year $ million**
Fields/development projects	259.3	379.7
Exploration and evaluation	57.7	137.0
Other	1.3	0.9
Total	**318.3**	**517.6**

The principal development projects were the Solan and Catcher fields in the UK.

In addition, expenditure related to decommissioning in the period was US$55.8 million and included a one off US$53 million catch up payment into escrow for future decommissioning of Chim Sao, the balance of which is held within non-current other receivables.

Balance sheet position

Decommissioning Funding

As part of the E.On acquisition, Premier entered into a separate Decommissioning Liability Agreement with E.On, whereby E.On agreed to part fund Premier's share of decommissioning the Johnston and Ravenspurn North assets. Under the terms of the agreement, E.On will provide 70 per cent of the decommissioning costs between a range of GBP 40 million to GBP 130 million based on Premier's net share of the total decommissioning cost of the two assets. This results in maximum possible funding of GBP 63.0 million from Eon.

At 30 June 2016, a long term decommissioning funding asset of US$78.8 million has, therefore, been recognised within other non-current receivables utilising the period end GBP:USD exchange rate.

Provisions

The group's long term provisions increased to US$1,456.7 million at 30 June 2016, up from US$1,065.7 million at 31 December 2015. The increase is driven by the recognition of a long term provision for decommissioning related to E.On assets acquired in the period of US$565.9 million, which has been partially offset by a reduction for the UK assets driven by the weakening of the GBP:USD exchange rate at 30 June 2016.

Financial risk management

Commodity hedge position	2016 H2	2017	2018 H1
Oil hedges			
Volume (bopd)	3,310,787	1,530,000	-
Average price (US$/bbl)	65.22	45.82	-
Production hedged (per cent)	37	9	-
Indonesian gas			
Indonesian gas (mt)	36,000	-	-
Average price (US$/mt)	400.00	-	-
Production hedged (per cent)	16	-	-
UK natural gas			
UK natural gas (mm therms)	30.55	36.58	4.50
Average price (pence/therm)	62.00	55.70	57.32
Production hedged (per cent)	29	21	6

The fair value of the commodity swaps at 30 June 2016 was an asset of US$70.9 million (2015: US$114.3 million), which is expected to be released to the income statement by 2018 H1 as the related barrels are lifted and gas volumes sold.

During the first half of 2016 , forward oil sales of 1.9 mmbbls, and forward fuel oil sales of 36,000 mt expired resulting in a net credit of US$54.8 million (2015 H1: US$145.0 million) which has been included within sales revenue for the period.

Foreign exchange

Premier's functional and reporting currency is US dollars. Exchange rate exposures relate only to local currency receipts, and local currency expenditures within individual business units. Local currency needs are acquired on a short-term basis. At 30 June 2016, the fair value of the outstanding foreign exchange contracts was a liability of US$2.6 million. The Group currently has £150.0 million retail bonds, €60.0 million long-term senior loan notes and £100.0 million term loan in issuance which have been hedged under cross currency swaps in US dollars at average fixed rates of US$1.64:£ and US$1.37:€ and which at 30 June 2016 had a fair value liability of US$110.0 million. Post the period-end, Premier has taken advantage of the recent weakness in the sterling dollar exchange rate to lock in £140 million of forward expenditure in the second half of the year at an average rate of 1.31.

Interest rates

The Group has various financing instruments including senior loan notes, convertible bonds, UK retail bonds, term loans and revolving credit facilities. As 30 June 2016, approximately 55 per cent of total borrowings is fixed or has been fixed using the interest rate swap markets, with a fair value liability at that date of US$6.6 million. On average, the cost of drawn funds for the year was 4.0 per cent. Mark-to-market losses on interest rate swaps amounted to US$6.6 million, which are recorded as movements in other comprehensive income.

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. During 2016, Premier have received cash of US$17.9 million for insurance claims made.

Going concern

The Group monitors its funding position and its liquidity risk throughout the year to ensure it has access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced based on, inter alia, the Group's latest life of field production and expenditure forecasts, management's best estimate of future commodity prices (based on recent forward curves, adjusted for the Group's hedging programme) and the Group's borrowing facilities. Sensitivities are run to reflect different scenarios including, but not limited to, changes in oil and gas production rates, possible reductions in commodity prices and delays or cost overruns on major development projects. This is done to identify risks to liquidity and covenant compliance and enable management to formulate appropriate and timely mitigation strategies.

At 30 June 2016, the Group continued to have significant headroom on its borrowing facilities. However, whilst the Group expects to have sufficient liquidity available under these existing facilities during the next 12 months, the Group's projections currently indicate that a breach of one of the financial covenants within the Group's borrowing facilities is likely to arise in respect of the next covenant testing period which, as part of the lender discussions outlined below, has been revised from the 12 months ending 30 June 2016 to the 12 months ending 31 August 2016.

Discussions with Premier's lending group are ongoing and management expect the testing date for the financial covenants to continue to be deferred until modified terms for the financing facilities are agreed. Management also expect, based on the discussions held to date, that the modified terms will involve a relaxation of financial covenants such that there is a reasonable expectation that the Group will be able to live within the terms of the amended facilities for the foreseeable future. However, in the event that the testing of the financial covenants is not deferred or if a suitable agreement cannot be reached with the lending group and a breach of a financial covenant were to arise, under the existing terms of the group's financing facilities, the Group's debt holders on all of the Group's facilities will have the right to request re-payment of the outstanding debt and to cancel the relevant facilities.

The risk that the Group will be unable to defer the testing of the current financial covenants until appropriate modification of the terms of its financing facilities is agreed with the lending group in order to avoid a breach of covenant or that such appropriate modification of the terms cannot be agreed is a material uncertainty which the Financial Reporting Council Guidance on Risk Management, Internal Control and Related Financial and Business Reporting requires us to report may cast significant doubt upon the Company's ability to continue to apply the going concern basis of accounting.

Nevertheless, after making enquiries and considering the uncertainties described above, the Directors have a reasonable expectation that the Group will be able to secure an appropriate modification to the terms of its financing facilities to avoid a covenant breach. Therefore, the Group and Company are expected to have adequate resources to continue in operational existence for the foreseeable future, being at least the next 12 months from the date of approval of the 2016 Interim Report and Accounts. Accordingly, the Directors continue to adopt the going concern basis of accounting in preparing these consolidated 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, which have not changed since 31 December 2015, for the remaining 6 months of the year as being:

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

Further information detailing the way in which these risks are mitigated is provided on pages 30 to 36 of the 2015 Annual Report and Financial Statements. This information is also available on company's website www.premier-oil.com.

STATEMENT OF DIRECTORS' RESPONSIBILITIES

Each of the directors of the company confirms that to the best of his or her knowledge:

a) the condensed set of financial statements, which has been prepared in accordance with International Accounting Standard 34 – 'Interim Financial Reporting' gives a true and fair view of the assets, liabilities, financial position and profit of the company;

b) the Half-Yearly Results statement 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 Half-Yearly Results statement includes a fair review of the information required by DTR 4.2.8R (disclosure of related parties' transactions and changes therein).

On behalf of the Board

Richard Rose
Finance Director

Half-Yearly Results for the six months to 30 June 2016

CONDENSED CONSOLIDATED INCOME STATEMENT

	Note	**Six months to 30 June 2016 Unaudited $ million**	Six months to 30 June 2015 Unaudited $ million*	Year to 31 December 2015 Audited $ million
Sales revenues	*2*	**393.8**	577.0	1,067.2
Other operating income		**0.2**	-	31.9
Cost of sales	*3*	**(355.2)**	(298.8)	(661.0)
Impairment charge on oil and gas properties		**-**	(385.3)	(1,023.7)
Reduction in decommissioning estimates	*13*	**100.8**	-	-
Exploration expense		**(9.5)**	(45.3)	(95.4)
Pre-licence exploration costs		**(5.0)**	(6.2)	(13.6)
Excess of fair value over cost	*12*	**106.9**		
Costs related to the acquisition of subsidiaries	*12*	**(21.6)**	-	-
Profit on disposal of assets		**-**	-	1.2
General and administration costs		**(13.4)**	(8.4)	(14.4)
Operating profit/(loss)		**197.0**	(167.0)	(707.8)
Share of profit in associate		**-**	-	(1.9)
Interest revenue, finance and other gains	*4*	**10.3**	47.4	40.7
Finance costs and other finance expenses	*4*	**(97.3)**	(95.0)	(160.6)
Profit/(loss) before tax		**110.0**	(214.6)	(829.6)
Tax	*5*	**63.1**	(160.5)	(241.1)
Profit/(loss) for the period/year from continuing operations		**173.1**	(375.1)	(1,070.7)
Discontinued operations				
(Loss) for the period/year from discontinued operations	*7*	**(6.0)**	(0.1)	(33.1)
Profit/(loss) after tax		**167.1**	(375.2)	(1,103.8)
Earnings/(losses) per share (cents):				
From continuing operations				
Basic	*7*	**33.9**	(73.4)	(209.6)
Diluted	*7*	**32.2**	(73.4)	(209.6)
From continuing and discontinued operations				
Basic	*7*	**32.7**	(73.5)	(216.1)
Diluted	*7*	**31.1**	(73.5)	(216.1)

* restated for discontinued operations.

Notes 1 to 13 form an integral part of these condensed financial statements.

Half-Yearly Results for the six months to 30 June 2016

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Note	**Six months to 30 June 2016 Unaudited $ million**	Six months to 30 June 2015 Unaudited $ million	Year to 31 December 2015 Audited $ million
Profit/(loss) for the period/year		**167.1**	(375.2)	(1,103.8)
Cash flow hedges on commodity swaps:				
Gains/(losses) arising during the period/year		**(36.9)**	4.8	164.4
Less: reclassification adjustments for (gains)/ losses in the period/year		**(47.5)**	(145.0)	(278.9)
		(84.4)	(140.2)	(114.5)
Tax relating to components of other comprehensive income	*6*	**54.3**	80.9	76.0
Cash flow hedges on interest rate and foreign exchange swaps		**(14.6)**	(2.8)	19.8
Exchange differences on translation of foreign operations		**(10.1)**	(13.4)	(37.0)
Losses on long-term employee benefit plans*		**-**	-	(0.1)
Other comprehensive expense		**(54.8)**	(75.5)	(55.8)
Total comprehensive income/(expense) for the period/year		**112.3**	(450.7)	(1,159.6)

* 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	**At 30 June 2016 Unaudited $ million**	At 30 June 2015 Unaudited $ million	At 31 December 2015 Audited $ million
Non-current assets:				
Goodwill		**240.8**	240.8	240.8
Intangible exploration and evaluation assets	8	**929.0**	910.3	749.7
Property, plant and equipment	9	**3,320.4**	2,946.9	2,611.7
Investments		**4.9**	7.7	5.3
Long-term employee benefit plan surplus		**0.5**	0.8	0.5
Other receivables		**148.1**	9.1	11.5
Deferred tax assets	6	**935.5**	945.3	871.6
		5,579.2	5,060.9	4,491.1
Current assets:				
Inventories		**22.9**	29.8	20.8
Trade and other receivables		**345.4**	344.4	240.8
Tax recoverable		**21.5**	41.1	33.6
Derivative financial instruments	11	**81.1**	96.5	118.3
Cash and cash equivalents		**207.7**	372.4	401.3
		678.6	884.2	814.8
Total assets		**6,257.8**	5,945.1	5,305.9
Current liabilities:				
Trade and other payables		**(588.4)**	(469.2)	(407.4)
Current tax payable		**(45.6)**	(74.5)	(64.6)
Provisions	13	**(37.1)**	(11.8)	(24.8)
Derivative financial instruments	11	**(129.4)**	(53.2)	(76.5)
Deferred income		**(37.5)**	(17.3)	(20.9)
		(838.0)	(626.0)	(594.2)
Net current assets		**(159.4)**	258.2	220.6
Non-current liabilities:				
Convertible bonds		**(235.0)**	(230.3)	(232.6)
Other long-term debt		**(2,583.9)**	(2,211.3)	(2,382.5)
Deferred tax liabilities	6	**(192.8)**	(244.3)	(193.3)
Deferred income		**(80.1)**	(82.7)	(87.6)
Long-term provisions	13	**(1,456.3)**	(1,100.2)	(1,065.7)
Long-term employee benefit plan deficit		**(16.3)**	(17.2)	(15.2)
		(4,564.4)	(3,886.0)	(3,976.9)
Total liabilities		**(5,402.4)**	(4,512.0)	(4,571.1)
Net assets		**855.4**	1,433.1	734.8

CONDENSED CONSOLIDATED BALANCE SHEET *(continued)*

	Note	**At 30 June 2016 Unaudited $ million**	At 30 June 2015 Unaudited $ million	At 31 December 2015 Audited $ million
Equity and reserves:				
Share capital		**106.7**	106.7	106.7
Share premium account		**275.4**	275.4	275.4
Merger reserve		**374.3**	374.3	374.3
Retained earnings		**179.3**	718.8	46.3
Other reserves		**(80.3)**	(42.1)	(67.9)
		855.4	1,433.1	734.8

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	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 2015	106.7	275.4	1,142.3	374.3	8.1	(48.7)	14.1	1,872.2
Purchase of ESOP Trust	-	-	(0.9)	-	-	-	-	(0.9)
Provision for share-based payments	-	-	23.0	-	-	-	-	23.0
Transfer between reserves*	-	-	4.5	-	-	-	(4.5)	-
Total comprehensive expense	-	-	(1,122.6)	-	-	(37.0)	-	(1,159.6)
At 31 December 2015	106.7	275.4	46.3	374.3	8.1	(85.7)	9.6	734.8
ESOP Trust shared	-	-	0.2	-	-	-	-	0.2
Provision for share-based payments	-	-	8.2	-	-	-	-	8.2
Transfer between reserves*	-	-	2.2	-	-	-	(2.2)	-
Total comprehensive expense	-	-	122.4	-	-	(10.1)	-	112.3
At 30 June 2016	**106.7**	**275.4**	**179.3**	**374.3**	**8.1**	**(95.8)**	**7.4**	**855.4**

At 1 January 2015	106.7	275.4	1,142.3	374.3	8.1	(48.7)	14.1	1,872.2
Provision for share-based payments	-	-	11.6	-	-	-	-	11.6
Transfer between reserves*	-	-	2.2	-	-	-	(2.2)	-
Total comprehensive income	-	-	(437.3)	-	-	(13.4)	-	(450.7)
At 30 June 2015	106.7	275.4	718.8	374.3	8.1	(62.1)	11.9	1.433.1

* 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.

PremierOil

Half-Yearly Results for the six months to 30 June 2016

CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Note	**Six months to 30 June 2016 Unaudited $ million**	Six months to 30 June 2015 Unaudited $ million	Year to 31 December 2015 Audited $ million
Net cash from operating activities	*10*	**108.7**	513.0	809.5
Investing activities:				
Capital expenditure		**(318.3)**	(439.7)	(992.2)
Acquisition of subsidiaries	*12*	**(135.0)**	-	-
Cash balance acquired in the period	*12*	**24.9**	-	-
Decommissioning funding		**(55.8)**	-	-
Proceeds from disposal of oil and gas properties		**-**	82.7	219.6
Loan to joint venture partner*		**-**	(77.9)	(77.9)
Net cash used in investing activities		**(484.2)**	(434.9)	(850.5)
Financing activities:				
Net purchases of ESOP Trust shares		**-**	-	(0.9)
Proceeds from drawdown of bank loans		**230.0**	550.0	775.0
Debt arrangement fees		**-**	-	(9.6)
Repayment of long term bank loans		**-**	(500.8)	(300.0)
Repayment of senior loan notes		**-**	-	(209.4)
Interest paid		**(55.3)**	(48.7)	(91.6)
Net cash from financing activities		**174.7**	0.5	163.5
Currency translation differences relating to cash and cash equivalents		**7.2**	2.0	(13.0)
Net (decrease)/increase in cash and cash equivalents		**(193.6)**	80.6	109.5
Cash and cash equivalents at the beginning of the period/year		**401.3**	291.8	291.8
Cash and cash equivalents at the end of the period/year	*10*	**207.7**	372.4	401.3

*Funding provided to the former Joint Venture partner on the Solan field until the completion of the asset acquisition of their 40 per cent interest.

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 2016 were approved for issue in accordance with a resolution of a committee of the Board of Directors on 17 August 2016.

The information for the year ended 31 December 2015 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 2015 were approved by the Board of Directors on 24 February 2016 and delivered to the Registrar of Companies. The auditor reported on those accounts; the report was unqualified and did not contain any statement under section 498(2) or 498(3) of the Companies Act 2006. However, an emphasis of matter with regards to a material uncertainty in the application of the going concern basis of accounting was included in the audit report.

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 2016, and the condensed consolidated balance sheet as at 30 June 2016 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 2016 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 Conduct Authority. These condensed financial statements should be read in conjunction with the annual financial statements for the year ended 31 December 2015, 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 including details of a material uncertainty due to the risk of a covenant breach 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 2015, as described in those annual financial statements. A number of new standards, amendments to existing standards and interpretations were applicable from 1 January 2016. 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 2016.

2. OPERATING SEGMENTS

The group's operations are located and managed in six business units; namely the Falkland Islands, Indonesia, 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.

	Six months to 30 June 2016 Unaudited $ million	Six months to 30 June 2015 Unaudited $ million	Year to 31 December 2015 Audited $ million
Revenue:			
Indonesia	**68.0**	124.1	215.4
Pakistan (including Mauritania)	**29.2**	52.1	88.9
Vietnam	**91.9**	142.5	227.8
United Kingdom	**204.7**	258.3	535.1
Total group sales revenue	**393.8**	577.0	1,067.2
Other operating income	**0.2**	-	31.9
Interest and other finance revenue	**0.5**	28.5	29.3
Total group revenue from continuing operations	**394.5**	605.5	1,128.4

Group operating profit/(loss):			
Indonesia	**7.5**	59.1	62.0
Pakistan (including Mauritania)	**12.2**	17.9	12.2
Vietnam	**14.0**	37.1	27.0
United Kingdom	**97.2**	(236.9)	(721.9)
Rest of the World	**(0.8)**	(29.5)	(59.1)
Unallocated*	**66.9**	(13.4)	(28.0)
Group operating profit/(loss)	**197.0**	(165.7)	(707.8)
Share of profit in associate	**-**	-	(1.9)
Interest revenue, finance and other gains	**10.3**	47.6	40.7
Finance costs and other finance expenses	**(97.3)**	(94.9)	(160.6)
Profit/(loss) before tax	**110.0**	(213.0)	(829.6)
Tax	**63.1**	(162.1)	(241.1)
Profit/(loss) after tax from continuing operations	**173.1**	(375.1)	(1,070.7)
Loss from discontinued operations	**(6.0)**	(0.1)	(33.1)

2. OPERATING SEGMENTS *(continued)*

	Six months to 30 June 2016 Unaudited $ million	Six months to 30 June 2015 Unaudited $ million	Year to 31 December 2015 Audited $ million
Balance sheet - Segment assets:			
Falkland Islands	**655.3**	553.0	591.4
Indonesia	**542.4**	653.2	560.3
Norway	**-**	189.9	-
Pakistan (including Mauritania)	**53.5**	85.2	59.3
Vietnam	**400.7**	476.3	388.2
United Kingdom**	**4,236.97**	3,442.6	3,122.5
Rest of the World	**80.2**	76.1	64.6
Unallocated*	**288.8**	468.8	519.6
Total assets	**6,257.8**	5,945.1	5.305.9

* 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 and pre-licence exploration costs, cash and cash equivalents and mark-to-market valuations of commodity contracts and interest rate swaps.

** Includes goodwill of US$240.8 million.

3. COST OF SALES

	Six months to 30 June 2016 Unaudited $ million	Six months to 30 June 2015 Unaudited $ million*	Year to 31 December 2015 Audited $ million
Operating costs	**183.7**	149.8	323.6
Stock overlift/underlift movement	**7.8**	(39.7)	(11.4)
Royalties	**6.9**	12.6	22.1
Amortisation and depreciation of property, plant and equipment			
- Oil and gas properties	**152.8**	170.6	315.9
- Other fixed assets	**4.0**	5.5	10.8
	355.2	298.8	661.0

* Restated for discontinued operations

4. INTEREST REVENUE AND FINANCE COSTS

	Six months to 30 June 2016 Unaudited $ million	Six months to 30 June 2015 Unaudited $ million*	Year to 31 December 2015 Audited $ million
Interest revenue, finance and other gains:			
Short-term deposits	**0.5**	0.7	0.8
Gain on forward contracts	**-**	9.9	3.8
Gain on extinguishment of debt	**-**	4.1	3.8
Loan to joint venture partner	**-**	27.9	27.9
Exchange differences and others	**9.8**	5.0	4.4
	10.3	47.6	40.7
Finance costs:			
Bank loans, overdrafts and bonds	**(40.4)**	(28.9)	(68.1)
Payable in respect of convertible bonds	**(5.4)**	(5.3)	(10.7)
Payable in respect of senior loan notes	**(14.0)**	(15.6)	(23.4)
Long-term debt arrangement fees	**(5.8)**	(4.4)	(8.8)
Loss of valuation of cross currency swap	**(0.5)**	(11.3)	(20.6)
Loss on forward contracts	**(0.5)**	-	-
Loss of valuation of oil and gas hedges	**(16.9)**	-	-
Exchange differences and others	**(0.8)**	-	-
	(84.3)	(65.4)	(131.6)
Other finance expenses			
Unwinding of discount on decommissioning provision	**(28.7)**	(21.5)	(46.1)
Impairment of loan to joint venture partner	**-**	(33.2)	(33.2)
Finance expense on deferred income	**(9.1)**	-	(8.5)
	(37.8)	(54.7)	(87.8)
Gross finance costs and other finance expenses	**(122.1)**	(120.2)	(219.4)
Finance costs capitalised during the period/year	**24.8**	25.2	58.8
	(97.3)	(95.0)	(160.6)

* Restated for discontinued operations

5. TAX

	Six months to 30 June 2016 Unaudited $ million	Six months to 30 June 2015 Unaudited $ million	Year to 31 December 2015 Audited $ million
Current tax:			
UK corporation tax on profits	**(1.0)**	-	(2.3)
UK petroleum revenue tax	**0.1**	21.3	19.4
Overseas tax	**15.4**	40.9	80.1
Adjustments in respect of prior years	**(2.2)**	(0.4)	1.4
Total current tax	**12.3**	61.7	98.6
Deferred tax:			
UK corporation tax	**(68.5)**	117.5	187.4
UK petroleum revenue tax	**1.2**	(10.1)	(10.6)
Overseas tax	**(8.1)**	(8.6)	(34.3)
Total deferred tax	**(75.4)**	98.8	142.5
Tax on profit/(loss) on ordinary activities	**(63.1)**	160.5	241.1

The group has a current tax charge for the period of US$12.3 million (2015: US$61.7 million) and a non-cash deferred tax credit for the period of US$75.4 million (2015: charge of US$98.8 million) which results in a total tax credit for the period of US$63.1 million (2015: charge of US$160.5 million).

The deferred tax credit arises largely as a result of the recognition of UK tax losses and allowances in the period, as a result of anticipated future profitability from the acquisition of E.On's UK North Sea assets.

6. DEFERRED TAX

	30 June 2016 Unaudited $ million	30 June 2015 Unaudited $ million	31 December 2015 Audited $ million
Deferred tax assets	**935.5**	945.3	871.6
Deferred tax liabilities	**(192.8)**	(244.3)	(193.3)
	742.7	701.0	678.3

	At 1 January 2016 $ million	**Acquisition of subsidiary $ million**	**(Charged)/ credited to income statement $ million**	**Credit to retained earnings $ million**	**At 30 June 2016 $ million**
UK deferred corporation tax:					
Fixed assets and allowances	(581.0)	(323.8)	61.8	-	(843.0)
Decommissioning	378.8	246.9	60.5	-	686.2
Deferred petroleum revenue tax	7.2	-	0.6	-	7.8
Tax losses and allowances	1,129.4	41.2	(64.3)	-	1,106.3
Other	-	(8.4)	5.0	-	(3.4)
Derivative financial instruments	(49.1)	(21.2)	4.8	54.3	(11.2)
Total UK deferred corporation tax	885.3	(65.3)	68.5	54.3	942.8
UK deferred petroleum revenue tax[1]	(14.4)	-	(1.2)	-	(15.6)
Overseas deferred tax[2]	(192.6)	-	8.1	-	(184.5)
Total	**678.3**	**(65.3)**	**75.4**	**54.3**	**742.7**

1 The UK deferred petroleum revenue tax relates mainly to temporary differences associated with fixed assets.

2 The overseas deferred tax relates mainly to temporary differences associated with fixed asset balances.

The group's deferred tax assets at 30 June 2016 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 2016 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 an oil price assumption of Dated Brent forward curve in 2H 2016, 2017 and H1 2018, then 2H 2018 and H1 2019 at US$65/bbl followed by US$80/bbl in 'real' terms thereafter. The results of the corporate model demonstrated that as a result of an increase in the group's estimated future UK profitability arising from the acquisition of subsidiaries in the period, a net amount of US$66.3 million in respect of the group's UK ring fence deferred tax assets relating to tax losses and allowances that was previously de-recognised, could be recognised.

6. DEFERRED TAX *(continued)*

In addition to the above, there are carried forward non-ring fence UK tax losses of approximately US$364.8 million (2015: US$283.2 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.

During the period it was announced that the rate of supplementary tax charge on UK ring fence profits is to be further reduced from 20 per cent to 10 per cent with effect from 1 January 2016. This rate reduction was not substantially enacted at the 30 June 2016 balance sheet date and therefore has not been reflected in the calculation of the group's tax charge for the period. Once enacted, the group's deferred UK tax balances at 31 December 2015 will be recognised at the reduced rate which will give rise to a deferred tax charge of US$183.9 million in the income statement to reflect the decrease in the opening deferred tax assets at 1 January 2016.

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/(loss) per share are calculated as follows:

	Six months to 30 June 2016 Unaudited	Six months to 30 June 2015 Unaudited	Year to 31 December 2015 Audited
Earnings/(loss) ($ millions):			
Earnings/(loss) from continuing operations	**173.1**	(375.1)	(1070.7)
Effect of dilutive potential Ordinary Shares:			
Interest on convertible bonds – dilutive	**5.4**	-	-
Earnings/(loss) for the purposes of diluted earnings/(loss) per share on continuing operations	**178.5**	(375.1)	(1,070.7)
Profit/(loss) from discontinued operations	**(6.0)**	(0.1)	(33.1)
Earnings/(loss) for the purpose of diluted earnings/(loss) per share on continuing and discontinued operations	**172.5**	(375.2)	(1,103.8)
Number of shares (millions):			
Weighted average number of Ordinary Shares for the purpose of basic earnings per share	**510.8**	510.8	510.8
Effects of dilutive potential Ordinary Shares:			
Contingently issuable shares –dilutive	**43.6**	-	-
Weighted average number of Ordinary Shares for the purpose of diluted earnings per share	**554.4**	510.8	510.8
Earnings/(loss) per share (cents) from continuing operations			
Basic	**33.9**	(73.4)	(209.6)
Diluted	**32.2**	(73.4)	(209.6)
Earnings/(loss) per share (cents) from discontinued operations			
Basic	**(1.2)**	(0.1)	(6.5)
Diluted	**(1.1)**	(0.1)	(6.5)

Discontinued operations in all periods relate to the results of the Group's former Norwegian business, which was sold in December 2015 (results for 2015 H1 have been restated accordingly).

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

	Oil and gas properties $ million
Cost:	
At 1 January 2016	749.7
Exchange movements	8.1
Additions during the period	105.7
Acquisition (see note 12)	75.0
Exploration expense	(9.5)
At 30 June 2016	**929.0**

At 30 June 2015	910.3

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 2016	7,025.7	61.4	7.087.1
Exchange movements	-	(2.8)	(2.8)
Acquisition (see note 12)	600.0	7.1	607.1
Additions during the period	257.9	1.3	259.2
At 30 June 2016	**7,883.6**	**67.0**	**7,950.6**
Amortisation and depreciation:			
At 1 January 2016	4,430.9	44.5	4,475.4
Exchange movements	-	(2.0)	(2.0)
Charge for the period	152.8	4.0	156.8
At 30 June 2016	**4,583.7**	**46.5**	**4,630.2**
Net book value:			
At 31 December 2015	2,594.8	16.9	2,611.7
At 30 June 2016	**3,299.9**	**20.5**	**3,320.4**
At 30 June 2015	2,929.0	17.9	2,946.9

In April 2016, Premier completed the acquisition of E.ON E&P UK Ltd for cash consideration of US$135.0 million. For further details of the assets and liabilities acquired see note 12.

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.

10. NOTES TO THE CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Note	**Six months to 30 June 2016 Unaudited $ million**	Six months to 30 June 2015 Unaudited $ million	Year to 31 December 2015 Audited $ million
Profit/(loss) before tax for the period/year		**110.0**	(214.7)	(829.6)
Adjustments for:			-	
Depreciation, depletion, amortisation and impairment		**156.8**	561.4	1,350.4
Other operating income		**(0.2)**	-	(31.9)
Exploration expense		**9.5**	45.3	95.4
Excess of fair value over consideration	12	**(106.9)**	-	-
Settlement provision	12	**16.0**	-	-
Reduction in decommissioning estimates	13	**(100.8)**	-	-
Provision for share-based payments		**8.2**	5.9	7.2
Share of profit in associate		**-**	-	1.9
Interest revenue and finance gains		**(10.3)**	(47.4)	(40.7)
Finance costs and other finance expenses		**97.3**	95.0	160.6
Loss/(profit) on disposal of non-current assets		**-**	-	(1.2)
Deferred income		**-**	100.0	100.0
Operating cash flows before movements in working capital		**179.6**	545.6	812.1
(Increase)/decrease in inventories		**(2.1)**	(3.7)	5.3
Decrease/(increase) in receivables		**(74.3)**	15.8	382.1
Increase/(decrease) in payables		**42.0**	12.6	(297.6)
Cash generated by operations		**145.2**	570.3	901.9
Income taxes paid		**(37.0)**	(58.0)	(94.0)
Interest income received		**0.5**	0.7	1.6
Net cash from operating activities		**108.7**	513.0	809.5

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

Analysis of changes in net debt:

	Six months to 30 June 2016 Unaudited $ million	Six months to 30 June 2015 Unaudited $ million	Year to 31 December 2015 Audited $ million
a) Reconciliation of net cash flow to movement in net debt:			
Movement in cash and cash equivalents	**(193.6)**	80.6	109.5
Proceeds from drawdown of bank loans and senior loan notes	**(230.0)**	(550.0)	(775.0)
Repayment of long-term bank loans	**-**	500.8	300.0
Repayment of senior loan note	**-**	-	209.4
Non-cash movements on debt and cash balances	**31.2**	(1.7)	36.1
Decrease/(increase) in net debt in the period/year	**(392.4)**	29.7	(120.0)
Opening net debt	**(2,242.2)**	(2,122.2)	(2,122.2)
Closing net debt	**(2,634.6)**	(2,092.5)	(2,242.2)

b) Analysis of net debt:			
Cash and cash equivalents	**207.7**	372.4	401.3
Borrowings*	**(2,842.3)**	(2,464.9)	(2,643.5)
Total net debt	**(2,634.6)**	(2,092.5)	(2,242.2)

* Borrowings consist of 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$0.2 million (December 2015: US$0.3 million) and debt arrangement fees of US$23.2 million (December 2015: US$28.1 million) respectively.

11. FINANCIAL INSTRUMENTS

Derivative financial instruments

The group held the following financial instruments at fair value at 30 June 2016. 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.

	At 30 June 2016 Level 2 $ million	At 31 December 2015 Level 2 $ million
Financial assets:		
Gas forward sale contracts	28.3	16.0
Oil forward sales contracts	52.8	98.2
Interest rate swaps	-	4.1
Total	**81.1**	**118.3**
Financial Liabilities:		
Oil forward sales contracts	10.2	-
Forward foreign exchange contracts	2.6	2.2
Cross currency swaps	110.0	74.3
Interest rate swaps	6.6	-
Total	**129.4**	**76.5**

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 and fair values of the group's non derivative financial assets and financial liabilities (excluding current assets and current liabilities for which carrying values approximate to fair values due to their short-term nature) are shown below.

	At 30 June 2016		At 31 December 2015	
	Fair value amount $ million	Carrying amount $ million	Fair value amount $ million	Carrying amount $ million
Primary financial instruments held or issued to finance the group's operations:				
Bank loans	1,913.0	1,913.0	1,697.0	1,697.0
Senior loan notes	494.6	494.6	493.1	493.1
Retail bond	140.5	199.5	108.8	220.5
Convertible bonds	163.6	235.2	191.1	232.9

12. ACQUISITION OF SUBSIDIARIES

On 28 April 2016 (the acquisition date) the Group acquired 100 per cent of the share capital of E.ON E&P UK Ltd ("EPUK"), a wholly owned subsidiary of E.ON SE, a German listed utility and its subsidiaries. The acquisition of EPUK brings additional high quality assets to Premier's UK North Sea business, the opportunity for cost and operating synergies in the North Sea, more balanced production portfolio and adds significant immediate production and cash flow.

The Group reached agreement on the acquisition on 13 January 2016 and the Class I Circular was approved by Premier shareholders on 25 April 2016. Premier paid total cash consideration of US$135.0 million.

The acquisition has been accounted for as a business combination. The fair value assessment of the EPUK identifiable assets and liabilities acquired have been reviewed in accordance with the provisions of IFRS3 – Business Combinations. The fair values are provisional and will be finalised in our full year 2016 financial statements.

The fair values of the oil and gas properties and intangible assets acquired have been determined using valuation techniques based on discounted cash flows using forward curve commodity prices, a discount rate based on market observable data and cost and production profiles consistent with the 2P reserves acquired with each asset. The financial instruments acquired have been valued using our forward curve oil and gas price assumptions at the date of the acquisition. The decommissioning provisions recognised have been created based on Premier's internal estimates.

The fair value of the identifiable assets and liabilities of EPUK as at the date of acquisition were:

	Fair value as at 28 April 2016 US$ Million
Assets	
Intangible exploration and evaluation assets	105.7
Oil and gas properties	600.0
Other fixed assets	7.1
Long term decommissioning funding asset	85.9
Inventory	2.7
Trade and other receivables	51.4
Derivative financial instruments	59.4
Cash and cash equivalents	24.9
	937.1
Liabilities	
Trade and other payables	(50.0)
Decommissioning obligations – current	(13.7)
Decommissioning obligations – non-current	(565.9)
Deferred tax liabilities	(65.6)
	(695.2)
Total identifiable net assets acquired at fair value	241.9
Total consideration	(135.0)
Excess of fair value over cost (negative goodwill)	106.9

12. ACQUISITION OF SUBSIDIARIES (continued)

The excess of fair value over cost has arisen primarily due to E.On's strategic decision to exit the UK and Norway E&P sectors, and Premier's willingness to acquire the entire UK business. The negative goodwill has been recognised immediately in the condensed consolidated income statement.

From the date of acquisition to 30 June 2016, EPUK contributed US$44.2 million to Group revenue and increased the Group's profit before tax by US$5.0 million. If the acquisition of EPUK had taken place at the beginning of the year, EPUK contribution to Group revenue for period ended 30 June 2016 would be US$162.7 million and would have reduced the Group's profit before tax by US$25.0 million.

Costs related to the acquisition represent transaction costs of US$5.6 million and the recognition of a settlement provision of US$16.0 million at 30 June 2016 in respect of employee costs.

13. PROVISIONS

The most significant component of the group's provisions balance relates to the decommissioning of the group's oil and gas interests, totalling US$1,474.2 million at 30 June 2016 (31 December 2015: US$1,062.6 million). The increase during the period was primarily due to the E.ON acquisition ($579.6 million – see note 12) and unwinding of the discount (US$28.7 million), partially offset by foreign exchange gains of US$154.7 million and other downward changes in estimates of US$42.3 million.

The large foreign exchange gain relates to the group's UK North Sea business unit where the underlying decommissioning costs will largely be incurred in GBP and has been principally caused by a significant reduction in the USD to GBP exchange rate at 30 June 2016. Included within the foreign exchange gain is an amount of $100.8 million which has been credited to the income statement, representing a reduction in the decommissioning cost estimate in excess of the carrying value recognised for the underlying assets, with the remaining US$53.9 million netted against the fixed asset additions figure in note 9.

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 2016 which comprises the condensed consolidated income statement, the condensed consolidated balance sheet, the condensed consolidated statement of changes in equity, the condensed consolidated statement of comprehensive income, the condensed consolidated cash flow statement and related notes 1 to 13. 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 Standard on Review Engagements (UK and Ireland) 2410 "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Auditing Practices Board. 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 Standard on Review Engagements (UK and Ireland) 2410 "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Auditing Practices Board for use in the United Kingdom. A review of interim financial information consists of making 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 2016 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 Conduct Authority.

Emphasis of matter - going concern

In forming our conclusion on our review of the condensed financial statements, we have considered the adequacy of the disclosure made in note 1 of the condensed financial statements concerning the group's ability to continue as a going concern. As disclosed in note 1, the group's projections currently indicate that a breach of one of the financial covenants within the group's borrowing facilities is likely to arise in respect of the next covenant testing period for the 12 months ending 31 August 2016. Should a covenant breach occur, then the group's debt holders on all of the group's facilities will have the right to request repayment of the outstanding debt and to cancel the relevant facilities.

In order to address the risk of a covenant breach, discussions are ongoing with Premier's lending group in order to continue deferring the testing date for the financial covenants whilst modified terms are agreed. Management expects that the modified terms will include amendments of the financial covenants such that there is a reasonable expectation that the group will remain in compliance with the amended loan facility terms for the foreseeable future.

Whilst we have concluded that the directors' use of the going concern basis of accounting in the preparation of the condensed financial statements is appropriate, these conditions, along with the other matters explained in note 1, indicate the existence of a material uncertainty which may give rise to significant doubt over the group's ability to continue as a going concern. The condensed financial statements do not include the adjustments that would result if the group was unable to continue as a going concern. Our review conclusion is not modified in respect of this matter.

Deloitte LLP
Chartered Accountants and Statutory Auditor
London, UK
17 August 2016

PremierOil

Half-Yearly Results for the six months to 30 June 2016

WORKING INTEREST PRODUCTION BY REGION (unaudited)

	Six months to 30 June 2016 kboepd	Six months to 30 June 2015 kboepd	Year to 31 December 2015 kboepd
UK:			
Balmoral area*	**1.7**	3.4	3.2
Huntington**	**8.8**	6.2	6.2
Wytch Farm	**5.1**	5.4	5.2
Kyle	**1.8**	-	1.9
Babbage	**1.2**	-	-
Elgin Franklin	**1.7**	-	-
Other UK	**1.9**	1.9	0.1
	22.2	16.9	16.7
Indonesia:			
Natuna Sea Block A	**12.5**	11.4	12.3
Kakap	**1.3**	1.8	1.6
	13.8	13.2	13.9
Vietnam:			
Chim Sáo	**16.7**	19.6	16.9
	16.7	19.6	16.9
Pakistan:			
Bhit/Badhra	**2.6**	3.3	3.2
Kadanwari	**1.1**	2.0	1.7
Qadirpur	**2.5**	2.8	2.7
Zamzama	**1.7**	2.2	1.9
Mauritania:			
Chinguetti	**0.4**	0.4	0.4
	8.3	10.7	10.1
TOTAL	**61.0**	60.4	57.6

* Includes Balmoral, Brenda, Nicol and Stirling fields.

** Huntington at 100% working interest since completion of the E.ON acquisition