H1 2018 Financial results

NEPTUNE ENERGY GROUP

NEPTUNE ENERGY

Report for Neptune Energy Group Midco Limited

About Neptune Energy Group

Neptune is an independent global E&P company. Having completed the acquisition of the exploration and production business of the ENGIE group ('EPI') in February 2018, Neptune is now active across the North Sea, North Africa and Asia Pacific. The Company's parent company, Neptune Energy Group Limited, is backed by CIC and funds advised by The Carlyle Group and CVC Capital Partners.

Further background information is available on the corporate website www.neptuneenergy.com

General

Except as the context otherwise indicates, "Neptune" or "Neptune Energy", "Group", "we," "us," and "our," refers to the group of companies comprising Neptune Energy Group Midco Limited (the Company) and its consolidated subsidiaries and equity accounted investments. "EPI" refers to the business of ENGIE E&P International S.A. (now renamed Neptune Energy International S.A.) and its direct or indirect subsidiaries.

This report includes the results of the acquired EPI business consolidated since 15 February 2018, which is the acquisition date as that is when Neptune acquired control over EPI. Equivalent data for Neptune for the corresponding reporting period ended 30 June 2017, starting when the Company was incorporated on 22 March 2017, are generally not informative, as the Company had minimal activity at the time, principally comprising only minor administration expenses. Therefore, in respect of certain measures, including production, EBITDAX and capital expenditure, we have provided additional approximate pro forma information relating to the acquired EPI business, to enable a comparison of the results for the full six months ended 30 June 2018 (including the period prior to our acquisition on 15 February) with those for the six months ended 30 June 2017.

In this report, unless otherwise indicated, our production, reserves and resources figures are presented on a basis including our ownership share of volumes of companies that we account for under the equity accounting method, in particular, for the interest held in the Touat project in Algeria through a joint venture company. Production for interests held under production sharing contracts is reported on an entitlements basis.

The discussion in this report includes forward looking statements which, although based on assumptions that we consider reasonable, are subject to risks and uncertainties which could cause actual events or conditions to materially differ from those expressed or implied by the forward looking statements. While these forward-looking statements are based on our internal expectations, estimates, projections, assumptions and beliefs as at the date of such statements or information, including, among other things, assumptions with respect to production, future capital expenditures and cash flow, we caution you that the assumptions used in the preparation of such information may prove to be incorrect and no assurance can be given that our expectations, or the assumptions underlying these expectations, will prove to be correct. Any forward-looking statements that we make in this report speak only as of the date of such statement or the date of this report.

This report contains non-GAAP and non-IFRS measures and ratios that are not required by, or presented in accordance with, any generally accepted accounting principles ("GAAP") or IFRS. These non-IFRS and non-GAAP measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS or GAAP. Non-IFRS and non-GAAP measures and ratios are not measurements of our performance or liquidity under IFRS or GAAP and should not be considered as alternatives to operating profit or profit from continuing operations or any other performance measures derived in accordance with IFRS or GAAP or as alternatives to cash flow from operating, investing or financing activities.

Highlights

Production

	Neptune Energy (note a)	Information in relation to EPI	
	June 2018 (period 15 February to 30 June)	6 Months to June 2018 (note c)	6 Months to June 2017
Total production (mmboe)	**22.5**	**30.1**	**27.7**
Daily average production (note b)			
Dry gas production (kboepd)	**87.4**	**86.8**	**91.6**
Gas production for sale as LNG (kboepd)	**33.5**	**33.5**	**12.2**
Liquid production (kbpd)	**44.7**	**45.8**	**49.3**
Total production (kboepd)	**165.6**	**166.1**	**153.1**

a) Neptune owned no producing assets in 2017 and hence production for 2017 was nil.
b) Production for this period for Neptune relates to the post acquisition period only, from 15 February 2018 to 30 June 2018. Average daily production is therefore calculated over 136 days, in order to provide data comparable with other periods.
c) Production for the six months to 30 June 2018 for EPI, as above, is analysed by quarter in the following table:

	Q2 2018	Q1 2018
Total Gas production (kboepd)	**89.6**	**84.0**
Total Gas production for sale as LNG (kboepd)	**33.7**	**33.4**
Total Liquid production (kbpd)	**44.4**	**47 .0**
Total production (kboepd)	**167.6**	**164.4**

Summary of financial results

	Period to 30 June 2018 (note a) $ millions
Revenues	1,033.3
EBITDAX (note b)	766.9
Operating profit (note c)	464.4
Profit before tax	340.0
Net Income	70.4
Net income before acquisition-related expenses (note d)	133.8
Cash flow from operations, after tax before acquisition related expenses (note d)	506.6
Net debt (book value)	973.6

a) Results for this period consolidate the acquired EPI business for the post acquisition period, from 15 February 2018 to 30 June 2018
b) EBITDAX comprises net income for the period before income tax expense, financial expenses, financial income, non-recurring acquisition-related expenses, mark-to-market adjustments on commodity contracts exploration expense and depreciation and amortisation,
c) Operating profit comprises current operating income after share in net income of entities accounted for using the equity method, and is stated before tax, finance costs, mark to-market on commodity contracts and non-recurring items.
d) Adjustment for acquisition-related expenses and taxes of $63.4 million incurred in connection with the EPI acquisition.
e) The Group's result for the period ended 30 June 2017 was a loss before and after tax of $0.4 million due to administrative expenses.

	Pro forma information relating to EPI business	
	6 Months ended June 2018	6 Months ended June 2017
	$ millions	$millions
EBITDAX	**939**	709
Cash capital expenditure (note f)	**162**	410

f) Includes expenditure of $33 million for period to 30 June 2018 and $48 million for period to 30 June 2017 in respect of the Touat project, held by a joint venture company which Neptune accounts for under the equity method.

Summary

Neptune Energy Group is pleased to present the Company's first quarterly report to new investors who participated in our inaugural bond issue in May 2018.

The Group completed the acquisition of the worldwide oil and gas exploration and production business of ENGIE on 15 February 2018, through the purchase of 100% of the share capital of ENGIE E&P International S.A. ('EPI'). This report therefore includes the results of the acquired EPI business consolidated for four and a half months from 15 February 2018.

The acquisition of EPI provides Neptune with a platform for achieving our goal of building a leading international, independent exploration and production group with a diversified asset base, across NW Europe, SE Asia and North Africa; as well as capabilities across the asset life cycle from exploration, through development and production; a reserves base of 542 mmboe[1]; and 1,800 employees.

Since completing the acquisition of EPI, key achievements have included:

- An improvement of the main HSSE metrics across the entire organisation highlighting an increased focus on this key element;
- A strong production performance of the acquired business, with average production of 165.6 kboepd in the period from acquisition to 30 June 2018;
- Significant progress in the integration of the acquired group of companies, including strengthening of the management team through the recruitment of several key managers to lead our operations, technical, projects and business development functions;
- Four exploration and appraisal wells drilled so far in 2018; including a successful appraisal of the Sigrun discovery in Norway and two wells in the Netherlands which will be brought into production by the end of 2018;
- The securing of long-term issuer credit ratings of BB- and Ba3 and successful $550 million bond issue;
- Early progress in further strengthening of our core businesses through agreements reached for two further acquisitions: the acquisition of VNG Norge AS, adding a portfolio which is strongly complementary to our existing Norwegian business, that will provide significant additional production from 2021; and the purchase of two UK central North Sea growth assets from Apache Corporation.

Highlights of our financial results for period to 30 June 2018, reflecting EPI being consolidated for four and a half months from 15 February 2018, include:

- A realised oil price of $69.9 per barrel and dry gas sales price of $7.6 per mcf, before hedging;
- Operating cash flow (post tax) before non-recurring acquisition-related expenses of $598.4 million;
- Net income before non-recurring acquisition-related expenses of $133.8 million (reported net income after all expenses of $70.4 million);
- Net cash inflow before EPI acquisition cost and related expenses of $487.4 million.
- Net debt at 30 June 2018 of $973.6 million; net debt to 12 month pro forma EBITDAX of 0.64 times and leverage (net debt to total capital[2]) of 34%;
- Cash flow strength and the bond issue result in total headroom, including undrawn debt facilities, of $1.58 billion at 30 June 2018.

Since the closing in February, we have identified additional opportunities within our acquired portfolio, which continues to impress in respect of for the quality of key assets. A combination of strong production performance and financial results leaves us well-placed to continue building the business and to take advantage of ongoing re-positioning within the E&P sector.

1 Proved and probable reserves at 31 December 2017
2 Interest bearing debt, net of cash, to aggregate of net debt plus equity.

Operating review

Health, safety, security and environment

Heath, safety, security and environmental (HSSE) performance is always of paramount importance in our activities, and underpins our "licence to operate". Our goal is to strive for continuous improvement and industry-leading standards in HSSE performance.

Following the closing of the EPI acquisition in February 2018, we launched several initiatives aimed at a structural improvement of HSSE results. The main initiative is the Safety Cultural Project that serves to reiterate the safety basics and firmly establishes HSSE elements as key objectives for our leaders. Others are the introduction of a common incident management system and the global commemoration of the Piper Alpha disaster, which happened 30 years ago.

We monitor HSSE performance using various metrics indicating the number of events in different categories, relative to the number of hours worked, on a 12 month rolling timescale. Since closing, the HSSE results of the business have gradually improved and are now within the set targets for all areas. New targets are being introduced to drive continuous improvement.

At our Touat project in Algeria, construction activity continued at a high level, with an average of 1 million working hours per month over the 12 months ended 30 June 2018. We continue efforts to drive HSSE performance on the site, including measures such as increased auditing frequency, additional HSSE resources and continuous coaching and supervising of construction personnel. HSSE results at Touat have improved and are within target levels, but require constant vigilance.

Operations

Neptune produced 22.5 mmboe in the period ended 30 June 2018 (2017: nil) or 165.6 kboepd, reflecting the results from EPI for four and a half months from the date of acquisition of 15 February 2018. On a pro forma basis, production would have been 30.1 mmboe, or 166.1 kboepd, had EPI been consolidated from 1 January 2018 (compared with EPI's performance of 27.7 mmboe, or 153.1 kboepd for the equivalent period in 2017). The increase in EPI's production compared with the first six months of 2017 was principally due to the Jangkrik field in Indonesia commencing production on 15 May 2017, as well as higher production from the UK Cygnus gas field. These increases more than offset some natural decline in other regions.

On a quarterly basis, Neptune produced 161.4 kboepd in the period 15 February to 31 March, 2018 and 167.6 kboepd in the quarter ended 30 June 2018. EPI's production for the full first quarter 2018 was 164.4 kboepd. The increase in second quarter production compared with first quarter production was principally due to production outages in early March at Cygnus, Gjøa and in the Dutch sector which resulted from extremely low prevailing temperatures.

On a regional basis, production changes compared with the same period last year, using pro forma data for the full six month period to 30 June 2018 compared with EPI historical production for the same period of 2017, were principally as described below:

In Norway, production was 2% lower for the six months ended 30 June 2018, as a result of declining rates as fields come off plateau, in particular for liquids, at Gjøa and Gudrun. Snohvit production was higher due to increased capacity and a turnaround in 2017.

In the UK, our Cygnus field, which came onstream at the end of 2016 and was originally designed to produce with a maximum capacity of 250 mmcfpd, has been producing at up to 300 mmcfpd (gross) at times, following debottlenecking during 2017, with a plan to increase capacity further to 320 mmcfpd. Well performance is continuing to exceed original expectations. The average gas production for the six months ended 30 June 2018 was 274 mmcfpd with 476 bpd of condensate (both gross).

In the Netherlands, production was 11% lower during the six months ended 30 June 2018 compared with the same period of 2017, due to expected general decline in field production. The new L5a-D Sierra development came onstream in February, however, the single well productivity is lower than anticipated.

In Germany, production was in line with 2017 levels.

In our international segment, which includes production from Indonesia and Egypt, we saw increasing production volumes from the Jangkrik field, which averaged approximately 653 mmcf per day gross production, well above the original estimates for the floating production unit. We shared in the sale of 17 LNG cargoes in the second quarter and in a total of 37 cargoes in the six months to 30 June 2018, all sold to the buyers under our long term contracts.

In Egypt, production was in line with 2017 levels.

Summary of production by area

	Neptune Energy	Information in relation to EPI	
	June 2018 (note 1)	6 Months ended June 2018	6 Months ended 30 June 2017
Gas production (kboepd)			
Norway	29.8	30.1	31.8
UK	20.3	19.8	18.5
The Netherlands	27.3	26.9	30.3
Germany	7.2	7.2	7.5
Outside Europe (note 2)	2.8	2.8	3.5
Total gas production	**87.4**	**86.8**	**91.6**
Gas production for sale as LNG (kboepd)			
Norway	13.6	13.8	10.1
Outside Europe (note 2)	19.9	19.7	2.1
Total Gas production for sale as LNG (kboepd)	**33.5**	**33.5**	**12.2**
Liquid production (kbpd) (note 3)			
Norway	33.8	34.8	38.3
UK	0.3	0.3	0.3
The Netherlands	2.8	2.9	3.3
Germany	5.8	5.8	5.8
Outside Europe (note 2)	2.0	2.0	1.6
Total Liquid production (kbpd)	**44.7**	**45.8**	**49.3**
Total production (kboepd)			
Norway	77.2	78.7	80.2
UK	20.6	20.1	18.8
The Netherlands	30.1	29.8	33.6
Germany	13.0	13.0	13.3
Outside Europe (note 2)	24.7	24.5	7.2
Total production (kboepd)	**165.6**	**166.1**	**153.1**

1) Daily average production over the period 15 February to 30 June.
2) Outside Europe includes assets located in North Africa and Asia Pacific.
3) Liquid includes oil and condensate and other natural gas liquids.

Projects

Our principal operated development projects underway in 2018 are the Touat gas development onshore in Algeria; the P1 and Cara oil and gas subsea tie-backs to Gjøa in Norway and the Römerberg onshore oil field in Germany. In the Netherlands, our operated L5a-D Sierra gas development came onstream on 16 February 2018, with a second development well planned for 2019. Additional development projects include the Njord field re-development, Bauge and Askeladd field developments, and additional Fram development wells, all of which are in Norway. We are also providing the host facilities for the Nova development at our Gjøa facility in Norway and for the planned Pegasus subsea tie-back to the Cygnus platform in the UK. At Cygnus we also drilled and completed development well B1z in the second quarter 2018.

Touat (Neptune 35% interest held through Touat joint venture; Neptune and Sonatrach co-operators): At our Touat gas project, construction of the central processing facility and pipelines has seen some delay but with all phase 1 wells having been drilled the overall project is now 90% complete. First gas is expected in the first half of 2019.

P1 and Cara (Operator; Neptune 30% in both licences): These potential projects have now been combined in their pre-sanction phase. The tie back to existing Gjøa subsea infrastructure is 5km for the PL636 Cara, and 2km for the PL153 P1, respectively. Sanction of both projects is planned for early 2019 with an anticipated first hydrocarbon date by the end of 2020.

Römerberg (Operator; Neptune 50%): At Römerberg in southern Germany, we started well site upgrades, including enhancement of electrical supply, and preparation continued for the next drilling campaign, comprising the Römerberg 8 and Römerberg 6 wells. Spud of Römerberg 8 is planned for end of September 2018.

Njord re-development (Neptune 20%): The project remains on schedule and on budget, with production re-start anticipated by the end of 2020. The Njord A production unit has been moved to Stord for installation of the new pontoons to enhance stability, with the heavy lift campaign planned to start in the third quarter of 2018. The Njord B storage tanker has been moved into dry dock for inspection and refit.

Askeladd development (Neptune 12%): We sanctioned this project in March 2018 as a subsea tie-back with three 3 wells as a plateau extender of the Snøhvit LNG project. First hydrocarbons are expected by the end of 2020.

Bauge development (Neptune 10%): This is a three well subsea tie-back to be linked to the Njord facility with first hydrocarbons expected by end 2020.

Fram 3 Well development (Neptune 15%): We also sanctioned three new development wells at Fram, which will re-use existing subsea infrastructure and tie-back to the Troll C semi-submersible facility, with first hydrocarbons expected in the fourth quarter of 2019.

We are also operating the host platform facilities project at the Gjøa platform in Norway for the Nova development, which achieved PDO approval earlier this year. The Nova production will benefit the Gjøa hub through a tariff income stream and synergies with the P1 and Cara projects.

In Australia, we are evaluating potential options for commercial development of the substantial Petrel gas discovery in the Bonaparte basin.

Decommissioning: In the Netherlands we completed well plugging and abandonment operations at our operated L10 C/D/G platforms and heavy-lift and facilities decommissioning contracts are in place to remove the platforms in a flexible removable window from July 2018 to November 2019.

Exploration

In the period to 30 June 2018, our cash spend on exploration and appraisal (E&A) was $33.2 million, of which $10.2 million was capital expenditure. Including the period 1 January to the acquisition date of 15 February 2018, exploration expenditure by the EPI business for the six months ended 30 June 2018 was $36.5 million, of which $13 million was capital expenditure. A significant proportion of the expense ($10.6 million) was incurred on acquisition of new seismic data in areas where we have recently been awarded new licences and to refresh and revitalise our data library in support of new venture activity.

Three exploration and appraisal wells were drilled in the Netherlands:

- prior to the acquisition date, the L10-39 Ziegler exploration well (Operator; Neptune 38.6%) discovered gas, though the connected volume is at the lower end of pre-drill expectations, at between 2.2-4.0 bcf (gross) preliminary in-place estimate. Production start-up is expected during Q4 2018, across the L10-A platform;
- the D12-7 Andalusite exploration well (Neptune 10.5%) was also a gas discovery with a preliminary estimate of in-place volume of 32 bcf (gross). The well was started up in April 2018, showing excellent productivity, at a plateau of 18 mmscf per day (gross); and
- the F17-CK3 (Neptune 20%) exploration well was disappointing.

In Norway, an appraisal well on the PL025 Sigrun (Neptune 25%) discovery close to our Gudrun field was spudded in June and well operations were completed in August 2018. The operator, Equinor, has since announced that preliminary estimates of the total recoverable volumes of the Sigrun structure are between 7 and 12.6 mmboe (recoverable, gross). The partnership will now assess the potential of the discovery with regard to a development over the Gudrun field.

We were also successful in acquiring new acreage in the UK and Norwegian sectors of the North Sea. In January, the Norwegian Ministry announced the results of the APA 2017 licensing round in which we were awarded four licences (PL929 and PL153C close to Gjøa, PL09I in the Fram area and PL938 in the Njord area).

In June 2018, the OGA announced the preliminary awards of the 30th UK licence round and Neptune was offered two licences in the vicinity of Cygnus field; as operator of blocks 43/10,43/15,44/7,44/8b,44/11d,44/12d,44/12e (proposed P2429 licence) and partner with Spirit Energy as operator in block 43/14a (proposed P2430 licence). Formal awards are expected to happen in early October 2018.

During the second half of 2018, we expect to spud three exploration wells. FB9, north of Cygnus in the UK, is expected to be spudded in September and aims at adding production in the medium term to the existing Cygnus infrastructure. In Germany, the onshore Schwegenheim exploration well is expected to be started on the Römerberg licence. Finally, a third well, the Bagha C-88 exploration well, is expected to be drilled in October by Shell on the Alam El Shawish licence in Egypt.

Business development

We have made early progress on our goal to build-out the business acquired from ENGIE by signing two further sale and purchase agreements. On 28 June 2018, we agreed to acquire VNG Norge AS ('VNG Norge') from its parent, VNG AG, the German natural gas wholesaler and energy service provider, with completion, subject to customary conditions including various regulatory approvals, expected to occur later in 2018.

We believe the VNG Norge portfolio provides a high-quality bolt-on acquisition in one of our core business areas, with a complementary set of assets in the Greater Njord area including the operated Fenja oil development and the North Sea / Utsira High area, with the addition of an interest in the Ivar Aasen asset. VNG Norge has built a portfolio of production, development and exploration assets on the Norwegian Continental Shelf comprised of 42 licences, five producing fields and three development projects including, in Norway: Fenja (30% and operator), Bauge (2.5%); and in Denmark: the potential Solsort development (13.8%). Fenja is a sub-sea development which will be produced as a tie-back to the Njord production hub and is scheduled to come onstream in 2021. Net production for VNG Norge for 2017 was approximately 4,000 boepd, with an increase in production targeted by 2022 as new capacity comes onstream. Net reserves and resources for the acquired assets as at 31 December 2017 were over 50 mmboe.

We also entered into a sale and purchase agreement in August 2018 to acquire certain development and exploration assets in the UK Central North Sea from Apache Corporation. Under the sale and purchase agreement Neptune will acquire Apache's 35% working interest in the Seagull development and a 50% working interest in the Isabella prospect. The transaction is subject to customary approvals, with completion expected later this year. The Seagull development will consist of a multi-well subsea tieback to existing nearby facilities, planned to commence development during 2019, with first production expected around end 2021. The Isabella prospect, though high risk, is considered one of the larger undrilled exploration opportunities in the Central North Sea.

Management organisation

We have also made good progress with building the Neptune management team through a combination of new recruits and the team which joined with EPI. External additions include Vice Presidents to head each of: Operations, Exploration, Projects, Reservoir Engineering, HR and Business Development, and new managing directors for the UK and German businesses. We are pleased to have attracted candidates with very strong credentials and a shared enthusiasm to execute the vision for Neptune. We continue to implement new business processes in the group, more suitable for a standalone E&P company, including: a revised management organisation structure with clear accountabilities; regular performance and outlook reviews; a sharpened investment approval process; and new corporate financial management and treasury capabilities.

Financial review

We completed the acquisition of 100% of the share capital of ENGIE E&P International S.A. (‘EPI’) on 15 February, 2018. EPI was the holding company for the worldwide exploration and production business of ENGIE, a large and diversified French energy, water and utility group. We acquired 70% of the shares of EPI from ENGIE, for cash, as well as the 30% owned by China Investment Corporation (CIC). See Note 4 to the condensed financial statements regarding details of the acquisition and funding. CIC consequently became a shareholder in the company’s parent, Neptune Energy Group Limited. At the same date, we arranged the repayment of certain loans provided to EPI by the ENGIE group.

This report therefore includes the results of the acquired EPI business consolidated since 15 February 2018, which is the acquisition date as that is when Neptune acquired control over EPI. As the effective date, or “locked-box” date, of the EPI acquisition was 1 January 2016, Neptune has received the economic benefits of cash flows relating to the EPI business since that date, with cash flow for the interim period to closing of the acquisition effectively forming an adjustment to the acquisition price for accounting purposes. Comparative data for Neptune for the corresponding reporting period ended 30 June 2017, starting when the Company was incorporated on 22 March 2017, is not informative as Neptune had minimal activity for the period to 30 June 2017, principally comprising administration expenses in preparation for the EPI acquisition. Therefore, in respect of certain measures, including production, EBITDAX and capital expenditure, we have provided additional approximate pro forma information relating to the acquired EPI business, to enable a comparison of the results for the six months ended 30 June 2018 (including the period prior to the EPI acquisition on 15 February) with those for the six months ended 30 June 2017.

In accordance with IFRS standards for accounting for business combinations, we have recorded the acquired assets and liabilities of EPI as at the acquisition date at their fair values, or otherwise as required by IFRS. Oil and gas assets acquired were recorded at the net present value of expected future cash flows, post-tax, based on independent reserves reports, management plans and expectations and using projections of oil and gas prices based on a combination of forward prices and long term company assumptions. Liabilities were established in respect of decommissioning costs, post-employment benefits and deferred taxes. The assigned fair values are provisional and are subject to adjustment based on availability of additional information. The business combination accounting resulted in the recognition of $774.5 million of goodwill (revalued to $744.8 million as at 30 June 2018); this arises largely as a result of the requirement to recognise deferred tax provisions in respect of differences between the fair value of oil and gas assets recorded in PP&E and their tax base available as future tax deductions.

Results of operations

	Neptune Energy	
	Period to June 2018 (note a) US$ millions	6 Months ended 30 June 2017
Sales	1,033.3	–
EBITDAX (note b)	766.9	(0.4)
Operating profit (note c)	464.5	(0.4)
Profit before tax	340.0	(0.4)
Net Income	70.4	(0.4)
Net income before acquisition-related expenses (note d)	133.8	(0.4)

a) Results for this period consolidate the acquired EPI business for the post acquisition period only, from 15 February 2018 to 30 June 2018.
b) EBITDAX comprises net income for the period before income tax expense, financial expenses, financial income, non-recurring acquisition-related expenses, mark-to-market adjustments on commodity contracts, exploration expense and depreciation and amortisation.
c) Operating profit comprises current operating income after share in net income of entities accounted for using the equity method, and is stated before tax, finance costs, mark- to-market on commodity contracts and non-recurring items.
d) Adjusted for acquisition-related expenses and taxes of $63.4 million incurred in connection with the EPI acquisition.

Total sales for the period ended 30 June 2018 were $1,033.3 million, reflecting total production of 22.5 mmboe and realised prices, before and after hedging, as shown in the table below. Our results benefited from strengthening markets for both oil and gas. The Brent crude price averaged $70.58 per barrel for the six months to 30 June 2018 and our average realised oil price was $69.9 per barrel for the period. The LNG sales prices are linked to a combination of movements in oil and gas market prices, depending on the contract.

Realised prices data:

	Neptune Energy	Information in relation to EPI	
	15 February to June 2018	6 Months ended 30 June 2018	6 Months ended 30 June 2017
Excluding impact of hedging:			
Average realised gas price ($/mcf)	**7.6**	**7.5**	**5.6**
Average realised LNG price ($/mcf)	**7.3**	**7.1**	**5.2**
Average realised oil price ($ /bbl)	**69.9**	**69.4**	**51.3**
Average realised price, other liquids ($ /bbl) (note 1)	**43.7**	**43.9**	**45.4**
Including impact of hedging:			
Average realised gas price ($/mcf)	**6.5**	**6.5**	**5.7**
Average realised LNG price ($/mcf)	**7.3**	**7.1**	**5.2**
Average realised oil price ($ /bbl)	**67.2**	**66.6**	**47.5**
Average realised price, other liquids ($ /bbl) (note 1)	**43.7**	**43.9**	**45.4**

1) Other liquids includes condensate and other natural gas liquids

Operating costs were $245.7 million for the period to 30 June 2018 and our average operating cost per boe produced was $10.0 / boe. This compares with average operating cost per boe of $10.5/boe for EPI for the year 2017. The lower per boe cost partly reflects reduced expense for LPG purchases at Jangkrik used for blending to meet LNG export specifications. Operating costs for the purpose of per boe expense are adjusted by $21.0 million for the period ended 30 June 2018 to exclude changes in the value of under-lifted entitlement to production and to net-off income from tariffs and services which serve to recover costs.

Depreciation and amortisation expense of $276.7 million reflects an uplift in asset carrying values as a result of fair valuation of assets required for purchase accounting for the EPI business combination. The charge represents $12.30/boe produced. No impairment expense was required in the period.

Exploration expense of $23.0 million reflects a higher-than-normal level of expense for seismic data acquisition as the group seeks to add new licences and additional data to support upcoming exploration programmes and as part of commercial arrangements to ensure ongoing access to data historically acquired by EPI, following its change of control.

General and administration expense of $31.1 million includes approximately $7 million non-recurring expenses related to recruitment and establishing Neptune as a new E&P company.

Share in net income of entities accounted for under the equity method principally represents tariff income of one of our Dutch pipeline interests.

The Group's operating profit for period to 30 June 2018, reflecting the EPI contribution consolidated for four and a half months from 15 February 2018, was $464.4 million. Group EBITDAX for the period to 30 June 2018 was $766.9 million, and for the full six months to 30 June 2018 pro forma EBITDAX including the EPI business from 1 January 2018 to the acquisition date was $938.8 million, compared with $709 million for the same period of 2017. The increase in EPI EBITDAX principally reflects higher realised prices and higher production in 2018.

The loss on mark to market of derivatives of $20.1 million relates to economic hedging transactions that do not qualify for hedge accounting treatment, and reflects the mark-to-market adjustment, net of previously recognised value changes recycled to sales in the period of the related physical production. This unrealised loss reflects the rising trend of commodity prices in the period. Non-recurring acquisition-related expenses were $63.4 million, reflecting the requirement to charge business combination transaction expenses and related costs (such as taxes levied in respect of share transfers and change of control) to net income.

Financial expenses were $48.8 million for the period, and include interest costs and unwinding of discounting of provisions.

The tax charge for the period represents 79% of pre-tax income, which is unusually high as the pre-tax result reflects acquisition expenses of $63.4 million on which no tax relief is presently assumed. Adjusting for this item, the effective tax rate was 67% of pre-tax income.

Net income for the period was $70.4 million on a reported basis, or $133.8 million excluding non-recurring acquisition-related expenses of the EPI acquisition.

Hedging

Group policy is to seek to reduce risk related to commodity price fluctuations by using hedging instruments to set a floor for the sales realisations for a proportion of forecast revenues on a rolling basis, with reducing levels of hedging for each of the next three years. The group actively manages this hedging programme using a mix of swaps, forwards and options, including as option collar structures.

At acquisition of EPI, we inherited a substantial hedge book which was novated from the ENGIE group to Neptune's bank group. As at the acquisition date, the net fair value (mark-to-market) of this hedge book was a net liability of $53.8 million, which is reflected in the acquisition balance sheet. The liability reflected generally rising commodity prices since the hedges were put in place in prior years.

We have continued to hedge a proportion of revenues for future periods since closing the EPI acquisition, mostly using option collars. As at 30 June 2018, the approximate share of tax-effected production hedged for future periods was as shown in the table below. Hedges for the remainder of 2018 predominantly comprise swap contracts, with weighted average prices of $53 /barrel for oil and $5.33 / mmbtu for gas. The majority of hedges for subsequent periods are in the form of option collars. For oil, put options provide floors for the hedged volumes at a weighted average of approximately $58 / barrel for 2019 and $53 / barrel for 2020, with upside capped at around $73 to $75 / barrel on the hedged volumes. For gas, put options provide weighted average floor prices for the hedged volumes at $5.9 / mmmbtu for 2019 and 2020, with average call strikes just above $7 / mmbtu.

Aggregate post-tax hedge ratio:

	2H2018	2019	2020	2021
Oil	26%	46%	8%	0%
Gas	73%	52%	23%	3%

1) Oil price hedges include hedges of realisations for gas production sold as LNG and priced in relation to oil prices.
2) Post tax hedge ratios adjust for different tax rates on physical sales and hedge gains and losses, which mean that effective post tax hedges can be achieved through hedging contracts for volumes which may be significantly less than anticipated sales.

The estimated net fair value (comprised of current and non-current assets and liabilities) on a mark-to-market basis of all our commodity derivative instruments at 30 June 2018, was a liability of $231 million, before tax, of which $133 million relates to contracts expiring in 2018.

Cash flow

Operating cash flow, after cash taxes, for the period to 30 June 2018 was $535.0 million. Adjusted to exclude expenses relating to business combinations, this would have been $598.4 million.

Cash taxes were $247.9 million and largely relate to Norwegian taxes. The effective rate of cash tax as a percentage of pre tax operating cash flow was 32%.

Capital expenditure

Cash capital expenditure for the period to 30 June 2018, before acquisitions, was $91.1 million, including $10.2 million of capitalised exploration expenditure. This excludes expenditure at the Touat project, where the joint venture is accounted for under the equity method of accounting as an associate. Our statement of cash flows reflects investment at Touat in terms of the cash injections made to fund the joint venture company, which were nil in the period as the JV had been well-funded ahead of completion of the EPI acquisition.

	Neptune Energy
In $ millions	Period to June 2018 (note a)
Investing cash flows:	
Development capex	80.9
Exploration capex	10.2
Acquisitions	3,205.2
Total cash capital expenditure	3,296.3

a) Results for this period relate to the post acquisition period only, from 15 February 2018 to 30 June 2018

Total exploration expenditure comprised the $10.2 million cash capex plus $23 million expensed in respect of G&G costs.

Development cash capex was $80.9 million. We have experienced some slippage and deferral of capex in 2018 compared with our plans and the original budgets prepared by EPI. This arises especially at the Touat project. We have also seen re-phasing of some activities within the Njord project and reduced spend in Germany.

On a pro forma basis, including capital expenditure prior to the EPI acquisition date, and including $33 million expenditure in respect of our 35% indirect share of the Touat project, capital expenditure by EPI for the six months ended 30 June 2018 was $162 million, compared with $410 million for the same period of 2017 on a comparable basis. The reduction in capex compared with the same period in 2017 principally reflects the completion of the Jangkrik project in mid 2017 and full completion of the Cygnus project including the Bravo production platform in August 2017.

We incurred $14.5 million on decommissioning expenditure in the period to 30 June 2018, principally at the L10 hub offshore the Netherlands. On a pro forma basis for the full six months to 30 June, decommissioning expenditure was $21 million.

Acquisitions

As noted above, on 28 June 2018 we signed a sale and purchase agreement to acquire 100% of the share capital of VNG Norge AS from its parent, VNG AG, with completion being subject to customary conditions including regulatory approvals. The business of VNG Norge comprises a mix of producing fields and development projects, including the Fenja development project, which will produce via our existing Njord hub. We expect completion of the acquisition to occur later in 2018. The base consideration for the acquisition is $352 million, based on an effective date of 1 January 2018, which includes $22 million for acquired cash and working capital, with up to $50 million of contingent consideration by 2021 based on milestones linked to development of contingent resources. The consideration includes value in respect of significant tax allowances, of which we expect that, at present commodity prices, some $200 million will be realised in 2019, given the synergies between the tax position of the VNG and existing Neptune Norwegian business.

On 1 August 2018 we entered into a sale and purchase agreement to acquire certain development and exploration assets in the UK Central North Sea from a subsidiary of Apache Corporation (“Apache”). Neptune will acquire Apache’s 35% working interest in the Seagull development and a 50% working interest in the Isabella exploration prospect. The proposed transaction is subject to regulatory approvals, with completion expected later this year. Consideration for the acquisition is $70 million, based on an effective date of 1 January 2018, and subject to customary adjustments.

Financing and liquidity

In connection with the EPI acquisition, in February 2018 we issued $1.98 billion of equity. This includes shares issued in consideration for a promissory note used to acquire the 30% stake in EPI previously owned by CIC. We also received funding under three debt facilities used as part of the acquisition:

- We borrowed $1,010 million and €300 million under our $2 billion borrowing base bank credit facility. We have since repaid $660 million and €100 million, including out of the proceeds of the bond issue noted below;
- We assumed $187.2 million of debt under the Touat project finance facility provided by ENGIE. This facility is available to be used to finance half of the capital expenditure required for our indirect 35% interest in the Touat gas development and is repayable only from the net revenues of the Touat project in almost all circumstances;
- We borrowed $100 million from our parent company as a subordinated loan, due 2024, representing the on-lending of a vendor loan facility provided to the parent company by ENGIE.

We repaid a shareholder loan of £3.3 million provided by the parent company to fund pre-acquisition expenses.

On 12 May 2018 we issued $550 million of Senior Notes due 2025, paying a 6.625% coupon, to re-finance part of the acquisition bank debt, increase average maturity of debt and increase the Group’s liquidity and financial flexibility. The bond was upsized from an initial $500 million following strong investor demand and placed with a broad range of investors in the UK, US, Europe and internationally. We secured long-term issuer credit ratings in preparation for the bond issue of BB- from Standard & Poor’s and Ba3 from Moody’s.

At 30 June 2018 we had cash balances totalling $374.9 million and available and undrawn headroom under the borrowing base facility of $1,207 million. The availability of the bank facility depends on a borrowing base calculated by reference to the net present value of future cash flows of the secured assets. The re-calculation of the borrowing base to be effective from 1 October 2018 is underway, and is expected to result in an increase in availability.

At 30 June 2018 we had £13 million of letters of credit outstanding, which were drawn down under an ancillary facility under the credit facility.

We have entered into $400 million of interest rate swaps to adjust our exposure to floating interest rates to fixed rates, maturing in 2021.

Financial condition

Adjusting for expenses related to the business combination, operating cash flows of $598.4 million more than covered investing cash flows before the cost of the EPI acquisition of $91.1 million plus net finance costs of $19.9 million, resulting in a free cash flow surplus of $487.4 million for the period to 30 June 2018. After the EPI acquisition and financing activities summarised above, we ended the period with gross interest-bearing debt of $1,348.5 million (book value) and net debt of $973.6 million. This represents a ratio of 0.65 times pro forma EBITDAX for the 12 months ended 30 June 2018. Leverage (net debt to total capital) was 34% as at 30 June 2018.

Outlook

The production outlook remains in line with previous guidance, with average daily production for the full year 2018 anticipated to show low single digit percentage growth over the 2017 full year production of the EPI business of 154.3 kboepd, after reflecting changes including planned maintenance shutdowns over the summer. On a full year basis for 2018, we expect to incur development capital expenditure, excluding the impact of acquisitions, but including our share of Touat project expenditure, of approximately $420 million and exploration expenditure of around $90 million. The acquisition of VNG Norge is expected to add approximately $430 million, including the purchase consideration and impact of 2018 cash flows, while the acquisition of the Seagull asset from Apache is expected to add approximately a further $75 million to full year capex, including expenditure to be incurred in 2018. Full year exploration expenditure is expected to be approximately $90 million. We anticipate that this level of total capex will be more than covered by full year post tax operating cash flow, based on current commodity prices.

Risks and Uncertainties

Investment in Neptune involves risks and uncertainties as described in the company's Offering Memorandum dated 1 May 2018. As an oil and gas exploration and production company, exploration results, reserve and resource estimates and estimates for capital and operating expenditures involve inherent uncertainties. A field's production performance may be uncertain over time. The Group is exposed to various forms of financial risks, including, but not limited to, fluctuation in oil and gas prices, currency exchange rates, interest rates and capital requirements. The Group is also exposed to uncertainties relating to political risks, the international capital markets and access to capital and this may influence the speed with which growth can be accomplished.

NEPTUNE ENERGY GROUP MIDCO LIMITED

UNAUDITED INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

For the six months ended 30 June 2018

Condensed Consolidated Statement of Profit and Loss

In millions of US$	Notes	Six months ended 30 June 2018	period from 22nd March to 30 June 2017
Revenues	3	1,033.3	–
Operating costs		(245.7)	–
Depreciation, amortisation and provisions		(276.7)	–
GROSS PROFIT		**510.9**	**–**
Exploration costs		(23.0)	–
General and administration expenses		(31.1)	(0.4)
Share in net income from joint ventures (equity method)		7.6	–
NET OPERATING PROFIT AFTER EQUITY ACCOUNTED INVESTMENTS	3	**464.4**	**(0.4)**
Mark-to-market on commodity contracts other than cash flow hedges	1	(20.1)	–
Restructuring costs		2.8	–
Business combination transaction costs		(63.4)	–
PROFIT BEFORE FINANCIAL ITEMS		**383.7**	**(0.4)**
Financial expenses		(48.8)	–
Financial income		5.1	–
PROFIT BEFORE TAX		**340.0**	**(0.4)**
Income tax expense	5	(269.6)	–
NET PROFIT		**70.4**	**(0.4)**

All profits and losses arise as a result of continuing operations.

Condensed Consolidated Statement of Other Comprehensive Income

In millions of US$	Notes	Six months ended 30 June 2018	period from 22nd March to 30 June 2017
Profit for the Period		70.4	(0.4)
Other comprehensive Income:			
Items that may be reclassified to the Profit and Loss		–	–
Hedge Adjustments Net of Tax (note 1)		(106.1)	–
Foreign Currency Translation		(41.2)	–
Other Comprehensive Income Net of Tax		**(147.3)**	**–**
Total Comprehensive Income for the period		**(76.9)**	**(0.4)**

1) Income tax related to hedge adjustments is US$69.2 million (2017 nil)

Condensed Consolidated Statement of Financial Position

In millions of US$	Notes	30 June 2018	31 December 2017
NON-CURRENT ASSETS			
Intangible assets	6	107.4	–
Goodwill		744.8	–
Property, plant and equipment	7	3,658.2	–
Derivative instruments	8	17.9	–
Investments in entities accounted for using the equity method		523.4	–
Other non-current assets		44.4	–
Deferred tax assets		346.1	–
TOTAL NON-CURRENT ASSETS		**5,442.2**	**–**
CURRENT ASSETS			
Derivative instruments	8	5.6	–
Trade and other receivables		501.3	–
Inventories		62.8	–
Cash and cash equivalents	9	374.9	0.4
Prepayments and other current assets		296.5	0.4
TOTAL CURRENT ASSETS		**1,241.1**	**0.8**
TOTAL ASSETS		**6,683.3**	**0.8**
Share capital	12	1,977.1	–
Hedging reserve		(106.1)	–
Foreign currency translation		(41.2)	–
Retained earnings (deficit)		66.6	(3.8)
TOTAL EQUITY		**1,896.4**	**(3.8)**
NON-CURRENT LIABILITIES			
Provisions	10	1,589.3	–
Long-term borrowings	8	1,348.5	–
Derivative instruments	8	68.5	–
Non-current tax payable		169.3	
Other non-current liabilities		35.1	–
Deferred tax liabilities		555.6	–
TOTAL NON-CURRENT LIABILITIES		**3,766.3**	**–**
CURRENT LIABILITIES			
Provisions	10	9.3	
Derivative instruments	8	191.4	–
Trade and other payables	8 & 11	351.0	4.6
Current tax payable		1.5	
Other current liabilities	8 & 11	467.4	–
TOTAL CURRENT LIABILITIES		**1,020.6**	**4.6**
TOTAL EQUITY AND LIABILITIES		**6,683.3**	**0.8**

Condensed Consolidated Statement of Equity

In millions of US$	Share Capital	Hedging reserve	Foreign currency translation	Retained Earnings	Total
As at 1 January 2018	–	–	–	(3.8)	(3.8)
Profit for the period	–	–	–	70.4	70.4
Other comprehensive income for the period	–	(106.1)	(41.2)	-	(147.3)
Total Comprehensive Income for the period	**–**	**(106.1)**	**(41.2)**	**70.4**	**(76.9)**
Transactions with Owners of the Company:					
Issue of ordinary shares related to business combinations	1,977.1	–	–	–	1,977.1
Total Contributions and Distributions	**1,977.1**	**(106.1)**	**(41.2)**	**70.4**	**1,900.2**
Balance 30 June 2018	**1,977.1**	**(106.1)**	**(41.2)**	**66.6**	**1,896.4**

Condensed Consolidated Statement of Equity

In millions of US$	Share Capital	Retained Earnings	Total
As at 22 March 2017 (incorporation)	**–**	**–**	**–**
Loss for the period	–	(0.4)	(0.4)
Total Comprehensive Income for the period	**–**	**(0.4)**	**(0.4)**
Transactions with Owners of the Company			
Issue of ordinary shares	–	–	–
Total Contributions and Distributions	**–**	**(0.4)**	**(0.4)**
Balance 30 June 2017	**–**	**(0.4)**	**(0.4)**

On incorporation 728 US$1 shares were allotted, called up and fully paid.

Consolidated Statement of Cash flows

In millions of US$	Six months ended 30 June 2018
Cash Flows from Operating Activities	
Profit before taxation	340.0
Adjustments to reconcile profit before tax to net cash flows:	
Depreciation, depletion and amortisation	276.7
Financial expenses	48.8
Financial income	(5.1)
Net income from Equity investments	(7.6)
Fair value movement on commodity based derivative instruments	7.4
Decommissioning expenditure	(14.5)
Working capital adjustments	137.2
Income tax paid	(247.9)
Net cash flows from operating activities	**535.0**
Cash Flows from Investing Activities	
Expenditure on exploration and evaluation assets	(10.2)
Expenditure on property, plant and equipment	(80.9)
Expenditure on business combination and acquisitions, net of cash acquired	(3,205.2)
Net cash flows from investing activities	**(3,296.3)**
Cash Flows from Financing Activities	
Proceeds from issue of shares	1,977.2
Proceeds from new borrowings	1,479.4
Issue of bond	550.0
Debt arrangement fees	(77.1)
Repayment from borrowings	(783.6)
Financial income received	5.1
Financial costs paid	(25.0)
Net cash flows from financing activities	**3,126.0**
Net increase cash held	364.7
Cash at 1 January 2018	0.4
Net foreign exchange differences	9.8
Cash at 30 June 2018	**374.9**

As at 30 June 2017 the Company was still in the process of opening a bank account, consequently, no cash flow is included in the 30 June 2017 comparative.

General information

Neptune Energy Group Midco Limited is a limited company, incorporated and domiciled in the United Kingdom. The registered office is located at Nova North, 11 Bressenden Place, London SW1E 5BY.

The interim condensed consolidated financial statements of Neptune Energy Group Midco Limited and its subsidiaries (collectively, the Group) for the six months ended 30 June 2018 were authorised for issue in accordance with a resolution of the Board on 5 September 2018.

The Group is principally engaged in oil and gas exploration and production.

The information for the period ended 31 December 2017 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 period ended 31 December 2017 were approved by the Board of Directors on 7 March 2018 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.

1. Basis of preparation and significant accounting policies

The interim condensed consolidated financial statements for the six months ended 30 June 2018 have been prepared in accordance with IAS 34 Interim Financial Reporting.

The interim condensed consolidated financial statements do not include all the information and disclosures required in the annual financial statements and should be read in conjunction with the Group's consolidated financial statements as at 31 December 2017. The preparation of financial statements in conformity with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise its judgement in the process of applying the Group's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, are disclosed below in note 1.3

The accounting policies adopted in the preparation of the interim consolidated financial statements are consistent with those followed in the preparation of the Group's annual consolidated financial statements for the period ending 31 December 2017 and are detailed below due to the implementation of new accounting policies related to businesses acquired during the period (see note 4) as well as the adoption of new standards effective as of 1 January 2018. The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective.

1.1 New standards, interpretations and amendments adopted by the Group

The Group has applied IFRS 15 *Revenue from Contracts with Customers* and IFRS 9 *Financial Instruments;* implementation of these standards does not have any significant impact on the Group's previously reported financial statements as the company neither reported any revenue nor held any financial instruments during 2017.

IFRS 9 replaces IAS 39 *Financial Instruments: Recognition and Measurement* for annual periods beginning on or after 1 January 2018, bringing together all three aspects of the accounting for financial instruments: classification and measurement; impairment; and hedge accounting.

IFRS 15 is a new standard under which revenue is recognised when the customer obtains control of goods or services promised in the contract, for the amount of consideration to which an entity expects to be entitled in exchange for said promised goods or services.

Several other financial reporting amendments and interpretations apply for the first time in 2018, but do not have an impact on the interim condensed consolidated financial statements of the Group.

In January 2016, the IASB has issued a new standard on leases, IFRS 16. The Group has elected not to early adopt IFRS 16. Under the new standard, all lease commitments will be recognised on the face of the statement of financial position, without distinguishing between operating leases and finance leases. The impact of the transition as at January 1, 2019, is being finalised. The main impact we expect on the consolidated financial statements is a recognition in the "right-of-use" assets on the asset side and a recognition in the lease liabilities on the liabilities side, regarding leases for which the Group acts as a lessee and which are currently classified as "operating leases". They mainly concern real estate, vessels such as supply boats and, potentially in future, drilling units. In the consolidated income statement, the reversal of the rental expenses of these "operating leases" will lead to a reduction in operating expenses and an increase in depreciation and financial expenses.

1.2 Measurement and presentation basis

The condensed consolidated financial statements have been prepared using the historical cost convention, except for financial instruments that are accounted for according to the financial instrument categories defined by IFRS 9.

The consolidated financial statements are presented in US dollars and rounded to millions, except when otherwise indicated.

1.3 Significant judgements and estimates

Estimates and judgements are continually evaluated and are based on historical experiences and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

1.3.1 Estimates

The preparation of condensed consolidated financial statements requires the use of estimates and assumptions to determine the value of assets and liabilities and contingent assets and liabilities at the reporting date, as well as revenues and expenses reported during the period.

The key estimates used in preparing the Group's consolidated financial statements relate mainly to:

– measurement of the recoverable amount of property, plant and equipment, other intangible exploration assets and goodwill;
– assessments of fair value of assets and liabilities acquired as part of a business combination;
– calculations of depreciation and amortisation which involve estimates of volumes of commercial reserves of oil and gas;
– measurement of provisions, particularly for decommissioning obligations, pensions and other employee post-retirement benefits; and
– measurement of recognised tax loss carry-forwards.

Each of these categories of key estimates are described further below. Due to uncertainties inherent in the estimation process, the Group regularly revises its estimates in light of currently available information. Final outcomes could differ from those estimates.

Recoverable amount of intangible assets and property, plant and equipment and goodwill
The recoverable amounts of intangible assets and property, plant and equipment and goodwill are based on estimates and assumptions, regarding in particular the expected market outlook (including future commodity prices) used for the measurement of cash flows, estimates of the volume of commercially recoverable reserves and resources of oil and gas future production rates and costs to develop reserves and resources, and the determination of the discount rate.

Any changes in these assumptions may have a material impact on the measurement of the recoverable amount and could result in adjustments to any impairment losses to be recognised.

Business combination
In accounting for the acquisition of EPI, as disclosed in note 4, the identifiable assets and liabilities acquired were recognised at their fair value in accordance with IFRS 3 'Business combinations'. The determination of their fair values is based, to a considerable extent, on estimates and judgements.

Commercial reserves and depreciation of oil and gas production assets
Charges for depreciation and amortisation of oil and gas producing properties are calculated on a unit of production rate based on production as a proportion of estimated quantities of proved and probable oil and gas reserves. The Group has adopted the definitions and guidelines presented in the Petroleum Resources Management System (SPE-PRMS 2007) for the classification and reporting of commercial reserves and resources of oil and gas. Commercial reserves are those in the proved and probable categories of reserves.

Estimates of reserves is a subjective process involving estimating underground resource accumulations and recovery rates, and is a function of many factors, such as the properties of the reservoir rock and petroleum fluid. Changes in the estimates of commercial reserves will consequently impact depreciation and amortisation expense. Changes in factors or assumptions used in estimating reserves could include:

– changes due to revised estimates of volumes in place and recovery factors;
– the effect on proved and probable reserves of differences between actual commodity prices and assumptions; and

– unforeseen operational issues.

Estimates of decommissioning provisions
Parameters having a significant influence on the amount of provisions for decommissioning costs include the forecast of costs to be incurred to decommission facilities, plug wells and restore sites used for production and drilling, the anticipated scope of such decommissioning obligations, which may depend on laws and regulation in force at the time, the timing of such expenditure and the discount rate applied to forecast cash flows. These parameters are based on information and estimates deemed to be appropriate by the Group at the current time.

The modification of certain parameters could involve a significant adjustment of these provisions.

Pensions and post–employment benefit obligations
Pension commitments are measured on the basis of actuarial assumptions. These include assumptions in respect of mortality rates and future salary increases, as well as appropriate discount rates. The Group considers that the assumptions used to measure its obligations are appropriate and documented. However, any changes in these assumptions may have a material impact on the resulting calculations.

Pension costs for interim periods are calculated on the basis of the actuarial valuations performed at the end of the prior year. If necessary, these valuations are adjusted to take account of curtailments, settlements or other major non-recurring events that have occurred during the period.

Measurement of recognised tax loss carry-forwards
Deferred tax assets are recognised on tax loss carry-forwards when it is probable that taxable profit will be available against which the tax loss carry-forwards can be utilised. The estimates of the taxable profit that will be available against which the unused tax losses can be utilised, are based on taxable temporary differences relating to the same taxation authority and the same taxable entity and estimates future taxable profits. These estimates and utilisations of tax loss carry-forwards are prepared on the basis of profit and loss forecasts as included in the medium-term business plan and, if necessary, on the basis of additional forecasts.

1.3.2 Judgements

As well as relying on estimates, the Directors make judgments to define the appropriate accounting policies and decisions to apply to certain activities and transactions, including when the effective IFRS standards and interpretations do not specifically deal with the related accounting issues. Key areas of judgement include:

Carrying value of intangible exploration and evaluation assets (notes 1.6 and 1.7): the amounts capitalised for exploration and evaluation assets represent cost in respect of active exploration and appraisal projects. These amounts will be written off to the income statement as exploration expense unless commercial reserves are established or the determination process as to the success or otherwise of the activity is not yet completed and there are no indications of impairment in accordance with the Group's accounting policy. The process of determining whether there is an indicator for impairment or calculating the impairment requires critical judgement, including: the Group's intention to proceed with a future work programme for a prospect or licence; the likelihood of licence renewal or extension; the assessment of whether sufficient data exists to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the exploration and evaluation asset is unlikely to be recovered in full from successful development or by sale, and the success of a well result.

Commercial reserves: the estimation of commercial reserves of oil and gas in accordance with SPE-PRMS guidelines, as outlined above, involves complex technical judgements.

1.4 Basis of consolidation

Subsidiaries and business combinations
Subsidiaries are all entities over which the group has control. The Group consolidates an entity when it is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the Group (the "acquisition date").

Inter-company transactions, balances and unrealised gains on transactions between group companies are eliminated. Unrealised losses are also eliminated.

Where necessary, amounts reported by subsidiaries have been adjusted to conform with the Group's accounting policies.

The Group applies the acquisition method to account for business combinations. The consideration transferred for the acquisition of a subsidiary is the fair value of the assets transferred, the liabilities incurred to the former owners of the acquiree, and the equity interests issued by the Group. The consideration transferred includes the fair value of any asset or liability resulting from a contingent consideration arrangement.

Identifiable assets acquired, and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair value at the acquisition date. The fair value of acquired oil and gas properties is based on the post-tax net present value of expected future cash flows. The fair values of assets and liabilities acquired which are initially recognised at provisional amounts may be adjusted within 12 months of the acquisition date based on assessment of additional data relating to the condition of item as at the acquisition date.

Acquisition-related costs of a business combination are expensed as incurred.

Any contingent consideration to be transferred by the Group is recognised at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration are recognised in accordance with IFRS 9, either in profit or loss. Contingent consideration that is classified as equity is not re-measured, and its subsequent settlement is accounted for within equity.

Goodwill arising in a business combination is recognised as an asset at the acquisition date. Goodwill is measured as the excess of the sum of the consideration transferred over the net of the acquisition-date amounts of the identifiable assets acquired and the liabilities assumed. After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash-generating units that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill has been allocated to a cash-generating unit (CGU) and part of the operation within that unit is

disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill disposed in these circumstances is measured

based on the relative values of the disposed operation and the portion of the cash-generating unit retained. The carrying value of goodwill is reviewed at least annually at the end of the financial year or following a trigger event.

If the Group's interest in the fair value of the acquiree's identifiable net assets exceeds the sum of the consideration transferred, the excess is recognised immediately in net income.

Investments in Joint Operations and Joint Ventures
A joint arrangement is one in which two or more parties have joint control and may take the form of a joint operation or a joint venture. Joint control is the contractually agreed sharing of control of an arrangement, which exists when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Most of the Group's activities are conducted through joint operations, whereby the parties that have joint control of the arrangement have rights to the underlying assets, and obligations for the liabilities, relating to the arrangement. The Group reports its share of the assets, liabilities, income and expenses of the joint operation within the equivalent items in the consolidated financial statements, on a line-by-line basis. Certain of the Group's joint operations derive from production sharing contracts ("PSCs"), entered into with host governments or their agencies. PSCs typically result in economic rights similar to other licence and concession arrangements and are accounted for using the same line-by-line basis, with the Group using the entitlement method (rather than its working interest) to recognise its share of production, revenues and reserves attributable to the PSC.

A joint venture, which normally involves the establishment of a separate legal entity, is a contractual arrangement whereby the parties that have joint control of the arrangement have the rights to the arrangement's net assets. The results, assets and liabilities of a joint venture are incorporated in the consolidated financial statements using the equity method.

Interests in associates
An associate is an entity over which the Group has significant influence, through the power to participate in the financial and operating policy decisions of the investee, but which is not a subsidiary or a joint arrangement. Interests in associates are accounted for using the equity method.

1.5 Foreign currency translation

Presentation and functional currency
Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which each Group Company operates (its "functional currency"). The financial statements are presented in US dollars, which is the Company's presentation and functional currency.

Transactions and balances
Foreign currency transactions are translated into the functional currency using exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are re-measured at the end of each accounting period. Foreign exchange gains and losses resulting from the settlement or re-valuation of monetary assets and liabilities denominated in foreign currencies are recognised in the income statement, except when deferred in other comprehensive income as qualifying cash flow hedges and qualifying net investment hedges (if applicable). Foreign exchange gains and losses included in net income are presented within 'Foreign exchange gain / loss' as part of financial income/expense.

Group companies
The results and financial position of all of the group entities (none of which has the currency of a hyper-inflationary economy) that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

– Assets and liabilities for each balance sheet presented are translated at the closing rate at the date of that balance sheet; and
– Income and expenses for each income statement are translated at average exchange rates (unless this average is not a reasonable approximation of the rates prevailing on the transaction dates, in which case income and expenses are translated at the rate on the dates of each transaction).
– The exchange differences arising on translation for consolidation are recognised in other comprehensive income.
– Any goodwill arising on the acquisition of a foreign operation and any fair value adjustments to the carrying amounts of assets and liabilities arising on the acquisition are treated as assets and liabilities of the foreign operation and translated at the spot rate of exchange at the reporting date.

1.6 Intangible assets other

Intangible assets (other than goodwill and exploration and evaluation rights) are carried at cost less any accumulated amortisation and any accumulated impairment losses. These assets principally comprise I.T. software and are amortised on a straight line basis over their useful economic lives.

1.7 Assets relating to the exploration and production of mineral resources

i) *Acquisition costs of unproved properties*: Exploration licences and concessions correspond to licences or rights acquired in areas in which the existence of oil and gas reserves has not yet been demonstrated. The costs of acquiring such exploration licences are capitalised within intangible assets.

ii) *Exploration & evaluation costs:* The Group adopts the successful efforts method of accounting for exploration and evaluation costs. Costs incurred prior to the award of a licence are expensed in the period in which they are incurred. The costs of geological and geophysical surveys and studies are expensed in the period incurred. Exploration and appraisal drilling costs are capitalised in cost centres by well, field or exploration area, as appropriate, pending the results of the exploration activities. Internal costs are expensed unless directly attributed to drilling operations. Costs are then written off as exploration expense in the income statement unless commercial reserves have been established or if the determination process has not been completed and there are no indications of impairment. When the exploratory phase has resulted in the recognition of commercial reserves, the related costs are first assessed for impairment and (if required) any impairment recognised, then the remaining balance is transferred to property, plant and equipment.

iii) *Property, Plant & Equipment:* Expenditure on the acquisition of proved properties and on the construction, installation or completion of facilities such as platforms, pipelines and the drilling of development wells, including any development or delineation wells, is capitalised within oil and gas properties – PP&E.

In accordance with IAS 16, the initial cost of assets relating to the exploration and production includes an initial estimate of the costs of decommissioning, and restoring the site on which the facilities are located when production operations cease, when the entity has a present legal or constructive obligation for decommissioning or to restore the site. A corresponding provision for this decommissioning obligation is recorded for the amount of the asset component.

Borrowing costs that are directly attributable to the construction of the qualifying asset are capitalised as part of the cost of that asset.

iv) *Depreciation of production assets:*
The depreciation of production assets, including decommissioning costs, starts when the oil or gas field is brought into production, and is based on the unit of production method According to this method, the depletion rate is equal to the ratio of oil and gas production for the period to proved and probable reserves, as applied to the capitalised cost plus future estimated costs to develop those reserves.

Pipeline assets for which third party tariff income is the main source of revenue are depreciated on a straight line basis over a period not exceeding the projected useful economic life of the asset.

v) Acquisition of Assets
Acquired assets are valued at their purchase price and assessed for impairment (if required).

1.8 Other property, plant and equipment

Items of property, plant and equipment are recognised at cost and are subsequently carried at their historical cost less any accumulated depreciation and any accumulated impairment losses.

1.9 Depreciation

Property, plant and equipment, other than assets related to exploration and production of mineral resources, is depreciated using the straight-line method over the following useful lives:

Main depreciation periods (years)	Minimum	Maximum
Computer equipment	3	5

1.10 Impairment of property, plant and equipment and intangible assets including goodwill

In accordance with IAS 36, impairment tests are carried out on items of property, plant and equipment and intangible assets where there is an indication that the assets may be impaired. Such indications may be based on events or changes in the market environment, or on internal sources of information.

Impairment indicators
Property, plant and equipment and intangible assets with finite useful lives are only tested for impairment when there is an indication that they may be impaired. This is generally the result of significant changes to the environment in which the assets are operated or when asset performance is worse than expected.

The main impairment indicators used by the Group are described below:

- external sources of information:
  - significant changes in the economic, technological, political or market environment in which the entity operates or to which an asset is dedicated;
  - fall in demand;
  - changes in energy prices and exchange rates.
- internal sources of information:
  - evidence of obsolescence or physical damage not budgeted for in the depreciation/amortisation schedule;
  - worse-than-expected production or cost performance;
  - reduction in reserves and resources, including as a result of unsuccessful results of drilling operations;
  - pending expiry of licence or other rights; and
  - In respect of capitalised exploration and evaluation costs, lack of planned future activity on the prospect or licence.

Measurement of recoverable amount
In order to review the recoverable amount in an impairment test, the assets are grouped, where appropriate, into cash-generating units (CGUs) and the carrying amount of each unit is compared with its recoverable amount.

For operating entities which the Group intends to hold on a long-term and going concern basis, the recoverable amount of an asset corresponds to the higher of its fair value less costs to sell and its value in use. Value in use is primarily determined based on the present value of future operating cash flows. Standard valuation techniques are used based on the discount rates based on the specific characteristics of the operating entities concerned; discount rates are determined on a post-tax basis and applied to post-tax cash flows. The recoverable amounts calculated on the basis of these discount rates are the same as the amounts obtained by applying the pre-tax discount rates to cash flows estimated on a pre-tax basis, as required by IAS 36.

Any impairment loss is recorded in the consolidated income statement under “Impairment losses”.

Impairment losses recorded in relation to property, plant and equipment may be subsequently reversed if the recoverable amount of the assets subsequently increases above carrying value. The increased carrying amount of an item of property, plant or equipment attributable to a reversal of an impairment loss may not exceed the carrying amount that would have been determined (net of depreciation/amortisation) had no impairment loss been recognised in prior periods. Impairment losses in respect of intangible assets may not be reversed on a future change in circumstances that led to the impairment.

Goodwill
Goodwill is not amortised but is reviewed for impairment at least annually. For the purpose of impairment testing, goodwill is allocated to each of the Group’s cash-generating units expected to benefit from the business combination. Cash-generating units to which goodwill has been allocated are tested for impairment annually, or more frequently when there is an indication the unit may be impaired. If the recoverable amount of the cash-generating unit is less than the carrying amount of the unit, the impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the unit and then to the other assets of the unit pro-rata on the basis of the carrying amount of each asset in the unit. An impairment loss recognised for goodwill is not reversed in a subsequent period.

On disposal of a subsidiary, the attributable amount of goodwill is included in the determination of the profit or loss on disposal.

1.11 Leases

The Group holds assets for its various activities under lease contracts as set out in IAS 17.

Payments made under operating leases are recognised as an expense on a straight-line basis over the lease term.

1.12 Inventories

Inventories of equipment and materials are measured at the lower of cost and net realisable value. Cost is determined based on the first-in, first-out method or the weighted average cost formula.

An impairment loss is recognised when the net realisable value of inventories is lower than their weighted average cost.

Hydrocarbon inventories are stated at net realisable value with movements in value recognised in the profit and loss account. Net realisable value corresponds to the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale

See also *1.19* “Revenue”, regarding volumes of under and over lifted entitlement to production.

1.13 Financial instruments

Financial instruments are recognised and measured in accordance with IFRS 9.

1.14 Financial assets

Financial assets comprise, loans and receivables carried at amortised cost, including trade and other receivables, hedging derivatives, and financial assets measured at fair value through income, including certain derivative financial instruments. Financial assets are analysed into current and non-current assets in the consolidated statement of financial position.

Loans and receivables carried at amortised cost
This item primarily includes loans and advances to associates or non-consolidated companies, guarantee deposits, trade and other receivables.

On initial recognition, these loans and receivables are recorded at fair value plus transaction costs. At each statement of financial position date, they are measured at amortised cost using the effective interest rate method.

Leasing guarantee deposits are recognised at their nominal value.

On initial recognition, trade and other receivables are recorded at fair value, which generally corresponds to their nominal value. Impairment losses are recorded based on the estimated risk of non-recovery.

1.15 Derivatives and hedge accounting - Assets and Liabilities

Derivative financial instruments are contracts: (i) whose value changes in response to the change in one or more observable variables; (ii) that do not require any material initial net investment; and (iii) that are settled at a future date. Derivative instruments include swaps, options, futures and swaptions, as well as forward commitments to purchase or sell listed and unlisted securities, and firm commitments or options to purchase or sell non-financial assets that involve physical delivery of the underlying.

The Group uses derivative financial instruments to manage and reduce its exposure to market risks arising from fluctuations in interest rates, foreign currency exchange rates and commodity prices, mainly for oil and gas. The use of derivative instruments is governed by a Group policy for managing interest rate, currency and commodity risks.

Hedging instruments: recognition and presentation
Derivative instruments qualifying as hedging instruments are recognised in the consolidated statement of financial position within current assets or liabilities if expiry is less than 12 months, or as non-current items if expiring after 12 months and measured at fair value.

Cash flow hedges
A cash flow hedge is a hedge of the exposure to variability in cash flows that could affect the Group's profit or loss. The hedged cash flows may be attributable to a particular risk associated with a recognised financial or non-financial asset or a highly probable forecast transaction.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognised directly in other comprehensive income (OCI), net of tax, while the ineffective portion is recognised in net income. The gains or losses accumulated in OCI are reclassified to the consolidated income statement under the same caption as the loss or gain on the hedged item – i.e., within current operating income for operating cash flows and financial income or expenses for other cash flows – in the same periods in which the hedged cash flows affect profit or loss.

If the hedging relationship is discontinued, the cumulative gain or loss on the hedging instrument remains recognised in OCI until the forecast transaction occurs. However, if a forecast transaction is no longer expected to occur, the cumulative gain or loss on the hedging instrument is immediately recognised in net income.

Identification and documentation of hedging relationships
The hedging instruments and hedged items are designated at the inception of the hedging relationship. The hedging relationship is formally documented in each case, specifying the risk management strategy, risk management objective, the hedged risk, sources of hedge ineffectiveness and the methods used to assess hedge effectiveness. Only derivative contracts entered into with external counterparties are considered as being eligible for hedge accounting.

Hedge effectiveness is assessed and documented at the inception of the hedging relationship and on an ongoing basis throughout the periods for which the hedge was designated. Hedge effectiveness is demonstrated prospectively using various methods, based mainly on a qualitative assessment of the critical terms of the hedging instrument and the hedged item as to whether their values will generally move in the opposite direction because of the same risk being hedged. Methods based on a regression analysis of statistical correlations between historical price data are also used.

Upon the designation of option instruments as hedging instruments, the intrinsic and time value components are separated, with only the intrinsic component being designated as the hedging instrument and the time value component is deferred in OCI as a cost of hedging.

Derivative instruments not qualifying for hedge accounting: recognition and presentation
These items mainly include derivative financial instruments used in economic hedges that have not been – or are no longer – documented as hedging relationships for accounting purposes.

When a derivative financial instrument does not qualify or no longer qualifies for hedge accounting, changes in fair value are recognised directly in net income, under “Mark-to-market on commodity contracts other than hedging instruments”, below the current operating income, for derivative instruments with non-financial assets as the underlying, and in financial income or expenses for currency, interest rate and equity derivatives.

Derivative instruments not qualifying for hedge accounting and other derivatives expiring in less than 12 months are recognised in the consolidated statement of financial position in current assets and liabilities, while derivatives expiring after this period are classified as non-current items.

Fair value measurement
The fair value of instruments listed on an active market is determined by reference to the market price. In this case, these instruments are presented in level 1 of the fair value hierarchy.

The fair value of unlisted financial instruments for which there is no active market and for which observable market data exist is determined based on valuation techniques such as option pricing models or the discounted cash flow method.

Models used to evaluate these instruments take into account assumptions based on market inputs:

– the fair value of interest rate swaps is calculated based on the present value of future cash flows. Cash flows are discounted using standard valuation techniques and observable market-based inputs, including interest rate curves, having regard to the timing of the cash flows;
– Commodity derivatives contracts are valued by reference to observable market-based inputs based on the present value of future cash flows (commodity swaps or commodity forwards) or option pricing models (options), which factor in market price volatility. Contracts with maturities exceeding the depth of transactions for which prices are observable, or which are particularly complex, may be valued based on internal assumptions;

These instruments are presented in level 2 of the fair value hierarchy except when the evaluation is based mainly on data that are not observable; in this case they are presented in level 3 of the fair value hierarchy.

To comply with the provisions of IFRS 13, the Group incorporates credit valuation adjustments to reflect appropriately both its own non-performance risk and the respective counterparty’s non-performance risk in the fair value measurements. In adjusting the fair value of its derivative contracts for the effect of non-performance risk, the Group has considered the impact of netting and any applicable credit enhancements, such as collateral postings, thresholds, mutual puts, and guarantees.

1.16 Financial liabilities

Financial liabilities include borrowings, trade and other payables, derivative financial instruments and other financial liabilities.

Financial liabilities are broken down into current and non-current liabilities in the consolidated statement of financial position. Current financial liabilities primarily comprise:

– financial liabilities with a settlement or maturity date within 12 months after the reporting date;
– financial liabilities in respect of which the Group does not have an unconditional right to defer settlement beyond 12 months after the reporting date;
– derivative financial instruments qualifying as fair value hedges where the underlying is classified as a current item; (see note 1.13)
– commodity trading derivatives not qualifying as hedges. (see note 1.1.3).

Measurement of borrowings
Borrowings are measured at amortised cost using the effective interest rate method. On initial recognition, any issue or redemption premiums and discounts and issuing costs are added to/deducted from the nominal value of the borrowings concerned. These items are taken into account when calculating the effective interest rate and are therefore recorded in the consolidated income statement over the life of the borrowings using the amortised cost method.

1.17 Cash and cash equivalents

Cash and cash equivalents in the statement of financial position comprise cash at banks and on hand and short-term deposits with a maturity of three months or less, which are subject to an insignificant risk of changes in value. For the purpose of the consolidated statement of cash flows, cash and cash equivalents consist of cash and short-term deposits, as defined above, net of outstanding bank overdrafts, as they are considered an integral part of the Group's cash management.

1.18 Provisions

1.18.1 General

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and the amount of the obligation can be estimated reliably.

Provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate. If it is no longer probable that an outflow of economic resources will be required to settle the obligation, the provision is reversed. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. When discounting is used, the increase in the provision due to the passage of time is recognised as a finance cost.

1.18.2 Provisions for post-employment benefit obligations and other long term employee benefits

Depending on the laws and practices in force in the countries where the Group operates, Group companies have obligations in terms of pensions, early retirement payments, retirement bonuses and other post-employment benefit plans.

The Group's obligations in relation to pensions and other employee benefits are recognised and measured in compliance with IAS 19. Accordingly:

– the cost of defined contribution plans is expensed based on the amount of contributions payable in the period;

– the Group's obligations concerning pensions and other employee benefits payable under defined benefit plans are assessed on an actuarial basis using the projected unit credit method. These calculations are based on assumptions relating to mortality, staff turnover and estimated future salary increases, as well as the economic conditions specific to each country or subsidiary of the Group. Discount rates are determined by reference to the yield, at the measurement date, on high-quality corporate bonds in the related geographical area (or on government bonds in countries where no representative market for such corporate bonds exists).

Provisions are recorded when commitments under these plans exceed the fair value of plan assets. Where the value of plan assets (capped where appropriate) is greater than the related commitments, the surplus is recorded as an asset under "Other assets" (current or non-current).

As regards post-employment benefit obligations, actuarial gains and losses are recognised in other comprehensive income. Where appropriate, adjustments resulting from applying the asset ceiling to net assets relating to overfunded plans are treated in a similar way. However, actuarial gains and losses on other long-term benefits such as long-service awards, are recognised immediately in income.

Net interest on the net defined benefit liability (asset) is presented in net financial expense (income).

1.18.3 Decommissioning costs

A provision is recognised when the Group has a present legal or constructive obligation to plug wells, dismantle facilities or to restore a site. An asset is recorded simultaneously by including this decommissioning obligation in the carrying amount of the facilities concerned. Adjustments to the provision due to subsequent changes in the expected outflow of resources, the decommissioning date or the discount rate are deducted from or added to the cost of the corresponding asset. The impact of unwinding the discount ("accretion") is recognised in financial expenses for the period.

Provisions with a maturity of over 12 months are discounted when the effect of discounting is material. The discount rate (or rates) used reflect current market assessments of the time value of money, based on the relevant risk-free rate, adjusted if appropriate for any risks specific to the liability concerned.

1.19 Revenues

Revenues is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. The Group recognises revenue when it transfers control over a product or service to a customer. This generally occurs when product is physically transferred into a vessel, pipe or other delivery mechanism.

Differences may arise in a joint operation between the Group's share of production entitlement from an oil or gas field and the volume which has been lifted and sold. Such "Under or Over lift" entitlement are recognised in current assets or liabilities, respectively, at net realisable value, with a corresponding adjustment through production costs. As a result, the reported operating result for each period reflects the Group's share of saleable production in that period.

The Group recognises its share of LNG revenues in respect of its Indonesian production sharing contracts based on its contractual entitlement under the contract. Revenues include volumes allocated to the Group for sale as reimbursement of costs of operation of the LNG processing facility, with corresponding costs included as operating expenses.

Further information regarding segmental analysis is contained in note 3.

1.20 Condensed consolidated statement of cash flows

The consolidated statement of cash flows is prepared using the indirect method starting from net income.

"Interest received on non-current financial assets" is classified within investing activities because it represents a return on investments. "Interest received on cash and cash equivalents" is shown as a component of financing activities because the interest can be used to reduce borrowing costs. This classification is consistent with the Group's internal organisation, where debt and cash are managed centrally by the treasury department.

Cash flows relating to the payment of income tax are presented on a separate line of the consolidated statement of cash flows.

1.21 Income tax expense

Current tax, including corporation tax and foreign tax is provided at amounts expected to be paid (or recovered) using the tax rates and laws that have been enacted or substantively enacted by the balance sheet date. Tax is recognised in the income statement, except to the extent that it relates to items recognised directly in equity. In this case, the tax is recognised in equity. Deferred tax is recognised in respect of all temporary differences identified at the balance sheet date, except to the extent that the deferred tax arises from the initial recognition of goodwill or the initial recognition of an asset or liability in a transaction which is not a business combination and at the time of the transaction affects neither accounting profit nor taxable profit and loss. Temporary differences are differences between the carrying amount of the Company's assets and liabilities and their tax base. Deferred tax assets are recognised only to the extent that the deductible temporary differences will reverse in the future and it is probable that there will be sufficient taxable profit available against which the temporary differences can be utilised. The amount of deferred tax provided is using tax rates that have been enacted or substantively enacted at the balances sheet date. Deferred taxes are reviewed at least annually at the end of the financial year to take into account factors including the impact of changes in tax laws and the prospects of recovering deferred tax assets arising from deductible temporary differences. Deferred tax assets and liabilities are not discounted.

Current and deferred income tax expense for interim periods is calculated at the level of each tax entity by applying the average estimated annual effective tax rate for the current year to the taxable income for the interim period, with the exception of significant exceptional items. Significant exceptional items, if any, are recognised using their specific applicable taxation rates.

2. Financial risk management

Group financial risk factors
The Group's activities expose it to a variety of financial risks: market risk (e.g. currency risks), credit risk and liquidity risk. The group's overall risk management programme focusses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the group's financial performance.

Market risk (foreign exchange risk)
The Group operates internationally and therefore exposed to foreign exchange risk arising from various currency exposures, primarily with respect to the Pound Sterling (GBP), Norwegian Krone (NOK) and Euros. Foreign exchange risk arises from future commercial transactions, recognised assets and liabilities and net investments in foreign operations.

Credit risk
Currently credit risk only arises from cash and cash equivalents, sales receivables, hedging derivatives. For banks and financial institutions, only independently rated parties with a minimum rating of 'BBB' are accepted.

Liquidity risk
Liquidity risk is the risk that the Group might not have sources of funding to meet its business needs. The Directors believe that the Group has sufficient cash, undrawn committed funds under its borrowing base facility and expected sources of liquidity to meet the business's forecast requirements.

3. Segment information

3.1 Revenue from contracts with customers

The Group's activities consist of a single class of business, representing the acquisition, exploration, development and production of the Group's own oil and gas reserves and resources and is focused on five geographical regions, UK, Norway, Netherlands, Germany and International.

	Six months ended 30 June 2018							period from 22 March to 30 June 2017
In millions of US$	UK	Norway	Netherlands	Germany	International	Corporate	Total	Total
Production revenue by origin	103.6	512.6	143.1	75.6	184.6	–	1,019.5	–
Other revenue	5.5	0.1	4.3	2.9	–	1.0	13.8	–
Revenues	**109.1**	**512.7**	**147.4**	**78.5**	**184.6**	**1.0**	**1,033.3**	**–**
Current Operating Income	**35.2**	**308.6**	**39.4**	**(2.6)**	**93.1**	**(16.9)**	**456.8**	**(0.4)**
Share in net income from joint ventures (equity method)							7.6	–
Net Operating Profit After Equity Accounted Investments							**464.4**	**(0.4)**
Mark-to-market on commodity contracts other than trading instruments							(20.1)	–
Restructuring costs							2.8	-
Acquisition transaction costs							(63.4)	-
Profit Before Financial Items							**383.7**	**(0.4)**
Financial expenses							(48.8)	–
Financial income							5.1	–
Profit Before Tax							**340.0**	**(0.4)**

All activities in 2017 relate to the UK.

4. Business combinations

4.1 Acquisition of ENGIE E&P International SA

On 15 February 2018, the group acquired 100% of the voting shares of ENGIE E&P International S.A. (now renamed Neptune Energy International S.A.), an unlisted company based in France which was the holding company of a group ("EPI") involved internationally in oil and gas exploration and production. The acquisition sees the Group become an international independent E&P business across the North Sea, North Africa and South East Asia The acquisition has been accounted for using the acquisition method. The interim condensed consolidated financial statements include the results of EPI from the acquisition date of 15 February 2018 to 30 June 2018.

The fair values of the identifiable assets and liabilities of EPI as at the date of acquisition were:

In millions of US$	Fair value recognised on acquisition
Non-Current Assets	
Exploration and evaluation assets	89.0
Other Intangible assets	15.9
Property, plant and equipment	3,962.6
Derivative instruments	47.6
Investments in entities accounted for using the equity method	513.0
Other non-current assets	42.0
Deferred tax assets	595.8
Total Non-Current Assets	**5,265.9**
Current Assets	
Derivative instruments	2.9
Trade and other receivables	472.7
Inventories	58.2
Other current assets	326.3
Cash and cash equivalents	68.8
Total Current-Assets	**928.9**
Total Assets	**6,194.8**
Non-Current Liabilities	
Provisions	(1,677.4)
Long-term borrowings	(187.2)
Derivative instruments	(32.1)
Other non-current liabilities	(217.2)
Deferred tax liabilities	(955.5)
Total Non-Current Liabilities	**(3,069.4)**
Current Liabilities	
Provisions	(15.9)
Derivative instruments	(72.0)
Trade and other payables	(165.2)
Income taxes payable	(215.0)
Other current liabilities	(136.8)
Total Current Liabilities	**(604.9)**
Total Identifiable Net Assets At Fair Value	**2,520.5**
Goodwill arising on acquisition (provisional)	774.5
Purchase Consideration	**3,295.0**
Analysis Of Cash Flows On Consideration	
Net cash acquired with the subsidiary (including in cash flows from investing activities)	68.8
Purchase Consideration	(3,295.0)
Contingent Consideration outstanding	21.0
Net Cash Flow On Acquisition	**(3,205.2)**

Purchase consideration comprised cash of US$3,256.5 million and contingent consideration of US$38.5 million.

From the date of acquisition, the acquisition has contributed all the reported revenue from the continuing operations of the Group and net profit of US$167.1 million before any adjustment to finance costs. If the acquisition had taken place at the beginning of the year, revenue from continuing operations would have been US$1,286.6 million and net profit US$222.8 million.

The goodwill recognised arises principally as a result of recognition of deferred tax liabilities for the temporary difference between assigned fair values of oil and gas properties, which are based on post-tax values, and their tax base. The goodwill is not deductible for income tax purposes.

Transaction costs of US$63.4 million have been expensed in the condensed consolidated statement of profit and loss and are part of operating cash flow in the statement of cash flows.

Contingent Consideration
Included in the purchase consideration at acquisition was $38.5 million which would be payable based upon satisfaction of certain project milestones. No contingent consideration is payable if the milestones are not achieved. No fair value adjustment to this contingent consideration was required in the six months ended 30 June 2018.

The possible outcome for contingent consideration ranges from US$17.5 million to US$52.5 million.

4.2 Acquisition of VNG Norge A/S

On 28 June 2018 the Group announced that it had entered into a sales and purchase agreement (the “VNG SPA”) under which a Group company will acquire 100% of the ordinary share capital of VNG Norge AS from its parent VNG AG, a German natural gas and energy service provider.

Completion of the VNG SPA is subject to the customary regulatory approvals and is expected to occur later in 2018.

VNG Norge AS has a portfolio of 42 licences, five producing fields and three development projects including, in Norway: the Fenja oil development (30% and operator), Bauge (2.5%); and in Denmark: Solsort (13.8%). The VNG Norge asset base is highly complementary to Neptune’s existing Norwegian portfolio.

5. Taxation

The Group calculates the period income tax expense using the tax rate that would be applicable to the expected total annual earnings. The major components of income tax expense in the interim condensed statement of profit or loss are:

In millions of US$	Six months ended 30 June 2018	period from 22 March to 30 June 2017
Current taxation	(346.7)	–
Deferred taxation	77.1	–
	(269.6)	**–**

6. Intangible assets

	30 June 2018		
In millions of US$	Exploration assets	Other assets	Total intangible assets
At 1 January	–	–	–
business combinations	89.0	15.9	104.9
additions	9.3	0.9	10.2
amortisation	–	(5.3)	(5.3)
currency translation adjustments	(1.8)	(0.6)	(2.4)
Net book value at 30 June	**96.5**	**10.9**	**107.4**

There were no intangible assets held in 2017.

7. Property, plant and equipment

	30 June 2018		
In millions of US$	Oil and gas assets	Other fixed assets	Total fixed assets
Cost at 1 January	–	–	–
business combinations	3,946.5	16.1	3,962.6
additions	94.0	1.8	95.8
currency translation adjustments	(137.4)	(1.6)	(139.0)
At 30 June	3,903.1	16.3	3,919.4
Depreciation at 1 January	**–**	**–**	**–**
charge for period	(270.3)	(1.1)	(271.4)
currency translation adjustments	10.1	0.1	10.2
At 30 June	(260.2)	(1.0)	(261.2)
Net book value at 30 June	**3,642.9**	**15.3**	**3,658.2**

Other fixed assets held in 2017 amounted to a cost of US$40,938 and depreciation of US$3,187.

8. Financial assets and financial liabilities

Set out below is an overview of financial assets, other than cash and short term deposits, held by the Group as at 30 June 2018 and 31 December 2017

In millions of US$	30 June 2018	31 December 2017
Financial Assets at fair values		
Commodity derivatives at fair value through profit and loss	3.3	–
Commodity derivatives in qualifying hedging relationships	20.2	
Total	**23.5**	**–**
Total current	**5.6**	**–**
Total Non-current	**17.9**	**–**

In millions of US$	30 June 2018	31 December 2017
Financial Liabilities at fair values		
Commodity derivatives at fair value through profit and loss	40.5	–
Commodity derivatives in qualifying hedging relationships	218.2	–
Interest rate derivatives in qualifying hedging relationships	1.2	
Contingent consideration	21.0	–
Financial Liabilities amortised at cost:		
Trade and other payables	797.4	4.6
Non-current interest bearing loans and borrowings		
RBL facility	523.9	–
Senior notes 2025	537.4	–
Touat project finance facility	187.2	–
Subordinated NEGL loan	100.0	–
Total	**2,426.8**	**4.6**
Total current	**1,009.8**	**4.6**
Total Non-current	**1,417.0**	**–**

On 11 May 2017 the certain subsidiaries within the Group entered into a revolving reserves-based lending facility (“RBL”) with total aggregate commitments of $2,000 million. The outstanding debt is repayable in line with the amortisation of bank commitments over the period from 1 April 2020 to the final maturity date of 11 May 2024, or such time as is determined by reference to the remaining reserves of the assets, whichever is earlier. The maximum amount that the relevant subsidiaries (the “RBL group”) can drawdown under this facility is subject to a consolidated cash flow and debt service projection, which is reviewed twice a year, in March and September. On these dates there is a redetermination of the available size of the facility, which takes into account, amongst other things, the most up-to-date forecast of the RBL group’s production. Until the 31 March 2018, the available size of the facility was USD 1,428 million and from that date and until 30 September 2018, the size was increased to USD 1,795 million. The facility is a multi-currency facility and incurs interest on outstanding debt at US dollar and Sterling LIBOR, EURIBOR or NIBOR plus an applicable margin. The facility is secured over the shares of certain companies within the RBL group, and certain of their oil and gas assets. As at 30 June 2018, total drawings under the facility were $350 million and €200 million.

In May 2018 the Company's 100% subsidiary Neptune Energy Bondco Plc issued $550 million in senior notes due in 2025, bearing interest at an annual rate of 6.625%.

Neptune Energy Touat Holding BV (an indirect 100% subsidiary of the Company) has a term loan from ENGIE CC SR. The Lender has agreed to provide loan financing to fund costs in respect of the Group's interest in the Touat field in Algeria. As at 30 June $187 million had been drawn under the facility. The loan incurs interest at 6% until production commences at the field and at 8% thereafter.

In February 2018 the Company entered into a $100 million shareholder loan from Neptune Energy Group Limited, for the purposes of part-funding the costs of acquiring the shares in EPI. The loan is for a period of 6 years and incurs interest at 7.75%.

9. Cash and cash equivalents

For the purposes of the interim condensed statement of cash flows, cash and cash equivalents comprise the following:

In millions of US$	30 June 2018	31 December 2017
Cash at bank and in hand	374.9	0.4
Total cash and cash equivalents	**374.9**	**0.4**

10. Provisions

In millions of US$	30 June 2018	31 December 2017
Current		
Restructuring	6.7	–
Other	2.6	–
	9.3	**–**
Non-Current		
Post-employment benefit and other long term benefits	234.9	–
Decommissioning	1,348.1	–
Other	6.3	–
	1,589.3	**–**

11. Trade payables and accruals

In millions of US$	30 June 2018	31 December 2017
Trade and other payables	351.0	4.6
Other current liabilities	467.4	–
	818.4	**4.6**

Trade payables are usually paid within 30 days of recognition. The carrying amount of financial assets and financial liabilities approximates their fair value.

12. Share capital

	Number	$m
Allotted, called up and fully paid		
Issued in the period	1,977,175,201	1,977.1
At 31 December 2017	**728**	**–**

728 US$1 shares were allotted, called up and fully paid on incorporation on 22 March 2017.

13. Contingent liabilities

During the normal course of its business, the Group may be involved in disputes, including tax disputes. The group has made accruals for probable liabilities related to litigation and claims based on management's best judgement and in line with IAS 37 and IAS 12.

14. Events after the reporting period

On 1 August 2017, the Group entered into a sale and purchase agreement to acquire a 35% working interest in the Seagull development and a 50% working interest in the Isabella prospect, both in the UK Central North Sea, from Apache Corporation. The proposed transaction is subject to customary approvals, with completion expected before the end of 2018.