26 September 2017

FAROE PETROLEUM PLC
("Faroe Petroleum", "Faroe", the "Company" or the "Group")

Unaudited Interim Results for the six months ended 30 June 2017

Faroe Petroleum, the independent oil and gas company focusing principally on exploration, appraisal and production opportunities in Norway and the UK, announces its unaudited Interim Results for the six months ended 30 June 2017.

Highlights

Exploration and Appraisal – significant resource upgrade following Brasse appraisal

- Successful Brasse (Faroe 50% and operator) appraisal well, production testing and side-track well, announced in July 2017, proving up recoverable volumes to 56-92 mmboe gross, an increase of approximately 20%
- Four new licences awarded in Norway under the 2016 APA licensing round in January 2017, including an extension to the Brasse discovery and two operatorships
- Farm-out secured on licence option 16/23 in Ireland to Nexen – Faroe retains 20% and is carried through the work programme, including a possible exploration well

Development and Production – good production performance and all projects progressing to plan and on budget

- Average H1 2017 production of 14,800 boepd from existing portfolio (H1 2016: 18,800[1] boepd) – reflecting no production from Njord and Hyme as the facilities undergo life-extending refurbishment and upgrades
- Average operating cost for producing assets approximately $26 per boe (2016: $25), reflecting lower volume until new lower operating cost subsea fields come on stream
- Further 14% of Blane oil field acquired from JX Nippon in July 2017 for a consideration of $5.25 million
- Plan for the Development and Operation ("PDO") for Oda approved by Norwegian Ministry of Petroleum, triggering initial compensation payment from Oda partners (Faroe 15%) to Oselvar partners (Faroe 55%) (net £7.4 million receipt to Faroe) resulting in payback on the DONG deal within 6 months of completion
- PDO for Njord and Bauge approved by the Norwegian Ministry of Petroleum

Finance – strong cash generation from producing assets

- Revenue £80.1 million (H1 2016: £23.1 million) – reflecting higher accounting production as a result of the DONG asset acquisition completed in December 2016
- EBITDAX £44.0 million (H1 2016: £16.7 million) – includes net income of £10.4 million in relation to Oselvar compensation payments received and made following Oda PDA approval
- Operating loss of £0.3 million (H1 2016: £34.3 million) and loss after tax of £2.9 million (H1 2016: £13.0 million) – reflecting higher revenue and higher other income
- Exploration and appraisal capex £33.4 million (H1 2016: £14.8 million), equivalent to £7.3 million (H1 2016: £3.7 million) on a post-tax basis, taking account of 78% Norwegian exploration tax rebate
- Development and production capex £22.0 million (H1 2016: £2.5 million)
- Unrestricted cash and net cash at 30 June 2017 £117.6 million (31 December 2016: £96.8 million)
- $250 million reserve based lending ("RBL") facility, undrawn at 30 June 2017 (31 December 2016: £nil), and NOK 1 billion exploration finance facility ("EFF") in place

Outlook – step-up in economically attractive organic development and production investments, fully funded

- Production guidance for 2017 maintained at 13,000-15,000 boepd as all key producing fields have been performing in line with expectations and with limited downtime
- Approximately 90% of gas production hedged to December 2018 averaging 42p/therm; and approximately 30% of oil production hedged to December 2018 averaging $55/bbl (all on post-tax basis)
- Exploration and appraisal drilling programme continues in H2 2017 in Norway – Goanna exploration well (Faroe 30% and fully cost-carried) spudded in August 2017 (dry); Iris/Hades (Aerosmith) exploration well (Faroe 20%) expected to commence in December 2017; Fogelberg appraisal well (Faroe 33.3%) forecast to spud in February 2018

1 Economic production including production from assets acquired from DONG with an effective date of 1 January 2016 – the transaction completed in December 2016. Accounting production, excluding production from the assets acquired from DONG, was 9,043 boepd.

- Investment step-up planned on developments and infill drilling, following approvals of Oda, Njord, Bauge developments, and Tambar infill drilling and gas lift projects – all fully funded from cash, cashflow and undrawn RBL credit facility
- Fully funded net capital expenditure for 2017 on exploration is estimated at approximately £45 million pre-tax (£10.5 million post-tax), and on development and production is estimated at approximately £90 million

Graham Stewart, Chief Executive of Faroe Petroleum, commented:

"I am pleased to report that Faroe Petroleum is performing ahead of expectation across its range of activities, despite continuing low oil prices. Faroe benefited from a number of positives in the period including: strong production performance in H1 2017, averaging 14,800 boepd; appraisal success on the Brasse discovery, increasing our recoverable resource range; a growing low cost exploration and appraisal programme; significant progress on our organic development projects; the acquisition of a further 14% interest in the Blane field (announced in July 2017); and rapid payback achieved on the DONG deal within 6 months of completion. Faroe now has a strong and diversified asset base with a clear path to increase profitable production to over 40,000 boepd within the next five years, with robust project economics even at low commodity prices.

"The Brasse field is clearly a standout project for Faroe. Brasse was applied for, drilled, discovered and appraised by our team. We now move forward to the exciting phase of planning its development, in the knowledge that the significant resources in this prolific reservoir have considerable value, particularly given their shallow water location close to competing process and export infrastructure. Gross plateau flow rates for this field have the potential to exceed 30,000 boepd, with first production scheduled for 2020/21.

"The Company has delivered good financial performance in H1 2017 with strong cash flow, improved cash reserves and an undrawn RBL credit facility of $250 million, ensuring significant financial flexibility going forward as we progress our development and exploration programmes simultaneously. Looking ahead, while we actively manage our organic programme, we will seek to continue to capitalise on our strong strategic and financial position as we pursue further attractive and value accretive M&A opportunities."

Ends

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CHAIRMAN'S AND CHIEF EXECUTIVE'S STATEMENT

Faroe continues to weather the lows of the oil price cycle as the Company capitalises on its successful transition into a full cycle independent oil and gas company. Faroe's performance demonstrates the robustness of the Company's business model as we continue the momentum of last year, which saw us double production through the highly value accretive acquisition of four fields from DONG and the discovery of Brasse, the largest discovery made in Norway in 2016. In May 2017, the Company commenced the drilling of an appraisal well on the Brasse discovery and, following production testing and a side-track well, announced a significant increase in estimated recoverable reserves, further de-risking the project and improving its economics. Group production at 14,800 boepd in H1 2017 generated EBITDAX of £44.0 million and PDO approval was received on each of the Oda, Njord and Bauge developments. Payback was achieved on the DONG asset transaction during H1 2017, less than 12 months after the transaction was first announced and less than six months after deal completion.

With a cash balance of £117.8 million and an undrawn $250 million RBL credit facility, the platform is in place for further value growth as we invest in our key development projects, in our existing producing fields and in maturing the Brasse project towards development and monetisation. We continue to evaluate new value-accretive asset acquisition opportunities, and in July this year we announced the modest but important acquisition of a further 14% stake in the Blane field, taking our interest to 44.5%.

Brasse appraisal success underpins Faroe's strategic focus on near-field exploration and appraisal

In May 2017, appraisal drilling commenced on the Brasse discovery (Faroe 50% and operator) in the Norwegian North Sea, less than 12 months after its discovery in the summer of 2016. The appraisal well encountered oil in a sand-rich reservoir of very good quality and a drill stem test ("DST") was undertaken followed by a side-track well. The DST confirmed high quality light crude with maximum stable flow rates of 6,187 bpd. The subsequent side-track well in the southern part of the Brasse discovery encountered 18 metres of gross oil-bearing and 4 metres of gross gas-bearing Jurassic reservoir. Based on extensive data collected, the total gross volumes of recoverable hydrocarbons for the Brasse field have been revised upwards to 56-92 mmboe, from 43-80 mmboe, an increase of approximately 20%.

Extensive feasibility studies of the Brasse field development have been carried out focusing on a subsea development solution tied-back to either one of the hosts in the nearby area, Brage and Oseberg. Gross plateau flow rates for this field have the potential to exceed 30,000 boepd, with first production scheduled for 2020/21. The Brasse field is a valuable asset with attractive economics even at long term low commodity prices. The close proximity to existing infrastructure combined with its prolific reservoir qualities and location in shallow water will allow Brasse to be developed expediently and with strong economics.

The Brasse success further underpins our strategic focus on near-field exploration and appraisal opportunities as we maintain our consistent exploration-led business model. Faroe recently committed to an appraisal well on the Fogelberg discovery (Faroe 33.3%). Faroe was also fully cost carried on the exploration well on the Goanna licence (Faroe 30%) in Norway (recently announced as dry).

In Ireland, Faroe entered into a farm-out agreement on licence option 16/23 (Faroe 100%), east of the producing Corrib gas field, under which Nexen takes over operatorship and an 80% interest (Faroe 20%) in return for meeting the costs of the associated work programme, including the acquisition of seismic data and a possible exploration well.

Two field development sanctions received in H1 2017

Faroe and our joint venture partners are taking full advantage of the current market for services and supplies, as we invest at the bottom of the cycle in field development and production enhancement activities across our portfolio. Locking in low costs in this manner offers real scope to improve significantly economic returns and portfolio value. Furthermore, Faroe's approach to risk diversification ensures a prudent yet potent portfolio mix from which to deliver core value growth.

In May 2017, the partners in the Oda oil field development received PDO approval from the Norwegian Ministry of Petroleum and Energy. The Centrica-operated Oda field (Faroe 15%) in the Norwegian North Sea will be developed via a four-slot seabed template with a subsea tie-back to the Ula platform (Faroe 20%), approximately 13 kilometres to the east. The Oda subsea tie-back will connect to the existing pipeline between Oselvar (Faroe 55% and operator) and Ula, re-using the Oselvar facilities at the Ula platform. Production from Oselvar is scheduled to cease in Q2 2018 to allow the Oda tie in to be undertaken and the Oselvar owners are being compensated accordingly. Faroe received an initial net compensation of £7.4 million in H1 2017 (taking into account the payment Faroe makes as an

Oda partner). Payback of Faroe's acquisition of four producing fields from DONG, which completed in December 2016, has already been achieved in H1 2017.

Norwegian Ministry of Petroleum and Energy approval of the PDO was granted in June 2017 for the Statoil-operated Njord Future Project and Bauge field (Faroe 7.5%). The works to date on the Njord A Facility in the Stord dry dock have been completed on time and on budget. In parallel, the project to refurbish the Njord B storage tanker is also progressing to plan. The planning for the Bauge subsea tie-back (also operated by Statoil) is ongoing with the finalisation of the contract strategy for project execution.

Faroe has also agreed to make significant investments in infill drilling and a gas lift installation project on the Tambar field as well as infill drilling on the Brage field. These investments all have compelling economics and are expected to boost production considerably.

The Company continues to work with operator VNG to progress the Fenja project, previously named Pil & Bue (Faroe 25%) with PDO submission expected around the end of 2017. The joint venture has selected the Njord Facility as the field export route on this exciting project.

Production portfolio performing well

Faroe has built, through a combination of M&A and field investment, a diversified, operated and non-operated production portfolio, located across the Norwegian North Sea and Norwegian Sea and the UK southern and central North Sea. The Company's tax efficient production portfolio remains core to our strategy and is a principal source of funding for the Group's drilling and investment programme. Faroe delivered net average production of 14,800 boepd in the first half of 2017 with an average opex per boe of $26 for its producing fields. Faroe's production is spread across a balanced and high quality portfolio of assets with an approximate geographic volume split currently of 78%/22% Norway/UK respectively and an oil/gas split of 57%/43% respectively. With an operating netback of approximately $19 per boe, the production portfolio generated EBITDAX of £44.0 million, including the compensation payment recognised on Oselvar following Oda PDO consent in the period. Trym, which contributed approximately one third of the Group's production in H1 2017, is now expected to produce until August 2019 before being suspended until refurbishment work is completed on Tyra, the host facility in the Danish sector.

Faroe's medium term objective, as it unlocks value in its portfolio, is to reduce unit opex and full cycle costs further, such that the Company grows increasingly profitable, even on the basis of a possible 'lower-for-longer' oil price.

Outlook

Faroe has a diversified and high quality portfolio comprising significant and attractive production, pre-development and development projects centred principally around the three core Norwegian hubs of Njord, Brage and Ula. Material investments will be made across the key assets in these three hub areas over the coming years, markedly increasing the Company's scale. Faroe now has an asset base with the deliverable potential to increase production to over 40,000 boepd within the next five years, founded on robust project economics even at low commodity prices.

At the core of our value creation model, we continue to manage our exploration portfolio with a view to identifying strong prospects to add to the programme. The current rig market offers us the scope to drill at materially lower cost than in past years giving the potential for even lower finding costs going forward. Faroe's exploration track record has been exceptional, and we look forward to continuing our dynamic well programme, which continues with the Iris/Hades and Fogelberg wells, scheduled for late 2017 and early 2018.

Faroe also has an excellent track record of growth through M&A. Following the acquisition of four producing assets from DONG in Norway in 2016 and the purchase of additional equity in Blane in the UK in 2017, we aim to capitalise on our strong strategic and financial position by pursuing further M&A opportunities focused on both the Norwegian and UK continental shelves.

John Bentley	Graham Stewart
Chairman	Chief Executive

REVIEW OF ACTIVITIES

The Company has continued to make good progress across all areas of activity with operational highlights being the successful operated appraisal programme on the Brasse discovery, production from the portfolio coming in at the higher end of guidance and approval of two key development projects.

Exploration and Appraisal

In H1 2017, Faroe participated in two E&A wells, the Eni-operated Boné exploration well in the Barents Sea and the Faroe operated Brasse appraisal well. The Company also added to the licence portfolio through awards in the Norwegian APA licensing round. The drilling programme continued with the Goanna exploration well (Faroe 30%) in August 2017. The well was unfortunately dry but Faroe was carried on the dry-hole well cost. Next will be the OMV-operated Iris/Hades (Aerosmith) exploration well in the Norwegian Sea (Faroe 20%) in December 2017 followed by the Centrica-operated Fogelberg appraisal well (Faroe 33.3%) early next year. All these wells are in Norway where Faroe receives a tax rebate of 78% on all exploration and appraisal expenditure.

Drilling operations
Faroe's first exploration well of the year targeted the Boné prospect (Faroe 20%) located in the western part of the Norwegian Barents Sea in a similar structural setting to the Johan Castberg Discovery. The primary targets for the well were the Jurassic Stø- and Nordmela sandstone and whilst approximately 106 metres of reservoir was encountered, it was found to be water bearing.

Following our significant drilling success on the Brasse prospect last year, drilling commenced in May 2017 on the appraisal well (Faroe 50% and operator) targeting a location approximately two kilometres to the southeast of the main discovery well. The appraisal well successfully penetrated the oil-water contact on the flank of the field and encountered approximately 8.5 metres of gross oil-bearing Jurassic reservoir above the oil water contact. A Drill Stem Test (DST) was then undertaken which exceeded expectations flowing at a constrained maximum stable rate of 6,187 bpd, through a 1" choke with 800 psia at the wellhead. An excellent quality light crude was produced similar to that found in the nearby Brage field (Faroe 14.3%)

The Brasse appraisal well sidetrack was then drilled targeting the reservoir one kilometre to the west of the appraisal well and 2.4 kilometres to the south of the main discovery well. The sidetrack well successfully penetrated the gas-oil contact and the oil-water contact in the southern part of the Brasse field and encountered approximately 18 metres of gross oil-bearing and 4 metres of gross gas bearing Jurassic reservoir above the same oil-water contact as in the discovery well and in the main bore of the appraisal well (31/7-2). The pressure data indicate good pressure communication within the reservoir. The Brasse appraisal well, DST and sidetrack appraisal well, together with the discovery well, provide clear evidence of a very prolific reservoir, excellent sands and high quality light crude.

Based on these results, the total gross volumes of recoverable hydrocarbons for the Brasse field have been revised up to 46-76 mmbbls of oil and 59-97 bcf of dry gas (56-92 mmboe in aggregate), an increase of approximately 20%. Extensive feasibility studies of the Brasse field development have also been carried out focusing on a sub-sea development solution tied-back to either one of the nearby hosts, Oseberg or Brage. The preliminary reservoir development plan includes three to six production wells and an optional water injection well for pressure support. Gross plateau flow rates for this field have the potential to exceed 30,000 boepd, with first production scheduled for 2020/21.

Based on the completed reservoir and feasibility studies, preliminary total gross development capex has been estimated at approximately $550 million for the mid-case development scenario consisting of four wells and one subsea template. Key project milestones going forward include the Final Concept Selection and the submission of a PDO, both of which are planned for 2018.

Norwegian licence round awards
In January 2017, Faroe was awarded four new prospective exploration licences including two operatorships under the 2016 Norwegian APA Licence Round on the Norwegian Continental Shelf. Three of the licences are located in the Norwegian North Sea, which include the Brasse Extension (Faroe operator) and the Goanna licence. The Canela licence (Faroe operator) is located in the Norwegian Sea west of the Heidrun field.

Farm-out in Ireland
In H1 2017 Faroe executed a farm out of its Irish licence option 16/23 (Faroe 100%), east of the Corrib field, to Nexen. Under the terms of the farm-out agreement, for which Faroe already has received Ministerial approval, Nexen takes over operatorship and an 80% working interest (Faroe 20%). In return Nexen will meet the costs of the associated work programme, including any acquisition of seismic data and the drilling of an exploration well, if a positive drilling decision is made once the seismic work phase has been completed.

Production

During the first half of 2017, Faroe achieved net average production of 14,800 boepd (H1 2016: 18,800 economic production) a significant increase as a result of the highly value-accretive acquisition of four fields from DONG in 2016. Production guidance remains at between 13,000 to 15,000 boepd as Faroe's key producing assets continue their good performance and with limited production downtime. Average operating expenditure per barrel of oil equivalent (opex/boe) in the period was $26 (2016: $25). Faroe expects to see a material reduction in unit operating costs in the medium term as it invests across its various fields in low cost subsea satellite production.

Faroe's diversified production is spread across a well balanced portfolio of oil and gas assets in Norway and the UK. Approximately 78% of total production came from Norwegian fields and approximately 57% of total production was oil. In Norway, the main producing fields are Trym, Tambar, Ula, Brage and Ringhorne East. The uncertainty over the future of the Trym field (Faroe 50% and operator) located near the Norwegian-Danish boundary, as a result of subsidence of the Tyra host platform (which gathers gas from a number of fields to deliver in excess of 90% of Denmark's gas production) was resolved positively earlier in the year when plans for the redevelopment of the Tyra facilities were announced. Final investment decision on the Tyra redevelopment is expected around year-end. Trym, which contributed approximately one third of the Group's production in H1 2017, is now scheduled to produce for an extended period, until August 2019 before being suspended in order to allow the Tyra redevelopment works to be completed, following which a return to production is expected.

On Tambar (Faroe 45%) operated by AkerBP, work is underway to increase production significantly. The infill well drilling campaign and gas lift installation projects, designed collectively to boost production from 2018 onwards, are expected to commence in Q4 2017. The main scope for this programme is the installation of gas lift for up to five wells, and the drilling of two infill wells. The installation of gas lift is expected to increase materially long term robust flow rates. The Mærsk Interceptor rig has been contracted for this work and to provide accommodation for the offshore workers.

On Brage (Faroe 14.3%) the drilling rig has been remobilised as planned for the drilling of three wells, with one producer-injector pair in the Statfjord horizon and one producer in the Fensfjord. The first Statfjord producer has been drilled and is now on stream with encouraging initial performance. Many targets have been identified for the possible continued further infill drilling beyond the current three wells, which will be subject to the results and performance of the ongoing drilling campaign.

The principal producing fields in the UK are Blane, Schooner and Ketch. Blane continues to perform in line with expectations and the replacement of a sub-sea valve has now been completed to enable production from this low opex field to recommence. Production from Schooner and Ketch has been in line with expectations, but is being impacted by issues within the export system at the Theddlethorpe terminal where the operator has announced its intention to shut down that onshore gas facility at the end of 2018. Faroe is exploring alternative export solutions for Schooner and Ketch. In the event this is unsuccessful, it is likely that the fields will cease production at the end of 2018.

Development projects

Oda (Faroe 15%): In May 2017, the partners in the Oda development received PDO approval of the Oda field from the Norwegian Ministry of Petroleum and Energy. The Oda field in the Norwegian North Sea will be developed via a four-slot seabed template with two production wells and one water injection well which will tie back to the Ula platform (Faroe 20%), located approximately 13 kilometres to the east. The Oda subsea tie-in will connect to the existing pipeline between Oselvar (Faroe 55% and operator) and Ula and reuse the existing Oselvar facilities at the Ula platform. Oselvar production is scheduled to be suspended in Q2 2018 to allow the Oda tie-in works to be undertaken and the Oselvar owners are being financially compensated accordingly. The net compensation payment to Faroe as an Oselvar and Ula joint venture partner is estimated to be approximately £14 million, due to Faroe in 2017 & 2018 (taking into account the payment it makes as an Oda partner and the final tariff compensation payable to Ula). An initial payment to Faroe of £7.4 million net was received in June 2017.

Njord and Bauge (Faroe 7.5%): Approval of the PDO for the Njord Future Project and Bauge field was received in June 2017 from the Norwegian Ministry of Petroleum and Energy. In the meantime the works on the hull of the Njord A Facility in the Stord dry dock have progressed on time and on budget, including the pre-fabrication and subsequent installation of new pontoons. This work is now complete and in early September, the Njord A facility exited the dry dock successfully and on schedule. In parallel, the project to refurbish the Njord B storage tanker is also progressing to plan. The Bauge subsea tie-back project is also progressing to plan. It is envisaged that first oil from Bauge will coincide with production recommencing on Njord and Hyme in 2020.

Fenja (Faroe 25%): Following its discovery in 2014, the Fenja (formerly Pil & Bue) area now includes the Fenja, Bue and Boomerang discoveries. At the end of last year the joint venture partners approved the concept of a subsea development tied back to the Njord platform (Faroe 7.5%). In February 2017 this project entered the Front End Engineering Design (FEED) stage and FDP is expected to be submitted around the end of 2017.

FINANCE REVIEW

The first half of 2017 saw a significant increase in cash flow from operations, as a result of higher accounting production following the acquisition of producing fields from DONG in December 2016, and an increase in realised commodity prices, partially offset by the planned shut down of Njord and Hyme. This contributed to an increased cash balance of £117.6 million (31 December 2016: £96.8 million). Faroe's active exploration programme in Norway, which benefits from the 78% exploration tax rebate, has continued with two wells drilled in H1 2017, of which the Faroe-operated Brasse appraisal well resulted in an increase in estimated recoverable resource volumes and the Boné well (Faroe 20%) which was announced as dry in March 2017.

Revenue adjusted for underlift and including realised hedging losses, totalled £95.5 million, averaging \$45.2 per boe (H1 2016: \$38.7 per boe). Operating costs, excluding depreciation, depletion and amortisation (DDA) increased slightly to \$26.0 per boe[2] compared to \$24.9 per boe in 2016. DDA per boe decreased to \$10.0 compared to \$11.1 in H1 2016.

Income statement

Revenue in the period was £80.1 million (H1 2016: £23.1 million) and is different to 'adjusted revenue' of £95.5 million (H1 2016: £47.4 million) as the former excludes volumes of oil and gas produced but not physically lifted in the period ("Underlift"). The underlift movement of £15.6 million (H1 2016: £20.2 million) is credited to (i.e. reduces) cost of sales under IFRS. The increase in revenue reflects higher production, mainly due to the acquisition of interests in producing fields from DONG in December 2016, and a higher realised price per boe. Overall, the Company realised a £0.5 million gain (H1 2016: £4.1 million) on its hedging and forwards sales activities in H1 2017.

Cost of sales for the period was £74.3 million (H1 2016: £24.2 million). Cost of sales excluding net underlift movement (see paragraph above) was £89.9 million (H1 2016: £44.4 million) reflecting an increase in production and one off estimated future upgrade tariff costs of £11.9 million falling due to Ula as a result of the planned shut-down of Oselvar, and is partially offset by the estimated £4.3 million tariff receipt which is included in Revenue as a result of the Group's interest in Ula. DDA for the period was £20.5 million (H1 2016: £13.7 million). An impairment charge of £3.0 million was booked in the period against Schooner and Ketch (H1 2016: £nil) as a result of uncertainties in the longevity of the downstream infrastructure beyond 2018.

Other income was £21.7 million (H1 2016: expense £3.1 million), of which £18.1 million related to compensation income between Oselvar (Faroe 55%) and Oda (Faroe 15%). £10.4 million of the compensation income was received in June 2017 following PDO approval of the Oda development. A further £7.6 million has been recognised as income and will be received in 2018, when Oselvar is taken offline. The compensation income is partially offset due to the Group's ownership of Oda, with capex costs of £3.0 million being paid in June 2017 and £2.1 million being accrued at the period end reflecting further compensation due to Oselvar for the planned shut down. EBITDAX in H1 2017 increased to £44.0 million compared to £16.7 million in H1 2016.

Pre-tax expensed exploration costs for the half year were £22.8 million (H1 2016: £25.9 million) and include write-offs of the Boné well costs (£20.4 million) and a number of licences where active exploration activity has ceased. Expensed exploration costs also includes £1.6 million (H1 2016: £1.7 million) of pre-award expenditure, which comprises costs associated with licence round applications. Expensed administration costs in H1 2017 were £2.0 million (H1 2016: £4.2 million). The reduction in administrative expenses was due to higher recovery of administration costs as a result of increased operational activity.

The Group made a loss before tax of £6.1 million (H1 2016: £35.9 million). Finance charges were £6.1 million, of which £6.0 million relates to accretion on decommissioning provisions and is non-cash. The tax credit recognised in the income statement in the period was £3.2 million (H1 2016: £22.9 million) largely reflecting higher profits from production in Norway, resulting in a post-tax loss of £2.9 million (H1 2016: £13.0 million).

Taxation

Faroe is an active and successful explorer in Norway with a substantial licence portfolio and relatively high average working interests. Thanks to Norway's progressive fiscal incentive for exploration, Faroe is able to pursue a multi-well exploration programme in Norway for a fraction of the cost of a similar programme outside Norway. The Company benefits directly from a 78% exploration tax rebate, meaning that for every £1 spent the Norwegian Government will return 78p of eligible expenditure in the form of a rebate at the end of the following year, to the extent it is not offset by current year profits from producing assets. The Group had a tax receivable at 30 June 2017 of £51.0 million (31 December 2016: £41.8 million) consisting of 78% of exploration expenditure, net of production profits in Norway. The Company will receive the 2016 tax rebate in November 2017.

2 Opex per boe excludes opex on development assets and non producing assets and tariff costs in relation to future upgrades

At 30 June 2017 the Group had unrelieved UK tax losses of approximately £53.0 million (31 December 2016: £58.1 million). The unrelieved tax losses are available indefinitely for offset against future taxable profits in the UK. The carried forward losses are expected to be utilised in coming years, depending upon commodity prices, and are recognised as a deferred tax asset at the prevailing rate of 40%, being corporation tax of 30% and supplementary corporation tax ('SCT') of 10%.

Development capex in Norway is depreciated on a straight line basis over six years for tax purposes. In addition, an uplift of 21.6% can be offset against the 53% special tax. The uplift is taken on a straight line basis over four years. This means that close to 90% of capex spend is recovered through the tax system. At 30 June 2017, Faroe had carried forward capex balances of £71.2 million and carried forward capex uplift of £39.8 million in Norway. In addition, at 30 June 2017, Faroe had carried forward tax losses in Norway of £18.4 million and £14.5 million for corporation tax and special tax respectively.

In June 2017, the Company had a deferred tax asset of £113.0 million in respect of carried forward tax losses, capex balances and uplifts in the UK and Norway, net of other temporary differences.

Balance sheet and cash flow

Expenditure of £55.4 million (H1 2016: £17.3 million) on intangible and tangible assets, prior to tax rebate, was made in the period, of which £33.4 million (post tax £7.3 million) related to exploration expenditure, primarily on Brasse and Boné. £22.0 million related to development expenditure, principally reflecting pre-sanction cost on the Oda field and the Njord capital enhancement project.

During the period, the book value of Bauge (previously Snilehorn) was reclassified from intangible exploration assets to property plant and equipment, totalling £5.9 million following PDO approval from Norwegian authorities and a clearly defined path and timeline to project sanction.

The Group recognises the discounted cost of decommissioning when obligations arise. The amount recognised is the present value of the estimated future expenditure, net of any amounts carried by third parties. At 30 June 2017 the Group had decommissioning provisions of £268.2 million (31 December 2016: £267.1 million). Most of the decommissioning expenditure is scheduled to be incurred from 2020 to 2040.

The net assets of Faroe Petroleum decreased during the period to £238.4 million (31 December 2016: £246.6 million).

Cash and net cash at 30 June 2017 was £117.6 million (31 December 2016: £96.8 million). This excludes restricted cash of £7.7 million (31 December 2016: £11.8 million) primarily consisting of monies set aside for asset retirement obligations on the acquired assets from DONG. The increase in cash at 30 June 2017 is primarily due to increased cash flow from operations due to a combination of higher production, higher price realisations and relatively constant operating costs per barrel, offset by increased capex in the period.

Hedging

The Group operates a policy to hedge a proportion of its production in order to safeguard revenues and budgets. Hedged volumes, on a post-tax basis, currently amount to approximately 100% of total estimated gas production in H2 2017 and 80% in 2018. The hedging instruments selected are primarily put options and swaps at a weighted average of 41 pence per therm in H2 2017 and 42 pence per therm in 2018. Approximately 35%, 50% and 10% of expected post-tax oil production in H2 2017, H1 2018 and H2 2018 respectively has been hedged with put options at a weighted average strike price of $55 / bbl.

Open hedge contracts are marked to market at the end of each period with unrealised gains or losses taken to the Income Statement as other income/expense as a non-cash item. Unrealised hedging gains for H1 2017 were £4.0 million (H1 2016: loss £7.2 million). Hedging gains of £0.8 million were realised in H1 2017 (H1 2016: gain £4.7 million) before incurring hedging premiums of £1.1 million (H1 2016: £0.5 million) leading to a realised hedging loss of £0.3 million (H1 2016: gain £4.1 million) and these are also included in other income / (expense).

Dividend

The Directors do not recommend payment of a dividend.

Group Income Statement	Unaudited Six months to 30 June 2017	Unaudited Six months to 30 June 2016	Audited Year to 31 December 2016
	£'000	£'000	£'000
Revenue	80,139	23,083	94,779
Cost of sales	(74,324)	(24,173)	(96,666)
Asset impairment	(3,000)	-	(2,823)
Gross profit / (loss)	2,815	(1,090)	(4,710)
Other income / (expense)	21,725	(3,079)	(8,412)
Exploration and evaluation expenses	(22,796)	(25,936)	(33,468)
Administrative expenses	(2,021)	(4,205)	(10,189)
Operating loss	(277)	(34,310)	(56,779)
Finance revenue	238	296	6,423
Finance costs	(6,092)	(1,932)	(11,139)
Loss on ordinary activities before tax	(6,131)	(35,946)	(61,495)
Tax credit	3,191	22,903	28,686
Loss for the period	(2,940)	(13,043)	(32,809)
Loss per share – basic (pence)	(0.80)	(4.85)	(10.5)
Loss per share – diluted (pence)	(0.80)	(4.85)	(10.5)

Statement of Other Comprehensive Income	Unaudited Six months to 30 June 2017	Unaudited Six months to 30 June 2016	Audited Year to 31 December 2016
	£'000	£'000	£'000
Loss for the period	(2,940)	(13,043)	(32,809)
Items that may be reclassified subsequently to profit or loss:			
Exchange differences on retranslation of foreign operations net of tax	(7,160)	14,542	21,855
Total comprehensive (loss) / profit for the period	(10,100)	1,499	(10,954)

Group Balance Sheet	Unaudited 30 June 2017	Unaudited 30 June 2016	Audited 31 December 2016
	£'000	£'000	£'000
Non-current assets			
Goodwill	7,534	-	7,744
Intangible assets	110,203	88,990	107,376
Property, plant and equipment: development & production	160,086	107,310	157,428
Property, plant and equipment: other	495	374	611
Deferred tax asset	112,974	39,306	122,055
	391,292	235,980	395,114
Current assets			
Inventories	10,478	6,618	10,456
Trade and other receivables	86,931	45,738	63,063
Current tax receivable	50,999	64,534	41,764
Financial assets	2,072	3,129	-
Cash and cash equivalents	117,574	83,895	96,769
	268,054	203,914	212,052
Total assets	659,346	439,894	607,266
Current liabilities			
Trade and other payables	(105,436)	(38,601)	(53,900)
Current Taxation	-	-	(31)
Financial liabilities	(44,968)	(81,840)	(35,845)
Financial liabilities – other	-	-	(1,383)
	(150,404)	(120,441)	(91,159)
Non-current liabilities			
Deferred tax liabilities	-	(29,814)	-
Provisions	(270,533)	(94,634)	(269,469)
	(270,533)	(124,448)	(269,469)
Total liabilities	(420,937)	(244,889)	(360,628)
Net assets	238,409	195,005	246,638
Equity attributable to equity holders			
Equity share capital	36,657	26,903	36,453
Share premium account	315,580	262,478	315,580
Cumulative translation reserve	10,580	9,290	17,740
Retained earnings	(124,408)	(103,666)	(123,135)
Total equity	238,409	195,005	246,638

Condensed Group Cash Flow Statement	Unaudited Six months to 30 June 2017	Unaudited Six months to 30 June 2016	Audited Year to 31 December 2016
	£'000	£'000	£'000
Loss before tax	(6,131)	(35,946)	(61,495)
Depreciation, depletion and amortisation	20,663	13,661	23,369
Exploration asset write off	21,175	10,117	29,908
Unrealised hedging losses / (gains)	(3,975)	7,211	13,095
Asset impairment	3,000	-	2,823
Fair value of share based payments	1,662	1,900	4,408
Movement in trade and other receivables	(25,940)	(10,282)	(24,478)
Movement in inventories	(22)	(696)	(4,534)
Movement in trade and other payables	50,153	6,183	22,865
Currency translation adjustments	(1,988)	(3,003)	(5,814)
Expense recognised in respect of equity settled share based transaction	-	-	-
Interest receivable	(238)	(296)	(609)
Interest and financing fees payable	8,081	4,935	11,139
Tax (payment)/rebate	(193)	(873)	44,729
Net cash generated from / (used in) operating activities	66,247	(7,089)	55,406
Investing activities			
Purchases of intangible and tangible assets	(55,432)	(17,269)	(79,447)
Interest received	238	296	609
Net cash used in investing activities	(55,194)	(16,973)	(78,838)
Financing activities			
Proceeds from issue of equity instruments	204	104	66,901
Issue costs	-	-	(4,145)
Net proceeds / (repayments) from borrowings	9,123	19,635	(19,931)
Interest and financing fees paid	(1,661)	(2,170)	(4,225)
Net cash inflow provided from financing activities	7,666	17,569	38,600
Net increase / (decrease) in cash and cash equivalents	18,719	(6,493)	15,168
Cash and cash equivalents at the beginning of period/year	96,769	91,515	91,515
Effect of foreign exchange rate changes	2,086	(1,127)	(9,914)
Cash and cash equivalents at end of period/year	117,574	83,895	96,769

Group Statement of Changes in Equity for the period ended 30 June 2017	Share capital £000	Share premium account £000	Cumulative translation reserve £000	Retained earnings £000	Total £000
As at 1 January 2017	**36,453**	**315,580**	**17,740**	**(123,135)**	**246,638**
Loss for the period	-	-	-	(2,940)	(2,940)
Other comprehensive loss:					
Loss on retranslation of foreign subsidiaries	-	-	(7,160)	-	(7,160)
Total comprehensive loss	-	-	(7,160)	(2,940)	(10,100)
Issue of ordinary shares under EBT	204	-	-	-	204
Share based payments	-	-	-	1,667	1,667
As at 30 June 2017	**36,657**	**315,580**	**10,580**	**(124,408)**	**236,477**

Group Statement of Changes in Equity for the period ended 30 June 2016	Share capital £000	Share premium account £000	Cumulative translation reserve £000	Retained earnings £000	Total £000
As at 1 January 2016	**26,824**	**262,453**	**(4,055)**	**(92,866)**	**192,356**
Loss for the period	-	-	-	(13,043)	(13,043)
Other comprehensive income:					
Gain on retranslation of foreign subsidiaries	-	-	14,542	-	14,542
Total comprehensive income/(loss)	-	-	14,542	(13,043)	1,499
Transfer to retained earnings*	-	-	(1,197)	1,197	-
Issue of ordinary shares under EBT	79	25	-	-	104
Share based payments	-	-	-	1,046	1,046
As at 30 June 2016	**26,903**	**262,478**	**9,290**	**(103,666)**	**195,005**

*An adjustment has been made to align the financial statements to the underlying accounting records following the intercompany loan balance between the Company and Føroya Kolvetni P/F being repaid as a capital contribution. Since the loan was classified as quasi-equity, historic revaluation balances were transferred to Retained Earnings.

Group Statement of Changes in Equity for the period ended 31 December 2016	**Share capital £000**	**Share premium account £000**	**Cumulative translation reserve £000**	**Retained earnings £000**	**Total £000**
As at 1 January 2016	**26,824**	**262,453**	**(4,055)**	**(92,866)**	**192,356**
Loss for the year	-	-	-	(32,809)	(32,809)
Other comprehensive income:					
Gain on retranslation of foreign subsidiaries	-	-	21,855	-	21,855
Total comprehensive income / (loss)	-	-	21,855	(32,809)	(10,954)
Transfer to retained earnings	-	-	(60)	60	-
Issue of ordinary shares	9,629	57,272	-	-	66,901
Issue costs	-	(4,145)	-	-	(4,145)
Share based payments	-	-	-	2,480	2,480
As at 31 December 2016	**36,453**	**315,580**	**17,740**	**(123,135)**	**246,638**

Notes

(i) Basis of preparation

As required in AIM Rule 18, the interim financial information for the six months ended 30 June 2017 is presented and prepared in a form consistent with those that which will be adopted in the annual statutory financial statement for the year ended 31 December 2016 and having regard to the International Financial Reporting Standards ("IFRS") applicable to such annual accounts.

The financial information contained in this announcement for the year ended 31 December 2016 does not constitute statutory financial statements within the meaning of Section 435 of the Companies Act 2006.

An unqualified audit opinion was expressed on the statutory accounts for the year ended 31 December 2016, as delivered to the Registrar. This unqualified audit opinion did not contain a statement under s498(2) or s498(3) of the Companies Act 2006.

(ii) Earnings per share

The calculation of earnings per share is based upon the weighted average number of ordinary shares in issue during the period of 365,352,143 (30 June 2016: 268,954,509 and 31 December 2016: 311,582,557).

Total shares in issue as at 30 June 2017 amounted to 366,571,040 with potential for an additional 30,973,255 contingently issuable shares under the Company Share Option and Company Incentive Plan schemes. The contingently issuable shares are anti-dilutive as their conversion would decrease the loss per share.

(iii) Dividend

The Directors do not recommend payment of a dividend.

(iv) Foreign currencies

The assets and liabilities of foreign operations are translated into sterling at the rate of exchange ruling at the balance sheet date. The resulting exchange differences are taken directly to a separate component of equity. On disposal of a foreign entity, the deferred cumulative amount recognised in equity relating to that particular foreign operation is recognised in the income statement.

(v) Taxation

Tax on profit on ordinary activities	Unaudited Six months to 30 June 2017	Unaudited Six months to 30 June 2016	Audited Year to 31 December 2016
	£'000	£'000	£'000
Current tax			
Overseas tax credit	10,367	23,882	41,764
UK Tax charge	-	-	(214)
Amounts (underprovided) / overprovided in previous period/ year	(163)	188	195
Total current tax credit	10,204	24,070	41,745
Deferred tax			
Origination of temporary differences	(6,238)	491	(11,316)
Prior period/year adjustment	(702)	(168)	75
Total deferred tax charge	(6,940)	(323)	(11,241)
Foreign exchange differences			
Differences arising from the use of period end and average exchange rates	(73)	(844)	(1,818)
Total foreign exchange differences	(73)	(844)	(1,818)
Total tax credit in the Income Statement*	3,191	22,903	28,686

* Non-cash tax credit / (charge)

(vi) Cost of sales

Analysis of cost of sales	Unaudited six months to 30 June 2017	Unaudited six months to 30 June 2016	Audited Year to 31 December 2016
	£000	£000	£000
Operating costs*	36,416	18,301	40,671
Commercial tariffs*	17,684	10,961	24,524
Commercial tariffs relating to future upgrades	11,944	-	-
Depreciation, depletion and amortisation	20,473	13,661	22,994
(Underlift)/overlift in the year	(15,632)	(20,234)	6,985
Other cost of sales*	3,439	1,484	1,492
Total cost of sales	74,324	24,173	96,666

* included in the opex per boe metric

(vii) Other income / (expense)

Analysis of other income	Unaudited six months to 30 June 2017 £000	Unaudited six months to 30 June 2016 £000	Audited Year to 31 December 2016 £000
Compensation received[3]	10,441	-	-
Compensation accrued[3]	7,619	-	-
Realised hedging (losses) / gains*	(310)	4,132	4,683
Unrealised hedging gains / (losses)	3,975	(7,211)	(13,095)
Total other income / (expense)	21,725	(3,079)	(8,412)

* included in the revenue per boe metric

(viii) Post balance sheet events

On 26 July 2017, the Company announced the successful Brasse appraisal well, which proved up recoverable resource volumes now estimated to be between 56 and 92 mmboe (previously 43-80 mmboe).

On 28 July 2017, the Company announced the conditional acquisition of a further 13.9935% interest in the Blane field in the UK North Sea from JX Nippon Exploration and Production (U.K.) Limited for a total consideration of $5.25 million.

On 12 September 2017, the Company announced that drilling had reached the target depth on the Goanna exploration well 33/9-22 S (Faroe carried interest 30%) in licence PL 881 and encountered approximately 49 metres of gross water bearing reservoir in the primary target, the Upper Jurassic Munin Formation sandstones. The cost of the well, operated by Wellesley Petroleum (70%), is expected to come in below budget and as such Faroe's associated costs will be fully carried by its joint venture partner.

3 The PDO for Oda was approved in H1 2017 and this led to a payment from the Oda partnership to the Oselvar partnership. The Group received £10.4 million due to its ownership of Oselvar. A further £7.6 million has been recognised in relation to future receipts when Oselvar is taken off line in 2018. Two further compensation payments, which have not been recognised, are expected, one related to production volumes and one related to the completion of the Oda tie-in.

Glossary

APA	awards in pre-defined areas
bcf	billions of standard cubic feet
boe	barrels of oil equivalent
boepd	barrels of oil equivalent per day
Bpd	barrels per day
DDA	depletion, depreciation and amortisation
DONG	DONG E&P Norge AS
DST	drill stem test
EBITDAX	earnings before interest, taxation, depreciation, amortisation and exploration expenditure
economic production	production to which the Company has an economic entitlement. It includes production between the effective (economic) date and the completion date of an acquisition. Accounting production excludes all pre-completion production.
mmbbls	million barrels of oil
mmboe	million barrels of oil equivalent
netback	revenue less operating cost per boe
net cash	cash and cash equivalents less financial liabilities excluding the balance of the Exploration Financing Facility which is directly linked to the Norway tax rebate (disclosed as tax receivable in the balance sheet).
PDO	Plan for development and operation
psia	pounds per square inch absolute

John Wood, is the UK Asset Manager of Faroe Petroleum and an engineer (M.Sc in Petroleum Engineering, Imperial College, London), who has been involved in the energy industry for more than 16 years, has read and approved the technical disclosure in this regulatory announcement.

Andrew Roberts, Group Exploration Manager of Faroe Petroleum and a Geophysicist (BSc. Joint Honours in Physics and Chemistry from Manchester university), who has been involved in the energy industry for more than 25 years, has read and approved the exploration and appraisal disclosure in this regulatory announcement.

Estimates of reserves and resources contained in this announcement were prepared in accordance with the Petroleum Resource Management System guidelines endorsed by the Society of Petroleum Engineers, World Petroleum Congress, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers.

The information contained within this announcement is considered to be inside information prior to its release, as defined in Article 7 of the Market Abuse Regulation No. 596/2014, and is disclosed in accordance with the Company's obligations under Article 17 of those Regulations.

Forward looking statements and dates referenced in this announcement, in relation to Faroe's exploration, development and production assets are estimates and subject to change. Oil and gas operations, particularly those relating to development stage assets are subject to varying inputs that may impact timing, including inter alia permitting; environmental regulation; changes to regulators and regulation; third party manufacturers and service providers; the weather and asset partner and operator actions. The Company's estimates of timing for forward looking operations are based on the best information it has to hand at the time, however these timings may change with little or no notice to the Company. The Company will update the market as and when it becomes aware of a material change to any of the operations or timings referenced in this announcement.