SOCO International plc
("SOCO" or the "Company")

PRELIMINARY RESULTS

SOCO, an international oil and gas exploration and production company, today announces its preliminary full year results for the year ended 31 December 2016.

Ed Story, President and Chief Executive Officer of SOCO, commented,
"With our disciplined approach to capital allocation, we performed well against our peers during the prolonged oil price downturn and continued to return cash to shareholders, with a recommended 5p dividend announced today. Following the improved macro environment, we are increasing our efforts to provide material growth to the Company. During the extremely low and volatile prices, asset or corporate transactions were difficult to secure. However, at current, more stable prices we are seeing a window of opportunity which we intend to take advantage of in order to grow the portfolio and create more value for shareholders.

After nearly two years of very limited investment on our prime asset, we are now able to address the lack of drilling and the liquid handling restrictions on the TGT producing field. With development drilling recommenced at the end of 2016 and with an approved updated FFDP, we expect to arrest the performance decline and grow production."

2016 FINANCIAL HIGHLIGHTS

- Robust balance sheet, zero debt, solid cash flow, low cash operating costs
    - Year end cash balance of $100.3m (2015: $103.6m) and no debt;
        - $150.5m as of 22 March 2017 following receipt of the remaining proceeds ($42.7m) associated with the disposal of our Mongolia assets
    - Revenue of $154.6m (2015: $214.8m)
    - Average realised crude oil price of $45 per bbl (2015: $54), a premium to Brent of over $1 per bbl
    - $46.0m generated from operations (2015: $80.3m)
    - After tax loss of $18.3m (2015: $33.8m loss)
    - Cash capital expenditure of $40.1m (2015: $92.4m), fully funded from existing cash resources
        - Vietnam $13.9m
        - Africa $26.2m, including cost savings achieved on the MPS well
    - Low cash operating expenditure of $11.70 per bbl[1] (2015: $10.06 per bbl); operating cash flow break-even oil price per bbl[1] still in the low $20s
- Recommended dividend of 5 pence per share (approx. $20.6m)
    - Dividends to shareholders during 2016 of $17.5m via two 2p dividends (2015: $51.1m)
    - $455m returned to shareholders to date.

2016 OPERATIONAL HIGHLIGHTS

- Net production of 9,883 BOEPD (2015: 11,976 BOEPD)
- Resumption of TGT development drilling in November
- Approval of the TGT updated FFDP
- New ventures negotiations for Blocks 125 & 126, offshore Vietnam, near conclusion; the execution of a PSC is expected 1H 2017
- Marine XI Lidongo Permit Production Exploitation Licence application has been approved by authorities granting 20 year rights; renegotiation of PSC commercial terms are near positive conclusion
- Group year-end 2016 commercial reserves 33.3 MMboe (2015: 37.3 MMboe) following production

OUTLOOK FOR 2017

- Continued focus on value creation, sustainable returns and capital discipline
- Heighten the pursuit of growth and rationalisation of our portfolio, with Mike Watts and Jann Brown, former FTSE100 directors, spearheading business development efforts
- Blocks 125 & 126, offshore Vietnam, PSC formal signing expected in the first half
- Production Licence applications to be considered for remaining discovery areas on Marine XI in Congo
- 2017 capital expenditure of approx. $50m to cover the development drilling and infrastructure upgrade on our existing Vietnam assets, purchase of seismic data for our new venture Blocks 125 & 126 in Vietnam and PEX bonuses in Africa on Marine XI
- Production guidance of 8,000 to 9,000 BOEPD for the full year 2017

ENQUIRIES:

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NOTES TO EDITORS

SOCO is an international oil and gas exploration and production company, headquartered in London and traded on the London Stock Exchange. The Company has field development and production interests in Vietnam and exploration and appraisal interests in the Republic of Congo (Brazzaville) and Angola.

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[1] See Glossary

CHAIRMAN AND CHIEF EXECUTIVE'S STATEMENT

2017 marks the Company's 20th anniversary. During the intervening period, the industry has experienced the highest ever oil prices and one of the most significant oil price downturns, but throughout, because of our disciplined approach to capital allocation, we have been able to deliver significant and sustainable value to shareholders.

A BRIGHT FUTURE, BUILT ON A SOLID PAST

With only one small equity fundraising subsequent to the IPO, bringing total equity raised since inception to $231m, we have built shareholder value; returned over $455m through capital returns, share buybacks and dividends. We have achieved this by recognising opportunity, capturing potential and realising value.

Early on, we recognised the significant opportunity in then under explored Vietnam. By initially focusing on the under-regarded basement plays, we acquired two blocks, Blocks 16-1 and 9-2, offshore southern Vietnam at the turn of the millennium. With basement exploration yielding results in Block 9-2 with the discovery of the Ca Ngu Vang ("CNV") Field in 2002, emphasis on Block 16-1 changed to more conventional targets, delivering the discovery of the Te Giac Trang ("TGT") Field in 2005. Our investment in Vietnam has been significant, but unquestionably fruitful. TGT and CNV together now comprise one of Vietnam's largest producers, generating strong and stable revenues for SOCO and its partners throughout the commodity price cycle adding by continued low operating costs.

Through a series of 13 separate transactions, the Company internally funded a significant development programme in Vietnam and pursued new exploration ventures, primarily in West Africa. Since TGT production came on stream in 2011, not only were we able to continue to fund internally our ongoing development and exploration efforts, we were also able to commence sustainable cash returns to shareholders.

The challenge that comes with oil prices being at extreme lows or extreme highs is to sustainably deliver on growth without exposure to high risk and high cost exploration. However, as oil prices have recently recovered to a fairly stable mid-price range, we see a window of opportunity to deliver the growth aspect of our strategy for building shareholder value. Towards this end, in early 2017, we added two former FTSE100 executives to co-head a newly formed business development function. Dr Mike Watts and Jann Brown have the experience, track record and industry knowledge to add the next leg of growth to our stable and high value producing assets.

2016 PERFORMANCE

SOCO's balance sheet remained robust throughout 2016 with zero debt, solid cash flow and low cash operating costs. The Company finished the year with no debt and over $100m in cash, cash equivalents and liquid investments after fully funding its operating and capital expenditure programme and returning $17.5m to shareholders through two cash dividends.

Overall net production was 9,883 BOEPD (2015: 11,976 BOEPD). Levels were slightly below the lower end guidance of 10,000 BOEPD due to a lack of development drilling for almost two years in TGT. This was primarily as a result of our joint venture government partners experiencing cash constraints, as well as unexpected additional production downtime due to pressure-testing on CNV, along with production stoppage to allow for rig positioning and down-well intervention work.

Capital expenditure in 2016, fully funded from existing cash resources, was $40.1m (2015: $92.4m), a significant reduction for the second year resulting from reduced or postponed spending on capital equipment that had little bottom line impact. Actual capital expenditure for Vietnam was below the $17m budgeted amount at just under $14m. This included long lead items for the anticipated resumption of TGT Field development drilling and new venture costs associated with Blocks 125 & 126. Capital expenditure for 2017 is for the infill drilling costs, costs associated with a water handling facilities upgrade following Full Field Development Plan ("FFDP") approval and costs to complete drilling activities on the TGT-14X appraisal well. Capital expenditure for Africa exploration operations was $26m, reflecting cost savings achieved on the Mer Profonde Sud commitment well, drilled offshore Congo (Brazzaville) in Q1 2016.

Net cash generated from operations fell to $46.0m in 2016, from $80.3m in 2015, reflecting lower oil prices and the decrease in production described above. An average crude oil sales price of $45 per barrel was realised during 2016, representing a premium of over $1 per bbl to Brent and generating revenues of $154.6m (2015: $214.8m), against low cash operating expenditure of $11.70 per bbl (2015: $10.06 per bbl). SOCO's full operating cost break-even oil price per bbl remains in the low $20s. The Group posted a loss of $18.3m (2015: $33.8m loss) in the period after taking account of taxation. There has been no impairment of our producing assets in the period (2015: nil).

In December 2016, SOCO received $10.0m as partial payment for the $52.7m Subsequent Payment Amount associated with SOCO's 2005 sale of its Mongolia assets. The full remaining unpaid amount of $42.7m was received in March 2017. Group year-end 2016 commercial reserves were 33.3 MMboe (2015: 37.3 MMboe), down from year-end 2015 primarily due to yearly production.

OPERATIONS

VIETNAM

Operations on the TGT and CNV Fields in our core business area offshore Vietnam were centred on optimising production efficiency, and preparing for and beginning the next phase of development of the TGT Field aimed at a halting the production decline resulting from almost two years without drilling activity on TGT, which remains not fully developed. The 2016 TGT development drilling programme commenced in the latter part of 2016 in advance of formal approval of the updated FFDP in February 2017, signalling a positive realignment amongst partners.

Production

Production averaged 9,883 BOEPD net to SOCO's working interest (2015: 11,976). SOCO's production guidance range for 2017 is affected by the additional shut-ins on TGT planned to accommodate rig moves, as well as the extended shut down for the installation, hook up and commissioning of the equipment for additional liquid handling capacity, and the FPSO maintenance shut down. Thus, full year production guidance for 2017 is presently anticipated to average 8,000 to 9,000 BOEPD net to SOCO's working interest.

Block 16-1 – TGT Field – Development Drilling and Optimisation

(30.5% working interest; operated by Hoang Long Joint Operating Company ("HLJOC"))

Well intervention work carried out in 1H 2016 included perforations to six wells and a water shut off liner on one well. The impact of the interventions exceeded expectations by adding approx. 2,200 BOEPD to gross production.

The 2016 TGT Development Drilling Programme recommenced in Q4 2016. Drilling began with two infill wells, TGT-27PST1 and TGT-28P, "batch drilled" on the H4-WHP. The HLJOC partners have agreed to add an additional infill well from the H1-WHP, which commenced on 8 March 2017. Following that a further infill well on the southern H5-WHP, followed by the TGT-14X well drilling into the H5 South fault block, are also planned be drilled as part of the 2017 programme.

The first full draft of the updated FFDP underwent review by all the HLJOC partners during 1H 2016. SOCO utilised the review period to ensure that the FFDP development scenarios match the Company's performance objectives. The final draft of the updated FFDP was formally submitted to the relevant authorities during 2H 2016. Approval was received during Q1 2017.

Block 9-2 – CNV Field

(25% working interest; operated by Hoan Vu Joint Operating Company ("HVJOC"))

Discussions with the Bach Ho owners are ongoing to establish the most effective means of enhancing performance through modifications at the reception terminal.

AFRICA EXPLORATION

Marine XI Block, offshore Congo (Brazzaville)

(Operated, 40.39% working interest)

The Marine XI partners secured the 20-year permit for the area around the Lidongo discovery well in September 2016. The partners will consider submitting three additional PEX applications over Lideka East, Viodo and Loubana prior to the end of the Marine XI Exploration Licence.

Mer Profonde Sud ("MPS") Block, offshore Congo (Brazzaville)

The Baobab Marine-1 commitment well spudded on 5 February 2016, but was plugged and abandoned after no hydrocarbons were encountered. All parties agreed to relinquish the MPS Block at the licence expiry date of 31 May 2016.

Cabinda North Block, onshore Cabinda, Angola

(Non-operated, 17% working interest)

During 2016, discussions continued amongst the partners and with the authorities to agree the new partnership, operator and activities during the licence extension period to April 2018. The legal documents to complete the changes are now being circulated among the parties for formal approval.

NEW VENTURES

Negotiations are near conclusion for a 70% interest in a Production Sharing Contract ("PSC") over two blocks, Blocks 125 & 126, in the Phu Khanh Basin offshore central Vietnam. The PSC amongst SOCO, Sovico Holdings Company and PetroVietnam is expected to be executed during 1H 2017.

The Company actively reviewed acquisition opportunities throughout 2016 and is continuing this initiative through 2017 with a newly launched business development group.

CORPORATE

Non-Executive Directors

During the year, John Norton and Robert Cathery, retired from the Board at the June AGM, after announcing in March 2016 that they would not seek reappointment by shareholders. Marianne Daryabegui stood down from the Board at the expiry of her initial contract in October due to her employer limiting its employees' participation as non-executive directors. In January 2017, Mike Watts stood down to co-head Business Development for the Group. Rob Gray, the Board's Senior Independent Director, has replaced Mike Watts as Chairman of the Audit & Risk Committee.

Corporate governance remains a priority and the Company remains committed to its programme of Board refreshment. The Directors will continue to review the balance and effectiveness of the Board with a view to adding independent non-executives commensurate with our size and need.

Dividend recommendation

The Board proposes a final dividend for the year ended 31 December 2016 of 5 pence per share which will be recommended for shareholder approval at the Annual General Meeting to be held in June of this year.

SOCO remains committed to the strategy of value creation for shareholders including through sustainable cash returns and growth of the ongoing business. SOCO's capital strategy includes retaining a strong balance sheet under all reasonable oil price scenarios and maintaining flexibility to invest organically and inorganically in attractive risk/return profile projects.

The Company's consistently successful management of its asset and capital base has enabled it to return over $450m to shareholders over the last eight years via dividends, capital returns and share buybacks, and through the difficult market economy of 2016, to deliver a fully funded capital expenditure programme and two, 2 pence cash dividends. SOCO continues to generate solid cash flow, closing the year with over $100m of cash and no debt.

OUTLOOK

In recent years, significant differentiators have developed between the Company and its sector peers:

- Balance sheet strength, no debt and steady cash flows
- Low operating costs and attractive production economics
- Sustainable cash returns to shareholders

In 2017, our focus will be three-fold:

1) Continuing our disciplined approach to capital allocation;
2) Arresting the decline of our major producing asset, the TGT Field; and
3) Growing the portfolio of assets.

We seek to seize real opportunities as they arise, looking to optimise exposure to upside without jeopardising the Company's focus on sustainable cash flow generation. The launch of the new Business Development group has added impetus to these efforts.

In the coming months, we expect to announce a new PSC over two blocks, offshore Vietnam, adding to our existing strong presence in the region. For our production assets in Vietnam, development drilling and infrastructure upgrade on TGT remains a priority. Production guidance for 2017 is maintained at 8,000 to 9,000 BOEPD for the full year 2017. Efforts to maximise value from our Africa exploration portfolio will remain a prominent feature in 2017.

Although we do not foresee a return to either the recently experienced low oil price environment or the extremely high oil prices of past years, we remain confident that, regardless of the macro environment, our strategy will deliver substantial and sustainable value to shareholders, as has already been demonstrated in the past.

Rui de Sousa
Chairman

Ed Story
President and Chief Executive Officer

REVIEW OF OPERATIONS

Operations in 2016 centred on optimizing production efficiency on Te Giac Trang ("TGT") and Ca Ngu Vang ("CNV") Fields in our core business area, offshore southern Vietnam. The TGT Field, which was discovered in 2005 and achieved first oil in 2011, is producing from three platforms with 30 producing wells and one injector well drilled in the field. The next phase of development of the TGT Field commenced in the latter part of 2016 and in advance of formal approval of the updated Full Field Development Plan ("FFDP") in February 2017, signalling a positive realignment amongst partners and a halt to the production decline resulting from almost two years of no drilling. Group production was 9,883 BOEPD (2015: 11,976) net to SOCO's working interest.

New venture final negotiations over two blocks, Blocks 125 & 126, offshore Vietnam, should secure a 70% interest in the new Production Sharing Contract ("PSC"). Signing of the PSC is expected to occur during 1H 2017.

In Africa, activity concentrated on commercialisation discussions for the Lidongo discovery area and the interpretation of the reprocessed 3D seismic data on the Marine XI Block, offshore Congo (Brazzaville). Efforts to maximise value from our Africa exploration portfolio were a prominent feature in 2016 and will continue to be so in 2017.

VIETNAM

In Vietnam, Blocks 16-1 and 9-2, which comprise the TGT and CNV Fields, respectively, are located in shallow water in the oil rich Cuu Long Basin, near the Bach Ho Field, the largest field in the region which has produced more than one billion barrels. The Blocks are operated through non-profit joint operating companies in which each partner holds an interest equivalent to its share in the respective Petroleum Contract. SOCO holds a 30.5% working interest in Block 16-1 and a 25% working interest in Block 9-2 through its wholly owned subsidiaries, SOCO Vietnam Ltd and OPECO Vietnam Limited. SOCO's partners in both Blocks are PetroVietnam Exploration and Production, a subsidiary of the national oil company of Vietnam, and PTTEP, the national oil company of Thailand.

Production

SOCO's production interests are the TGT and CNV Fields. Gross production averaged 33,861 BOEPD — 9,883 BOEPD net to SOCO's working interest (2015: 41,029 and 11,976, respectively). Overall net production of 9,883 BOEPD was slightly below the lower end guidance of 10,000 BOEPD due to the delay in development drilling, unexpected additional downtime due to pressure-testing on CNV, along with the recent stoppage for rig positioning and down-well intervention work beyond that originally planned for extra wireline and other types of intervention work.

TGT production averaged 27,650 BOEPD gross — 8,330 BOEPD net to SOCO's working interest in 2016 (2015: 34,032 BOEPD gross and 10,227 BOEPD, respectively). CNV production averaged 6,211 BOEPD gross — 1,553 BOEPD net to SOCO's working interest in 2016 (2015: 6,997 BOEPD gross and 1,749 BOEPD, respectively).

SOCO's production guidance range for 2017 is affected by the additional shut-ins (equivalent to up to approximately 25-30 days in total) on TGT planned to accommodate rig moves, as well as the extended shut down for the installation, hook up and commissioning of the equipment for additional liquid handling capacity, and the FPSO scheduled maintenance shut down. This is significantly higher than occurred in 2016 and, as such, impacts on the expected total average production for the year. Thus, full year production guidance for 2017 is presently anticipated to average 8,000 to 9,000 BOEPD.

The average realised crude oil price for 2016 was approximately $45 per bbl, a premium to Brent of over $1 per bbl

Production by field	**FY 2016**	**FY 2015**
TGT Production	**8,330**	10,227
Oil	7,825	9,397
Gas[1]	505	830
CNV Production	**1,553**	1,749
Oil	1,076	1,204
Gas[1]	477	545
Total Production	**9,883**	11,976
Oil	8,901	10,601
Gas[1]	982	1,375

Figures in BOEPD
[1] *Assumes oil equivalent conversion factor of 6,000 standard cubic feet per barrel of oil equivalent.*

Block 16-1 – TGT Field

(30.5% working interest; operated by Hoang Long Joint Operating Company ("HLJOC"))

The TGT Field is located in the north eastern part of Block 16-1 offshore Vietnam and is operated by HLJOC. SOCO's interest in the Block was awarded in December 1999 and the first commercial discovery was made in 2005.

TGT is a simple structure, with complex production intervals, extending over 16 km and with hydrocarbons located in at least five major fault blocks. The producing reservoir comprises a complex series of over 80 modelled clastic reservoir intervals of Miocene and Oligocene age. Each reservoir interval requires individual reservoir management to optimise field recovery. The TGT Field has been a rewarding investment for SOCO with its attractive economics and cost recovery terms, along with low operating costs, and a benign operating and geopolitical backdrop.

The first platform, H1-WHP, came on stream in August 2011, followed by the H4-WHP in July 2012. Crude oil from TGT is transported via subsea pipeline to a floating, production, storage and offloading vessel ("FPSO") where it is processed, stored and exported by tankers to regional oil refineries. Gas produced from the Field is transported by pipeline to the nearby Bach Ho facilities for processing and onward transportation to shore by pipeline to supply the Vietnamese domestic market.

TGT - ongoing field development

After the third TGT platform, H5-WHP, was successfully brought onstream on 10 August 2015, activities for 2016 focussed on optimizing production efficiency from existing wells, formalising the updated FFDP and advancing towards the start of the next phase of development.

Early in Q1 2016, the HLJOC partners agreed to purchase long lead items for four wells plus items to complete the TGT-14X step out well. The drilling programme commenced in November 2016, in advance of formal approval of the updated FFDP in February 2017, signalling a positive realignment amongst partners with regards to managing this key resource. The infill wells, the TGT-27PST1 and TGT-28P, were "batch drilled". The first well was spudded on 6 November 2016 by the PetroVietnam Drilling PVD-6 jack-up rig on the H4-Well Head Platform ("WHP") in the central area of the TGT Field. Both wells encountered hydrocarbons throughout both the Miocene and Oligocene reservoir horizons. Following the execution of the initial perforation programme, preparations for production logging performance assessment are being made.

The TGT partners have agreed to add a further two infill wells in 2017, one from the southern H5-WHP and one from the H1-WHP, following the delivery of long lead items. The first, TGT-30P, an additional infill well from the H1-WHP, commenced on 8 March 2017. Following that a further infill well on the southern H5-WHP, and the TGT-14X well into the H5 South fault block, will also be drilled.

Full Field Development Plan ("FFDP")

HLJOC's updated TGT Reserve Assessment Report ("RAR"), which included a subsurface review by the HLJOC partners, was formally presented to the Vietnam authorities during Q1 2016 with final approval received on 1 April 2016. Based on the RAR approval and the reworking carried out on the TGT Geological Model and the Dynamic Simulation Mode during 2015, the HLJOC commenced running prediction cases for inclusion in the FFDP during Q2 2016.

The first full draft of the updated FFDP underwent a review by the HLJOC partners, which progressed throughout Q2 and Q3 2016. SOCO utilised the review period to ensure that the FFDP development scenarios matched the Company's performance objectives.

The updated FFDP was formally submitted to the relevant authorities in Q4 2016 and received approval in February 2017. The approval covers up to 18 additional wells, with locations and additional support to be provided at a later date, and the addition of new processing equipment to be installed on the H1-WHP in 2017. The processing equipment will be designed to handle an additional 90,000 barrels of liquid per day ("BLPD") with specific water handling capacity of up to 65,000 barrels of water per day. The increase in the total system handling capacity to approximately 180,000 BLPD allows for higher levels of oil production at the same or higher water cut rate than previously possible.

TGT - production and optimisation

A priority focus of 2016 activity on TGT, in parallel with advancing towards further development, was increasing production from existing wells by perforating additional horizons, optimising reservoir management by shutting off higher water-cut wells and introducing infill wells.

Well intervention work was carried out during 1H 2016, which included perforations to six wells and a water shut off liner on one well. The results of the interventions exceeded expectation by adding approx. 2,200 BOEPD to gross production. As part of the regular evaluation programme, production logging on a selection of wells was completed in Q2 2016 which will be used to prepare the next batch of proposals for additional perforations and/or water shut-offs.

TGT - performance evaluation and prediction

Following the original 2014 building of the Geological Model and the Dynamic Simulation Model and the update in 2015, SOCO retained ERC Equipoise to update both the Geological Model and the Dynamic Simulation Model of the TGT Field with the new wells from 2015 and the additional production history. This work involved a re-evaluation of the fundamental input geoscience data, integration of the results from all the wells and encompassed a major effort from a multi-disciplinary team. This activity highlights the significant complexity and technical uncertainty of the field with further addition of complexity to the previous models.

The reworked Dynamic Model has been history matched against the field production data to date and then a series of forecasts run to evaluate the ultimate oil volume recoverable given various levels of development drilling and pressure maintenance under various FPSO and alternative liquid handling options. This work demonstrated a significant range of potential further development scenarios depending on the level of development drilling, infrastructure optimisation and upgrade, as well as reservoir performance management to optimise field recovery. The output from the model has been reviewed by the reserve auditor and used to focus on the development programme choices required for the updated FFDP.

2016 capital expenditure and development drilling

Actual capital expenditure for Vietnam was below the $17m budgeted amount at $14m. This included costs for the purchase of long lead items for the ongoing TGT field development drilling and the recommencement of drilling, in addition to preliminary engineering costs associated with water handling facilities upgrade and new venture costs associated with Blocks 125 & 126. Capital expenditure for the additional processing equipment included in the updated FFDP is currently estimated at $25m gross.

Forward Plans

The TGT partners have agreed to add a further two infill wells in 2017, one from the southern H5-WHP and one from the H1-WHP and to complete the TGT-14X well into the H5 South fault block as part of the programme. Commitment to the engineering design, construction and installation of additional fluid handling facilities had been made in advance of the updated FFDP approval, and the equipment remains on course for installation in Q3 2017.

Evaluating how production from TGT could be increased from the existing well stock by perforating additional horizons and optimising reservoir management by shutting off higher water-cut wells remains a key part of the programme. Evaluation of the results of the new infill wells will provide input to the selection of the future infill well locations in 2018 and beyond. At the same time, evaluation of small investment, late field life acceleration projects are also being considered.

For 2017, no firm production target has been agreed between the HLJOC partners pending agreement on the updated FFDP, as well as receipt of optimised 2016 production scenarios from the HLJOC utilising full reservoir potential from existing wells.

Block 9-2 – CNV Field

(25% working interest; operated by Hoan Vu Joint Operating Company ("HVJOC"))

The CNV Field is located in the western part of Block 9-2, offshore southern Vietnam and is operated by the HVJOC. In contrast to the geology of TGT, the CNV Field reservoir is fractured granitic basement which produces highly volatile oil with a high gas to oil ratio. Exploitation is dependent on the fracture interconnectivity to deplete the reservoir efficiently. Accordingly, traditional reservoir properties and Stock Tank Oil Initially In Place ("STOIIP") calculations are not straightforward. Hydrocarbons produced from CNV are transported via subsea pipeline to the Bach Ho Central Processing Platform ("BHCPP") where wet gas is separated from oil and transported via pipeline to an offshore gas facility for further distribution. The crude oil is stored on a floating, storage and offloading vessel prior to sale. On the BHCPP, dedicated test separation and metering facilities have been installed.

CNV - production and optimisation

The CNV Field has performed steadily throughout the year. CNV production averaged 6,211 BOEPD gross and 1,553 BOEPD net to SOCO's working interest in 2016 (2015: 6,997 BOEPD gross and 1,749 BOEPD, respectively).

Optimisation considerations to maximise the long-term performance and recovery of the field include a number of scenarios which continue to be evaluated. In 2016, it was agreed to convert the CNV-6PST1 injection well to a producer and modify the processing facilities on the BHCPP to lower the minimum tubing head pressure. This would take advantage of the movement from bottom-up "water-based" pressure maintenance to using the liberated gas in the reservoir as the "top-down" reservoir drive mechanism. The liberated gas would displace the oil from the upper parts of the reservoir and acts as a pressure drive from above.

The HVJOC partners approved the conversion of the CNV-6P-ST1 and the engineering design work for the modification of the BHCPP during 2016. During the execution of the well conversion, a wireline was left in the completion. Following further evaluation, it was decided that the required wireline recovery and remedial work would be performed during Q2 2017 to establish if the full conversion can be completed without further work. The detailed engineering studies of additional technical options for increasing production through modifications to the BHCPP are ongoing and were presented to the HVJOC partners in Q3 2016. Discussions with the owner of the BHCPP are underway to establish the most effective and cost effective solution.

VIETNAM NEW VENTURES

Detailed negotiations for the Production Sharing Contract ("PSC") over Blocks 125 & 126 began in May 2016 following the signing of a Memorandum of Understanding in July 2015 and agreement of the main terms. Negotiations of the final points are expected to conclude in Q1 2017 with SOCO securing a 70% operated interest over the two blocks. Signing of the PSC between SOCO, Sovico Holdings Company and PetroVietnam is expected to take place during 1H 2017.

Blocks 125 & 126 are in moderate to deep waters in the Phu Khanh Basin, north of the Cuu Long Basin, and have multiple structural and stratigraphic plays observed on the available 2D seismic data. Interpretation of the available data indicates there is good potential for source, expulsion and migration of oil with numerous reservoir and seal intervals likely.

REPUBLIC OF CONGO (BRAZZAVILLE)

SOCO holds its interests in the Marine XI Block, located offshore Congo (Brazzaville) in the shallow water Lower Congo Basin, through an 85% owned subsidiary, SOCO Exploration and Production Congo. SOCO previously held a 60% working interest in the Mer Profonde Sud Block, offshore Congo (Brazzaville) through its wholly owned subsidiary, SOCO Congo BEX Limited.

Marine XI Block, offshore Congo (Brazzaville)

(40.39% working interest; SOCO-operated)

Marine XI activity during the year concentrated commercialisation discussions for the Lidongo discovery area and the interpretation of the reprocessed 3D seismic data. In 2H 2016, SOCO secured the 20-year Lidongo Permit, after the Production and Exploitation Licence ("PEX") application for the area around the Lidongo well was submitted to the Congo (Brazzaville) authorities and approved in September 2016. The Lidongo Permit commenced in October 2016. Discussions with the authorities to improve its commercial terms were positively concluded in 1Q 2017, with finalisation of the precise terms nearing completion. Discussions with the authorities together with the Marine XII partners on commercialisation of the Lidongo area continue.

Following completion of reprocessing and remapping of 3D seismic data during 2016, three further areas within the Marine XI Block were identified for further interest. The Marine XI partners will submit three PEX applications over Lideka East, Viodo and Loubana prior to the end of the Marine XI Exploration Licence.

Mer Profonde Sud ("MPS") Block, offshore Congo (Brazzaville)

The Baobab Marine-1 commitment well spudded on the RR Prospect on 5 February 2016. The well reached total measured depth of 3,275 metres on 25 February and intersected the stacked early Miocene channel complexes that were targeted. Although good quality sands were present, no hydrocarbons were encountered, suggesting lack of communication with the known oil source. The well was subsequently plugged and abandoned.

SOCO's operatorship of the MPS Block was acquired under a 2013 farm-in agreement committing to drill one exploration well in the remaining licence period, which was extended to 31 May 2016. The drilling programme was executed under budget and with no lost time injuries. The technical data has been delivered to the Ministry of Hydrocarbons in accordance with the contract. All parties agreed to relinquish the MPS Block at the expiration date of 31 May 2016. Final financial and legal reviews are being performed by the authorities to allow for the formal signoff.

ANGOLA

Cabinda North Block

(Non-operated, 17% working interest)

SOCO's 85% owned subsidiary, SOCO Cabinda Limited, holds a 17% participation interest in the Production Sharing Agreement for the Cabinda North Block, onshore the Angolan Cabinda enclave. Discussions are ongoing among the partners and with the authorities to agree the new partnership, operator and activities during the licence extension period to April 2018. The legal documents to complete the changes are now being circulated among the parties for formal approval.

GROUP RESERVES AND CONTINGENT RESOURCES

An independent audit of management estimates of Reserves and Contingent Resources for TGT and CNV, as of 31 December 2016, was completed by Gaffney, Cline and Associates ("GCA") in March 2017.

TGT Reserves and Contingent Resources

The year end 2016 TGT estimated reserves were based on the scope of the wells already approved to be drilled in 2016-2017, with consideration given to a small number of likely near-term wells, optimal field management and increased liquid handling capacity at the H1-WHP. The year end 2016 TGT estimated reserves do not take into account the fully approved programme in the updated FFDP. This conservative approach will be reviewed following the interpretation and incorporation of the results of the 2016-2017 infill drilling programme into the static and dynamic models. All volumes beyond the scope outlined above were classified as contingent.

The range of reserves and Contingent Resources volumes continue to capture management's view of the full potential of the TGT Field. The estimates are grounded in the results of the revised ERCE Dynamic Simulation Model and the current field performance and reflect the degree of uncertainty around the oil-in-place estimates.

The initial ERCE static and dynamic models, developed in 2013-14, have been updated and matched with the additional production from the field. Production from TGT in 2016 has been slightly below expectation due to the delay in drilling postponed to the end of the year, rig positioning and down-well intervention work beyond that originally planned for extra wireline and intervention work. The under-performance of the H5 platform wells that came on stream in August 2015 has also led to a reduction in the estimates of STOIIP in the H5 Block, but the change to overall field STOIIP estimates is not material. With the approved updated FFDP which includes a significant upgrade to the fluid processing capacity of the H1 platform, and the commencement of drilling campaign earlier than was anticipated in estimating the reserves, after subtracting production during 2016, there is only a minor revision to the Reserves compared to year-end 2015.

TGT Field Oil-In-Place Estimates (MMbbl)			
	P90	**P50**	**P10**
Stock Tank Oil Initially in Place	376	585	880

TGT Field Estimated Ultimate Recovery Inception to Year End 2016			
Reserves + Production	**1P**	**2P**	**3P**
Oil	115.6	152.7	185.5
Gas[1]	6.8	8.8	12.0
Total	122.4	161.5	197.5
Contingent Resources	**1C**	**2C**	**3C**
Oil	15.0	33.0	95.0
Gas[1]	1.0	1.9	8.1
Total	16.0	34.9	103.1
Total Ultimate Recovery			
Oil	130.6	185.7	280.5
Gas[1]	7.8	10.7	20.1
Total	138.4	196.4	300.6

Figures in MMboe

[1] Assumes oil equivalent conversion factor of 6,000 standard cubic feet per barrel of oil equivalent.
[2] This table has been derived by SOCO from the audited figures.
[3] Following the identification of allocation calculation errors, there has been adjustments to the prior years oil and gas production for TGT. There has been a decrease in allocated gas production and a small increase in allocated oil production

SOCO Working Interest Reserves and Resources TGT Field at 31 December 2016			
Reserves	**1P**	**2P**	**3P**
Oil	14.2	25.4	35.3
Gas[1]	0.8	1.4	2.3
Total	15.0	26.8	37.6
Contingent Resources	**1C**	**2C**	**3C**
Oil	4.5	9.4	26.5
Gas[1]	0.3	0.6	2.3
Total	4.8	10.0	28.8
Sum of Reserves and Contingent Resources	**1P & 1C**	**2P & 2C**	**3P & 3C**
Oil	18.7	34.8	61.8
Gas[1]	1.1	2.0	4.6
Total	19.8	36.8	66.4

Figures in MMboe

[1] Assumes oil equivalent conversion factor of 6,000 standard cubic feet per barrel of oil equivalent.
[2] The summation of reserves and Contingent Resources has been prepared by the Company.

CNV Reserves and Contingent Resources

Re-evaluation of the field performance dynamics has led to the HVJOC Partners ceasing water injection and agreeing to convert the CNV-6P-ST1 injection well to production. This will change the drive mechanism from "bottom-up" water drive to "top-down" gas drive, as due to the volatile nature of the oil, gas will be liberated in the well bore. This gas will rise to the crest of the reservoir, expanding and therefore displacing oil into the wells. Extensive simulation has demonstrated the benefit of this approach. Volumes associated with the CNV-7P and a future well is included in Contingent Resources.

SOCO Working Interest Reserves and Contingent Resources CNV Field at 31 December 2016			
Reserves	**1P**	**2P**	**3P**
Oil	3.5	4.8	6.0
Gas[1]	1.3	1.7	2.2
Total	4.8	6.5	8.2
Contingent Resources[2,3]	**1C**	**2C**	**3C**
Oil	-	1.7	1.9
Gas[1]	-	1.2	1.4
Total	-	2.9	3.3
Sum of Reserves and Contingent Resources[4]	**1P & 1C**	**2P & 2C**	**3P & 3C**
Oil	3.5	6.5	7.9
Gas[1]	1.3	2.9	3.6
Total	4.8	9.4	11.5

Figures in MMboe

[1] Assumes oil equivalent conversion factor of 6,000 standard cubic feet per barrel of oil equivalent.
[2] 3C Contingent Resources are unaudited and reflect Management's estimates.
[3] At the beginning of March 2017, SOCO was informed by its reserves auditor, Gaffney, Cline & Associates ("GCA"), that it had identified a calculation error in GCA's estimation of 2C Contingent Resources for the CNV Field for year end 31 December 2015. The impact of this error is to reduce SOCO's year end 2015 CNV 2C Contingent Resources from 9.0 mmboe to 2.3 mmboe. This calculation error has been checked and has resulted in a restatement in the CNV Contingent Resources for year end 2015.
[4] The summation of reserves and Contingent Resources has been prepared by the Company.

Viodo Reserves and Contingent Resources

There are no plans for commercial standalone development of the Viodo Field in the Marine XI Block at this time. However, there remains potential to recognise additional Contingent Resources on the Marine XI Block from Lideka East, and from the Lidongo Discovery as it is progressed towards unitisation with the nearby Litchendjili Field which has commenced production.

SOCO Working Interest Contingent Resources Viodo Field at 31 December 2016	
Contingent Resources	**2C**
Oil	8.1
Gas	-
Total	8.1

Figures in MMbbl

Independent Auditors' Report to the Shareholders of SOCO International plc on the Preliminary announcement of SOCO International plc

We confirm that we have issued an unqualified opinion on the full financial statements of SOCO International plc.

Our audit report on the full financial statements sets out the following risks of material misstatement which had the greatest effect on our audit strategy; the allocation of resources in our audit; and directing the efforts of the engagement team, together with how our audit responded to those risks and the key observations arising from our work:

<table>
<tr><th colspan="2">Impairment of Producing Oil & Gas Assets</th></tr>
<tr><td>Risk description</td><td>The value of property, plant and equipment relating to the Group's producing oil and gas assets as at 31 December 2016 was $690.0 million (2015: $759.7 million). This is considered a significant risk due to the significant judgements and estimates involved in assessing whether any impairment, or impairment reversal, has arisen at year-end, and in quantifying any such impairments or reversals.

Management reviewed both of its producing fields in Vietnam for indicators of impairment, identifying in each case that indicators of impairment were present. Management has estimated the fair values less costs of disposal of each field and compared these to the carrying amount of each field on the balance sheet. Management's fair value estimate is based on key assumptions which include:
• oil and gas prices;
• reserves estimates and production profiles;
• the incremental value of contingent resources; and
• the discount rate.

As referenced in note 4 of the financial statements the carrying value of property, plant and equipment is considered by management as a critical accounting judgement and key source of estimation uncertainty.

No impairment charges or impairment reversals were recorded during the year. Further details of the key assumptions used by management in their impairment evaluation are provided in note 17 of the financial statements (note 7 of this announcement) and in the Audit & Risk Committee Report in the annual report.</td></tr>
<tr><td>How the scope of our audit responded to the risk</td><td>As well as our work on reserves as noted below;
• we compared oil and gas price assumptions with third party forecasts and publicly available forward curves;
• we used our internal valuation specialists to perform an independent recalculation of the discount rates used for each of the group's producing assets in Vietnam;
• we assessed management's other assumptions by reference to other third party information, our knowledge of the Group and industry and also budgeted and forecast performance;
• we tested management's impairment calculations for mechanical accuracy;
• we considered whether the incremental value attributed to contingent resource estimates was appropriate;
• we reviewed management's sensitivity tests for a range of input assumptions, including oil price and discount rates, and performed our own sensitivity tests using management's impairment model with a range of reasonable assumptions; and
• we considered whether management's disclosures relating to impairment and associated estimation uncertainty were adequate.</td></tr>
<tr><td>Key observations</td><td>We are satisfied that no impairment charges or impairment reversals are required in the current year and that the related disclosures in note 17 of the financial statements (note 7 of this announcement) are appropriate.</td></tr>
</table>

Impairment of Intangible Exploration & Evaluation ("E&E") Assets	
Risk description	The total value of E&E assets as at 31 December 2016 held by the Group was $218.2 million (2015: $211.5 million). The Group's principal interests are in the Marine XI licence in the Republic of Congo (Brazzaville) and the Cabinda licence in Angola. In accordance with relevant accounting standards, E&E costs are assessed for impairment at least annually. This is considered a key risk due to the significant judgments that are required and the material carrying values of E&E assets in the financial statements. These judgements include the effect of the significant and prolonged fall in oil price on the viability of the Group's E&E projects. Management assesses whether there were any indicators of impairment of the Group's E&E assets by reference to IFRS 6 "Exploration for and evaluation of mineral resources", such as; • expiry or relinquishment of exploration and evaluation licences; • substantive expenditure for further exploration and evaluation in the specific area is neither budgeted nor planned; • whether exploration and evaluation activities have not led to the discovery of commercially viable quantities of mineral resources and the entity has decided to discontinue activities in the area; or • whether data exists to suggest that the carrying amount of the E&E asset is unlikely to be recovered in full from successful development or by sale. As referenced in note 4 of the financial statements, the carrying value of E&E assets is considered by management as a critical accounting judgement and key source of estimation uncertainty. The current status of the Marine XI and Cabinda licences together with activity during the year is summarised in the review of operations. No impairment charges were recorded in the year. Further details of the group's E&E assets and the related impairment judgements are given in note 16 of the financial statements and in the Audit & Risk Committee Report in the annual report.
How the scope of our audit responded to the risk	We challenged the outcome of management's review of the Group's E&E assets for impairment. Our procedures included: • participating in meetings with key operational and finance staff to understand the current status and future intention for each asset; • confirming that all assets which remain capitalised are included in future budgets and identifying any fields where the Group's right to explore is either at, or close to expiry; and • obtaining appropriate audit evidence regarding material facts, for example by agreement to approved internal or operator budgets and work programmes or contractual agreements.
Key observations	We are satisfied that no impairments were required in the current year.

Oil & Gas Reserves and Contingent Resource Estimates	
Risk description	This was considered to be a key risk due to the subjective nature of reserves and contingent resource estimates, their impact on the financial statements as key inputs within the impairment assessment and the depreciation, depletion and amortisation ("DD&A") calculations, and because both the Te Giac Trang ("TGT") and Ca Ngu Vang ("CNV") fields are complex fields contributing all of the value of the Group's recognised reserves. Management has engaged a third party reservoir engineering expert to provide an independent report on the Group's reserves and contingent resource estimates using standard industry reserve estimation methods and definitions for both the CNV and TGT fields. Management's reserves and contingent resource estimates are included in the Review of Operations. In addition, management has explained the scope of work of the third party expert and their findings in the Review of Operations, as well as highlighting oil and gas reserves as a key source of estimation uncertainty in note 4 to the financial statements. The Audit & Risk Committee has also outlined its considerations in this area in the annual report. In reviewing the third party reservoir engineer's conclusions, an error was identified in relation to the prior year CNV contingent resource estimates, as discussed in the review of operations.
How the scope of	For both TGT and CNV assets:

our audit responded to the risk	• we understood the process used by management to derive their estimates of reserves and contingent resources and how they provide information to, and interact with, the third party expert; • we reviewed the third party expert's report on SOCO's reserves and resource estimates as disclosed in the annual report and checked that these estimates were used consistently throughout the accounting calculations reflected in the financial statements; • we communicated directly with the third party experts to discuss and assess their scope of work, expertise and objectivity which included consideration of findings in relation to the prior year CNV contingent resource estimate error; and • we enquired about the differences between current and prior estimates and considered whether the explanations were consistent with other information obtained by us during the course of our audit.
Key observation	We are satisfied that the reserves and contingent resources figures are appropriate to utilise in the group's DD&A and impairment calculations and that there was no financial statement impact in relation to the prior year restatement of CNV contingent resources.

Accounting for Depletion, Depreciation and Amortisation ("DD&A") of Producing Oil & Gas Assets	
Risk description	As outlined in note 6 of the financial statements (note 3 of this announcement) the total DD&A charge for the year was $80.0 million (2015:$ 99.2 million). This is considered a key risk due to the calculation including judgmental estimates of the remaining commercial oil & gas reserves, the estimation of future capital works and related expenditure required to extract those reserves and the date of application relating to any revisions to estimates. As referenced in note 4 of the financial statements accounting for DD&A is considered by management as a critical accounting judgement and key source of estimation uncertainty.
How the scope of our audit responded to the risk	As well as the work performed on the reserves quantities included in the DD&A calculation, as outlined above: • we compared the estimates of future capital expenditure to plans and budgets; • we checked that the development scenarios from which capital expenditure estimates are derived are consistent with the scenario on which reserves estimates are based; • we considered the timing of adoption of any revised reserves and future capital expenditure estimates for the purposes of calculating DD&A in light of the timing of events and circumstances that led to the revision to estimates; and • we re-performed the DD&A calculation to check for mechanical accuracy.
Key observations	We are satisfied that management's calculation of DD&A is appropriate and based on reasonable underlying estimates.

These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we did not provide a separate opinion on these matters.

Our liability for this report, and for our full audit report on the financial statements is to the company's members as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for our audit report or this report, or for the opinions we have formed.

Deloitte LLP
Chartered Accountants and Statutory Auditor

Consolidated Income Statement

for the year to 31 December 2016

	Notes	**2016** **$ million**	2015 $ million
Revenue	3	**154.6**	214.8
Cost of sales		**(135.0)**	(166.4)
Gross profit		**19.6**	48.4
Administrative expenses		**(13.5)**	(10.0)
Pre-licence exploration costs		**-**	(0.8)
Exploration write back / (expense)	6	**1.1**	(35.6)
Operating profit		**7.2**	2.0
Investment revenue		**0.5**	0.4
Other gains and losses		**-**	7.4
Finance costs		**(2.0)**	(1.6)
Profit before tax	3	**5.7**	8.2
Tax	3,4	**(24.0)**	(42.0)
Loss for the year		**(18.3)**	(33.8)
Loss per share (cents)			
Basic	5	**(5.6)**	(10.3)
Diluted	5	**(5.6)**	(10.3)

Consolidated Statement of Comprehensive Income

for the year to 31 December 2016

	2016 **$ million**	2015 $ million
Loss for the year	**(18.3)**	(33.8)
Items that may be subsequently reclassified to profit or loss:		
Unrealised currency translation differences	**(0.2)**	1.8
Total comprehensive loss for the year	**(18.5)**	(32.0)

Balance Sheets

as at 31 December 2016

		Group		Company	
		2016	2015	**2016**	2015
	Notes	**$ million**	$ million	**$ million**	$ million
Non-current assets					
Intangible assets		**218.2**	211.5	**-**	-
Property, plant and equipment	7	**690.6**	760.5	**0.6**	0.8
Investments		**-**	-	**530.6**	637.1
Other receivables		**33.8**	29.5	**-**	-
		942.6	1,001.5	**531.2**	637.9
Current assets					
Inventories		**5.7**	3.1	**-**	-
Trade and other receivables		**24.7**	19.5	**0.8**	0.9
Tax receivables		**0.7**	0.7	**0.3**	0.3
Financial asset	8,11	**42.7**	52.7	**-**	-
Liquid investments		**15.3**	-	**-**	-
Cash and cash equivalents		**85.0**	103.6	**0.5**	0.2
		174.1	179.6	**1.6**	1.4
Total assets		**1,116.7**	1,181.1	**532.8**	639.3
Current liabilities					
Trade and other payables		**(22.4)**	(37.2)	**(6.7)**	(3.0)
Tax payable		**(9.2)**	(7.8)	**(0.1)**	(0.8)
		(31.6)	(45.0)	**(6.8)**	(3.8)
Net current assets (liabilities)		**142.5**	134.6	**(5.2)**	(2.4)
Non-current liabilities					
Deferred tax liabilities		**(165.7)**	(183.7)	**-**	-
Long term provisions		**(62.9)**	(59.9)	**-**	-
		(228.6)	(243.6)	**-**	**-**
Total liabilities		**(260.2)**	(288.6)	**(6.8)**	(3.8)
Net assets		**856.5**	892.5	**526.0**	635.5
Equity					
Share capital		**27.6**	27.6	**27.6**	27.6
Other reserves		**243.8**	242.3	**194.5**	195.3
Retained earnings		**585.1**	622.6	**303.9**	412.6
Total equity		**856.5**	892.5	**526.0**	635.5

Statements of Changes in Equity

for the year to 31 December 2016

				Group
	Called up share capital $ million	**Other reserves $ million**	**Retained earnings $ million**	**Total $ million**
As at 1 January 2015	27.6	239.5	708.0	975.1
Loss for the year	-	-	(33.8)	(33.8)
Unrealised currency translation differences	-	-	1.8	1.8
Distributions	-	-	(51.1)	(51.1)
Share-based payments	-	0.5	-	0.5
Transfer relating to share-based payments	-	2.3	(2.3)	-
As at 1 January 2016	**27.6**	**242.3**	**622.6**	**892.5**
Loss for the year	**-**	**-**	**(18.3)**	**(18.3)**
Unrealised currency translation differences	**-**	**(0.2)**	**(0.2)**	**(0.4)**
Distributions	**-**	**-**	**(17.5)**	**(17.5)**
Share-based payments	**-**	**0.2**	**-**	**0.2**
Transfer relating to share-based payments	**-**	**1.5**	**(1.5)**	**-**
As at 31 December 2016	**27.6**	**243.8**	**585.1**	**856.5**

				Company
	Called up share capital $ million	**Other reserves $ million**	**Retained earnings $ million**	**Total $ million**
As at 1 January 2015	27.6	195.0	466.7	689.3
Retained profit for the year	-	-	30.8	30.8
Unrealised currency translation differences	-	(0.1)	(31.5)	(31.6)
Distributions	-	-	(51.1)	(51.1)
Share-based payments	-	0.5	-	0.5
Transfer relating to share-based payments	-	(0.1)	(2.3)	(2.4)
As at 1 January 2016	**27.6**	**195.3**	**412.6**	**635.5**
Retained profit for the year	**-**	**-**	**17.5**	**17.5**
Unrealised currency translation differences	**-**	**(0.2)**	**(107.2)**	**(107.4)**
Distributions	**-**	**-**	**(17.5)**	**(17.5)**
Share-based payments	**-**	**0.2**	**-**	**0.2**
Transfer relating to share-based payments	**-**	**(0.8)**	**(1.5)**	**(2.3)**
As at 31 December 2016	**27.6**	**194.5**	**303.9**	**526.0**

Cash Flow Statements

for the year to 31 December 2016

	Note	Group		Company	
		2016	2015	**2016**	2015
		$ million	$ million	**$ million**	$ million
Net cash from (used in) operating activities	10	**46.0**	80.3	**(7.9)**	(6.5)
Investing activities					
Purchase of intangible assets		**(27.4)**	(17.5)	**-**	-
Purchase of property, plant and equipment		**(8.4)**	(70.0)	**(0.1)**	(0.1)
(Increase) decrease in liquid investments [1]		**(15.3)**	40.2	**-**	-
Payment to abandonment fund		**(4.3)**	(4.9)	**-**	-
Deferred proceeds on disposal of Mongolia assets		**10.0**	-	**-**	-
Investment in subsidiary undertakings		**-**	-	**(2.9)**	(5.7)
Dividends received from subsidiary undertakings		**-**	-	**30.0**	62.5
Net cash (used in) from investing activities		**(45.4)**	(52.2)	**27.0**	56.7
Financing activities					
Share-based payments		**(0.9)**	(1.0)	**(0.9)**	(1.0)
Distributions	9	**(17.5)**	(51.1)	**(17.5)**	(51.1)
Net cash used in financing activities		**(18.4)**	(52.1)	**(18.4)**	(52.1)
Net (decrease) increase in cash and cash equivalents		**(17.8)**	(24.0)	**0.7**	(1.9)
Cash and cash equivalents at beginning of year		**103.6**	126.2	**0.2**	0.2
Effect of foreign exchange rate changes		**(0.8)**	1.4	**(0.4)**	1.9
Cash and cash equivalents at end of year [1]		**85.0**	103.6	**0.5**	0.2

[1] Liquid investment's comprise short term liquid investments of between three to six months maturity while cash and cash equivalents comprise cash at bank and other short term highly liquid investments of less than three months maturity. The combined cash and cash equivalents and liquid investments balance at 31 December 2016 was $100.3m (2015: $103.6m).

Notes to the consolidated financial information

1. General information

The financial information set out above does not constitute the Company's statutory accounts for the years ended 31 December 2016 or 2015, but is derived from those accounts. A copy of the statutory accounts for 2015 has been delivered to the Registrar of Companies and those for 2016 will be delivered following the Company's annual general meeting. The auditors have reported on those accounts; their reports were unqualified, did not draw attention to any matters by way of emphasis without qualifying their report and did not contain statements under section 498(2) or (3) of the Companies Act 2006. Whilst the financial information included in this preliminary announcement has been computed in accordance with International Financial Reporting Standards (IFRS), this announcement does not itself contain sufficient information to comply with IFRS. The financial statements are presented in US dollars which is the functional currency of each of the Company's subsidiary undertakings.

2. Basis of preparation

The financial information has been prepared in accordance with the recognition and measurement criteria of IFRS and with IFRSs adopted for use in the European Union. The financial statements have been prepared under the historical cost basis, except for the valuation of hydrocarbon inventory and the revaluation of certain financial instruments.

The Group has a strong financial position and based on future cash flow projections should comfortably be able to continue in operational existence for the foreseeable future. Consequently, the Directors believe that the Group is well placed to manage its financial and operating risks successfully and have prepared the financial information on a going concern basis.

3. Segment information

The Group has one principal business activity being oil and gas exploration and production. The Group's operations are located in South East Asia and Africa (the Group's operating segments) and form the basis on which the Group reports its segment information. There are no inter-segment sales.

				2016
	SE Asia	**Africa [2]**	**Unallocated**	**Group**
	$ million	**$ million**	**$ million**	**$ million**
Oil and gas sales	**154.6**	**-**	**-**	**154.6**
Depreciation, depletion and amortisation	**79.8**	**-**	**0.2**	**80.0**
Exploration write back (see note 6)	**-**	**(1.1)**	**-**	**(1.1)**
Profit (loss) before tax [1]	**17.8**	**0.6**	**(12.7)**	**5.7**
Tax charge (see Note 4)	**23.8**	**-**	**0.2**	**24.0**

	2015			
	SE Asia	Africa [2]	Unallocated	Group
	$ million	$ million	$ million	$ million
Oil and gas sales	214.8	-	-	214.8
Depreciation, depletion and amortisation	99.0	-	0.2	99.2
Exploration expense	0.6	35.0	-	35.6
Profit (loss) before tax [1]	46.3	(35.8)	(2.3)	8.2
Tax charge	42.2	-	(0.2)	42.0

[1] Unallocated amounts included in profit before tax comprise corporate costs not attributable to an operating segment, investment revenue, other gains and losses and finance costs.

[2] Costs associated with the Africa segment are capitalised in accordance with the Group's accounting policy to the extent they are recoverable.

Included in revenues arising from South East Asia are revenues of $115.1m and $34.1m which arose from the Group's two largest customers who contributed more than 10% to the Group's oil and gas revenue (2015: $188.2m from the Group’s largest customer).

Geographical information

The Group’s oil and gas revenue and non-current assets (excluding other receivables) by geographical location are separately detailed below where they exceed 10% of total revenue or non-current assets, respectively:

Revenue

All of the Group's revenue is derived from foreign countries. The Group's oil and gas revenue by geographical location is determined by reference to the final destination of oil or gas sold.

	2016	2015
	$ million	$ million
Vietnam	**117.2**	192.4
China	**33.4**	9.3
Other	**4.0**	13.1
	154.6	214.8

Non-current assets

	2016	2015
	$ million	$ million
United Kingdom	**0.6**	0.8
Vietnam	**692.3**	760.7
Congo	**149.6**	157.7
Other - Africa	**66.3**	52.8
	908.8	972.0

Excludes other receivables.

4. Tax

	2016	2015
	$ million	$ million
Current tax	**42.0**	58.5
Deferred tax	**(18.0)**	(16.5)
	24.0	42.0

The Group's corporation tax is calculated at 50% (2015: 50%) of the estimated assessable profit for the year in Vietnam. During 2016 and 2015 both current and deferred taxation have arisen in overseas jurisdictions only.

The charge for the year can be reconciled to the profit per the income statement as follows:

	2016	2015
	$ million	$ million
Profit before tax	**5.7**	8.2
Profit before tax at 50% (2015: 50%)	**2.9**	4.1
Effects of:		
Non-taxable income	**-**	(4.1)
Non-deductible expenses	**16.4**	19.5
Tax losses not recognised	**5.1**	3.8
Non-deductible exploration costs written (back)/off	**(0.6)**	18.2
Adjustments to tax charge in respect of previous years	**0.2**	0.5
Tax charge for the year	**24.0**	42.0

The prevailing tax rate in the jurisdictions in which the Group produces oil and gas is 50%. The tax charge in future periods may also be affected by the factors in the reconciliation above.

Non-deductible expenses primarily relates to Vietnam DD&A charges for costs previously capitalised, which are non-deductible for Vietnamese tax purposes, contributing $13.6m (2015: $16.7m) to the effect of non-deductible expenses. A further $2.8m (2015: $2.8m) relates to non-deductible corporate costs including share scheme incentives.

The effect from tax losses not recognised relates to costs, primarily of the Company, deductible for tax in the UK but not expected to be utilised in the foreseeable future.

During 2016, following the completion of the MPS licence commitments, the amount of $1.1m was written back to the income statement (see Note 3) resulting in a tax effect adjustment of ($0.6m). In 2015, adjustments were made for the effect of non-deductible exploration costs written off related to the exploration costs associated with the relinquished Africa licence commitments, resulting in a tax effect of $17.9m, and to Vietnam pre-licence costs resulting in a tax effect of $0.3m.

5. Loss per share

The calculation of the basic and diluted earnings per share is based on the following data:

	2016	2015
	$ million	$ million
Earnings for the purposes of basic earnings per share	**(18.3)**	(33.8)
Effect of dilutive potential ordinary shares – Share awards and options	**(0.5)**	(0.2)
Earnings for the purposes of diluted earnings per share	**(18.8)**	(34.0)

	Number of shares (million)	
	2016	2015
Weighted average number of ordinary shares for the purpose of basic earnings per share	**329.4**	329.1
Effect of dilutive potential ordinary shares - Share awards and options	**2.8**	3.7
Weighted average number of ordinary shares for the purpose of diluted earnings per share	**332.2**	332.8

In accordance with IAS 33 “Earnings per Share”, the effects of antidilutive potential shares have not been included when calculating dilutive loss per share for the year ended 31 December 2016 and prior year.

6. Exploration write back/expense

In 2015, exploration costs of $13.1m were written off to the income statement of which $11.7m related to the carrying value of the MPS licence in Congo and the remaining $1.4m related to additional costs of a licence relinquished in the previous year. As well as fully impairing the MPS expenditure at 31 December 2015 of $11.7m, an accrual was made of $22.5m for the estimated cost of fulfilling the remaining onerous drilling commitment on the licence.

In 2016, following the completion of the drilling commitment, an amount of $1.1m was written back to the income statement.

7. Property, plant and equipment

As discussed in the Review of Operations, proved and probable oil and gas reserves audited by Gaffney, Cline & Associates have decreased slightly on TGT with a modest increase on CNV. The flattening of the oil price triggered an impairment test on the Group's CNV asset in Vietnam. The recoverable amount of the CNV producing asset has been determined using the fair value less costs of disposal method which constitutes a level 3 valuation within the fair value hierarchy. The net book value is fully supported by the fair value derived from a discounted cash flow valuation of the 2P production profile and whilst incremental value can be derived from the 2C contingent resources this is not required in support of the net book value. The key assumptions to which the fair value measurement is most sensitive are oil price, discount rate and 2P reserves (2015: oil price, discount rate, 2P reserves and the risked value ascribed to 2C contingent resources). As at 31 December 2016, the fair value of the asset is estimated based on a post tax nominal discount rate of 12.5% (2015: 12.5%) and an oil price reflecting a gradual increase over four years from $57/bbl in 2017 (2015: $58/bbl for 2017) to $69/bbl in 2020 (2015: $78/bbl for 2020) plus inflation of 2.0% (2015: 2.0%) thereafter.

The flattening of the oil price also triggered an impairment test on the Group's TGT asset in Vietnam. The recoverable amount of the TGT producing asset has been determined using the fair value less costs of disposal method which constitutes a level 3 valuation within the fair value hierarchy. The majority of the net book value is supported by a discounted cash flow valuation of the 2P production profile, with a portion supported by the incremental value of 2C contingent resources, risk adjusted. The key assumptions to which the fair value measurement is most sensitive are oil price, discount rate and 2P reserves (2015: oil price, discount rate, 2P reserves and the risked value ascribed to 2C contingent resources). As at 31 December 2016, the fair value of the asset is estimated based on a post tax nominal discount rate of 10% (2015: 10%) and an oil price reflecting a gradual increase over four years from $57/bbl in 2017 (2015: $58/bbl for 2017) to $69/bbl in 2020 (2015: $78/bbl for 2020) plus inflation of 2.0% (2015: 2.0%) thereafter.

Testing of sensitivity cases indicated that neither a $5/bbl reduction in the long term oil price nor a 1% increase in discount rates, used when determining fair value less costs of disposal method, would result in an impairment of our TGT nor CNV oil and gas assets.

8. Financial asset

In 2005, the Group disposed of its Mongolia interest to Daqing Oilfield Limited Company. Under the terms of the transaction the Group was entitled to receive a subsequent payment amount of up to $52.7m, once cumulative production reached 27.8 million barrels of oil, at the rate of 20% of the average monthly marker price for Daqing crude multiplied by the aggregate production for that month. Daqing notified SOCO that the production threshold of crude oil in excess of 27.8 million barrels was achieved in December 2015. The fair value of the subsequent payment amount was determined using a valuation technique as there was no active market against which direct comparisons can be made (Level 3 as defined in IFRS 13).The Directors expected the full subsequent payment amount to be settled by the end of 2016. On 19 December 2016, the Group received the first payment of $10.0m from Daqing Oilfield Limited Company as partial payment for the subsequent payment amount of $52.7m. The full remainder, as acknowledged by Daqing Oilfield Limited Company, was outstanding and past due at the reporting date. The delay was due to the requirement for an application for the necessary funds by Daqing Oilfield Limited Company to the Chinese Government and further steps required in the approval process imposed by Daqing's parent company, China National Petroleum Company. In March 2017, SOCO received the full outstanding amount of $42.7m (see Note 11).

9. Distribution to Shareholders

In June 2016, the Company paid a dividend to shareholders of $17.5m (2015: $51.1m) or 4 pence per Ordinary Share in two equal payments of 2 pence per share (2015: 10 pence per Ordinary Share). The Trust, which is consolidated within the Group, waived its rights to receive a dividend in 2016 and 2015.

The Board is recommending a final dividend of 5 pence per Ordinary Share, which amounts to approximately $20.6m. The proposed final dividend is subject to approval by shareholders at the Annual General Meeting and has not been included as a liability in these financial statements. The proposed dividend will be paid on 16 June 2017 to shareholders on the Register of Members at the close of business on 26 May 2017.

10. Reconciliation of operating profit to operating cash flows

	Group		Company	
	2016	2015	**2016**	2015
	$ million	$ million	**$ million**	$ million
Operating profit (loss)	**7.2**	2.0	**(12.5)**	(9.7)
Share-based payments	**1.1**	1.5	**1.1**	1.5
Depletion and depreciation	**80.0**	99.2	**0.2**	0.2
Exploration (write back) expense (see Note 7)	**(1.1)**	35.6	**-**	-
Operating cash flows before movements in working capital	**87.2**	138.3	**(11.2)**	(8.0)
(Increase)/decrease in inventories	**(2.6)**	3.0	**-**	-
(Increase)/decrease in receivables	**(6.8)**	12.4	**(0.2)**	(0.1)
Increase/(decrease) in payables	**7.8**	(11.4)	**3.6**	1.5
Cash generated by (used in) operations	**85.6**	142.3	**(7.8)**	(6.6)
Interest received	**0.4**	0.5	**-**	0.1
Interest paid	**(0.1)**	(0.1)	**(0.1)**	-
Income taxes paid	**(39.9)**	(62.4)	**-**	-
Net cash from (used in) operating activities	**46.0**	80.3	**(7.9)**	(6.5)

Cash is generated from continuing operating activities only.

11. Events after the balance sheet date

Financial Asset

The full value of the financial asset held at the balance sheet date of $42.7m relating to the subsequent amount of $52.7m associated with SOCO's 2005 sale of its Mongolia assets was received from Daqing Oilfield Limited Company in March 2017.

12. Preliminary results announced

Copies of the announcement will be available from the Company's head office, situated at 48 Dover Street, London, W1S 4FF and is also available to download from www.socointernational.com. The Annual Report and Accounts will be posted to shareholders in due course.

Glossary

Non-IFRS measures
The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures are cash operating cost per barrel and breakeven price per barrel, which are defined below:

Cash operating costs per barrel

Cash operating costs are defined as cost of sales less depreciation, depletion and amortisation, production based taxes, movement in inventories and certain other immaterial cost of sales.

Cash operating costs for the period is then divided by barrels of oil equivalent produced. This is a useful indicator of cash operating costs incurred to produce oil and gas from the Group's producing assets.

Breakeven price per barrel

The Group believes this non-IFRS measurement is useful to investors as it provides a guide price at which the Group covers the costs of operations. It is calculated asthe sales price (in $/bbl) which is equal to the sum of the Group's 2016 cash operating costs and production based taxes per barrel and the Group's 2016 corporation tax charge per barrel.