SOCO International plc

("SOCO" or "the Company")

PRELIMINARY RESULTS

SOCO, an international oil and gas exploration and production company, today announces its preliminary results for the year ended 31 December 2014.

Operational Highlights

- Annual production net to the Group's working interest averaged 13,605 BOEPD (2013: 16,694 BOEPD)
- TGT production net to the Group's working interest averaged 11,538 BOEPD
- TGT H5 development ahead of schedule for first oil targeted in September/October 2015
- ERC Equipoise study of TGT field completed demonstrating TGT's full potential
- Against a background of lower oil prices and resultant uncertainty around the scope and timing of future development, a prudent approach to reserve booking has reclassified a portion of reserves into Contingent Resources
- 2014 year-end Group 2P reserves of 40.8 mmboe and 2C Contingent Resources of 38.9 mmboe

Financial Highlights

- Revenue of $448.2 million (2013: $608.1 million)
- Profit after tax of $14.0 million (2013: $104.1 million) after non-cash $79.5 million of exploration write-offs and $60.5 million impairment of CNV
- Cash generated from operations of $251.2 million (2013: $314.4 million)
- Returned c.$119 million in cash to shareholders, or 22 pence per share, in October 2014
- Strong balance sheet: no debt and a cash balance (including cash equivalents and liquid investments) at 31 December 2014 of $166.4 million (2013: $210 million)

Corporate Highlights

- Appointment of Anya Weaving as Chief Financial Officer in May 2014
- Exemplary health and safety record maintained

Outlook for 2015

- Operational focus on bringing TGT's H5 fault block production on line and working with TGT partners to submit updated FDP in Q3
- Production guidance maintained at 10.5-12 KBOEPD reflecting reduced scope of TGT drilling
- Sufficient cash flow and cash balances to meet ongoing capital expenditure
- Balance sheet capacity to take advantage of opportunities in the market as they arise
- Recommended dividend of 10p per share (c.$50 million) to be approved at the AGM
- Ongoing focus on sustainable cash flow generation and commitment to strategy of cash returns

Ed Story, President and Chief Executive Officer of SOCO, commented:

"2014 was a strong year for SOCO. We concluded an independent study confirming TGT's full potential and also progressed development with the TGT H5 discovery remaining on a fast track for first production in Q3 2015. We also delivered a second material cash return to shareholders of c. $119 million. Notwithstanding the challenging market conditions, given our financial strength and near-term outlook and based on the results of 2014, the Board is recommending a cash dividend of 10 pence per share, amounting to c.$50 million.

We are committed to evaluating every alternative to optimise our exposure to upside without jeopardising our focus on sustainable cash generation. We remain value driven, see the current environment as an opportunity to plan for future growth and believe SOCO is well positioned to continue to execute its strategy."

ENQUIRIES:

SOCO International plc

Anya Weaving, Chief Financial Officer
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CHAIRMAN AND CHIEF EXECUTIVE'S STATEMENT

The dramatic fall in the oil price in the latter part of 2014 after a long period of stability introduced significant uncertainty and challenging conditions for the industry, bringing into focus the importance of substantial financial flexibility and strong capital discipline, and having a business capable of sustaining itself and generating cash flow in a low oil price environment.

The SOCO business model – with a strong balance sheet, low break even oil prices (in the low $20s) and capital discipline as part of our DNA – is resilient in this environment. As SOCO is staffed and managed by people who have extensive experience in this industry, we are also accustomed to having to deal with the cyclical nature of it. We have always been cost conscious and leanly resourced; therefore, we do not employ a lot of people and selectively use contractors, allowing us to scale our business up or down quickly depending on the prevailing environment. In response to the lower oil prices, we have deferred drilling the MPS exploration well to 2016 and undertaken several actions to reduce our general and administration costs, notably by eliminating the separate new ventures office and reducing general and administration costs in our regional offices by approximately 25%; in Vietnam, capital and operating expenditure savings are expected to be in the region of 10%.

However resilient the business model may be, there are negative consequences to business metrics as a consequence of the downturn in the macro environment as well as company specific developments. Against the background of lower oil prices and the resultant uncertainty around the scope and timing of future development, we have significantly revised last year's 2P reserves estimates associated with the TGT asset, with a portion of the reserves being reclassified into Contingent Resources. The reclassification has been done following on from an exhaustive technical study performed by ERC Equipoise, completed at the end of 2014. Further, due to drilling difficulties on the CNV-7P well, we were not able to complete the well thus leading to a write down of reserves attributed to the asset. It is now our intention to commission an independent reserve report covering all of our producing assets.

With our significant financial flexibility, fully funded capex programme and strict cost discipline, we can continue our strategy of focusing on cash flow generation and delivering to shareholders both value – through cash returns – and growth, be it organic or inorganic. The short term priority is to shape the business, which is already resilient in a downside scenario of persisting low oil prices, and to put plans in place for delivering sustainable growth as the oil price recovers.

2014 Performance

2014 was a strong year for SOCO. The Company progressed development of the TGT field with the H5 fault block discovery remaining on a fast track for first production in the third quarter of 2015, drilled a successful exploration well offshore the Congo (Brazzaville), delivered the second material cash return to shareholders and concluded an independent study demonstrating TGT's full potential.

Importantly, we were able to accomplish these excellent results and to maintain our exemplary record from the health and safety aspect.

The Group's production during 2014 of c. 13.6 KBOEPD was just below our guidance range at the beginning of last year, down from c. 16.7 KBOEPD in 2013. The year-on-year drop was mainly attributable to part of the capacity of the TGT FPSO being contractually available to the neighbouring third-party field from May 2013. Group financial results delivered solid revenue of $448.2 million, albeit down from the 2013 results, reflecting both lower production and lower realised average oil price of c. $103 per barrel (2013 - c. $113 per barrel). The Group is reporting a post-tax profit for the year of $14.0 million (2013 - $104.1 million), which includes an exploration write-off of $79.5 million associated with costs incurred on the Albertine Graben Block V in eastern

DRC and pre-licence costs of new ventures, and a gross impairment charge on the CNV asset of $60.5 million (net $38.2 million after tax impact). Before accounting for the non-cash impact of the exploration write-offs and impairments, post-tax profits were down from $196.1 million in 2013 to $131.7 million in 2014.

Cash generated from operations came in at $251.2 million in 2014, down from $314.4 million in 2013, reflecting lower sales volumes and lower realised oil prices. Capital expenditures were up from $99.1 million in 2013 to $162.5 million in 2014 predominantly due to the TGT H5 development and exploration activity in Africa.

SOCO made its second return of cash to shareholders during to 2014 of c. $119 million, or 60% of the 2013 free cash flow of c.$200 million, bringing the total returned in the Company's short history of making distributions to c. $333 million.

Vietnam

The TGT field has been a great investment for SOCO and the cash flow from the field has enabled the Company to initiate cash returns to shareholders.

The TGT field has attractive economics and cost recovery terms, low operating costs and benign operating and geopolitical backdrop. But the field economics also mean that the cash flow profile and returns are significantly geared to the oil price.

The ERC Equipoise (ERCE) study of the TGT field has significantly advanced our understanding of the field and by most indications improved that of our partners. The dynamic model developed by ERCE, a result of almost a year's work of a multi-disciplinary team, incorporating all available geological and field performance data, is the best tool available yet. The modelling study demonstrates a broad range of interpretations and of potential recovery scenarios depending on the level of development drilling, infrastructure optimisation and upgrade, as well as the most optimal reservoir performance management to optimise field recovery.

Clearly, the scope of the development programme in the updated full FDP will to a large extent depend on the oil price outlook at the time and JOC partners' alignment on a development path and appetite to commit capital.

Consequently, a substantial amount of TGT 2P reserves has been re-classified into 2C Contingent Resources, reflecting the fact that currently only the original FDP and H5 FDP wells are being drilled and that, at this stage, there is no agreement among the JOC partners on the scope of development and level of investment going forward. Therefore, we believe that the prudent approach to 2P reserve booking against this background, taking into account the level of reservoir complexity and uncertainty, is to include only the P50 recoverable volumes based on existing and likely near-term wells, and optimal field management. Additionally, a portion of the 2P reserves has been recognised as 3C Contingent Resources reflecting a degree of geological uncertainty around the range of oil-in-place estimates and partner alignment on the level of future capital investment in the field.

For CNV, our previous commercial reserve estimates were largely predicated on the successful drilling of the CNV-7P well, which was targeting the previously untapped south-west area of the field and material increase in production, leading to further development drilling. Disappointingly, due to unexpected geological issues the well failed to reach the target reservoir despite several attempts to side-track. Thus, we have significantly reduced our estimates of the 2P reserves for CNV and re-classified undrilled wells including the CNV-7P well into Contingent Resources.

Africa exploration

Marine XI

During 2014, we drilled, as operator, a very successful exploration well on Marine XI Block offshore Congo (Brazzaville), which suggests an extension into our Block of the Litchendjili field on the Marine XII Block which is scheduled to come on-stream this year. The Lidongo X Marine 101 exploration well significantly exceeded expectations, testing more than 5,000 barrels of oil per day. The well results are being analysed in order to determine the continuity of the productive reservoirs of the well with the nearby discoveries in the Marine XII Block and to progress towards potential unitisation with the Litchendjili field.

The reserves associated with the Viodo field in Marine XI have been re-classified to Contingent Resources as there are no plans for commercial standalone development. However, we believe that there is potential in the near future to recognise Contingent Resources on the Marine XI Block as the Lidongo discovery is further evaluated and advanced towards unitisation with the Litchendjili field and the exploitation of the East Lideka field progresses.

Mer Profonde Sud

Following completion of our farm-in into the MPS Block offshore Congo (Brazzaville), we have been working with our partners on a detailed well location study. We remain very optimistic about the exploration potential of the MPS Block, however, given the prevailing market conditions in early 2015, drilling of the well has been delayed until 2016.

Block V

After receiving all necessary regulatory approvals, a non-invasive seismic survey was completed over a portion of Lake Edward in an area of Block V in eastern DRC mid-2014. The survey was successfully completed in six weeks with no reported adverse impact on the environmental parameters of the region. Processing of the seismic data has been completed and data interpretation is currently underway in the UK and should be completed by mid-2015. The Company no longer has any personnel in Block V.

While we acknowledge that the DRC government is anticipating discussions with UNESCO involving the future of the Virunga National Park; we have no involvement in these discussions. After providing the DRC government with interpretation of the seismic results, SOCO will have no further involvement in the Block. Consequently, all costs incurred on Block V to date and any further costs anticipated in the course of 2015 have been written off as exploration expense in 2014. It is our intention to leave behind all the humanitarian aid that SOCO has provided in medical, water purification and communications facilities for the benefit of the people.

Corporate

Management

Executive refreshment and succession continue to be important to the Company. In April, SOCO announced that Anya Weaving joined the Company as Chief Financial Officer with effect from 1 May 2014. Anya joined from Bank of America Merrill Lynch where she was a Managing Director in Mergers and Acquisitions with responsibility for the oil and gas sector.

Review of Allegations

In the summer of 2014, the Company engaged Clifford Chance LLP to carry out an independent review to assess whether there is evidence supporting allegations of wrong doing made by various NGO’s and media members of its activities in the DRC. The law firm was also asked to advise as to whether, in the materials reviewed, there was any evidence contradicting the Company's conclusion, based on its own internal review, that neither SOCO nor its employees have been complicit in any intimidation and/or human rights abuses.

Given the absence of a response from NGOs to SOCO's request for assistance in evidencing the allegations, the exercise has been defined and focused by Clifford Chance in terms of the evidence considered. The Company has provided access to all the available personnel, processes and documents requested by the law firm in order for them to conduct a focused review and sufficient for them to advise the Board as to the appropriate steps to be taken.

Upon the conclusion of the independent review, the Company will take any necessary steps and advise its stakeholders.

Outlook

We are committed to evaluating every alternative to optimise our exposure to upside without jeopardising our focus on sustainable cash flow generation. Whereas exploration remains a cornerstone of our growth strategy, we believe now is not the right time to commit any material capital to this. Our exploration programme for 2015 is limited to reprocessing existing seismic on the Marine XI Block to define the lowest cost upside to the portfolio and doing further work on a potential well location for drilling Mer Profonde Sud in 2016.

Our production guidance range for 2015 remains at 10.5-12 KBOEPD, reflecting reduced scope of the 2015 TGT drilling programme, largely due to the uncertain oil price environment, and conservative estimates of initial flow rates from TGT/H5.

The operational focus for 2015 will be on bringing TGT's H5 fault Block production on line and working with the TGT partners to submit the updated FDP for TGT in Q3. Otherwise, it will be a year of prudent cost management whilst taking proactive measures to ramp the TGT development programme back up when conditions are more conducive.

Current market conditions notwithstanding, our distribution strategy of targeting cash returns of 50% of the previous year's free cash flow remains. Based on the results of 2014 and near term outlook, the Board has proposed a cash return of 10 pence per share (representing c. $50 million), payable in the form of a dividend, to be approved at the AGM on 10 June 2015.

As in the past, we remain value driven. We see the current environment as an opportunity to plan for future growth rather than a time for questioning the viability of the industry, and we believe SOCO is well positioned to continue to execute its strategy in this environment.

Rui de Sousa
Chairman

Ed Story
President and Chief Executive Officer

REVIEW OF OPERATIONS

Operational focus for 2014 was on the in-field development drilling of TGT, completion of the TGT dynamic model and the development of the TGT H5 fault Block. In Africa, we successfully drilled and tested an exploration well on Marine XI and successfully and safely completed a lake bed seismic survey on Lake Edward.

Group production for 2014 averaged 13,605 BOEPD (2013 – 16,694 BOEPD) with all production coming from the Company's interests in Vietnam.

Production of oil and gas by field

	FY 2014	1H 2014	FY 2013	1H 2013
TGT Production	**11,538**	**11,939**	**14,635**	**14,967**
Oil (BOPD)	10,464	10,751	13,301	14,967
Gas (BOEPD)	1,074	1,188	1,334	-
CNV Production	**2,067**	**2,021**	**2,059**	**2,168**
Oil (BOPD)	1,423	1,403	1,494	1,575
Gas (BOEPD)	644	618	565	593
Total Production	**13,605**	**13,960**	**16,694**	**17,135**
Oil (BOPD)	11,887	12,154	14,795	16,542
Gas (BOEPD)	1,719	1,806	1,899	593

Vietnam

Block 16-1 and Block 9-2 in Vietnam 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 by JOCs in which each partner holds and interest equivalent to its share in the respective Petroleum Contract.

SOCO's 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 Vietnam Ltd. SOCO's partners in both Blocks are PetroVietnam, the national oil company of Vietnam, and PTTEP, the national oil company of Thailand.

Block 16-1 – Te Giac Trang (TGT) Field (30.5% interest; operated by Hoang Long Joint Operating Company
The TGT field is located in the north-eastern part of Block 16-1 offshore Vietnam and is operated by the HLJOC. TGT is a simple structure, with complex production intervals, extending over 16km and with hydrocarbons located in at least five fault blocks. The producing reservoir comprises a complex series of over 50 clastic reservoir intervals of Miocene and Oligocene age. Each reservoir interval requires individual reservoir management to optimise field recovery. The field has attractive economics and cost recovery terms, low operating costs and a benign operating and geopolitical backdrop.

2014 production net to SOCO averaged 11,538 BOEPD. TGT crude sold at an average $4.13/bbl premium to Brent in 2014. In line with the lower oil price environment, TGT crude sales in 2015 have averaged a premium of approximately $1.92 per barrel.

H5 Development
Following on from the successful H5 discovery well, TGT-10XST1, in late 2013, the Company and its partners focussed on the fast track development of H5, agreeing to develop it using an unmanned wellhead platform, the H5-WHP, with production tied-in to the FPSO via the H1-WHP.

All parties agreed to commence construction of the platform in advance of formal approvals. The Hydrocarbons Initially In Place/Reserve Assessment Report was approved in June 2014, and the H5 FDP was approved in September 2014. The construction of the H5-WHP jacket and drilling deck was installed in August/September 2014 allowing drilling to commence from mid-September 2014.

The target date for first oil is September/October 2015 and we are on target to achieve this.

2014 Drilling Programme
Following the delay to the 2013 in field drilling programme from the extended testing on the H5 discovery well, TGT-10XST1, we drilled a total of eight wells in 2014 both on the H5 development and within the main part of the TGT field. A further five wells are expected to be completed by the end of the second quarter 2015, at which point the rigs are to be released.

Drilling commenced on the H1-WHP with two producer wells, TGT-17PST1 and TGT-18PST1, both now on-stream and producing in line with expectations. The third well, TGT-11X, an exploration/appraisal well on the H2S fault block, has been completed as a producer/injector. This well was targeting primarily an Oligocene oil column with a thin Lower Miocene column. However, the pay sections in both horizons were thinner than expected. The first targeted injection well, TGT-19I, was drilled on the eastern flank of the H1 fault block, with injection now ongoing to complement aquifer support and assist specific sand water-flooding.

In October 2014, the TGT-9X appraisal well was drilled from the H4-WHP appraising the Miocene and Oligocene sequences in the H3 fault block. Although the well found a thinner hydrocarbon column than predicted, it was completed in December 2014 as a producer. In January 2015 the TGT-20P, an in-fill producer in the H4 fault block targeting the Oligocene was drilled. Following this well, the rig will drill the H3N fault block in-fill producer, TGT-21P, and the H4 fault block in-fill producer, TGT-26P, both targeting the Miocene and Oligocene sequences.

The first H5 development well, TGT-22P, was drilled to establish the distribution of hydrocarbons in the Upper Miocene. The TGT-10XST1 well test produced gas during the final test although it was not possible to identify from which specific sand units. Fluid samples taken from the multi-layered Miocene have indicated that gas is more limited than previously thought, increasing oil in place.

The rig then batch-drilled and successfully completed the TGT-23P and TGT-24P wells by early January 2015. Following that, in January 2015, the TGT-12X well, an appraisal well of the previously undrilled H5N fault block was drilled. Unfortunately, the well encountered only a minor oil column in the target Miocene section. Having completed that well, the rig is now drilling the final H5 development well, TGT-25P, that will also appraise the deeper Oligocene section. It remains our expectation to drill the H5S fault block appraisal well following completion of the TGT-25P well, provided there is time ahead of the rig release in April 2015.

Floating, Production, Storage and Offloading Vessel Capacity Testing
As the TGT Field’s FPSO oil throughput remains contractually limited to 40,000 BOPD of the 55,000 BOPD nameplate capacity, FPSO de-bottlenecking to increase TGT production remains a strategic priority. Delays to the 2014 drilling programme required changes to other operational plans, the main one being to accelerate the testing of the total liquids (oil and water) handling capacity of the FPSO ahead of carrying out the second phase test of the oil handling capacity.

In July 2014, the HLJOC successfully tested the existing facilities on the FPSO beyond the current total liquids nameplate capacity of 120,000 barrels of liquids per day (BLPD) to approximately 140,000 BLPD. The test confirmed that minor systems modifications could increase total liquids handling capacity to in excess of 160,000 BLPD. The HLJOC has identified minor investments to improve liquid handling and is working with the vessel owner/operator (BAB-VSP Alliance) to define the technical projects and commercial terms to allow the vessel to be re-certified at higher capacities.

TGT Performance Evaluation and Prediction

In 2013, SOCO retained ERCE to build a Dynamic Simulation Model of the TGT field. In 2014, this engagement was expanded to include the integration of a new Geological Model. The Geological Model was integrated into a revised Dynamic Simulation Model for a technical evaluation of the TGT resources. On completion of the history match and H5 area additions, the model ran a series of forecasts to evaluate the ultimate oil volume recoverable given various levels of development drilling and pressure maintenance under various FPSO and alternative liquid handling options.

The ERCE study of TGT has significantly advanced our understanding of the field. The dynamic model encompassed almost a year's work of a multi-disciplinary team, incorporating all geological and field performance data, and is the best tool available yet, but also highlights significant complexity and technical uncertainty of the field. The modelling study demonstrates a significant range of potential development scenarios depending on the level of development drilling, infrastructure optimisation and upgrade, as well as reservoir performance management to optimise field recovery. We continue to refine and update the model to focus on the development programme choices required for the revised full FDP.

Forward Plans

At this time, the HLJOC partners are preparing an update to the TGT FDP for submission to the relevant Vietnamese authorities. The updated FDP will incorporate the development plans for the TGT field beyond 2015. The conclusions of the ERCE work were shared with the HLJOC Partners as part of this process as the work suggests a substantial increase in oil recovery can be achieved.

Clearly, the scope of the development programme in the updated FDP will to a large extent depend on the oil price outlook at the time and JOC partners' alignment on a development path and appetite to commit capital.

In light of the current oil price, Group production guidance for 2015, at 10,500-12,000 BOEPD, is lower than 2014 production performance reflecting the reduced scope of 2015 TGT drilling, limited to wells approved under the original FDP and the H5 FDP, as well as conservative estimates of initial flow rates from H5. Production from TGT could be increased from the existing well stock by perforating additional horizons, optimising reservoir management by shutting off higher water-cut wells and through the early start-up of the H5 development. SOCO is discussing all these initiatives with the HLJOC partners. It is our expectation that, with these measures and by having H5 coming on stream, the production in the field could be increased.

Block 9-2 – Ca Ngu Vang Field (CNV) (25% interest; operated by Hoan Vu Joint Operating Company

The CNV field is located in the western part of Block 9-2, offshore Vietnam and is operated by the HVJOC. SOCO's working interest production from CNV averaged 2,067 BOEPD in 2014 (2013: 2,059 BOEPD). In contrast to TGT, the CNV field reservoir is a fractured granitic basement which produces highly volatile oil with a high gas to oil ratio and exploitation is dependent on the fracture interconnectivity to deplete the reservoir efficiently. Accordingly, traditional reservoir properties and 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 onshore gas facility for further distribution. The crude oil is stored on a FSO vessel prior to sale. On the BHCPP, dedicated test separation and metering facilities have been installed.

The CNV-7P well drilled in 2014 was designed to target the thus far unpenetrated south west area of the field to increase production. The well encountered unexpected geological problems not previously seen in the upper hole section just above the reservoir, requiring the section to be redrilled. The same problems persisted during two attempted side tracks preventing successful completion.

The decision was made to suspend the well, and review alternative plans and well paths to enable successful completion. The decision on timing to return to the well is expected in mid-2015 following completion of detailed drilling engineering and rock mechanic studies. However in the current oil price environment SOCO believes the redrill of this well has a low likelihood.

Republic of Congo (Brazzaville)

SOCO holds its interests in the Marine XI Block in Congo (Brazzaville) through an 85% owned subsidiary, SOCO EPC. SOCO EPC holds a 40.39% interest in the Marine XI Block located offshore in the shallow water Lower Congo Basin and is the designated operator of the Block. SOCO holds a 60% working interest in the Mer Profonde Sud Block, offshore Congo (Brazzaville) through its wholly owned subsidiary, SOCO Congo BEX Limited.

Marine XI

Lidongo X Marine 101 Well

The LXM-101 well, 23 kilometres northwest of Pointe Noire in approximately 45 metres water depth, was drilled to a total depth of 2,665 metres, encountering oil in a clastics sequence in the Djeno sand formation. The test, over a perforated 20 metre section, produced at a stable average post-frac flow rate of 4,800 BOPD and 3.5 MMSCFD on a 56/64" fixed choke with a flowing wellhead pressure of 778 psi following the successful execution of the stimulation frac. The oil was 32 degrees API.

The well results are being analysed to determine continuity with the nearby discovery on Marine XII and discussions with the authorities are ongoing to submit the documentation required to allow unitisation with that field.

Nanga II A

Following the completion of the interpretation of the reprocessed seismic data, the exploitation license expired in October 2014. We are no longer undertaking work on Nanga II but have approached the Congolese Ministry of Hydrocarbons to discuss a potential work programme and commercial terms for a possible Production Sharing Agreement for the area. Discussions are ongoing at this time.

Mer Profonde Sud

The Company's farm-in to acquire a 60% working interest in the offshore MPS Block has been completed following government approval of the commencement of the relevant two year licence period from 1 June 2014. We have been working with our partners on a detailed well location study and are very optimistic about the exploration potential of the MPS Block. However, given the prevailing market conditions in early 2015, drilling of the well has been delayed until 2016.

Democratic Republic of Congo (Kinshasa)

SOCO holds its onshore interest in the DRC though its 85% owned subsidiary, SOCO E&P DRC. SOCO E&P DRC holds an 85% working interest and is the designated operator in Block V, situated in the southern Albertine Graben in eastern DRC.

Block V

After receiving all necessary regulatory approvals, the lake bed seismic survey on Lake Edward was completed in June 2014. Safety of the crew was of primary importance. The survey was successfully completed in six weeks amid challenging conditions with no lost time injuries. Processing of the seismic data has been completed. Data interpretation is currently underway in the UK and should be completed by mid-2015. The Company no longer has any personnel on Block V and after providing the DRC government with interpretation of the results of the seismic anticipates no further involvement in the Block. It is our intention to leave behind all the humanitarian aid that SOCO has provided in medical, water purification and communications facilities for the benefit of the people.

Angola

Cabinda North

Following incorporation of the results from the 2013 drilling programme Sonangol, the operator, detailed plans for operations in 2015 has been reviewed by the partnership. The license expires at the end of March 2015, however a three year licence extension for the continuation of exploration activities has been requested effective from 1 April 2015 with a new contractor group interested to continue their involvement.

Group Commercial Reserves and Contingent Resources Evaluation

Against the background of lower oil prices and the resultant uncertainty around the scope and timing of future development activities, in particular due to partner reluctance to commit to additional capital expenditures, we have revised down the 2P reserves estimates for our portfolio, with a portion being re-classified into Contingent Resources.

TGT Commercial Reserves and Contingent Resources

For TGT the re-classification of reserves into Contingent Resources reflects the fact that there is not yet agreement among JOC partners on the scope of development activities and level of investment following the current FDP and H5 FDP approved wells, all of which will be drilled in 2015. SOCO has estimated reserves assuming the drilling of only existing approved and a small number of likely near-term wells and optimal field management. All volumes beyond this scope of development activities are being 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 ERCE Dynamic Simulation Model and the current field performance and reflect the degree of uncertainty around the oil-in-place estimates.

Figures in MMbbl / MMboe	P90	P50	P10
Stock Tank Oil Initially In Place	498	759	1,052

Figures in MMbbl / MMboe

TGT Field Gross

Commercial Reserves + Production to Year End 2014	**1P**	**2P**	**3P**
Oil	120.0	160.0	200.0
Gas	6.3	9.8	13.6
Total	126.3	169.8	213.6
Contingent Resources	**1C**	**2C**	**3C**
Oil	55.0	80.0	115.0
Gas	4.8	8.0	11.9
Total	59.8	88.0	126.9
Total Ultimate Recovery	**1P & 1C**	**2P & 2C**	**3P & 3C**
Oil	175.0	240.0	315.0
Gas	11.1	17.8	25.5
Total	186.1	257.8	340.5

SOCO Working Interest Remaining Reserves and Resources

Commercial Reserves	**1P**	**2P**	**3P**
Oil	22.2	34.4	46.6
Gas	1.0	2.1	3.3
Total	23.2	36.5	49.9
Contingent Resources	**1C**	**2C**	**3C**
Oil	16.8	24.4	35.1
Gas	1.5	2.4	3.6
Total	18.2	26.8	38.7
Sum of Reserves and Contingent Resources	**1P & 1C**	**2P & 2C**	**3P & 3C**
Oil	39.0	58.8	81.7
Gas	2.5	4.5	6.9
Total	41.5	63.3	88.6

CNV Commercial Reserves and Contingent Resources

Our previous CNV 2P reserves estimate was predicated on the successful drilling of the CNV-7P well, targeting the south-west area of the field and a material increase in production. Disappointingly, due to unexpected geological issues the well failed to reach the target reservoir. The JOC partners have agreed to carry out further drilling studies and have included the cost of re-drilling the CNV-7P well in the contingent budget for 2015. However, as SOCO now believes there is a low likelihood of this well being drilled in the current oil price environment SOCO has reduced the CNV reserves estimate and moved volumes associated with the CNV-7P and future wells to Contingent Resources.

SOCO Working Interest Remaining

Commercial Reserves	**2P**
Oil	3.0
Gas	1.3
Total	4.3
Contingent Resources	**2C**
Oil	2.6
Gas	1.4
Total	4.0

All figures in MMbbl / MMboe

Viodo Commercial Reserves and Contingent Resources

The reserves associated with the Viodo field in the Marine XI Block have been reclassified as Contingent Resources as there are no plans for commercial standalone development at this time. However, we believe that there is potential in the future to recognise Contingent Resources on the Marine XI Block from Lideka East and from the Lidongo discovery as it is further evaluated and progressed towards unitisation with the nearby Litchendjili field which itself is being developed in 2015.

Field Gross In Place

Contingent Resources	**2C**
Oil	20.0
Gas	-
Total	20.0

SOCO Working Interest Remaining

Contingent Resources	**2C**
Oil	8.1
Gas	-
Total	8.1

All figures in MMbbl / MMboe

FINANCIAL REVIEW

Key Financial Metrics	FY 2014	FY 2013	Change
Sales revenue ($m)	448.2	608.1	-26.3%
Oil price realised ($/bbl)	102.91	112.62	-8.6%
Gross profit ($m)	304.4	439.0	-30.7%
Administrative expenses ($m)	(11.8)	(13.2)	-10.6%
Exploration costs written off ($m)	(79.5)	(92.0)	-13.6%
Impairment of property, plant and equipment ($m)	(60.5)	-	-
Operating profit ($m)	152.6	333.8	-54.3%
Operating profit before exploration write off and impairment ($m)	292.6	425.8	-31.3%
Profit after tax ($m)	14.0	104.1	-86.6%
Profit after tax before exploration write off and impairment ($m)	131.7	196.1	-32.8%
Operating cash flow before working capital, interest and tax ($m)	344.4	472.0	-27.0%
Change in working capital ($m)	37.6	3.3	n/a
Net cash from operating activities ($m)	251.2	314.4	-20.1%
Capital expenditure ($m)	(162.5)	(99.1)	64.0%
Payment to abandonment fund ($m)	(9.6)	(15.0)	-36.0%
Free cash flow ($m)	41.0[1]	200.3[2]	-79.5%
Cash, cash equivalents and liquid investments ($m)	166.4	210.0	-20.8%
Distributions to Shareholders ($m)	119.2	213.3	-44.1%
Distributions (pence per share)	22	40	-45.0%

[1] For 2014, free cash flow is calculated as operating cash flow before movements in working capital and after payments for income taxes, capital expenditure and abandonment.

[2] For 2013, free cash flow is calculated as net cash from operating activities and after payments for capital expenditure and abandonment.

The Group's financial results delivered solid revenue of $448.2 million and cash generated by operations of $382.0 million, albeit down from the 2013 results, reflecting both lower production and lower realised average oil price of c. $103 per barrel (2013 – c. $113 per barrel). The Group is reporting a post-tax profit for the year of $14.0 million (2013 – $104.1 million), which includes an exploration write off of $79.5 million associated with costs incurred on the Albertine Graben Block V in eastern DRC and costs of new ventures, and a gross impairment charge on the CNV asset of $60.5 million (net $38.2 million after tax impact). Before accounting for the non-cash impact of the exploration write offs and impairments, post-tax profits were down from $196.1 in 2013 to $131.7 million in 2014.

Operating cash flow came in at $251.2 million in 2014, down from $314.4 million in 2013, reflecting lower sales volumes and lower realised oil prices. Capital expenditures were up from $99.1 million in 2013 to $162.5 million in 2014 predominantly due to the TGT H5 development and exploration activity in Africa. SOCO made its second return of cash to shareholders during 2014 of c. $119 million, bringing the total returned in the Company's short history of making distributions to c. $333 million.

With cash, cash equivalents and liquid investments of $166.4 million at 2014 year end – dropping only $43.6 million year-on-year despite the significant capital programme, second substantial return to shareholders and lower operating cash inflows – SOCO has exited 2014 with substantial financial flexibility.

A significant drop in the oil price in the latter part of 2014 brought a lot of uncertainty and volatility to the industry highlighting the importance of financial flexibility and strong cost discipline. In response to the lower oil prices, we have deferred drilling the MPS exploration well to 2016 and undertaken several actions to reduce our general and administration costs, notably by eliminating the separate new ventures office and reducing general and administration costs in our regional offices by approximately 25%.

Against the challenging environment of lower oil prices, SOCO is in a relatively strong position given its robust balance sheet, low operating costs and attractive Vietnam production economics with operating cash flow break-even oil price per barrel in the low $20s. The cash operating costs of our production portfolio were approximately $9 per barrel of oil equivalent in 2014, estimated to move to just below $12 per boe in 2015, reflecting the predominantly fixed TGT cost base and lower production.

The Company has sufficient cash flow and cash balances to meet its ongoing development and exploration expenditure and has capacity beyond that to take advantage of opportunities that may arise in this market. The 2015 firm capital expenditure budget is in the region of $90 million, with c.$70 million for Vietnam and around $20 million for Africa, and a contingent capex budget of c.$25 million pending approval of additional development wells in Vietnam.

Income Statement

Operating Results

Revenue

Revenue from oil and gas production from the Group's South East Asia production assets in Vietnam was $448.2 million compared with $608.1 million in 2013. This decrease in revenue is due to lower sales volumes and a lower realised oil price. The Group's working interest share (which is equivalent to its entitlement interest) of production during 2014 was 13,605 BOEPD, down from 16,694 BOEPD in 2013, mainly due to part of the capacity of the TGT FPSO being made available, from May 2013, to the TLJOC which operates a contiguous field to the north of TGT (also see the Review of Operations). During 2014, the Group realised an average oil price of $102.91 per barrel of oil sold compared with $112.62 per barrel in 2013.

Cost of Sales

Cost of sales in 2014 were $143.8 million versus $169.1 million in 2013. This decrease is mainly associated with the TGT field where cost of sales was $125.7 million including an inventory credit, recorded at market value, of $1.0 million (2013 - $157.0 million including an inventory charge of $5.3 million). Cost of sales associated with the CNV field was $18.1 million, including an inventory charge of $2.5 million (2013 – $12.1 million, including an inventory credit of $1.7 million).

Production operating costs for TGT were $38.2 million for 2014 down from $42.6 million in 2013 mainly due to a full year's allocation of costs to the TLJOC via a tariff arrangement for the use of the TGT FPSO which started in May 2013, and lower production. Production operating costs associated with CNV were $5.0 million in 2014, similar to 2013.

Royalties on oil sales from TGT and CNV in 2014 totalled $34.3 million consistent with lower revenue compared with $46.4 million in 2013. Export duty arising on TGT oil sales amounted to $7.6 million in 2014, down from $19.6 million in 2013, due to lower oil sales revenues and a proportion of cargoes being sold into the domestic market which are not subject to export duty. All CNV oil was sold into the domestic market in both 2013 and 2014.

DD&A charges were $50.1 million during 2014 compared with $44.6 million in 2013 mainly reflecting the cost basis of the TGT development offset by lower production. Following the revision to reserves estimates and associated expenditures, as noted below, the carrying value of CNV has been reduced to its fair value as at 31

December 2014. DD&A on both TGT and CNV will reflect the revised production and future capital expenditure profiles from 2015.

Operating costs in 2014 on a per barrel basis (excluding DD&A, inventory movements and sales related duties and royalties) were approximately $9.00 per barrel compared with approximately $8.10 per barrel in 2013. The primary cause of the increase is related to the lower production volumes on the TGT field which has dedicated production and processing facilities on the FPSO, the costs of which, net of TLJOC allocations, are predominately fixed.

On a per barrel basis, DD&A increased from approximately $7.35 per barrel in 2013 to approximately $10.10 per barrel in 2014 reflecting a higher estimated cost basis of developing the TGT reserves, based on the prevailing estimates during 2014.

Administrative Expenses
Administrative expenses decreased to $11.8 million for the 12 months to December 2014 down from $13.2 million in 2013. This decrease is primarily due to lower employee costs in 2014 associated with the use of a deferred share bonus scheme.

Exploration Costs
During 2014, exploration costs including costs associated with the Albertine Graben Block V in eastern DRC and costs associated with the early stages of new ventures in the amount of $73.6 million, were written off in the income statement in accordance with the Group's accounting policy on oil and gas exploration and evaluation expenditure. In accordance with IAS 37, a further $5.9 million has been accrued in respect of anticipated future expenditure to complete the current work programme on Block V in the absence of plans to continue thereafter. In 2013, the charge of $92.0 million represents the costs incurred, since its acquisition, on the relinquished Nganzi licence, onshore DRC.

Impairment of Property, Plant and Equipment
As discussed in the Review of Operations, management's estimates of the CNV proved and probable oil and gas reserves have reduced. Combined with lower oil prices this has led to the estimated recoverable amount of the CNV producing asset being less than the book carrying value. Consequently, a pre-tax impairment charge in the amount of $60.5 million has been reflected in the income statement in accordance with the Group's accounting policy. The associated tax credit of $22.3 million is reflected in Note 5. As at 31 December 2014, the fair value of the asset is estimated at $104.4 million based on a discount rate of 10% and an oil price reflecting the current three year forward curve and $90 per barrel (plus 2.5% inflation) thereafter.

Tax
The tax expense decreased from $229.2 million in 2013 to $138.7 million in 2014 consistent with the lower profit in the year and tax credit associated with CNV impairment (see above). The effective tax rate in Vietnam during 2014 and 2013 approximated the statutory rate of 50%.

Profit for the Period
The Group's profit after tax in 2014 was $14.0 million, down from $104.1 million in 2013. Basic and diluted earnings per share decreased from 31.7 cents in 2013 to 4.3 cents in 2014 and from 31.6 cents in 2013 to 4.2 cents in 2014, respectively.

Balance Sheet

Intangible assets decreased by $6.6 million since year end 2013. The decrease caused by the exploration write off described above associated with prior period costs was offset by continued exploration activity in the Group's Africa region, including the successful LXM-101 exploration well on MXI, offshore Congo (Brazzaville).

Property, plant and equipment decreased by $11.3 million since 2013 year end due to pre-tax impairment on the CNV asset (see above), partially offset by costs associated with TGT field development and appraisal activities and CNV development drilling less DD&A charges.

Other non-current receivables of $24.6 million (31 December 2013 – $15.0 million) comprise abandonment security funds for TGT and CNV which have been established to ensure that sufficient funds exist to meet future abandonment obligations. The funds are operated by PetroVietnam and partners retain the legal rights to the funds pending commencement of abandonment operations.

Oil inventory was $6.1 million at 31 December 2014, down from $7.3 million at year end 2013. Trade and other receivables at year end 2014 were $39.6 million, down from $68.9 million 31 December 2013. The movements in oil inventory and trade receivables arise mainly due to the timing of oil sale liftings and the oil price realised.

SOCO's cash, cash equivalents and liquid investments decreased over the year from $210.0 million to $166.4 million at 31 December 2014. During 2014, the Company returned $119.2 million (2013 - $213.3 million) to shareholders (see below), funded exploration and development capital expenditure as described above, and made further contributions to two abandonment funds in Vietnam (see above). Despite these significant cash outflows cash generated from production operations in Vietnam meant that cash, cash equivalents and liquid investments decreased by just $43.6 million over the year.

The Group's trade and other payables increased to $43.9 million at 31 December 2014 from $36.1 million year end 2013 partly due to provision, in accordance with IAS 37, for costs expected to be incurred during 2015 in relation to Albertine Graben Block V, where, once the current work programme is complete, no further activity is planned. Tax payables decreased from $18.5 million last year end to $11.6 million this year end consistent with timing and volumes of liftings in Vietnam where tax is paid on each cargo lifted.

Deferred tax liabilities increased to $200.2 million at 31 December 2014 from $184.2 million year end 2013, mainly due to accelerated tax depreciation and other timing differences associated with the Group's South East Asia segment, net of the tax credit associated with the impairment of CNV (see above). Long term provisions related to the Group's decommissioning obligations in South East Asia at $51.1 million were up from $42.9 million last year end mainly due to the installation of additional TGT facilities and the drilling of TGT development wells.

Cash Flow

Net cash flows from operating activities in 2014 mainly comprise the Group's continuing Vietnam operations and amounted to $251.2 million compared with $314.4 million in 2013. The decrease is mainly due to the lower contribution of production from the TGT field including the associated impact on working capital movements, as described above.

Capital expenditure for the year ending 31 December 2014 was $162.5 million compared with $99.1 million in 2013. The higher capital spend in 2014 reflects a more active development programme, including the TGT H5 development and TGT and CNV drilling activity, compared to the prior year.

Distribution to Shareholders

During the year, the Company announced a second return of value to shareholders of 22 pence per Ordinary Share (2013 – 40 pence per Ordinary Share) amounting to £73 million, being $119.2 million (2013 – £133 million, being $213.3 million), in cash by way of a B/C share scheme, which gave shareholders (other than certain overseas shareholders) a choice between receiving cash in the form of income or in the form of capital. The return of value, which was approved by shareholders on 22 September 2014, became effective on 30 September 2014. Despite the current oil price environment, the Board has proposed a dividend of 10 pence per ordinary share subject to approval by Shareholders at the AGM (see Note 12).

Key Performance Indicators

SOCO uses a number of financial and non-financial KPIs against which it monitors its performance. Detailed KPI targets for the next year are set out in the annual budget. At each Board meeting these expectations are reviewed for progress against actual results and adjusted to accommodate changes in the operating environment including oil price fluctuations.

Own Shares

The SOCO Employee Benefit Trust holds ordinary shares of the Company (Shares) for the purpose of satisfying long term incentive awards for senior management. At the end of 2014, the Trust held 3,294,111 (2013 – 3,666,213) Shares, representing 0.97% (2013 – 1.08%) of the issued share capital.

In addition, as at 31 December 2014, the Company held 9,122,268 (2013 – 9,122,268) treasury Shares, representing 2.67% (2013 – 2.68%) of the issued share capital.

Going Concern

SOCO's business activities, its financial position, cash flows and liquidity position, together with an outlook of factors likely to affect the Group's future development, performance and position are discussed above. 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 accounts on a going concern basis.

CONSOLIDATED INCOME STATEMENT

for the year to 31 December 2014

	Notes	**2014** **$ million**	2013 $ million
Revenue	4	**448.2**	608.1
Cost of sales		**(143.8)**	(169.1)
Gross profit		**304.4**	439.0
Administrative expenses		**(11.8)**	(13.2)
Exploration costs written off	7	**(79.5)**	(92.0)
Impairment of property, plant and equipment	8	**(60.5)**	-
Operating profit		**152.6**	333.8
Investment revenue		**0.7**	1.0
Other gains and losses		**1.6**	1.3
Finance costs		**(2.2)**	(2.8)
Profit before tax	4	**152.7**	333.3
Tax	4, 5	**(138.7)**	(229.2)
Profit for the year		**14.0**	104.1
Earnings per share (cents)	6		
Basic		**4.3**	31.7
Diluted		**4.2**	31.6

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

for the year to 31 December 2014

	2014 **$ million**	2013 $ million
Profit for the year	**14.0**	104.1
Items that may be subsequently reclassified to profit or loss:		
Unrealised currency translation differences	**(1.8)**	9.3
Total comprehensive income for the year	**12.2**	113.4

BALANCE SHEETS

as at 31 December 2014

	Notes	Group 2014 $ million	Group 2013 $ million	Company 2014 $ million	Company 2013 $ million
Non-current assets					
Intangible assets	7	**209.1**	215.7	**-**	-
Property, plant and equipment	8	**790.0**	801.3	**1.0**	0.9
Investments		**-**	-	**689.4**	884.6
Financial asset	9	**45.0**	43.4	**-**	-
Other receivables		**24.6**	15.0	**-**	-
		1,068.7	1,075.4	**690.4**	885.5
Current assets					
Inventories		**6.1**	7.3	**-**	-
Trade and other receivables		**39.6**	68.9	**0.6**	0.8
Tax receivables		**1.1**	0.9	**0.5**	0.4
Liquid investments		**40.2**	80.1	**-**	-
Cash and cash equivalents		**126.2**	129.9	**0.2**	0.3
		213.2	287.1	**1.3**	1.5
Total assets		**1,281.9**	1,362.5	**691.7**	887.0
Current liabilities					
Trade and other payables		**(43.9)**	(36.1)	**(2.2)**	(1.7)
Tax payable		**(11.6)**	(18.5)	**(0.2)**	(0.1)
		(55.5)	(54.6)	**(2.4)**	(1.8)
Net current assets (liabilities)		**157.7**	232.5	**(1.1)**	(0.3)
Non-current liabilities					
Deferred tax liabilities		**(200.2)**	(184.2)	**-**	-
Long term provisions		**(51.1)**	(42.9)	**-**	-
		(251.3)	(227.1)	**-**	-
Total liabilities		**(306.8)**	(281.7)	**(2.4)**	(1.8)
Net assets		**975.1**	1,080.8	**689.3**	885.2
Equity					
Share capital		**27.6**	27.6	**27.6**	27.6
Share premium account		**-**	11.1	**-**	11.1
Other reserves		**239.5**	226.5	**195.0**	183.1
Retained earnings		**708.0**	815.6	**466.7**	663.4
Total equity		**975.1**	1,080.8	**689.3**	885.2

STATEMENTS OF CHANGES IN EQUITY

for the year to 31 December 2014

Group

	Called up share capital $ million	Share premium account $ million	Other reserves $ million	Retained earnings $ million	Total $ million
As at 1 January 2013	27.6	73.0	105.5	970.5	1,176.6
Distributions	-	-	-	(210.9)	(210.9)
Issue and redemption of B shares	-	(61.9)	61.9	-	-
Share-based payments	-	-	1.4	-	1.4
Transfer relating to share-based payments	-	-	(0.7)	0.7	-
Transfer relating to share-based payments in prior years	-	-	58.3	(58.3)	-
Transfer relating to convertible bonds	-	-	(0.2)	0.2	-
Unrealised currency translation differences	-	-	0.3	9.3	9.6
Retained profit for the year	-	-	-	104.1	104.1
As at 1 January 2014	**27.6**	**11.1**	**226.5**	**815.6**	**1,080.8**
Distributions	**-**	**-**	**-**	**(118.1)**	**(118.1)**
New shares issued	**-**	**0.1**	**-**	**-**	**0.1**
Issue and redemption of B shares	**-**	**(11.2)**	**11.2**	**-**	**-**
Share-based payments	**-**	**-**	**0.4**	**-**	**0.4**
Transfer relating to share-based payments	**-**	**-**	**1.7**	**(1.7)**	**-**
Unrealised currency translation differences	**-**	**-**	**(0.3)**	**(1.8)**	**(2.1)**
Retained profit for the year	**-**	**-**	**-**	**14.0**	**14.0**
As at 31 December 2014	**27.6**	**-**	**239.5**	**708.0**	**975.1**

Company

	Called up share capital $ million	Share premium account $ million	Other reserves $ million	Retained earnings $ million	Total $ million
As at 1 January 2013	27.6	73.0	60.8	646.7	808.1
Distributions	-	-	-	(213.3)	(213.3)
Issue and redemption of B shares	-	(61.9)	61.9	-	-
Share-based payments	-	-	1.4	-	1.4
Transfer relating to share-based payments	-	-	(0.7)	0.7	-
Transfers relating to share-based payments in prior years	-	-	59.7	(54.3)	5.4
Unrealised currency translation differences	-	-	-	27.8	27.8
Retained profit for the year	-	-	-	255.8	255.8
As at 1 January 2014	**27.6**	**11.1**	**183.1**	**663.4**	**885.2**
Distributions	**-**	**-**	**-**	**(119.2)**	**(119.2)**
New shares issued	**-**	**0.1**	**-**	**-**	**0.1**
Issue and redemption of B shares	**-**	**(11.2)**	**11.2**	**-**	**-**
Share-based payments	**-**	**-**	**0.4**	**-**	**0.4**
Transfer relating to share-based payments	**-**	**-**	**0.6**	**(1.7)**	**(1.1)**
Unrealised currency translation differences	**-**	**-**	**(0.3)**	**(53.9)**	**(54.2)**
Retained profit for the year	**-**	**-**	**-**	**(21.9)**	**(21.9)**
As at 31 December 2014	**27.6**	**-**	**195.0**	**466.7**	**689.3**

CASH FLOW STATEMENTS

for the year to 31 December 2014

	Notes	Group 2014 $ million	Group 2013 $ million	Company 2014 $ million	Company 2013 $ million
Net cash from (used in) operating activities	11	**251.2**	314.4	**(6.8)**	(13.7)
Investing activities					
Purchase of intangible assets		**(77.0)**	(63.1)	**-**	-
Purchase of property, plant and equipment		**(85.5)**	(36.0)	**(0.2)**	(0.1)
Decrease (increase) in liquid investments [1]		**39.9**	(30.1)	**-**	-
Payment to abandonment fund		**(9.6)**	(15.0)	**-**	-
Investment in subsidiary undertakings		**-**	-	**0.9**	(90.7)
Dividends received from subsidiary undertakings		**-**	-	**130.0**	309.7
Net cash (used in) from investing activities		**(132.2)**	(144.2)	**130.7**	218.9
Financing activities					
Share-based payments		**(1.2)**	-	**(1.2)**	-
Repayment/repurchase of convertible bonds		**-**	(47.8)	**-**	-
Distributions	10	**(118.1)**	(210.9)	**(119.2)**	(213.3)
Proceeds on issue of ordinary share capital		**0.1**	-	**0.1**	-
Net cash used in financing activities		**(119.2)**	(258.7)	**(120.3)**	(213.3)
Net (decrease) increase in cash and cash equivalents		**(0.2)**	(88.5)	**3.6**	(8.1)
Cash and cash equivalents at beginning of year		**129.9**	208.5	**0.3**	0.2
Effect of foreign exchange rate changes		**(3.5)**	9.9	**(3.7)**	8.2
Cash and cash equivalents at end of year [1]		**126.2**	129.9	**0.2**	0.3

[1] Liquid investments 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 2014 was $166.4 million (2013 - $210.0 million).

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 2014 or 2013, but is derived from those accounts. A copy of the statutory accounts for 2013 has been delivered to the Registrar of Companies and those for 2014 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 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 be able to satisfy its debt obligations and 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 Critical judgements and accounting estimates

Oil and gas reserves

Proven and probable reserves are estimated using standard recognised evaluation techniques. The estimate is reviewed at least twice a year and is regularly reviewed by independent consultants. Future development costs are estimated taking into account the level of development required to produce the reserves by reference to operators, where applicable, and internal engineers. As discussed in the Review of Operations, the TGT and CNV proved and probable reserves estimates have been revised based on ongoing work of ERCE in respect of TGT and collaboratively with the JOC in respect of CNV. Following impairment testing CNV was found to be impaired and its carrying value reduced to its fair value (see Note 8). TGT was not determined to be impaired. DD&A on both assets will reflect the revised production and expenditure profiles from 2015. Reserves estimates are inherently uncertain, especially in the early stages of a field's life, and are routinely revised over the producing lives of oil and gas fields as new information becomes available and as economic conditions evolve. Such revisions may impact the Group's future financial position and results, in particular, in relation to DD&A and impairment testing of oil and gas property plant and equipment.

Oil and gas assets

Management considers intangible exploration and evaluation assets and tangible property, plant and equipment assets for impairment at least annually with reference to indicators in IFRS 6 and IAS 36, respectively. Note 7 describes the write off of intangible exploration and evaluation assets during the year and Note 8 describes the impairment of property, plant and equipment during the year. Management considers the appropriateness of asset classification at least annually.

Financial asset

The key estimates that are used in calculating the fair value of the Group's financial asset arising on the disposal of its Mongolia interest are described in Note 9 and are reviewed at least annually. The only market risk assumption that has a significant impact on the fair value of this asset is the discount rate.

4 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.

				2014
	SE Asia $ million	**Africa [2] $ million**	**Unallocated $ million**	**Group $ million**
Oil and gas sales	**448.2**	**-**	**-**	**448.2**
Depletion and depreciation	**50.1**	**-**	**0.1**	**50.2**
Impairment of property, plant and equipment (see Note 8)	**60.5**	**-**	**-**	**60.5**
Profit (loss) before tax [1]	**241.5**	**(79.2)**	**(9.6)**	**152.7**
Tax charge (see Note 5)	**138.1**	**-**	**0.6**	**138.7**

				2013
	SE Asia $ million	Africa [2] $ million	Unallocated $ million	Group $ million
Oil and gas sales	608.1	-	-	608.1
Depletion and depreciation	44.6	-	0.2	44.8
Impairment of property plant and equipment	-	-	-	-
Profit (loss) before tax [1]	437.7	(92.0)	(12.4)	333.3
Tax charge	229.0	-	0.2	229.2

[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.

The accounting policies of the reportable segments are the same as the Group's accounting policies as described in Note 2.

Included in revenues arising from South East Asia are revenues of $234.5 million and $194.4 million (2013 - South East Asia $240.3 million, $102.2million, $64.9million) which arose from the Group's largest individual customers who have contributed 10% or more to the Group's revenue.

Geographical information

Group revenue and non-current assets (excluding the financial asset and 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 revenue by geographical location is determined by reference to the final destination of oil or gas sold.

	2014	2013
	$ million	$ million
Vietnam	**240.0**	74.7
China	**97.8**	86.0
Australia	**48.1**	137.5
Malaysia	**35.5**	146.9
Other	**26.8**	163.0
	448.2	608.1

Non-current assets

	2014	2013
	$ million	$ million
United Kingdom	**1.0**	0.9
Vietnam	**789.0**	800.6
Congo	**147.1**	116.7
Other - Africa	**62.0**	98.8
	999.1	1,017.0

5 Tax

	2014	2013
	$ million	$ million
Current tax	**122.7**	158.3
Deferred tax	**16.0**	70.9
	138.7	229.2

The Group's corporation tax is calculated at 50% (2013 - 50%) of the estimated assessable profit for the year in Vietnam. During 2014 and 2013 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:

	2014	2013
	$ million	$ million
Profit before tax	**152.7**	333.3
Profit before tax at 50% (2013 - 50%)	**76.4**	166.7
Effects of:		
Non-taxable income and non-deductible expenses	**18.1**	11.0
Tax losses not recognised	**3.9**	5.6
Non-deductible exploration costs written off	**39.7**	46.0
Adjustments to tax charge in respect of previous years	**0.6**	(0.1)
Tax charge for the year	**138.7**	229.2

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.

6 Earnings per share

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

	2014	2013
	$ million	$ million
Earnings for the purposes of basic and diluted earnings per share	**14.0**	104.1

	Number of shares (million)	
	2014	2013
Weighted average number of ordinary shares for the purpose of basic earnings per share	**328.6**	328.2
Effect of dilutive potential ordinary shares - Share awards and options	**1.3**	0.8
Weighted average number of ordinary shares for the purpose of diluted earnings per share	**329.9**	329.0

7 Intangible assets

During 2014, exploration costs including costs associated with the Albertine Graben Block V in eastern DRC and costs associated with the early stages of new ventures in the amount of $73.6 million, were written off in the income statement in accordance with the Group's accounting policy on oil and gas exploration and evaluation expenditure. In accordance with IAS 37, a further $5.9 million has been accrued in respect of anticipated future expenditure to complete the current work programme on Block V in the absence of plans to continue thereafter. In 2013, the charge of $92.0 million represents the costs incurred, since its acquisition, on the relinquished Nganzi licence, onshore DRC.

8 Property, plant and equipment

As discussed in the Review of Operations management's estimate of the CNV proved and probable oil and gas reserves has been reduced. Combined with lower oil prices this has led to the estimated recoverable amount of the CNV producing asset being less than the book carrying value. 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 majority of the fair value is derived from a discounted cash flow valuation of the 2P production profile, with a minor portion derived from the incremental value of 2C contingent resources, significantly risk adjusted. The key assumptions to which the fair value measurement is most sensitive are oil price, reserves and the risked value ascribed to contingent resources. Consequently a pre-tax impairment charge in the amount of $60.5 million has been reflected in the income statement in accordance with the Group's accounting policy. The associated tax credit of $22.3 million is reflected in Note 5. As at 31 December 2014, the fair value of the asset is estimated at $104.4 million based on a discount rate of 10% and an oil price reflecting the current three year forward curve and $90 per barrel plus inflation of 2.5% thereafter.

9 Financial asset

In 2005, the Group disposed of its Mongolia interest to Daqing Oilfield Limited Company. Under the terms of the transaction the Group will receive a subsequent payment amount of up to $52.7 million, once cumulative production reaches 27.8 million barrels of oil, at the rate of 20% of the average monthly posted marker price for Daqing crude multiplied by the aggregate production for that month. The subsequent payment amount is included in non-current assets as a financial asset at fair value through profit or loss. The timescale for the production of crude oil in excess of 27.8 million barrels is expected to be between one to two years from the date of this report, however the price of Daqing marker crude oil cannot accurately be predicted. Based upon the Directors' current estimates of proven and probable reserves from the Mongolia interests and the development scenarios as discussed with the buyer, the Directors believe that the full subsequent payment amount will be payable. The fair value of the subsequent payment amount was determined using a valuation technique as there is no active market against which direct comparisons can be made (Level 3 as defined in IFRS 7). Assumptions made in calculating the fair value include the factors mentioned above, risked as appropriate, with the resultant cash flows discounted at a commercial risk free interest rate. The fair value of the financial asset at the date of completion of the sale was $31.5 million. As at 31 December 2014 the fair value was $45.0 million (2013 - $43.4 million) after accounting for the change in fair value.

10 Distribution to Shareholders

During the year, the Company announced a second return of value to shareholders of 22 pence per Ordinary Share (2013 – 40 pence per Ordinary Share) amounting to £73 million, being $119.2 million (2013 - £133 million, being $213.3 million), in cash by way of a B/C share scheme, which gave shareholders (other than certain overseas shareholders) a choice between receiving cash in the form of income or in the form of capital. The return of value, which was approved by shareholders on 22 September 2014, became effective on 30 September 2014. Despite the current oil price environment, the Board has proposed a dividend of 10 pence per ordinary share subject to approval by Shareholders at the Annual General Meeting (see Note 12).

11 Reconciliation of operating profit to operating cash flows

	Group		Company	
	2014	2013	**2014**	2013
	$ million	$ million	**$ million**	$ million
Operating profit (loss)	**152.6**	333.8	**(10.9)**	(11.4)
Share-based payments	**1.6**	1.4	**1.6**	1.4
Depletion and depreciation	**50.2**	44.8	**0.1**	0.2
Impairment of property, plant and equipment (see Note 8)	**60.5**	-	**-**	-
Exploration write off (see Note 7)	**79.5**	92.0	**-**	-
Operating cash flows before movements in working capital	**344.4**	472.0	**(9.2)**	(9.8)
Decrease in inventories	**1.2**	3.8	**-**	-
Decrease (increase) in receivables	**32.1**	8.6	**(0.1)**	(0.2)
Increase (decrease) in payables	**4.3**	(9.1)	**2.4**	(3.8)
Cash generated by (used in) operations	**382.0**	475.3	**(6.9)**	(13.8)
Interest received	**0.7**	1.1	**0.1**	0.1
Interest paid	**(0.2)**	(1.2)	**-**	-
Income taxes paid	**(131.3)**	(160.8)	**-**	-
Net cash from (used in) operating activities	**251.2**	314.4	**(6.8)**	(13.7)

Cash is generated from continuing operating activities only.

Cash and cash equivalents (which are presented as a single class of asset on the balance sheet) comprise cash at bank and other short term highly liquid investments that are readily convertible to a known amount of cash and which are subject to an insignificant risk of change in value.

12 Events after the balance sheet date

On 11 March 2015, the Board proposed a final dividend of 10 pence per ordinary share subject to approval by Shareholders at the Annual General Meeting to be held on 10 June 2015. This dividend has not been recognised as a liability for the 2014 financial year end.

13 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.

RESERVES STATISTICS (UNAUDITED)

Net working interest, mmboe

	TGT	CNV	Vietnam	Congo [4]	Group
Oil and Gas 2P Commercial Reserves [1, 2, 3]					
As at 1 January 2014	87.5	29.8	117.3	12.8	130.1
Production	(4.2)	(0.8)	(5.0)	-	(5.0)
2P Commercial Reserves as at 31 December 2014 (pre revision and re-classification)	**83.3**	**29.0**	**112.3**	**12.8**	**125.1**
Transfer to 2C Contingent Resources	(26.8)	(4.0)	(30.8)	(8.1)	(38.9)
Revision	(20.0) [5]	(20.7)	(40.7)	(4.7)	(45.4)
2P Commercial Reserves as at 31 December 2014	**36.5**	**4.3**	**40.8**	**0.0**	**40.8**
Oil and Gas 2C Contingent Resources [1, 2, 3]					
1 January 2014	-	-	-	-	-
Transfer from Commercial Reserves	26.8	4.0	30.8	8.1	38.9
2C Contingent Resources as at 31 December 2014	**26.8**	**4.0**	**30.8**	**8.1**	**38.9**
Total of 2P Reserves and 2C Contingent Resources as at 31 December 2014	**63.3**	**8.3**	**71.6**	**8.1**	**79.7**

[1] Commercial Reserves and Contingent Resources are categorised in line with 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System (SPE PRMS).

[2] Commercial Reserves and Contingent Resources are internal management estimates based on operator data and the ERCE study of TGT field resources including the Geological and revised Dynamic Simulation model.

[3] Assumes oil equivalent conversion factor of 6,000 scf/boe.

[4] Congo volumes are associated with the Viodo discovery. Reserves are shown before deductions for non-controlling interests which are funded by the Group. The Group is entitled to receive 100% of the cash flows until it has recovered its funding of the non-controlling interest including a rate of return from the non-controlling interest's pro rata portion of those cash flows.

[5] Based on the assessment of the range of STOIIP and the recovery factors in the Dynamic Simulation Model prepared by ERCE, additional volumes are being recognised as 3C Contingent Resources. This is described in detail in the Review of Operations.

Risks associated with reserve evaluation and estimation uncertainty are discussed in Note 3.