Management's Discussion and Analysis

for the years ended December 31, 2019 and December 31, 2018

Montara platform

The following management’s discussion and analysis (“MD&A”) of the operational and financial results and position of Jadestone Energy Inc. (the “Company”, or “Jadestone”) is prepared as at April 23, 2020, and should be read in conjunction with the Company’s consolidated audited financial statements (the “Financial Statements”) as at, and for the years ended December 31, 2019 and December 31, 2018.

The MD&A was reviewed by the Company’s Audit Committee and approved by the Board of Directors on April 23, 2020. Any events subsequent to December 31, 2019, which could materially alter the reliability and usefulness of the information disclosed, have been considered and disclosed as appropriate.

The consolidated financial statements for the years ended December 31, 2019 and December 31, 2018, and comparative information presented therein, have been prepared in accordance with International Financial Reporting Standards (“IFRS”) and are expressed in United States Dollars (“US$” or “USD”). Unless otherwise stated, comparisons of results are for the years ended December 31, 2019 and 2018, and the Company’s financial position as at December 31, 2019 and 2018.

Forward Looking Statements

This MD&A contains forward-looking statements which are based on management assumptions, taking into account all known risks, uncertainties and any other factors which could cause the actual results, performance and achievements to be materially different. Management considers these assumptions to be reasonable, but they may prove to be incorrect, so readers are cautioned not to place reliance on these forward-looking statements.

Non-Gaap Measures

The Company uses measures primarily based on IFRS, but also uses some secondary non-GAAP measures. The non-GAAP measures included in this MD&A and related disclosures are: earnings before interest, tax, depreciation and exploration ("EBITDAX'), total debt and net debt. Neither of these measures is used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for EBITDAX, total debt and net debt. These are useful complimentary measures that are used by management in assessing the performance and liquidity of the Company. The non-GAAP measures do not have standardised meanings prescribed in IFRS, and are therefore unlikely to be comparable to similar measures presented by other issuers. They are common in the reports of other companies, but may differ by definition and application.

Corporate Overview & Strategy

Jadestone is an upstream oil and gas company incorporated in Canada. The Company's ordinary shares are listed on the Alternative Investment Market ("AIM"), a sub-market of the London Stock Exchange, and were listed on the TSX Ventures Exchange ("TSX-V") until March 24, 2020, when the Company delisted from the TSX-V. The Company remains a Canadian domiciled corporation, and has applied to the applicable securities commissions for designated foreign issuer reporting treatment. The Company trades under the symbol "JSE".

The Company and its subsidiaries (the "Group") are engaged in production, development, and exploration and appraisal activities in Australia, Vietnam, Philippines, and, once the Company closes its acquisition of the Maari asset described below, New Zealand.

On November 18, 2019, the Company executed a sale and purchase agreement ("SPA") with Österreichische Mineralölverwaltungs Aktiengesellschaft New Zealand ("OMV New Zealand"), to acquire an operated 69% interest in the Maari project, for a total consideration of US$50.0 million, subject to customary working capital adjustments. The transaction is subject to regulatory approvals, and joint venture partner acceptance. When the necessary approvals and acceptance have been received, the transaction will close, and operatorship of the Maari project will transfer to the Company. The economic benefits from January 1, 2019 until the closing date will be adjusted in the final consideration paid to OMV New Zealand. The Company anticipates to complete the acquisition in the second half of 2020.

Producing Assets

Australia

Stag Oilfield

The Stag Oilfield, in block WA-15-L, is located 60km offshore Western Australia in a water depth of approximately 47 meters. As at December 31, 2019, the field contained total proved plus probable reserves of 14.8 million barrels of oil (100% net to Jadestone), compared to 16.2 million barrels at the end of 2018.

During 2019, the Group drilled and successfully completed the 49H infill well, which targeted 1.2mm bbls of 2P reserves. First oil from the well was achieved on May 21, 2019, at a rate of 1,400 bbls/d, meeting expectations. The average production for 49H over the period between May 22, 2019 to the year-end averaged 838 bbls/d.

Montara Oilfield

On September 28, 2018, the Group acquired the Montara Assets, located in shallow water offshore Australia, from PTTEP Australasia (Ashmore Cartier) Pty Ltd ("PTTEP Australasia"). The Group reports the first full year of results for the Montara Assets in calendar year 2019.

The Montara project is located in production licenses AC/L7 and AC/L8, in the Timor Sea, in a water depth of approximately 77 meters. The Montara Assets, comprising the three separate fields being Montara, Skua and Swift/Swallow, are produced through a centralised FPSO. As at December 31, 2019, the Montara Assets had proven plus probable reserves of 27.0 million barrels of oil (100% net to Jadestone), compared to 26.6 million barrels at the end of 2018.

During 2019, the Group successfully installed the replacement subsea umbilical cables at Montara. The umbilical cables are an essential part of the control system providing electrical power and control signals to the subsea well-heads.

On January 11, 2019, production at Montara restarted following a voluntary shut down initiated on November 1, 2018, to rectify an inspection and maintenance backlog. As a result of the shutdown, on January 7, 2019, the seller (PTTEP Australasia) agreed to fund future cash calls to a cap of US$22.0 million. Management believed that the shutdown was the result of facts and circumstances that existed at the acquisition date, and so adjusted the purchase price allocation.

During calendar 2019, the Company completed the Montara purchase price allocation ("PPA") exercise to determine the fair values of the net assets acquired within the stipulated time period of 12 months from the acquisition date of September 28, 2018, and in accordance with IFRS3 *Business Combinations*. The adjusted fair values of identifiable assets and liabilities have been reflected in the consolidated statement of financial position, as at December 31, 2018.

New Zealand

Maari Oilfield

On November 18, 2019, the Group executed a SPA with OMV New Zealand, to acquire an operated 69% interest in the Maari project, for a total cash consideration of US$50.0 million, and subject to customary closing adjustments. The field holds 2P reserves of 13.9 million bbls of oil, net to Jadestone's 69% interest, and current production is approximately 4,000 bbls/d, again, on a net 69% basis. The transaction is expected to close in the second half of 2020

Exploration, appraisal and pre-development assets

The current Southeast Asia ("SEA") exploration and pre-development asset portfolio comprises approximately 4.6 million acres of awarded acreage, and comprises two production sharing contracts ("PSC") in Vietnam (Block 51 and Block 46/07), and two service contracts ("SC") in the Philippines (SC56 and SC57).

Vietnam

Block 51 PSC and Block 46/07 PSC
Jadestone holds a 100% operated working interest in the Block 51 PSC and the Block 46/07 PSC, both in shallow waters in the Malay Basin, offshore Southwest Vietnam. The two blocks hold three discoveries: the U Minh and Tho Chu gas/condensate fields in Block 51, and the Nam Du gas field in Block 46/07.

Prior to May 1, 2017, both blocks were held jointly with Petrovietnam Exploration and Production ("PVEP"), on a 70:30 Jadestone/PVEP working interest basis. Effective May 1, 2017, PVEP relinquished its working interests in both blocks, leaving Jadestone as operator with a 100% working interest. The amended investment licenses for the Block 51 PSC and Block 46/07 PSC, showing Jadestone as operator with a 100% working interest in both licenses, was approved by the Vietnam Government on October 14 and 15, 2019 respectively.

Jadestone's priority is to develop the Nam Du and U Minh fields with a view to selling gas into the Vietnamese domestic market. Accordingly, on May 21, 2018, the outline development plan ("ODP"), proposing a standalone joint development of these two fields, was approved by the Vietnamese Ministry of Industry and Trade. On October 17, 2019, Jadestone made the formal declaration of commercial discovery for the Nam Du and U Minh fields, and submitted the formal field development plan ("FDP") for the combined Nam Du/U Minh development project to Vietnam Oil and Gas Group ("PVN") for approval.

On March 19, 2020, the Company announced that in light of changing market conditions, and in the absence of government approvals of the FDP, the Company has decided to delay the project. It is now anticipated that first gas will be no earlier than late 2022.

Block 51 is currently held in a suspended development area ("SDA") status. The portion of the block containing the U Minh field will be converted to a development/production area upon approval of the FDP. The remainder of the block, including the Tho Chu field, will remain in SDA status until June 11, 2021. The Tho Chu field will be subject to a later development plan.

Under the terms of the Block 46/07 PSC, Jadestone is committed to drill one more appraisal well on the block. The Group plans to drill the appraisal well on the Nam Du field to prove up additional resource. This well is planned to be retained for future use as a Nam Du gas producer. On November 13, 2018, the Vietnam Government approved a request by the Group to extend the Block 46/07 exploration phase two period by a further two years to June 29, 2020. Jadestone submitted a request to PVN seeking Government approval for a further one-year extension to exploration phase two to June 29, 2021, and this was approved on February 26, 2020.

Block 127 PSC
Jadestone operated Block 127 PSC, with a 100% working interest, a legacy asset inherited from the prior management team. This predominantly deep water block covers an area of 9,000 km2 and is located at the southern end of the Phu Khanh Basin, off the east coast of Vietnam. During the quarter ended March 31, 2018, the Group performed a review of its asset base, and as a result of that review, decided to relinquish Block 127 at the end of the current exploration phase on May 24, 2018. Having completed all minimum work commitments, Jadestone informed PVN of its relinquishment decision on April 4, 2018, the license was returned in October 2018, and the Group has officially relinquished the PSC. The Group recorded an impairment charge of US$11.9 million during the three months ended March 31, 2018, reducing the book value to nil.

Block 05-1 PSC
On August 9, 2016, the Group, as buyer, signed a definitive agreement with Teikoku, a wholly-owned subsidiary of Inpex Corporation, as seller, for the acquisition of a 30% working interest in the Block 05-1 PSC, for a total cash consideration of US$14.3 million, and subject to normal closing adjustments.

On February 22, 2018, Teikoku delivered to Jadestone a purported notice of termination of the SPA, despite Teikoku having just received on February 9, 2018, the waiver by PVN, of PVN's statutory pre-emption rights, held under Vietnamese law. The Group has not accepted Inpex's alleged termination, and views the obligations of both parties under the SPA as continuing. The Group maintains its rights under the SPA, and is assessing its options, including remedies through legal action.

Philippines

Service Contract 56 ("SC56")
Jadestone holds a 25% interest in SC56 in partnership with operator Total E&P Philippines B.V. ("Total"). Four wells have previously been drilled on SC56, resulting in the Dabakan and Palendag discoveries. The current exploration period on the block runs until September 1, 2020.

In September 2012, Total farmed into SC56 and assumed a 75% interest, and in August 2014 formally confirmed its intention to drill an exploration well on the Halcon prospect. As a result of the Halcon confirmation, operatorship was transferred to Total, effective October 25, 2014. The Group views Halcon as an economically viable prospect with significant resource potential.

Total subsequently informed Jadestone that it did not intend to drill an exploration well on the Halcon prospect. In December 2017, the Group commenced an arbitration action against Total, claiming failure by Total to drill the well and resultant damages. On January 3, 2020, the tribunal found in favour of Jadestone and awarded monetary damages of US$11.1 million, plus legal fees of approximately US$4.3 million, less expenditure incurred prior to the breach.

On March 26, 2020, the Company received notification of the final award from the SIAC. The final award confirmed the appropriate deduction of US$0.7 million, which generated a net award of US$2.2 million after including all legal fees and the Company's share of the SIAC costs, and the deduction of litigation funding fees.

Under the terms of SC56, Total and Jadestone are committed to drill one more exploration well on the block prior to expiry. The Company continues to assess all available options in advance of the licence expiration on September 1, 2020. The Company's net share of the penalty in the event the well is not drilled is approximately US$2.4 million.

Service Contract 57 ("SC57")
The Group holds a 21% working interest in SC57, but it has been under force majeure since 2011, and these conditions are expected to continue for the next 12 to 24 months.

Operational Activities

Montara Oilfield

Production for 2019, the first full calendar year for Montara under Jadestone ownership, averaged 10,483 bbls/d[1], compared to 7,585 bbls/d for the post acquisition period September 28, 2018 to October 31, 2018 in the prior year. The facility was shut in from November 1, 2018 to January 11, 2019 to address an inspection and maintenance backlog. The 2018 full year production for Montara was 7,637 bbls/d, based on 304 days of production (i.e. excluding the voluntary shutdown during November and December, and including the period prior to the closing of the transaction on September 28, 2018).

During the three-month period ended December 31, 2019, Montara production averaged 10,894 bbls/d, compared to fourth quarter 2018 production of 2,570 bbls/d based on October production averaged across the whole quarter, as the field was voluntarily shut-in during November and December 2018.

There was a total of six liftings in 2019, resulting in total sales of 3,577,204 bbls, compared to the year ended December 31, 2018 of one lifting and total sales of 451,291 bbls from the date of closing the Montara acquisition on September 28, 2018 and the shut down between November 1, 2018 to January 11, 2019.

Stag Oilfield

Production for the 2019 calendar year averaged 3,049 bbls/d, compared to 2,799 bbls/d for the year ended December 31, 2018. The increase was due to the Stag 49H infill well which came online with an initial rate of 1,400 bbls/d upon completion on May 21, 2019, partially offset by downtime associated with cyclones in 2019, and delays to workovers in the first half of 2019, during the period that the 49H infill well was being drilled.

During the three-month period ended December 31, 2019, production was 3,808 bbls/d, compared to fourth quarter 2018 of 2,644 bbls/d, due to the impact of the additional production after completion of the 49H well on May 21, 2019, and also production optimisation for other wells.

There was a total of four liftings in 2019, resulting in total sales of 918,961 bbls, compared to the year ended December 31, 2018 of five liftings and total sales of 1,031,763 bbls.

Ogan Komering PSC

The Ogan Komering PSC expired on February 28, 2018, and a temporary co-operation contract was entered into, continuing the terms of the PSC which ended on May 19, 2018.

There was no production in 2019, compared to 1,439 bbls/d for the period January 1, 2018 to May 19, 2018. There was no production in the fourth quarter of 2019 or 2018.

1 Montara total production averaged across the full 365 days was 10,483bbl/d. Actual production for 2019 was 10,778 bbl/d averaged across 355 days of production from the start of Montara following the voluntary inspection and maintenance shutdown.

Selected Financial Information

The following table provides selected financial information of the Group, which was derived from, and should be read in conjunction with, the consolidated financial statements for the years ended December 31, 2019 and December 31, 2018.

USD'000 EXCEPT WHERE INDICATED	THREE MONTHS ENDED DEC 31, 2019	SEP 30, 2019	JUNE 30, 2019	MAR 31, 2019	DEC 31, 2018	SEP 31, 2018	JUNE 31, 2018	MAR 31, 2018
Production (boe/day)	14,702	13,036	13,315	13,059	5,215	3,080	4,239	4,101
Revenues [1]	91,200	62,500	115,341	56,366	44,972	32,669	17,496	18,287
Net earnings/(loss)	10,364	19	21,762	8,360	(6,573)	(2,955)	(4,912)	(16,593)
- Per share: basic & diluted	0.02	0.00	0.05	0.02	(0.01)	(0.01)	(0.02)	(0.07)
Funds from/(used in) operating activities	45,846	37,114	33,013	28,664	32,495	(12,224)	(2,583)	77
- Per share: basic & diluted	0.10	0.08	0.07	0.06	0.07	(0.03)	(0.01)	0.00

1 Revenue was restated during Q4 2018, including prior periods, from a gross to net basis after deducting royalties, but including realised effective hedging gains/losses. This restatement has been undertaken pursuant to IFRS15 and implemented in the consolidated financial statements for the year ended December 31, 2018.

Quarter ended: Dec 31, 2019
The average production for the period was 14,702 bbls/d. The Group lifted 1,266,318 bbls during the quarter, which generated US$87.7 million in revenues, before hedging income of US$3.5 million, and US$45.8 million in operational cashflows after changes in working capital, interest and taxes.

Quarter ended: Sep 30, 2019
The average production for the period was 13,036 bbls/d. Three workovers at Stag were completed during the period, which had been delayed from the prior period, due to the drilling of 49H infill well. The Group lifted 891,644 bbls during the quarter, which generated US$58.3 million in revenues, before hedging income of US$4.2 million, and US$37.1 million in operational cashflows after changes in working capital, interest and taxes.

Quarter ended: Jun 30, 2019
The average production for the period was 13,315 bbls/d. The completion of the 49H infill well at Stag on May 21 generated initial production of over 1,400 bbls/d. The additional production was offset by three wells requiring workovers (subsequently undertaken in Q3 2019). The Group lifted 1,589,352 bbls during the quarter, which generated US$114.0 million in revenues, before hedging income of US$1.4 million, and US$33.0 million in operational cashflows.

Quarter ended: Mar 31, 2019
The average production for the period was 13,059 bbls/d, with Montara restarting production on January 11, 2019 (averaged across the whole quarter). The Group lifted 748,851 bbls during the quarter, which generated US$50.6 million in revenues, before hedging revenue of US$5.7 million, and US$28.7 million in operational cashflows

Quarter ended: Dec 31, 2018
Montara production averaged 7,628 bbls/d during October 2018, but was shut in to address an inspection and maintenance backlog during November and December. The average quarter production at Stag was 2,644 bbls/d, or a total of 5,215 bbls/d for the quarter including Montara October production averaged across the whole quarter. The period was impacted by an additional US$4.0 million charge for the safety inspection and maintenance work.

Quarter ended: Sep 30, 2018
Stag reported production for the quarter to September 30, 2018 of 3,080 bbls/d. The Montara Assets were acquired on September 28, 2018 and averaged 7,585 bbls/d for the three days to September 30, 2018, which is excluded from the production shown in the quarterly summary above. Funds used in operations include a net investment (i.e. funds outflow) in working capital of US$12.2 million.

Quarter ended: Jun 30, 2018
Production was 4,239 boe/d for the quarter, reflecting improved uptime at Stag, despite planned maintenance activities which caused the deferral of 38,000 bbls of production, or 417 bbls/d, for the quarter. Revenue was US$17.5 million, due to higher benchmark prices offset by lower production, with the expiry of the Ogan Komering PSC on May 19, 2018.

Quarter ended: Mar 31, 2018
Stag production was impacted by marine breakaway coupling and electric submersible pump issues, plus poor weather conditions.
Ogan Komering maintained steady production. Net earnings were impacted by an US$11.9 million exploration write-off, with respect to Block 127.

Production

USD'000	THREE MONTHS ENDED DEC 31, 2019	THREE MONTHS ENDED DEC 31, 2018	YEAR ENDED DEC 31, 2019	YEAR ENDED DEC 31, 2018
Montara crude oil (bbls/d)	10,894	2,571	10,483[1]	710
Stag crude oil (bbls/d)	3,808	2,644	3,049	2,799
Ogan Komering oil and gas (boe/d)	-	-	-	548
Total (boe/d)	**14,702**	**5,215**	**13,826[1]**	**4,057**

Production averaged 13,826[1] bbls/d during 2019, compared to 4,057 boe/d for the twelve months ended December 31, 2018 due to:

- First full year of Montara production generated an average annual increase of 10,068 bbls/d (2018 production: 710 bbls/d);
- Increased production at Stag by 250 bbls/d, due to additional production generated after completion of the 49H infill well on May 21, 2019, partially offset with higher than anticipated downtime due to cyclones and delayed workovers while drilling 49H; and
- The Ogan Komering PSC expired in 2018, which resulted in a fall in production of 548 boe/d averaged across 365 days. Average production based on the 139 days of production from January 1, 2018 to May 19, 2018 was 1,439boe/d.

Fourth quarter 2019 production of 14,702 bbls/d compares with 5,215 boe/d for the same quarter a year ago, largely due to the impact of the Montara shutdown during November and December 2018, and higher production at Stag in Q4 2019 in part due to the contribution from 49H.

Benchmark Commodity Price and Realised Price

The average annual benchmark Brent crude oil price decreased to US$64.27/bbl in calendar 2019, compared to US$71.31/bbl, in the twelve months ended December 31, 2018. The benchmark price for Q4 2019 was US$63.08/bbl, compared to US$68.81/bbl for the same quarter in 2018.

The average annual realised price in calendar 2019 was US$69.07/bbl, compared to US$69.39/bbl in the twelve months ended December 31, 2018. Realised prices were able to be maintained during the year, despite declining benchmark oil prices, as sales premiums on Stag and Montara increased from an average of US$3.65/bbl in Q1 2019, to US$6.22/bbl by the end of 2019. The demand for sweet crude oil has increased, and in particular in the case of Stag, for heavy sweet crude oil, given the International Maritime Organization ("IMO") 2020 regulations, which came into effect from January 1, 2020, reducing marine sector sulphur emissions in international waters.

The Brent benchmark price in Q4 2019 was US$63.08/bbl (Q4 2018: US$68.81/bbl), compared to realised prices of US$69.24/bbl (Q4 2018: US$67.51/bbl). Realised prices in Q4 2019 included an average premium of US$6.22/bbl (Q4 2018: US$2.78/bbl), due to the increased demand for sweet heavy crudes caused by the IMO 2020 regulations.

Implementation of New Accounting Standards

IFRS16 *Leases*

The Group has applied IFRS16 *Leases* (as issued by the IASB in January 2016) from January 1, 2019. The Company adopted the cumulative catch-up approach under IFRS16, which permits Jadestone to elect not to restate comparatives.

On adoption, IFRS16 changed how the Group accounts for leases previously classified as operating leases.

IFRS16 has the following impacts on the Group accounts:

- Recognises right-of-use assets, and lease liabilities, in the consolidated statement of financial position, initially measured at the present value of future lease payments;
- Recognises depreciation of right of use assets, and interest on lease liabilities, in the consolidated statement of profit or loss; and
- Separates the total amount of cash paid into a principal portion (presented within financing activities), and interest (presented within operating activities), in the consolidated statement of cash flows.

1 Total Group (Montara) production averaged across the full 365 days of 2019 was 13,531 bbls/d (10,483 bbls/d). Total Group (Montara) actual production for 2019 was 13,826bbls/d (10,778 bbls/d), averaged across 355 days of production from the restart of Montara, following the voluntary inspection and maintenance shutdown.

Reclassification of Comparative Figures

Certain comparative figures in the financial statements of the Group have been reclassified, to conform to the presentation in the current financial year. These relate to the following:

Montara - Restatement of purchase price adjustments in accordance with *IFRS3 Business Combinations*

During the year, the Group has completed the purchase price allocation ("PPA") exercise to determine the fair values of the net assets acquired within the stipulated time period of 12 months from the acquisition date of September 28, 2018, in accordance with IFRS3 *Business Combinations*. Following the transfer of operatorship on August 6, 2019, the Group was able to confirm an inventory adjustment of US$14.0 million in order to align with the Group's accounting policies. The adjusted fair values of identifiable assets and liabilities have been reflected in the consolidated statement of financial position as at December 31, 2018.

Below are the effects of the final PPA adjustments in accordance with IFRS3:

FAIR VALUE OF PURCHASE CONSIDERATION	PROVISIONAL PPA USD'000	ADJUSTMENTS USD'000	FINAL PPA USD'000
Asset purchase price	195,000	-	195,000
Crude inventory value	6,657	-	6,657
Capital charge	6,982	-	6,982
Net cash adjustment	(75,547)	-	(75,547)
Cash payment on acquisition date	**133,092**	**-**	**133,092**
Deferred contingent consideration	15,805	-	15,805
Prepaid Asset for future cash calls	(22,000)	-	(22,000)
Working capital adjustment	997	819	1,816
Total	**127,894**	**819**	**128,713**

Assets acquired and liabilities assumed at the date of acquisition, September 28, 2018:

	PROVISIONAL PPA USD'000	ADJUSTMENTS USD'000	FINAL PPA USD'000
Asset			
Non-current assets			
Oil & gas properties	353,806	14,828	368,634
Current assets			
Inventories	35,373	(14,009)	21,364
Prepayments	4,917	-	4,917
Total assets	**394,096**	**819**	**394,915**
Liabilities			
Current liabilities			
Trade and other payables	(4,314)	-	(4,314)
Non-current liabilities			
Provision for asset restoration obligations	(183,020)	-	(183,020)
Deferred tax liabilities	(78,437)	-	(78,437)
Other provisions	(431)	-	(431)
Total liabilities	**(266,202)**	**-**	**(266,202)**
Net identifiable assets acquired	**127,894**	**819**	**128,713**

Results of Operations

CONSOLIDATED STATEMENT OF PROFIT & LOSS	THREE MONTHS ENDED DECEMBER 31, 2019 USD'000	THREE MONTHS ENDED DECEMBER 31, 2018 USD'000	YEAR ENDED DECEMBER 31, 2019 USD'000	YEAR ENDED DECEMBER 31, 2018 USD'000
Revenue	91,200	44,972	325,406	113,423
Production costs	(25,876)	(50,602)	(119,898)	(90,939)
Depletion, depreciation and amortisation	(27,331)	(5,932)	(90,746)	(13,776)
Staff costs	(6,328)	(3,921)	(19,714)	(13,538)
Other expenses	(2,471)	(3,276)	(11,692)	(10,374)
Impairment of assets	-	-	-	(11,901)
Other income	553	6,665	2,979	2,534
Finance costs	(3,267)	(5,186)	(16,443)	(9,240)
Other financial gains	582	12,345	3,389	12,345
Profit/(Loss) before tax	**27,062**	**(4,935)**	**73,281**	**(21,466)**
Income tax expense	(16,698)	(1,638)	(32,776)	(9,567)
Profit/(Loss) for the quarter/year	**10,364**	**(6,573)**	**40,505**	**(31,033)**
Earnings/(Loss) per ordinary share				
Basic and diluted (US$)	0.02	(0.01)	0.09	(0.10)
Consolidated statement of comprehensive income				
Profit/(Loss) for the quarter/year	**10,364**	**(6,573)**	**40,505**	**(31,033)**
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss:				
(Loss)/Gain on unrealised cash flow hedges	(9,688)	51,775	(30,542)	51,775
Hedging gain reclassified to profit & loss	(3,520)	(1,088)	(14,874)	(1,088)
	(13,208)	50,687	(45,416)	50,687
Tax income/(expense) relating to components of other comprehensive income	3,962	(15,207)	13,624	(15,207)
Other comprehensive (loss)/income	(9,246)	35,480	(31,792)	35,480
Total comprehensive income for the quarter/year	**1,118**	**28,907**	**8,713**	**4,447**

Revenue
Revenue for the year was US$325.4 million, compared to US$113.4 million for the twelve month period ended December 31, 2018. The variance of US$212.0 million was largely due to:

- Sales volumes of 4.5mm bbls in calendar 2019, compared to 1.7mm bbls in calendar 2018, or an additional US$195.2 million;
- An increase in hedging income of US$14.5 million, or income of US$14.9 million earned in 2019, compared to US$0.4 million incurred in 2018;
- An increase of US$3.5 million due to a royalty deduction in 2018 related to Ogan Komering not incurred in 2019; and
- A slight reduction in the annual net realised price to US$69.07/bbl in 2019, compared to US$69.39/boe in 2018, or a reduction of US$1.4 million.

Revenue for the three months ended December 31, 2019 was US$91.2 million, compared to US$45.0 million for the same quarter in 2018, or an increase of US$46.2 million, largely due to:

- Group liftings of 1.3mm bbls in Q4 2019, compared to 0.6mm bbls in Q4 2018, or an additional US$41.1 million;
- An increase in hedging income of US$3.1 million, or income of US$3.5 million earned in Q4 2019, compared to US$0.4 million in Q4 2018; and
- An increase in realised prices to US$69.24/bbl in Q4 2019, compared to US$67.51/bbl in Q4 2018, or an additional US$2.2 million.

Production costs
Production costs in 2019 were US$119.9 million, compared to US$90.9 million. The variance of US$29.0 million was due to:

- Montara's production costs increased by US$41.7 million, due to a full calendar year of ownership in 2019, compared to the period September 28, 2018 to December 31, 2018;
- Partly offset by a decrease in Stag's production costs of US$10.1 million, due in part to the adoption of IFRS16 *Leases* which transferred US$7.7 million to DD&A and finance costs. The remaining US$2.4 million year-on-year differential at Stag relates largely to movements in closing inventory. There were 581,128 bbls at December 31, 2019, compared to 138,425 bbls as at December 31, 2018; and
- Further partly offset by a decrease in Ogan Komering's production costs by US$2.6 million due to the expiry of the Ogan Komering PSC in 2018.

Production costs decreased to US$25.9 million during Q4 2019, compared to US$50.6 million for the same quarter in 2018, predominately due to:

- A decrease of US$15.6 million due to movements in crude oil inventories due to a significantly larger closing inventory balance for Q4 2019, compared to Q4 2018;
- A decrease of US$4.0 million in repairs and maintenance associated with the Montara shutdown between November 1, 2018 to January 10, 2019 incurred in 2018;
- A decrease of US$1.9 million due to the adoption of IFRS16, which transferred lease payments related to the Stag floating storage and offloading facility ("FSO") to DD&A and finance costs in Q4 2019, compared to Q4 2018 when they were recorded as production costs; and
- A decrease of US$3.4 million of inventory write down incurred at Montara in October 2018.

Depletion, depreciation and amortisation ("DD&A")
DD&A charge in 2019 was US$90.7 million, compared to US$13.8 million in 2018, with the increase predominately due to:

- An increase of US$68.7 million for the Montara depletion charge, largely due to a full year's operations in 2019, compared to one month in 2018. The Montara assets were acquired on September 28, 2018 and were shut down to address an inspection and maintenance backlog from November 1, 2018 to January 10, 2019. Montara's DD&A per unit of production increased from US$18.39/bbl in 2018 to US$19.20/bbl in 2019, due to the subsea umbilical project and other capex projects completed in 2019, which resulted in higher annual charges of US$3.3 million over the year;
- An additional US$14.9 million in calendar 2019 due to the recognition of right-of-use assets, pursuant to the adoption of IFRS16 *Leases*. In 2018, the operating leases were included in production costs and other expenses;
- Stag's DD&A increased by US$1.6 million, or from US$8.43/bbl in 2018 to US$9.20/bbl in 2019, due to the capital costs associated with the 49H infill well;
- A decrease of US$0.6 million related to the end of the PSC at Ogan Komering during 2018; and
- A decrease in inventory movements generated a negative variance of US$7.6 million, reflecting higher inventory balances at December 31, 2019 of 581,128 bbls, compared to 138,425 bbls held in inventory at December 31, 2018.

DD&A charge for the three-month period ended December 31, 2019 was US$27.3 million, compared to US$5.9 million in 2018, with the increase predominately due to:

- Montara depletion charges increased US$14.5 million due to additional production volumes in Q4 2019 of 1,002,224 bbls compared to 236,481 bbls in Q4 2018, as a result of the inspection and maintenance shutdown in November and December 2018;
- An additional US$4.1 million in Q4 2019, due to the recognition of right-of-use assets pursuant to the adoption of IFRS16 *Leases* from January 1, 2019;
- Montara unit DD&A increased from US$18.87/bbl in Q4 2018 to US$20.00/bbl in Q4 2019, generating an additional US$1.1 million expense, reflecting the capex projects brough on stream during the year including the subsea umbilical project;
- Stag produced higher volumes in Q4 2019 of 350,381 bbls, compared to 243,268 in Q4 2018, resulting in an increase of US$0.9 million in depletion charges; and
- The Stag unit DD&A increased from US$8.31/bbl in Q4 2018 to $9.24/bbl in Q4 2019, reflecting the additional capital expenditure associated with the 49H infill well, brought on-stream in Q2 2019. This generated a variance of US$0.3 million.

Staff costs
Staff costs in 2019 have increased to US$19.7 million in 2019, compared to US$13.5 million in 2018, predominately due to an increase in the number of staff in Australia since the Group took over the operatorship of Montara in August 2019, and in Vietnam in preparation for project sanction of Nam Du/U Minh.

As at December 31, 2019, there were 197 full time equivalent personnel ("FTE"), compared to 80 FTE's as at December 31, 2018.

Staff costs have increased to US$6.3 million during Q4 2019, compared to US$3.9 million for the same quarter in 2018, which reflected the annual trend in increased FTE's.

Other expenses

Other expenses for the full year 2019 were US$11.7 million (2018: US$10.4 million), with the variance predominately due to:

- An increase of US$1.6 million in one off projects (Maari US$0.7 million, Montara transition team US$3.1 million) and other consultancy services (US$1.1 million), compared to Montara acquisition costs of US$1.4 million and AIM listing expenses of US$1.9 million in 2018;
- An increase of US$0.8 million associated with ineffective cashflow hedge movements and foreign exchange losses, compared to US$ nil in 2018, due to ineffective hedge and foreign exchange gains recognised in other Income; and
- A decrease of US$0.7 million in office costs associated with the change in accounting policies under IFRS16 as office leases are now recognised in depreciation and finance costs.

During the quarter ended December 31, 2019, the Group incurred US$2.5 million of other expenses compared to US$3.3 million in Q4 2018, predominately due to:

- Professional fees incurred associated with the acquisition of Maari project of US$0.6 million in Q4 2019, compared US$1.1 million of fees in Q4 2018; and
- A decrease in rental expenses of US$0.3 million pursuant to the adoption of IFRS16.

Impairment of assets

The Group has conducted an impairment review in 2019 and concluded no impairment is required.

In 2018, the Group decided to relinquish block 127 in Vietnam after all work programme commitments had been performed, and wrote off all capitalised balances.

Finance costs

Finance costs have increased by US$7.2 million to US$16.4 million in 2019, compared to US$9.2 million 2018, predominately due to:

- An increase of US$3.1 million in interest expenses with US$6.1 million associated with a full year of interest in 2019 on the Group's reserve based loan ("RBL") (2018: US$3.0 million), compared to three months in 2018;
- An additional US$4.3 million of finance charges on lease liabilities pursuant to the adoption of IFRS16 effective January 1, 2019 (2018: US$ Nil);
- An increase of US$2.2 million of accretion expense for Montara and Stag's asset retirement obligations ("ARO") increased to US$5.8 million (2018: US$3.6 million), this was attributable to the annual update of changes in assumptions used in the calculation; and
- A decrease of US$ 2.5 million due to no convertible bond related expenses incurred in 2019, compared to US$2.5 million incurred in 2018 (convertible bond facility fees: US$0.6 million, bond accretion expense: US$0.7 million and fair value loss: US$1.2 million), as the bond was repaid in August 2018.

Finance costs for the quarter ended December 31, 2019 were US$3.3 million, a decrease of US$1.9 million from the same period in 2018, predominately due to:

- An increase of US$1.0 million for finance charges on lease liabilities pursuant to the adoption of IFRS16 effective January 1, 2019 (2018: US$ Nil);
- A decrease of US$2.1 million associated with lease RBL interest decreased from US$3.0 million in Q4 2018 to US$0.9 million in Q4 2019, as the Group paid down the loan from US$120.0 million since the draw down date of September 28, 2019, to US$49.1 million as at December 31, 2019; and
- A decrease of US$0.8 million of accretion expense on ARO in Q4 2019 to US$1.2 million (2018: US$2.0 million), due to the annual review and changes in assumptions supporting the calculation.

Other financial gains

Other financial gains decreased by US$9.0 million to US$3.4 million in 2019, compared to US$12.3 million in 2018, due to a change in the fair value of contingent payments associated with Montara.

Management deemed two Montara contingent payments as probable at the acquisition date closing date of September 28, 2018. The two contingent payments are US$20.0 million and US$10.0 million and are triggered if the average Dated Brent oil price is above US$80/bbl in each of 2019 and 2020 respectively. The fair value of the contingent payments as at the end of 2018 was US$3.7 million, having been revised down from US$15.8 million at acquisition closing date, generating a gain of US$12.1 million in 2018.

During 2019, the Group has derecognised the 2019 deferred contingent payment as the annual average Dated Brent oil price in 2019 fell below US$80/bbl. As at December 31, 2019, the fair value of the remaining US$10.0 million contingent payment has been re-assessed at US$0.4million, resulting in a gain of US$3.4 million.

The quarterly movement between Q4 2019 and Q4 2018 is US$11.8 million, this was predominately due to the assessed fair value of the Montara contingent payments of US$0.6 million (2018: $12.1 million).

Taxation

USD'000	THREE MONTHS ENDED DEC 31, 2019	THREE MONTHS ENDED DEC 31, 2018	YEAR ENDED DEC 31, 2019	YEAR ENDED DEC 31, 2018
Current tax				
Corporate	(11,953)	(483)	(43,370)	(2,188)
Petroleum resource rent tax ("PRRT")	(1,509)	(2,757)	1,850	(6,221)
	(13,462)	(3,240)	(41,520)	8,409
Deferred tax				
Tax depreciation	2,689	(4,014)	20,285	(3,196)
Tax losses	-	4,972	(5,257)	2,812
PRRT	(5,925)	644	(6,284)	(774)
	(3,236)	1,602	8,744	(1,158)
	(16,698)	**(1,638)**	**(32,776)**	**(9,567)**

The overall tax charge in 2019 increased by US$23.2 million, largely due to:

- Current corporate income tax increased by US$41.2 million predominately due to:
  - Montara generating an income tax charge of US$38.7 million (2018: US$ Nil). There was no income tax charge generated by Montara in 2018 due to losses incurred for the period between acquisition closing (September 28, 2019), to the financial year end. The comparable period tax losses arose largely due to to the assets being shut down for an inspection and maintenance backlog between November 1, 2018 to January 10, 2019;
  - Stag generating an income tax charge of US$4.7 million (2018: US$1.3 million) reflecting the increase in profitability during the year due to higher production and revenues, and lower production costs; and
  - No income tax charge for Ogan Komering in 2019, compared to US$0.9 million in 2018, following expiry of the Ogan Komering PSC in Q2 2018.
- Current period PRRT decreased by US$8.1 million as the Group paid US$6.2 million in 2018 but generated a PRRT tax credit of US$1.9 million in 2019; the latter a result of the drilling of the 49H infill well at Stag in Q2 2019 . Montara has PRRT carried forward credits of US$3.1 billion as at December 31, 2019, the utilisation of credits was exceeded by the augmentation of the existing balance;
- A reduction in deferred tax liabilities, associated with oil & gas properties depletion charges, resulted in a deferred tax credit of US$20.3 million for the current year (2018: increased tax expense by US$3.2 million). This portion of deferred tax liabilities relates to the larger accounting basis for Montara's oil & gas properties, relative to its tax basis, and the deferred tax liability reduces in line with depletion charges;
- Utilisation of Montara carry forward tax losses from 2018 in the course of 2019 gave rise to a charge of US$5.3 million (2018: income of US$2.8 million); and
- Deferred PRRT expense of US$6.3 million arose due to an increase in deferred tax liabilities associated with Stag PRRT (2018: US$0.8million), mostly attributable to the capitalised cost of the 49H infill well for book purposes.

The overall tax charge during Q4 2019 increased by US$15.1 million, largely due to:

- Current corporate income tax increased US$11.5 million predominately due to:
  - Montara generating an income tax charge of US$7.5 million (2018: (US$ Nil)). There was no income tax charge generated by Montara in 2018; and
  - Stag generating a charge of US$4.5 million (2018: US$0.5 million) reflecting the increase in profitability.
- Current PRRT expense for Q4 2019 was US$1.5 million, down US$1.2 million from PRRT expense in Q4 2018 of US$2.8 million, due to higher PRRT deductibles in 2019, including the costs of the 49 infill well;
- A reduction in deferred tax liabilities, associated with oil & gas properties depletion charges, resulted in a deferred tax credit of US$2.7 million (Q4 2018: increased tax expense by US$4.4 million). This portion of deferred tax liabilities relates to the larger accounting basis for Montara's oil & gas properties, relative to its tax basis, and the deferred tax liability reduces in line with depletion charges;
- Deferred taxes, in respect of historic carry forward tax losses, was unchanged in Q4 2019, whereas in Q4 2018 there was a tax credit of US$5.0 million arising from the creation of a deferred tax asset due to tax losses at Montara during Q4 2018, largely a result of the inspection and maintenance shutdown; and
- Deferred PRRT expense at US$5.9 million as a result of an increase in deferred tax liabilities associated with Stag PRRT (2018: tax credit of US$0.6million), mostly attributable to the capitalised cost of the 49H infill well for book purposes.

Other comprehensive income

USD'000	THREE MONTHS ENDED DEC 31, 2019	THREE MONTHS ENDED DEC 31, 2018	YEAR ENDED DEC 31, 2019	YEAR ENDED DEC 31, 2018
Profit/(Loss) for the quarter/year	10,364	(6,573)	40,505	(31,033)
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss:				
(Loss)/Gain on unrealised cash flow hedges	(9,688)	51,775	(30,542)	51,775
Hedging gain reclassified to profit & loss	(3,520)	(1,088)	(14,874)	(1,088)
	(13,208)	50,687	(45,416)	50,687
Tax income/(expense) relating to components of other comprehensive income	3,962	(15,207)	13,624	(15,207)
Other comprehensive (loss)/income	(9,246)	35,480	(31,792)	35,480
	1,118	**28,907**	**8,713**	**4,447**

Loss on cash flow hedges
During Q3 2018, the Group entered into a capped swap to hedge approximately 50% of planned production from the existing wells at Montara over the period October 1, 2018 through to September 30, 2020, at swap rates commencing at US$74.22/bbl, through to US$66.62/bbl, by September 2020. Calls for a portion of the swapped barrels were bought at a US$80/bbl strike price to September 30, 2019, and at US$85/bbl thereafter.

The swap contracts settle monthly, based on the average Dated Brent oil price in the prevailing month.

The capped swap has been designated as a cash flow hedge, and assessed to be effective with a fair value of US$5.3 million, as at December 31, 2019 (December 31, 2018: US$51.3 million). The fair value is based on third-party valuations for similar products on relevant markets.

The Group recognised a fair value loss on unrealised cashflow hedges for the year ended December 31, 2019 of US$30.5 million (year to December 31, 2018: gain of US$51.8 million), and a fair value loss on unrealised cashflow hedges of US$9.7 million in the three month period ended December 31, 2019 (Q4 2018: gain of US$51.8 million), reflecting the movements in fair value of the remaining hedge contracts on the balance sheet.

Hedging gain reclassified to profit and loss
Following swap settlements, the reclassification of hedge contracts for the year ended December 31, 2019 gave rise to a transfer from other comprehensive income to revenue of US$14.9 million (year to December 31, 2018: US$1.1 million), and for the three-month period ended December 31, 2019, a transfer to revenue of US$3.5 million (Q4 2018: US$1.1 million). The movement relates to the settlement of hedge contracts associated with the Montara capped swap throughout 2019, and the ineffective mark-to-market revaluation of the remaining open Montara capped swap contracts.

Tax relating to components of other comprehensive income
The tax components of other comprehensive income for the year ended and three months ended December 31, 2019 are a tax credit of US$13.6 million and US$4.0 million, respectively, which reflects the deferred tax impact on the net income or expense for the periods.

Financial Position

The following provides selected financial information of the Group, which was derived from, and should be read in conjunction with, the audited consolidated financial statements for the years December 31, 2019 and December 31, 2018.

USD'000	AS AT DECEMBER 31, 2019	AS AT DECEMBER 31, 2018
Non-current assets	594,170	587,696
Current assets	160,911	142,671
Non-current liabilities	395,463	429,936
Current liabilities	134,151	85,170
Shareholders' equity	225,467	215,261

Non-current assets

USD'000	DECEMBER 31, 2019	DECEMBER 31, 2018
Intangible exploration assets	116,096	95,607
Oil and gas properties	383,018	430,193
Plant and equipment	1,780	1,709
Right-of-use assets	59,787	-
Derivative financial instruments	-	15,339
Restricted cash	17,477	23,561
Deferred tax assets	16,012	21,287
Total non-current assets	**594,170**	**587,696**

Non-current assets as at December 31, 2019 are US$594.2 million (2018: US$587.7 million), an increase of US$6.5 million, predominately due to:

- **Intangible exploration assets** - increased by US$20.5 million largely due to the increased expenditure in Vietnam, in preparation of project sanction of Nam Du/U Minh;
- **Oil and gas properties** - decreased by US$47.2 million due to depletion charges for the year, partly offset by costs associated with the Stag 49H infill well, changes in ARO assumption at Montara and Stag, and pipeline maintenance, among other factors;
- **Right-of-use assets** - increased by US$59.8 million, pursuant to the adoption of IFRS16;
- **Derivative financial instruments** - reduced to nil as at December 31, 2019, from US$15.3 million in 2018, as the swap contracts expire on September 30, 2020 and the balance has been transferred to current assets;
- **Restricted cash** - decreased by US$6.1 million to US$ 17.5 million, reflecting the declining debt service reserve account balance under the RBL; and
- **Deferred tax assets** - decreased by US$5.3 million due to the utilisation of PRRT credits brought forward from the prior year at Stag.

Current assets

USD'000	DECEMBER 31, 2019	DECEMBER 31, 2018
Inventories	31,411	15,822
Trade and other receivables	42,283	32,800
Derivative financial instruments	5,275	35,985
Restricted cash	6,008	5,083
Cash and cash equivalents	75,934	52,981
Total current assets	**160,911**	**142,671**

Current assets as at December 31, 2019 were US$160.9 million, compared to US$142.7 million as at December 31, 2018, the increase of US$18.2 million predominately due to:

- **Inventories** - increased by US$15.6 million due to higher closing crude oil inventories at Stag and Montara;
- **Trade and other receivables** - increased by US$9.5 million due to the timing of liftings and invoice settlements at Montara. The last lifting for Montara was completed on December 17, 2019 with 30 days settlement terms; the cash receipt for this lifting of US$33.9 million was received in January 2020;
- **Derivative financial instruments** - decreased by US$30.7 million to reflect the changes in fair value of the remaining swap contracts that expire on September 30, 2020; and
- **Restricted cash, plus cash and cash equivalents** - increased by US$23.9 million, due to organic cash generation in the business in 2019.

Non-current liabilities

USD'000	DECEMBER 31, 2019	DECEMBER 31, 2018
Provisions	280,418	284,300
Borrowings	7,328	49,420
Lease liabilities	42,533	-
Other payable	359	3,748
Deferred tax liabilities	64,825	92,468
Total non-current liabilities	**395,463**	**429,936**

Non-current liabilities as at December 31, 2019 were US$395.5 million, a decrease of US$34.5 million from December 31, 2018, predominately due to:

- **Provisions** - decreased by US$3.9 million, due to a decrease in the ARO provision of US$2.3 million, reflecting the impact of changes in discount rate assumptions and estimates, and a reduction in the provision for Stag FSO of US$1.6 million due to changes in estimates;
- **Borrowings** - decreased by US$42.1 million due to the reclassification of non-current to current liabilities as at December 31, 2019 year end, following RBL repayments made by the Group during 2019;
- **Lease liabilities** - increased by US$42.5 million pursuant to the adoption of IFRS16;
- **Other payable** - decreased by US$3.4 million due to the reduction in fair values of the contingent payments to PTTEP, the vendor of the Montara assets; and
- **Deferred tax liabilities** - decreased by US$27.6 million due to changes in taxable timing differences from Montara.

Current liabilities

USD'000	DECEMBER 31, 2019	DECEMBER 31, 2018
Borrowings	41,795	52,393
Lease liabilities	19,739	-
Trade and other payables	27,962	31,493
Tax liabilities	44,655	1,284
Total current liabilities	**134,151**	**85,170**

Current liabilities as at December 31, 2019 were US$134.2 million, an increase of US$49.0 million from December 31, 2018, predominately due to:

- **Borrowings** - decreased by US$10.6 million due to repayments of the RBL by the Group during 2019;
- **Lease liabilities** - increased by US$19.7 million pursuant to the adoption of IFRS16;
- **Trade and other payables** - decreased by US$3.5 million due to differences in settlement dates of standard payables amounts; and
- **Tax liabilities** - increased by US$43.4 million mainly due to the increase in tax liabilities from Montara of US$38.7 million, as a result of profit before tax achieved by Montara in 2019, compared to a loss before tax in 2018.

Share Capital

The share capital consists of fully paid ordinary shares with a nil par value. All shares are equally eligible to receive dividends and the repayment of capital, and each share is entitled one vote at the shareholders' meeting.

	AS AT DECEMBER 31, 2019	AS AT DECEMBER 31, 2018
Number of issued ordinary shares	461,042,811	461,009,478
	USD'000	**USD'000**
At beginning of the year	466,562	364,466
Issued during the year	11	102,096
At end of the year	466,573	466,562

Shareholders' equity

Shareholders' equity increased by US$10.2 million compared to 2018, due to the profit after tax of US$40.5 million generated in the current year, and transactions with owners of US$1.4 million, partly offset by other comprehensive loss of US$31.8 million arising from Montara hedging instruments.

Liquidity And Capital Resources

Cash at bank

As at December 31, 2019, cash and bank balances were US$75.9 million, excluding restricted cash and the debt service reserve account established in support of the RBL, compared with US$53.0 million as at December 31, 2018. The following table provides select cashflow information for the 12 month periods indicated:

USD'000	DECEMBER 31, 2019	DECEMBER 31, 2018
Net cash generated from operating activities	144,637	17,763
Net cash used in investing activities	(50,829)	(161,354)
Net cash (used in)/generated from financing activities	(70,863)	184,861
Net increase in cash and cash equivalents	22,945	41,270
Cash and cash equivalents at beginning of the year	52,981	10,450
Cash and cash equivalents at end of the year	**75,934**	**52,981**

The cash balances improved as at December 31, 2019, compared to 2018, due to organic operating cash generation during the year. The increase in cash balances was partly used for acquisition of oil and gas properties of US$45.2 million and repayment of the RBL of US$54.2 million during the year, hence the net cash used in each of investing and financing activities in 2019.

Working capital

Working capital is the amount by which current assets exceed current liabilities. As at December 31, 2019, the Group's working capital remains positive at US$26.8 million, a decrease of US$30.7 million compared to December 31, 2018. A breakdown of the Group's working capital is as follows:

USD'000	AS AT DECEMBER 31, 2019	AS AT DECEMBER 31, 2018	CHANGE
Current assets	160,911	142,671	18,240
Current liabilities	134,151	85,170	48,981
Net working capital	**26,760**	**57,501**	**(30,741)**

The reduction in working capital is predominately due to the recognition of current lease liabilities of US$19.7 million pursuant to the adoption of IFRS16 effective January 1, 2019. Additionally, there was reduction in the carrying amount of derivative financial assets by US$30.7 million, based on the redetermination of its fair value as at December 31, 2019. The reduction is partially offset by the increase in inventories of US$15.6 million with higher unsold crude oil stocks as at December 31, 2019, relative to December 31, 2018.

Contractual obligations and commitments

At year-end, the Group has outstanding commitments under operational and capital commitments that fall due as follows:

	TOTAL USD'000	LESS THAN 1 YEAR 2019	1-5 YEARS USD'000	AFTER 5 YEARS USD'000
Montara operational and capital commitments	19,441	19,441	-	-
SEA portfolio PSC operational commitments	10,000	10,000	-	-
Total	**29,441**	**29,441**	**-**	**-**

The SEA portfolio PSC operational commitments as at December 31, 2019 amounting to US$10.0 million (2018: US$ 10.0 million), relates to the minimum work commitment outstanding in exploration phase two of the Block 46/07 PSC, for the drilling of a further well.

Under the terms of the Block 46/07 PSC, Jadestone is committed to drill one more appraisal well on the block. The Company plans to drill an appraisal well on the Nam Du field to facilitate transition of 3C resource to 2C status. This well would be retained for future use as a Nam Du gas producer. On July 9, 2019, the Company submitted a request to the Vietnam Government, for a further one-year extension to the Block 46/07 PSC exploration phase two period to June 29, 2021, and this was approved on February 26, 2020. Following the Group's announcement on March 19, 2020 to delay the project, the Group will seek Vietnam Government approval for a further extension in order to align drilling of the appraisal well with development of Nam Du/U Minh. The Group is committed to the project and expects to receive approval for the extension request.

Non-Gaap Measures

Net (cash)/debt

Net (cash)/debt is a non-GAAP measure which does not have a standardised meaning prescribed by IFRS. This non-GAAP finance measure is included because management uses the information to analyse financial strength of the Group. The measure is used to ensure capital is managed effectively in order to support its ongoing operations, and to raise additional funds if required.

	2019 USD'000	2019 USD'000
Gearing ratio		
Debt	49,123	101,813
Cash and cash equivalents	(75,934)	(52,981)
Restricted cash	(13,485)	(18,644)
Net (cash)/debt	**(40,296)**	**30,188**
Equity	225,467	215,261
Net debt to equity ratio	**N/M**	**14%**

Debt is defined as long and short-term interest bearing debt, and excludes derivatives. Cash and cash equivalents includes the Montara Assets' minimum working capital cash balance of US$15.0 million required under the RBL, while restricted cash comprises US$13.5 million in the RBL debt service reserve account (2018: US$18.6 million). Restricted cash, as shown here, excludes the US$10.0 million deposited in support of a bank guarantee to a key supplier in respect of the Stag FSO. Equity includes all capital and reserves of the Group that are managed as capital.

EBITDAX

EBITDAX is a non-GAAP measure which does not have a standardised meaning prescribed by IFRS. This non-GAAP finance measure is included because management uses the information to analyse financial performance of the Group.

	YEAR ENDED DECEMBER 31, 2019	YEAR ENDED DECEMBER 31, 2018
Revenue	325,406	113,423
Production cost	(119,898)	(90,939)
Staff cost	(19,714)	(13,538)
Impairment	-	(11,901)
Other expenses	(11,692)	(10,374)
Other financial gains	3,389	12,345
Reported EBITDAX	177,491	(984)
Depletion, depreciation and amortisation	(90,746)	(13,776)
	86,745	(14,760)
Non-recurring		
Hedge gain	14,242	(996)
Riserless light well intervention	(18,720)	-
Other well workovers	(5,065)	(2,220)
Impairment of assets	-	(11,901)
Montara shutdown costs	-	(4,043)
Others	(3,860)	(6,354)
Gain on contingent considerations	3,389	12,345
	(10,014)	(11,177)
Adjusted EBITDAX	**187,505**	**10,193**

Financial Instruments, Financial Risks And Capital Management

For a detailed analysis of how the Group manages its financial instruments, financial risks and capital management, see the audited consolidated financial statements for the years ended December 31, 2019 and December 31, 2018. The financial risks, instruments and capital market strategies have not materially changed since the year end.

Financial assets and liabilities

Current assets and liabilities

Management considers that due to the short-term nature of the Group's current assets and liabilities, the carrying values equate to their fair value.

Non-current assets and liabilities

All non-current assets and liabilities are reflected at fair value.

USD'000	DECEMBER 31, 2019	DECEMBER 31, 2018
Financial assets		
At amortised cost	135,737	86,539
Derivative instruments designated in hedge accounting relationships	5,275	51,324
	141,012	**137,863**
Financial liabilities		
At amortised cost	419,671	417,606
Contingent consideration for a business combination	359	3,748
	420,030	**421,354**

Fair values are based on management's best estimates, after consideration of current market conditions. The estimates are subjective and involve judgment, and as such are not necessarily indicative of the amount that the Group may incur in actual market transactions.

Commodity price risk

The Group's earnings are affected by changes in oil and gas prices. The Group manages this risk by monitoring oil and gas prices, and entering into commodity hedges against fluctuations in oil prices, if considered appropriate.

The Group has entered into hedge contracts for sales based upon planned production at Montara.

Montara
The Group hedged 50% of its planned production volumes at Montara for the 24 months to September 30, 2020 from its existing well stock. The hedge is a capped swap, providing downside price protection while allowing for participation in higher commodity prices via purchased call options. The call strike is set at US$80/bbl for the nine months to September 31, 2019 and US$85/bbl for the twelve months to September 2020. The swap price was set at US$78.26/bbl for Q4 2018, US$71.72/bbl for 2019 and US$68.45/bbl for the nine months to September 2020. Approximately two thirds of the swapped barrels in 2019 and 2020 have upside price participation via purchased calls. The effective date of the hedge contracts is October 1, 2018.

Commodity price sensitivity

The results of operations and cash flows from oil and gas production can vary significantly with fluctuations in the market prices of oil and/or natural gas. These prices are affected by factors outside the Group's control, including the market forces of supply and demand, regulatory and political actions of governments, and attempts by the OPEC cartel to control or influence prices, among a range of other factors.

The table below summarises the impact on profit/(loss) before tax, and on equity, from changes in commodity prices on the fair value of derivative financial instruments. The analysis is based on the assumption that the crude oil price moves 10%, with all other variables held constant. Reasonably possible movements in commodity prices were determined based on a review of recent historical prices and current economic forecasters' estimates.

GAIN OR LOSS	EFFECT ON THE RESULT BEFORE TAX FOR THE YEAR ENDED DECEMBER 31, 2019 USD'000	EFFECT ON OTHER COMPREHENSIVE INCOME BEFORE TAX FOR THE YEAR ENDED DECEMBER 31, 2019 USD'000	EFFECT ON THE RESULT BEFORE TAX FOR THE YEAR ENDED DECEMBER 31, 2018 USD'000	EFFECT ON OTHER COMPREHENSIVE INCOME BEFORE TAX FOR THE YEAR ENDED DECEMBER 31, 2018 USD'000
Increase by 10%	-	(7,266)	(1)	(16,729)
Decrease by 10%	-	7,266	1	16,729

Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between United States Dollars ("US Dollar") and foreign currencies will affect the fair value or future cash flows of the Group's financial assets or liabilities.

Cash and bank balances are generally held in the currency of likely future expenditures to minimise the impact of currency fluctuations. It is the Group's normal practice to hold the majority of funds in US Dollars in order to match the Group's revenue and expenditures. The Group's US$120.0 million reserve based loan facility is a US Dollar denominated instrument.

In addition to US Dollars, the Group transacts in various currencies, including Australian Dollars, Singapore Dollars, Vietnamese Dong, Malaysian Ringgit, Canadian Dollars, Indonesian Rupiah and Great British Pounds.

Material foreign denominated balances were as follows:

	2019 USD'000	2018 USD'000
Cash and bank balances		
Australian Dollars	7,088	4,923
Trade and other receivables		
Australian Dollars	5,853	5,237
Trade and other payables		
Australian Dollars	21,231	1,974

If the Australian dollar weakens/strengthens by 10% against the functional currency of the Group, profit or loss will increase/decrease by US$0.8 million (2018: decrease/increase by US$0.8 million).

Interest rate risk

The Group's interest rate exposure arises from some of its cash and bank balances and borrowings. The Group's other financial instruments are non-interest bearing or fixed rate, and are therefore not subject to interest rate risk.

Jadestone holds some of its cash in interest bearing accounts and short-term deposits. Interest rates currently received are at historically relatively low levels. Accordingly, a downward interest rate movement would not cause significant exposure to the Group.

On August 2, 2018, the Group entered into an RBL agreement with the Commonwealth Bank of Australia and Société Générale to borrow US$120.0 million, repayable quarterly to March 31, 2021. The loan was fully drawn down on September 28, 2018, and incurs interest at LIBOR plus 3%. The loan incurred initial costs of US$3.2 million, which were offset against the proceeds received.

Based on the carrying value of the RBL as at December 31, 2019, if interest rates had increased or decreased by 1% and all other variables remained constant, the Group's quarterly net income/(loss) before tax would have decreased or increased by US$0.1 million (2018: US$0.3 million).

Credit risk

Credit risk represents the financial loss that the Group would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms.

The Group actively manages its exposure to credit risk, granting credit limits consistent with the financial strength of the Group's counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures, and close monitoring of relevant accounts.

The Group trades only with recognised, creditworthy third parties.

The Group's current credit risk grading framework comprises the following categories:

CATEGORY	DESCRIPTION	BASIS FOR RECOGNISING EXPECTED CREDIT LOSSES ("ECL")
Performing	The counterparty has a low risk of default and does not have any past-due amounts.	12-month ECL
Doubtful	Amount is > 30 days past due or there has been a significant increase in credit risk since initial recognition.	Lifetime ECL - not credit-impaired
In default	Amount is > 90 days past due or there is evidence indicating the asset is credit-impaired.	Lifetime ECL - credit-impaired
Write-off	There is evidence indicating that the debtor is in severe financial difficulty and the Group has no realistic prospect of recovery.	Amount is written off

The table below details the credit quality of the Group's financial assets and other items, as well as maximum exposure to credit risk by credit risk rating grades:

	EXTERNAL CREDIT RATING	INTERNAL CREDIT RATING	12-MONTH ("12M") OR LIFETIME ECL	GROSS CARRYING AMOUNT (i) USD'000	LOSS ALLOWANCE USD'000	NET CARRYING AMOUNT USD'000
2019						
Cash and bank balances	n.a	Performing	12m ECL	99,419	-	99,419
Trade receivables	n.a	(i)	Lifetime ECL	34,007	-	34,007
Other receivables	n.a	Performing	12m ECL	2,311	-	2,311
2018						
Cash and bank balances	n.a	Performing	12m ECL	81,625	-	81,625
Trade receivables	n.a	(i)	Lifetime ECL	57	-	57
Other receivables	n.a	Performing	12m ECL	4,857	-	4,857

(i) For trade receivables, the Group has applied the simplified approach in IFRS9 to measure the loss allowance at lifetime ECL. The Group determines the expected credit losses on these items by using specific identification, estimated based on historical credit loss experience based on the past due status of the debtors, adjusted as appropriate to reflect current conditions and estimates of future economic conditions. Accordingly, the credit risk profile of these assets is presented based on their past due status in terms of specific identification.

As at December 31, 2019, total trade receivables amounted to US$34.0 million (2018: US$0.1 million). The balance in both 2019 and 2018 had been fully recovered in 2020 and 2019, respectively. The Group has derivative receivables of US$0.5 million and US$3.4 million within other receivables in 2019 and 2018, respectively, and these balances were received in full in January 2020 and 2019, respectively.

The concentration of credit risk relates to the main counterparty to oil and gas sales in Australia, where the sole customer has an A1 credit rating (Moody's). All trade receivables are generally settled 30 days after sale date. In the event that an invoice is issued on a provisional basis then the final reconciliation is paid within 3 days of the issuance of the final invoice, largely mitigating any credit risk.

The Group recognises lifetime ECL for trade receivables. The ECL on these financial assets are estimated based on days past due, by applying a percentage of expected non-recoveries for each group of receivables. As at financial period end, ECL from trade and other receivables are expected to be insignificant.

Cash and bank balances are placed with reputable banks and financial institutions, which are regulated, and with no history of default.

The maximum credit risk exposure relating to financial assets is represented by their carrying value as at the reporting date.

Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet all of its financial obligations, as they become due. This includes the risk that the Group cannot generate sufficient cash flow from producing assets or is unable to raise further capital in order to meet its obligations.

The Group manages it liquidity risk by optimising positive free cash flow from its producing assets, on-going cost reduction initiatives, bank balance on hand, and merger and acquisition strategies.

The Group net profit after tax for the year was US$40.5 million (2018: loss after tax US$31.0 million). Operating cash flows before movements in working capital and net cash generated from operating activities for the year ended December 31, 2019 was positive of US$176.7 million and US$144.6 million, respectively (year ended December 31, 2018: negative of US$0.3 million; net cash generated of US$17.8 million). The Group's net current assets remained positive at US$34.2 million as at December 31, 2019 (December 31, 2018: US$57.5 million).

The Group's RBL is sized on a borrowing base drawn from projected cash flows from the Montara Assets, and based on proved and probable producing reserves (2PD) but including certain infill wells. This borrowing base is subject to scheduled semi-annual redeterminations and as such, and in the event of a significant reduction in the borrowing base, there is a risk that scheduled repayments may increase to offset any such borrowing base deficiency. The existing borrowing base, as assessed by the lenders as at December 2019, is significantly above aggregate commitments.

The Group believes it has sufficient liquidity to meet all reasonable scenarios of operating and financial performance for the next 12 months.

Non-derivative financial liabilities

The following table details the expected maturity for non-derivative financial liabilities. The table below has been drawn up based on the undiscounted contractual maturities of the financial liabilities, including interest that will be accrue on those liabilities, except where the Group anticipates that the cash flow will occur in a different period. The adjustment column represents the estimated future cash flows attributable to the instrument included in the maturity analysis, which are not included in the carrying amount of the financial liability on the consolidated statement of financial position, namely interest expense.

	WEIGHTED AVERAGE EFFECTIVE INTEREST RATE %	ON DEMAND OR WITHIN 1 YEAR USD'000	WITHIN 2 TO 5 YEARS USD'000	MORE THAN 5 YEARS USD'000	ADJUSTMENTS USD'000	TOTAL USD'000
2019						
Non-interest bearing	-	48,086	55,503	275,422	(8,463)	370,548
Variable interest rate instruments	7.735	44,425	7,477	-	(2,779)	49,123
		92,511	**62,980**	**275,422**	**(11,242)**	**419,671**
2018						
Non-interest bearing	-	31,493	6,603	277,697	-	315,793
Variable interest rate instruments	8.071	58,907	52,182	-	(9,276)	101,813
		90,400	**58,785**	**277,697**	**(9,276)**	**417,606**

Non-derivative financial assets

The following table details the expected maturity for non-derivative financial assets. The inclusion of information on non-derivative financial assets is necessary in order to understand the Group's liquidity risk management, as the Group's liquidity risk is managed on a net asset and liability basis. The table has been drawn up based on the undiscounted contractual maturities of the financial assets, including interest that will be earned on those assets, except where the Group anticipates that the cash flow will occur in a different period. The adjustment column represents the estimated future cash flows attributable to the instrument included in the maturity analysis, which are not included in the carrying amount of the financial asset on the consolidated statement of financial position, namely interest income.

	WEIGHTED AVERAGE EFFECTIVE INTEREST RATE %	ON DEMAND OR WITHIN 1 YEAR USD'000	WITHIN 2 TO 5 YEARS USD'000	ADJUSTMENTS USD'000	TOTAL USD'000
2019					
Non-interest bearing	-	36,318	-	-	36,318
Variable interest rate instruments	-*	89,419	10,000	-*	99,419
		125,737	**10,000**	**-***	**135,737**
2018 (Restated)					
Non-interest bearing	-	4,914	-	-	4,914
Variable interest rate instruments	-*	58,064	23,561	-*	81,625
		62,978	**23,561**	**-***	**86,539**

* The effect of interest is not material.

Capital management

The Group manages its capital structure and makes adjustments to it, based on the funds available to the Group, in order to support the acquisition, exploration and development of resource properties and the ongoing operations of its producing assets. Given the nature of the Group's activities, the Board of Directors works with management to ensure that capital is managed effectively and the business has a sustainable future.

To carry-out planned asset acquisitions, exploration and development, and to pay for administrative costs, the Group may utilise excess cash generated from its ongoing operations and may utilise its existing working capital, and will work to raise additional funds should that be necessary.

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Group, is reasonable. There were no changes in the Group's approach to capital management during the financial year ended December 31, 2019. The Group is not subject to externally imposed capital requirements.

The Group's overall strategy remains unchanged from 2018.

Fair value measurements

The Group discloses fair value measurements by level of the following fair value measurement hierarchy:

i. Quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1);

ii. Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (Level 2); and

iii. Inputs for the asset or liability that are not based on observable market data (unobservable inputs) (Level 3).

FINANCIAL ASSETS/ FINANCIAL LIABILITIES	FAIR VALUE (USD'000) AS AT				FAIR VALUE HIERARCHY	VALUATION TECHNIQUE(S) AND KEY INPUT(S)	SIGNIFICANT UNOBSERVABLE INPUT(S)	RELATIONSHIP OF UNOBSERVABLE INPUTS TO FAIR VALUE
	2019		2018					
	ASSETS	LIABILITIES	ASSETS	LIABILITIES				
Derivative financial instruments								
1) Commodity capped swap contracts (Note 36)	5,275	-	51,324	-	Level 2	Third party valuations based on market comparable information.	n.a.	n.a.
Others - contingent consideration in a business combination								
2) Contingent consideration (Note 7 and 30)	-	359	-	3,748	Level 3	Based on the nature and the likelihood of occurrence of the trigger event. Fair value is estimated using future Dated Brent price forecasts at the end of the reporting period, taking into account the time value of money and volatility of oil prices.	Expected future oil price volatility of 25% is based on an analysis of Brent oil price movement prior to acquisition date.	A slight increase in Brent oil prices would result in a significant increase in the fair value and vice versa.

Business Risks and Uncertainties

Jadestone, like all companies in the oil and gas industry, operates in an environment subject to inherent risks. Many of these risks are beyond the ability of a company to control, including those associated with exploring for, developing, and producing economic quantities of hydrocarbons, volatile commodity prices, governmental regulations, and environmental matters.

Impact of Coronavirus outbreak ("COVID-19")

On January 30, 2020, the World Health Organisation declared the COVID-19 outbreak a "Public Health Emergency of International Concern" and on March 10, 2020, declared it to be a pandemic. Actions taken around the world to help mitigate the spread of COVID-19 include restrictions on travel, and quarantines in certain areas, and forced closures for certain types of public places and businesses. The COVID-19 and actions taken to mitigate it have had and are expected to continue to have an adverse impact on the economies and financial markets of many countries, including the geographical area in which the Group operates.

On April 12, 2020, members of Organisation of the Petroleum Exporting Countries and certain other countries including the Russian Federation, have agreed to cut global daily oil production by almost 10%, representing 9.7 mm bbls/d effectively from May 2020.

The decline in Dated Brent oil price due to factors set out above has been assessed to be a non-adjusting post balance sheet event in accordance with IAS 10.

The depressed Dated Brent oil price will reduce the Group's revenue in 2020, but the Group has no plan to reduce its crude oil production as the Group has significant downside protection in place, including via its capped swap and a relatively competitive cash operating cost base. The Group has hedged about a third of its planned production for the first nine months of 2020. Plus, the crude at both Stag and Montara has generated a premium above the benchmark crude oil prices.

In the absence of Vietnamese Government approvals for the Nam Du/U Minh field development plan in Q1 2020, and the decline in oil prices, the Group announced on March 19, 2020 to defer the Nam Du/U Minh gas field development. In respect of the Block 46/07 PSC appraisal well commitment, the Group will seek Vietnam Government approval for a further extension to the existing June 29, 2021 deadline, in order to align drilling of the appraisal well with development of Nam Du/U Minh. The Group is committed to the project and expects to receive approval for the extension request.

At the time the Group undertook the impairment review of its non-financial assets, as at December 31, 2019, the spot price for Dated Brent was US$66.8/bbl. Since that time, Dated Brent oil prices have fallen to around US$19.10/bbl as at April 20, 2020, due to the impact of Coronavirus ("COVID-19") on oil demand.

The Group will reflect updated oil price data during its next impairment review, including spot oil prices, but will also give due consideration to both the medium- and long-term outlook for crude oil prices.

The Group will closely monitor the development of the COVID-19 outbreak and related oil price outlook, and continue to evaluate its impact on the business, the Group's financial position and operating results. As part of the preparation of the current financial statements, a forward looking going concern analysis was undertaken at some of the lower current third party downside Brent crude oil price outlooks, including US$22/bbl in Q2 2020 and US$30/bbl in H2 2020. The Group was able to generate positive operating cashflow without resorting to significant cuts in operating costs, and comfortably continue as a going concern.

Operational

Key risks at an operational level include, but are not limited to: operational and safety considerations, risks from operating in an offshore environment, shipping and pipeline transportation and interruptions, reservoir performance and technical challenges, partner risks, competition, technology, the Company's ability to hire and retain necessary skilled personnel, the availability of drilling and related equipment, information systems, seasonality and disruptions from severe weather and met-ocean restrictions, timing and success of integrating the business and operations of acquired assets and companies, phased growth execution, risk of litigation, regulatory issues, increases in government taxes and other fiscal changes, and risk to reputation resulting from operational activities that may cause personal injury, property damage or environmental damage.

Environmental

Jadestone is currently subject to environmental regulations arising from a variety of federal, regional and/or state legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorisations, civil liability for pollution damage and the imposition of material fines and penalties. Further, environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Jadestone believes that it is, and will be, in material compliance with current applicable environmental legislation, however no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on Jadestone's business, financial, result of operations and prospects.

To mitigate these risks, the Group's HSE policy is reinforced at every stage of each operational contract. As part of all contract tendering, the Group may request, and may subsequently audit, the HSE procedures of relevant sub-contractors, to ensure they are in line with standard industry practice, local regulatory and Group's requirements.

In accordance with industry practice, the Group maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

The ability of the Group to meet its obligations is dependent upon there being sufficient financial resources. External financing, from the farm-out of equity in assets and potentially through the issuance of common shares may be required to fund future activities. There can be no assurance that the Group will be able to successfully raise funds in the future.

The forgoing list of risks and uncertainties is not exhaustive.

Segment Information

Information reported to the Group's Chief Executive Officer (the Chief Operating Decision Maker) for the purposes of resource allocation is focused on two reportable/business segments driven by different types of activities within the upstream oil and gas value chain, namely producing assets and secondly development and exploration assets. The geographic focus of the business is on SEA and Australia.

Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

	PRODUCING ASSETS		EXPLORATION		
	AUSTRALIA USD'000	SEA USD'000	SEA USD'000	CORPORATE USD'000	TOTAL USD'000
2019					
Revenue					
Liquids revenue	325,406	-	-	-	325,406
	325,406	**-**	**-**	**-**	**325,406**
Production cost	(119,898)	-	-	-	(119,898)
DD&A	(90,277)	-	(113)	(356)	(90,746)
Staff costs	(7,282)	-	(3,543)	(8,889)	(19,714)
Other expenses	(7,012)	-	(278)	(4,402)	(11,692)
Other income	2,971	-	2	6	2,979
Finance costs	(16,387)	-	(7)	(49)	(16,443)
Other financial gain	3,389	-	-	-	3,389
Profit/(Loss) before tax	**90,910**	**-**	**(3,939)**	**(13,690)**	**73,281**
Additions to non-current assets	84,444	-	20,456	65	104,965
Non-current assets	461,053	-	116,162	943	578,158
2018					
Revenue					
Liquids revenue	105,970	8,520	-	-	114,490
Gas revenue	-	2,482	-	-	2,482
Royalties	-	(3,549)	-	-	(3,549)
	105,970	**7,453**	**-**	**-**	**113,423**
Production cost	(88,159)	(2,780)	-	-	(90,939)
DD&A	(13,066)	(618)	-	(92)	(13,776)
Staff costs	(3,489)	(1,834)	(816)	(7,399)	(13,538)
Other expenses	(5,022)	(146)	(434)	(4,772)	(10,374)
Impairment of assets	-	-	(11,901)	-	(11,901)
Other income	2,345	-	-	189	2,534
Finance costs	(6,219)	-	(80)	(2,941)	(9,240)
Other financial gain	12,057	-	-	288	12,345
Profit/(Loss) before tax	**4,417**	**2,075**	**(13,231)**	**(14,727)**	**(21,466)**
Additions to non-current assets	376,856	-	1,835	183	378,874
Non-current assets	470,522	-	95,607	280	566,409

Non-current assets include oil and gas properties, intangible exploration assets, right-of-use assets, restricted cash and plant and equipment used in corporate offices.

Included in revenues arising from producing assets are revenues of approximately US$325.4 million (2018: US$106.0 million) which arose from sales to the Group's largest customer.

Off Balance Sheet Arrangements

The Group has no off-balance sheet arrangements.

Related Party Transactions

During the year, the Group entities did not enter into any transactions with related parties other than the following:

Compensation of key management personnel

	2019 USD'000	2018 USD'000
Short-term benefits	6,746	2,656
Other benefits	1,052	326
Share-based payments	1,038	234
	8,836	**3,216**

The total remuneration of members of key management in 2019 (including salaries and benefits) was US$8.8 million (2018: US$3.2 million).

Compensation of directors

	SHORT-TERM BENEFITS (a) USD'000	OTHER BENEFITS (a) USD'000	SHARE-BASED PAYMENTS USD'000	TOTAL COMPENSATION USD'000
2019				
A. Paul Blakeley	1,302	350	233	1,885
Daniel Young	707	174	139	1,020
Dennis McShane	130	-	21	151
Iain McLaren	81	-	13	94
Eric Schwitzer	68	-	25	93
Robert Lambert	69	-	13	82
Cedric Fontenit	66	-	9	75
David Neuhauser	56	-	12	68
Lisa Stewart	6	-	-	6
	2,485	**524**	**465**	**3,474**
2018				
A. Paul Blakeley	1,035	422	164	1,621
Daniel Young	546	149	74	769
Dennis McShane	130	-	19	149
Iain McLaren	70	-	9	79
Eric Schwitzer	58	-	9	67
Robert Lambert	50	-	9	59
David Neuhauser	45	-	9	54
Cedric Fontenit	18	-	-	18
	1,952	**571**	**293**	**2,816**

(a) Short-term benefits comprise salary, director fees as applicable, performance pay, pension and other allowances. Other benefits comprise benefits-in-kind.

Director participation in AIM equity raise

Certain directors and members of the management team of the Company ("Insiders") subscribed for new shares pursuant to the AIM equity raise and listing completed in August 2018. The issuance of new shares to these Insiders, pursuant to the AIM equity raise and listing, is considered to be a related party transaction within the meaning of TSX Venture exchange policy 5.9 and multilateral instrument 61-101 ("MI 61-101"), and disclosable in the December 31, 2018 year end financial statements under AIM rule 19. The Company has relied on the exemptions from the valuation and minority shareholder approval requirements of MI 61-101, contained in sections 5.5(b) and 5.7(1)(b) of MI 61-101, in respect of the Insider participation. Certain directors subscribed for a total of 1,961,271 new shares at 35 pence per share (or £688,545) as follows.

	NUMBER OF NEW SHARES
A. Paul Blakeley	544,798
David Neuhauser*	544,798
Daniel Young	217,919
Dennis McShane	217,919
Robert Lambert	217,919
Eric Schwitzer	108,959
Iain McLaren	108,959
	1,961,271

* These relate to ordinary shares that Mr. Neuhauser is deemed to have an interest in, through Livermore Strategic Opportunities LP. Mr. Neuhauser is the Managing Director of Livermore Strategic Opportunities LP and hence has the power and authority to direct its activities.

Repayment of secured convertible bond

Tyrus Capital Event S.à r.l., an entity controlled by Tyrus Capital S.A.M., entered into a secured convertible bond facility agreement with the Company in November 2016. Tyrus Capital S.A.M. controls entities that hold approximately 25.6% of the Company's ordinary share capital, as at December 31, 2019.

On August 1, 2018, the Company and Tyrus Capital Event S.à r.l. conditionally agreed, upon the Company's admission and listing on AIM, that the Company would redeem the secured convertible bond facility by paying US$17.4 million to Tyrus Capital Event S.à r.l., and all associated security released. At June 30, 2018, the balance on the bond was drawn to US$15.0 million. Repayment subsequently occurred on August 15, 2018.

Events After the Reporting Period

Award of damages in relation to Philippines arbitration

In December 2017, the Group commenced arbitration action against Total E&P Philippines BV ("Total"), with the Singapore International Arbitration Center, in response to a breach of the 2012 farm out agreement ("the FOA"), claiming that Total failed to drill an exploration well on the deepwater Halcon prospect, located within the block covered by SC56 in the Sulu Sea, offshore the Philippines. The FOA required Total to drill one exploration well and pay their 75% interest, along with the Group's 25% interest.

On January 3, 2020, the tribunal found in favour of the Group, concluding that Total breached the FOA, awarding (i) monetary damages to the Group of US$11.1 million, less specific expenditures incurred prior to the breach to be agreed or determined if the parties cannot agree; and (ii) legal costs of approximately US$4.3 million. The tribunal's costs will be borne by the Group and Total 25:75.

The parties were unable to agree the specific expenditures and, on March 24, 2020, the tribunal issued a final award in which it determined such expenditures to be US$0.7 million. The net award to the Group was US$10.4 million.

After the payment of all legal fees, funding costs, and the Company's share of the tribunal costs, net proceeds to the Group are expected to be approximately US$2.2 million. This will be recognised in FY2020.

Following the award of monetary damages to the Group, Total would be released from bearing the Group's 25% interest for the drilling of one exploration well, estimated at US$18.8 million. Consequently, the Group is potentially liable to pay US$2.4 million, being the penalty payable to the Department of Energy in Philippines if both Total and the Group fail to drill an exploration well prior the license expiration on September 1, 2020. However, no final decision has been reached between the Group and Total on the future plan for SC56. A discussion will take place during the next operator committee meeting, tentatively scheduled in second quarter of 2020.

At the end of the reporting period, no contingent assets nor contingent liabilities were recorded as the outcome of the arbitration was not finalised till after year end.

The total carrying value within intangible exploration assets in respect of SC56 as at December 31, 2019 was US$50.4 million (2018: US$50.4 million). The Group has reviewed, pursuant to IFRS6 *Exploration for and evaluation of mineral resources*, whether there are any impairment indicators for SC56 as at year end, and no change has been made to the SC56 carrying value within intangible exploration assets.

Vietnam Block 51 and 46/07

The Group holds a 100% operated working interest in the Block 51 PSC and the Block 46/07 PSC, both in the shallow water Malay-Tho Chu Basin, offshore southwest Vietnam. The Group has made three gas/condensate discoveries: the U Minh and Tho Chu fields in Block 51, and the Nam Du gas field in Block 46/07.

On October 17, 2019, the Group made the formal declaration of commercial discovery for the Nam Du and U Minh fields and submitted to the Vietnam Government the combined formal field development plan for the Nam Du and U Minh development, thus initiating the formal government approval process.

Following delays in the Vietnamese Government approval processes and the drop in the oil price in Q1 2020, the Group announced on March 19, 2020 that it would delay the sanction and development of Nam Du/U Minh and the first gas would not occur before Q4 2022 at the earliest.

As at year end, the Group has recognised US$65.6 million of intangible exploration assets in relation to Nam Du and U Minh fields.

TSX Venture Exchange de-listing

On February 25, 2020, Jadestone announced its intention to de-list from the TSX-V, and a formal application to the TSX-V was subsequently made by the Company on March 12, 2020. The final day of trading of Jadestone's common shares on the TSX-V was on March 24, 2020. The Company's shares continue to trade on AIM.

Upon de-listing from the TSX-V, the Company remains a Canadian domiciled corporation, and will continue as a reporting issuer under Canadian rules in the near term, although the Company has requested an order from the applicable securities commissions, to be granted an exemption from certain of its Canadian reporting requirements, in a manner similar to a designated foreign issuer.

Additional Information

Additional information relating to the Company, including Management Information Circulars, NI 51-101 oil and gas disclosures, material change reports, and other important items of disclosure, and previous interim and annual consolidated financial statements are available on the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.