JADESTONE ENERGY INC.

(the “Reporting Issuer” or the “Company”)

FORM NI 51-101F1
STATEMENT OF RESERVES DATA AND
OTHER OIL AND GAS INFORMATION
For fiscal year ended December 31, 2020

(This is the form referred to in item 1 of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (“NI 51-101”). Terms for which a meaning is given in NI 51-101 have the same meaning in this Form 51-101F1.)

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PART 1 DATE OF STATEMENT

Item 1.1 Relevant Dates

1. The date of this report and statement is: March 17, 2021.
2. The Effective Date of information provided in this statement is as of the Company’s most recently completed fiscal year ended: December 31, 2020.
3. The Preparation Date of the information provided in this statement is March 12, 2021.

PART 2 DISCLOSURE OF RESERVES DATA

Jadestone Energy Inc. (the “Company” or “Jadestone”) holds permits to two producing assets, which are the Montara Development (100% interest) located in the Vulcan Sub-Basin of Australia and the Stag field (100% interest) located in the Dampier Sub-Basin of the Northern Carnavon Basin in Australia. The Montara Development consists of two production licenses, which include AC/L7 (Montara field) and AC/L8 (Skua, Swift and Swallow fields). The Stag field is located in production license WA-15-L. ERC Equipoise Ltd. (“ERC”), an independent qualified reserves evaluator had been appointed by the Company to perform an audit and a review on the light and medium crude oil combined and net present values of future net revenue of the Montara Development and the Stag Field respectively.

The following tables, based on ERC’s report entitled “2020 Year-End Reserves Report for the Montara Development and Stag Field” (the “ERC Report”), and prepared in accordance with the Canadian Oil and Gas Evaluation Handbook, show the estimated share of the Company’s light and medium crude oil combined associated with the properties and the net present value of estimated future net revenue for these reserves, using forecast prices and costs as indicated. The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Company’s reserves. There is no assurance that the forecast price and cost assumptions contained in the ERC Report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the ERC Report. The recovery and reserve estimates of the Company’s oil and natural gas reserves stated herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates stated herein. Readers should note that the totals in the following tables may not add due to rounding. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Disclosure provided herein in respect of boe (barrels of oil equivalent) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (6 Mcf) to one barrel (1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Certain information in this statement may constitute "analogous information" as defined in NI 51-101, including, but not limited to, information relating to areas with similar geological characteristics to the lands held by the Company. Such information is derived from a variety of publicly available information from government sources, regulatory agencies, public databases or other industry participants (as at the date stated therein) that the Company believes are predominantly independent in nature. The Company believes this information is relevant as it helps to define the reservoir characteristics in which the Company may hold an interest. The Company is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor and in accordance with the COGE Handbook. Such information is not an estimate of the reserves or resources attributable to lands held or to be held by the Company and there is no certainty that the reservoir data and economics information for the lands held by the Company will be similar to the information presented therein. The reader is cautioned that the data relied upon by the Company may be in error and/or may not be analogous to the Company's land holdings.

Table 1: Summary of Oil and Gas Reserves as of December 31, 2020 using Forecast Prices and Costs

	RESERVES							
	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (MMbbl)	Net (MMbbl)	Gross (MMbbl)	Net (MMbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMbbl)	Net (MMbbl)
PROVED								
Developed Producing	16.8	16.8	0	0	0	0	0	0
Developed Non-Producing	0.0	0.0	0	0	0	0	0	0
Undeveloped	6.4	6.4	0	0	0	0	0	0
TOTAL PROVED	23.2	23.2	0	0	0	0	0	0
PROBABLE	13.9	13.9	0	0	0	0	0	0
TOTAL PROVED PLUS PROBABLE	37.1	37.1	0	0	0	0	0	0
POSSIBLE	17.3	17.3	0	0	0	0	0	0
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	54.4	54.4	0	0	0	0	0	0

Table 2: Summary of Net Present Values of Future Net Revenue as of December 31, 2020 using Forecast Prices and Costs

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	($/boe)
PROVED											
Developed Producing	-121	33	113	155	176	-171	-13	70	114	137	7
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	85	85	75	65	55	9	17	14	9	4	12
TOTAL PROVED	-36	118	189	220	231	-162	4	84	123	141	8
PROBABLE	556	519	453	390	338	395	382	334	286	245	32
TOTAL PROVED PLUS PROBABLE	521	637	641	610	569	234	385	418	408	386	17
POSSIBLE	1,196	951	763	628	530	851	696	566	469	399	44
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	1,716	1,588	1,404	1,237	1,099	1,085	1,081	983	877	784	26

Table 3: Total Future Net Revenue (Undiscounted) as of December 31, 2020 using Forecast Prices and Costs

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	ABANDONMENT AND RECLAMATION COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Proved Reserves	2,081	0	-1,303	-319	-519	-36	-126	-162
Proved Plus Probable Reserves	3,475	0	-1,987	-333	-566	521	-287	234
Proved Plus Probable Plus Possible Reserves	5,297	0	-2,578	-203	-605	1,716	-631	1,085

Table 4: Future Net Revenue by Production Group as of December 31, 2020 using Forecast Prices and Costs

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (CAMM$)	UNIT VALUE ($/Mcf) ($/bbl)
Proved Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	-	-
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	189	8.2
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	189	8.2
Proved Plus Probable Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	-	-
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	641	17.3
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	641	17.3
Proved Plus Probable Plus Possible Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	-	-
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	1,404	25.8
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	1,404	25.8

PART 3 PRICING ASSUMPTIONS

Table 5 below summarized the forecast benchmark reference price and pricing assumptions provided to the Company by its independent reserves evaluators, ERC. Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale. While ERC considered these forecasts reasonable at the time, users of forecasts should understand the inherently high uncertainty in forecasting any commodity or market.

Table 5: Summary of Pricing and Inflation Rate Assumptions as of December 31, 2020

Year	Brent Oil Price ($CAD/bbl)	INFLATION RATES (%/Year)
Historical (average over year)		
2017	89	
2018	87	
2019	84	
2020	58	
Forecast	Nominal, $ of the day	
2021	67	2.0
2022	78	2.0
2023	86	2.0
2024	87	2.0
2025	89	2.0
Thereafter	+2%/yr	

For the financial year ended December 31, 2020 the Company's weighted average price received for oil was $CAD 60.0 per bbl.

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation

Table 6 below disclosed the Company's changes in reserve for the production licences AC/L7 and AC/L8 for the Montara Development (100% interest), and WA-15-L for the Stag field (100% interest), which are all located offshore Australia.

Table 6: Reconciliation of Company Gross Reserves By Production Type

FACTORS	LIGHT AND MEDIUM CRUDE OIL					HEAVY CRUDE OIL					CONVENTIONAL ASSOCIATED AND NON-ASSOCIATED GAS				
	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Possible (MMbbl)	Gross Proved Plus Probable Plus Possible (MMbbl)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Possible (MMbbl)	Gross Proved Plus Probable Plus Possible (MMbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Possible (MMcf)	Gross Proved Plus Probable Plus Possible (MMcf)
December 31, 2019	25.1	16.7	41.8	18.4	60.2	-	-	-	-	-	-	-	-	-	-
Extension & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	0.5	-1.0	-0.5	-1.1	-1.6	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	1.8	-1.8	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-
Production	-4.2	-	-4.2	-	-4.2	-	-	-	-	-	-	-	-	-	-
December 31, 2020	23.2	13.9	37.1	17.3	54.4	-	-	-	-	-	-	-	-	-	-

The changes to the reserves estimates can be attributed to those factors set out in Table 6. These factors include:

- Production of 4.2 MMboe that the Company produced over 12-months period of fiscal year 2020.
- Technical revisions due to delayed of infill wells on both Montara Assets and Stag.
- Economic factors such as changes in the United States: Australia currency exchange rate, changes in oil price and changes in premium rate.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

Table 7 below disclosed the Company's proved undeveloped and probable undeveloped reserves that were first attributed in each of the three most recent financial years and in the aggregate, before that time:

Table 7: Company Gross Reserves First Attributed by Year

<u>Proved Undeveloped Reserves</u>

	Light & Medium Oil (MMbbl)		Heavy Oil (MMbbl)		Natural Gas (MMcf)		Natural Gas Liquids (MMbbl)		Oil Equivalent (MMboe)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior										
2019	5.9	5.9	-	-	-	-	-	-	5.9	5.9
2020	6.9	6.9	-	-	-	-	-	-	6.9	6.9
2021	6.4	6.4	-	-	-	-	-	-	6.4	6.4

<u>Probable Undeveloped Reserves</u>

	Light & Medium Oil (MMbbl)		Heavy Oil (MMbbl)		Natural Gas (MMcf)		Natural Gas Liquids (MMbbl)		Oil Equivalent (MMboe)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior										
2019	9.1	9.1	-	-	-	-	-	-	9.1	9.1
2020	8.3	8.3	-	-	-	-	-	-	8.3	8.3
2021	7.7	7.7	-	-	-	-	-	-	7.7	7.7

The Company plan to develop these undeveloped reserves by drilling further wells in both the Montara Development and the Stag field. For Stag field, the Company have drilled an infill well in 2019 and has plan to drill three horizontal producers and one horizontal water injector going forward. While for the Montara Development, the Company planned to drill one horizontal producer in the Montara field and two horizontal producers in the Skua field. Each of the proposed production wells targets an area that is interpreted not to have been efficiently swept by the current well stock.

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

Aside from the potential impact of material fluctuations in commodity prices, other significant factors or uncertainties that may affect the Company's reserves or the future net revenue associated with such reserves include:

- material changes to existing taxation or royalty rates and/or regulations;
- the United States: Australia currency exchange rate;
- the timing of completion and level of success of the Infill drilling; and

• the ability to obtain storage and sales contracts for crude oil and natural gas.

Item 5.3 Future Development Costs

The following table summarizes the estimated development costs deducted in the estimation of future net revenue attributable to various reserves categories and prepared under various price and cost assumptions in $CAD:

Table 8: Company Net Annual Capital Expenditures

Company Annual Capital Expenditures (CAMM$)				
Year	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved Plus Probable Plus Possible**
2021	8	58	58	8
2022	3	25	25	25
2023	3	3	3	3
2024	3	196	196	52
2025	3	28	28	28
Remainder	7	9	23	86
Total	26	319	333	203
10% Discounted	21	259	265	118

The Company expects to fund its estimated future development costs in Australia through a combination of existing working capital, cash generated from operations and an existing loan facility. These estimated costs are based on a number of factors and assumptions and there can be no guarantee that the organic funds will be available when required to proceed with the development on the schedule contemplated herein.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

The Company's oil and gas properties are located onshore in Indonesia (Lemang PSC) and offshore in Vietnam (Block 51 and Block 46/07), Australia (Production Licenses AC/L7, AC/L8 and WA-15-L) and the Philippines (SC 56 and SC 57). For Block 05-1 PSC in Vietnam and SC56 in Phillippines, the Company has agreed the final settlement of the dispute with related parties and announced the voluntary relinquishment of the blocks.

Indonesia

Lemang PSC

In December 2020, Jadestone acquired a 90% operated working interest in the Lemang PSC, located onshore Sumatra, Indonesia. The remaining 10% working interest in the PSC is held by PT Hexindo Gemilang Jaya. The block includes the Akatara gas field, which was previously developed as an oil producing asset and has undeveloped wet gas remaining. The asset has been substantially de-risked with 11 wells drilled into the structure, plus three years of oil production history, up until the field ceased production in December 2019.

The Company intends to commence a gas development project on the Lemang PSC and current efforts are focused on finalising a heads of agreement on gas sales, to be followed by a gas sales agreement with buyers before seeking formal field development sanction. The timeline for the Lemang development is highly flexible, and at Jadestone's discretion.

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 ("MOIT"). 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 Petrovietnam ("PVN") for approval.

On March 19, 2020 the Company announced in light of changing market conditions and in the absence of government approvals of the FDP the Company had decided to delay the project. It is now anticipated that the project will be sanctioned in 2022 with First Gas production in late 2023 or 2024.

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. Jadestone has requested an extension to the SDA for Tho Chu and is currently awaiting a response from Petrovietnam.

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 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 Company 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 2021 which was approved on February 26, 2020. A request for a further 3-year extension to exploration phase two was submitted to PVN on December 8, 2020 due to the delay in the ND/UM project schedule.

Block 05-1 PSC

On August 8, 2016, a wholly-owned subsidiary of the Company, signed a definitive agreement ("SPA") with Teikoku Oil (Con Son) Co. Ltd ("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 written waiver by Vietnam Oil and Gas Corporation ("PVN"), of PVN's statutory pre-emption rights, held under Vietnamese law.

Jadestone disagreed with Inpex's alleged termination and viewed the obligations of both parties under the SPA as continuing.

On July 3, 2020, the Group filed a notice of arbitration with the Singapore International Arbitration Centre, in accordance with the terms of the SPA. On November 11, 2020, the Group and Teikoku have agreed a full and final settlement in respect of the dispute. A Settlement Deed was signed and accordingly, the Group no longer holds an interest in the Block 05-1 PSC.

Philippines

Service Contract 56 ("SC56")

Jadestone held 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 exploration period on the block previously expired on September 1, 2020. During the year, Total was granted a 12-month extension until September 1, 2021, in view that the COVID-19 pandemic represented a force majeure event under the service contract.

Following a strategic review on available options for the asset, a mutual agreement was reached between Jadestone and Total on the voluntary termination of SC56 in the early of November 2020. On November 18, 2020, Total and Jadestone expressed its intention to the Philippines Department of Energy ("DOE") to voluntary surrender the entire interest on SC56 and accordingly, to terminate the contract. The effective date of termination was on December 21, 2020. The termination is subject to approval by the DOE.

The relinquishment decision made decision made by Jadestone constituted an impairment trigger event and this resulted to the recognition of impairment in relation to the capitalised intangible exploration assets of US$50.5 million during the year.

Following the termination, the Group is subject to pay 25% of the unfulfilled Minimum Work Programme as at the termination date. The total unfulfilled Minimum Work Programme amount has been submitted by Total to the DOE and is currently under review.

Service Contract 57 ("SC57")

The Company holds a 21% working interest in the block but it has been under force majeure since 2011 and these conditions are expected to continue for the next 12-24 months.

Australia

Production Licenses AC/L7 and AC/L8

Jadestone holds a 100% interest in in the Production Licenses AC/L7 (Montara field) and AC/L8 (Skua, Swift and Swallow fields). The Montara, Skua, Swift and Swallow field together form the Montara Development which is located in the Vulcan Sub-Basin, approximately 675 km west of Darwin, Australia in a water depth of 77 m. The Montara Development facilities include an unmanned wellhead platform that produces to a floating production, storage and offloading unit ("FPSO"). The Montara field wells are drilled from the wellhead platform, whilst those for the Skua, Swift and Swallow fields are subsea tie-backs. The production licence associated with the Montara, Skua, Swift and Swallow fields production licence have no expiry date.

Production Licenses WA-15-L

Jadestone holds a 100% working interest in the WA-15-L (Stag field). The Stag field is located approximately 60 km offshore of Western Australia. The field was developed using a fixed leg, 12 slot manned central processing facility platform with a production capacity of 50,000 bbl/day. A two km pipeline connects the platform to a CALM buoy which is itself connected to a Floating Storage and Offloading vessel (FSO). In September 2020, a new offtake arrangement was implemented for Stag, whereby offtake tankers are used to directly offload Stag Crude oil, in place of the existing long lease FSO. The production licence associated with the Stag field expires in 2039.

Item 6.2 Properties with No Attributed Reserves

The Company's working interest at December 31, 2020 in the various concessions is outlined in the table below together with the gross and net acreage of each:

Table 9: Company's Properties and Working Interest

Country	Contracts (1)	Operator	Current Working Interest	Gross Acreage (km^2)	Net Acreage (km^2)
Indonesia	Lemang PSC (Onshore)	Jadestone	90%	743	669
Philippines	SC 57 (Offshore)	CNOOC	21% (2)	7,120	1,495
Vietnam	Block 51 PSC (Offshore)	Jadestone	100%	2,900	2,030
	Block 46/07 PSC (Offshore)	Jadestone	100%	2,622	1,835
Australia	AC/L7 (Offshore)	Jadestone	100%	252	252
	AC/L8 (Offshore)	Jadestone	100%	420	420
	WA-15-L (Offshore)	Jadestone	100%	160	160

1 Philippines's Contracts are Services Contracts. Indonesia and Vietnam contracts are Production Sharing Contracts

2 Net Working Interest is subject to approval of Jadestone farm-in by the Philippines government. The SC 57 is under *force majeure.*

The principal work commitments, timing of completion and minimum expenditures to be incurred during the current exploration period of each of the respective Production Sharing Contracts are listed in the following tables:

Table 10: Principal Work Commitments, Timing of Completion and Minimum Expenditures of the Company

Region	Block	Current Exploration Phase and Expiry	Work Commitments	Minimum Expenditures (Gross US$)	Relinquishments of Gross Acreage required during 2021-2022
Lemang	Lemang PSC	PSC expiry January 2037 – no committed timeline for remaining exploration	• 3D seismic • 1 well	7.9 million	None
Philippines	SC 57	*Force majeure* status effective March 2006	None	None	None
Vietnam	Block 51 PSC	Phase 2 of exploration expired on 10th June 2016 Applied for Suspended Development Areas (SDAs) around U Minh and Tho Chu Discoveries (approved on 26th December 2016) Conversion of U Minh SDA to Development Area was approved on 15th November, 2019. Request submitted to extend Tho Chu SDA. Decision pending.	None	None	None

	Block 46/07 PSC	In extension to Phase 2 of exploration until 29th June 2021	• 1 well	10.0 million	None
		One year extension to Phase 2 of exploration until 29th June 2021 (approved on 26th February 2020) Request submitted to extend exploration phase 2 by 3 more years to align with ND/UM project schedule			
Australia	AC/L7 AC/L8	The Company has secured the legal ownership of the Montara Development operation on 6th August 2019	None	None	None
	WA-15-L	The Company has secured the legal ownership of the Stag Oilfield operation on 10th July 2017	None	None	None

Item 6.2.1 Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

As at the effective date of this report, reserves have yet to be attributed to any of the properties in Indonesia, Vietnam and Philippines in which the Company holds an interest. Contingent resources have been attributed to the Lemang PSC (Indonesia), Blocks 46/07 and 51 PSCs (Vietnam, Malay-Tho Chu Basin).

<u>Indonesia Lemang PSC – Akatara Field</u>

The contingencies associated with the Akatara Field in Indonesia Lemang PSC are as follows:

- A Heads of Agreement (HOA) for the Gas Sales Purchase Agreement (GSPA) has been initialled with the proposed buyer.
- A Heads of Agreement (HOA) for the LPG and Condensate Sales Purchase Agreement in progress with the proposed buyer.
- Evaluating optimum Condensate production evacuation route for marketing and sales.
- The Akatara Field Gas Plan of Development has been approved by the regulator SKKMigas.
- Some progress was made on pre-development activities to support the Akatara field development project. This includes the completion of facilities FEED, completion of offshore site surveys, land acquisition and approval of the Environmental Impact Assessment (EIA) and forestry permit.
- Although facilities FEED is completed, a further optimisation evaluation is ongoing.
- AFE submission for approval and tendering Project EPIC will be follow after project reach FID.

<u>Vietnam Block 46/07 PSC – Nam Du Field</u>

The contingencies associated with the Nam Du Field in Vietnam Block 46/07 PSC are as follows:

- Although an appraisal well is planned in order to fulfil licence commitments, the current evaluation is considered to be robust. Nevertheless, the drilling of an appraisal well is likely to result in revised low, best and high case resource volumes.
- The Field Development Plan (FDP) for the combined Nam Du/U Minh development project was submitted to Petrovietnam in October 2019 and was pending approval at the time of project suspension in March 2020. The FDP will be updated and resubmitted in 2021 to reflect the revise economics due to the delayed First Gas Date.

- Negotiations are currently ongoing with Petrovietnam on the revised gas sales profile.
- The project CAPEX assumptions will be subject to further review and refinement.

Vietnam Block 51 PSC – U Minh Field

The contingencies associated with the U Minh Field in Vietnam Block 51 PSC are as follows:

- Drilling of appraisal / development wells is likely to result in revised low, best and high case resource volumes.
- The Field Development Plan (FDP) for the combined Nam Du/U Minh development project was submitted to Petrovietnam in October 2019 and was pending approval at the time of project suspension in March 2020. The FDP will be updated and resubmitted in 2021 to reflect the revise economics due to the delayed First Gas Date.
- Negotiations are currently ongoing with Petrovietnam on the revised gas sales profile.
- The project CAPEX assumptions will be subject to further review and refinement.

Vietnam Block 51 PSC – Tho Chu Field

The contingencies associated with the Tho Chu Field in Vietnam Block 51 PSC are as follows:

- The subsurface assessment of Tho Chu is work in progress and consequently the project is currently at an early stage of evaluation.
- The project requires third party development of export route infrastructure. One potential route is via neighbouring (“Block B”) asset infrastructure; however this is yet to be installed and no confirmation of timing is available.
- The project CAPEX will be subject to further review and refinement.

Government Approval and Project Sanction

Regulatory support and approval will be required for the commercialisation of the company's Indonesia, Vietnam and Philippines Contingent Resources described above to proceed. In accordance with the Company's Production Sharing Contracts and joint venture agreements, field development plans must be agreed by the Company and its joint venture partners before submission for approval by the government.

Given the possible large scale of future development projects in Indonesia, Vietnam and Philippines to commercialise the Contingent Resources, significant capital requirements are anticipated. The Company may seek financing from external sources, including the issuance of debt and/or equity particularly as regards some of the longer term resource commercialisation, and should that be required. The Company may also consider a working interest farmout or partial divestiture arrangements. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to the Company.

Prior to project sanction for the areas in which the Company has an interest in Contingent Resources, numerous agreements and studies will need to be completed in addition to field development plans, including major engineering/procurement/construction agreements, environmental and social impact assessments and gas sales agreements.

Item 6.3 Forward Contracts

All oil produced at the Stag Field is sold pursuant to a Crude Oil and Condensate Sale, Purchase and Marketing Agreement dated August 4, 2009 between a subsidiary of the Company and a third party. The Agreement was extended for a 36 month period out to 26 February 2023 and can then be extended for a further 48 months.

All oil produced at the Montara Field is sold pursuant to a Crude Oil Sales Agreement dated September12 , 2018 between a subsidiary of the Company and a third party. The initial term of that Agreement is 3 years ("Initial Term"), which can be extended by a further two times for a period of three years each extension or 6 years in total from the expiry of the Initial Term.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

The following table summarizes the Company's abandonment and reclamation costs for the Stag Field and the Montara Development that are ascertained by estimating the costs to fulfil the current obligations using current techniques in regard to wells that are producing, under appraisal or pending development in $CAD:

Table 11: Company Net Annual Abandonment Costs

Company Annual Abandonment Cost (CAMM$)				
Year	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved Plus Probable Plus Possible**
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
Remainder	477	519	566	605
Total	477	519	566	605
10% Discounted	164	164	117	91

Item 6.6 Costs Incurred

In the year ending December 31, 2020, the Company made the following expenditures (whether capitalised or charged to expense) in $CAD:

Table 12: Cost Incurred for FY2020

Country	Australia
Property Acquisition Costs – Proved Properties	-
Property Acquisition Costs – Unproved Properties	-
Exploration Costs	7,945,755
Development Costs	6,461,218

Item 6.7 Exploration and Development Activities

The company drilled and brought on production an infill well in the Stag field in the fiscal year 2019. The primary focus for the company's development activities for the fiscal year 2021 are the following:

Table 13: Focus for Exploration and Development Activities

Country	Activities
Australia	Drill an infill producer on the Montara field Optimize existing production through reservoir management, ESP repair and maintenance
Vietnam	Progress the development of U Minh and Nam Du
Indonesia	Progress the development of Akatara field

For further detail of the Company's exploration and development activities for the 2021 fiscal year and as at the date of this statement, please refer to the heading "Part 6 Other Oil and Gas Information - Oil and Gas Properties and Wells" and "Part 6 Other Oil and Gas Information - Properties with No Attributed Reserves".

Item 6.8 Production Estimates

Estimated production volumes are derived from gross proved reserves and gross probable reserves associated with the Montara Development and the Stag Field disclosed under Part 2. Figures disclosed are net to the Company.

Table 14: Production Estimates for the Company (FY2021)

Product Type		Gross Proved	Gross Probable
Australia: Montara Development and Stag Field			
Light and Medium Crude Oil	(Mbbl)	4,014	248
Natural Gas	(MMcf)	0	0
Australia: AC/L7 and AC/L8 (Montara Development)			
Light and Medium Crude Oil	(Mbbl)	3,028	210
Natural Gas	(MMcf)	0	0
Australia: WA-15-L (Stag Field)			
Light and Medium Crude Oil	(Mbbl)	985	38
Natural Gas	(MMcf)	0	0

Item 6.9 Production History

The Company's historical production and netback for the period ended December 31, 2020 is presented below in $CAD:

Table 15: Production History and Netback of the Company (FY2020)

		Light and Medium Crude Oil				
		Q1 (Mar 2020)	**Q2 (Jun 2020)**	**Q3 (Sep 2020)**	**Q4 (Dec 2020)**	**Total**
Australia (AC/L7, AC/L8 and WA-15-L)						
Average Daily Production						
AC/L7 and AC/L8 (Montara Development)	(bbl/d)	8,799	10,081	8,320	8,987	9,045
WA-15-L (Stag)	(bbl/d)	2,866	2,485	1,764	2,466	2,394
Company share of daily production	(bbl/d)	11,665	12,566	10,084	11,454	11,438
Total Gross Production						
AC/L7 and AC/L8 (Montara Development)	(Mbbl)	801	917	765	827	3,310
WA-15-L (Stag)	(Mbbl)	261	226	162	227	876
Company share of daily production	(Mbbl)	1,062	1,144	928	1,054	4,186
Average ($/boe)						
Average Sales Prices Received	($CAD/bbl)	85.9	36.8	59.1	54.7	60.0
Royalties Paid	($CAD/bbl)	-	-	-	-	-
Operating Expenses	($CAD/bbl)	43.3	27.8	41.3	31.2	37.3
Netback Received	($CAD/bbl)	42.7	8.9	17.8	23.5	22.7