GRAND GULF ENERGY LIMITED

ABN 22 073 653 175

INTERIM REPORT

FOR THE HALF YEAR ENDED

31 December 2018

CONTENTS

DIRECTORS' REPORT	3-8
AUDITOR'S INDEPENDENCE DECLARATION	9
CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME	10
CONSOLIDATED STATEMENT OF FINANCIAL POSITION	11
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY	12
CONSOLIDATED STATEMENT OF CASH FLOWS	13
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS	14-20
DIRECTORS' DECLARATION	21
INDEPENDENT AUDITOR'S REVIEW REPORT TO THE MEMBERS	22-23

DIRECTORS' REPORT

Your directors submit the financial report of the consolidated entity for the half-year ended 31 December 2018.

DIRECTORS

The names of directors who held office during or since the end of the half-year are:

Mr Craig Burton – Non-Executive Chairman *(appointed 5 March 2019)*
Mr Charles Morgan – Executive Chairman *(resigned 5 March 2019)*
Mr Mark Freeman - Managing Director & Company Secretary
Mr Allan Boss – Executive Director *(resigned 5 March 2019)*
Mr Stephen Keenihan – Non-Executive Director *(resigned 5 March 2019)*
Mr Chris Bath - Non-Executive Director *(appointed 5 March 2019)*

EXPLORATION AND DEVELOPMENT

The Company's strategy continues to acquire development assets in the most attractive shale oil plays in the USA. As illustrated in the table below the oil prone Eagle Ford and DJ Basin are also the lowest unit cost producing areas and are where GGE is concentrating its efforts.

PLAY	AREA (km2)	GROSS THICKNESS	SALE AVERAGE PRICES (US$/acre)	BREAKEVEN COSTS US$/BOE
EAGLE FORD (US)	52,000	15-85m	$15,000	$54
DJ BASIN (US)	21,924	70-160m	$12,500	$50
BAKKEN (US/CAN)	520,000	Up to 40m	$12,500	$57
MONTNEY (CAN)	130,000	Up to 300m	$5,000	$58
BARNETT (US)	13,000	25-180m	$6,000	$64
HAYNESVILLE (US)	24,000	40-110m	$6,500	$66
MARCELLUS (US)	247,000	25-90m	$10,000	$89

DJ Basin, Colorado, USA

During the period, the Company settled on its acquisition in the highly productive Wattenberg Field in the Weld County portion of the DJ Basin which produces oil mainly from the Niobrara. Under this agreement, the Company's has acquired 36.5% working interest in a Joint Venture with PetroStone Inc (Operator), holding an initial 355 net acres across 8 sections. The Company's strategy, with its partner, is to utilise Colorado's development pooling process as a catalyst to create Drilling Spacing Units (DSUs) and maximise its interest in each. The acquired lands have the potential to yield 8 DSUs with a total of up to 64 drilling locations. If all the DSU's are awarded they will cover a total area of 5,120 acres. Until the DSU application process is resolved, GGE's final equity will be unknown but, on a simple pro rata basis, if no other interests become available, the Joint Venture's interest would average 11.9% across of the anticipated DSU's (GGE's ~4%). The DSU's remain active for a 2-year period with the ability to request a 12-month extension. GGE's final interest will only be know following issuing of AFEs for wells and interest holders elections as to whether they will participate or not.

PetroStone has made significant headway and expects to lodge applications for 3 drilling spacing units (DSU's) in the near future, having previously secured land surface agreements for the areas in question. In addition, Nickel Road, another local operator, recently lodged a DSU application over another part of the Company's holdings further confirming the Joint Venture strategy and the oil and gas potential of the areas.

The DSU's have a 35-day exposure period when others may apply and are expected to be granted within 90 days of lodgement. PetroStone has recently also secured a land surface agreement (SUA) for an additional proposed DSU (the SUA is a critical step in securing a DSU).

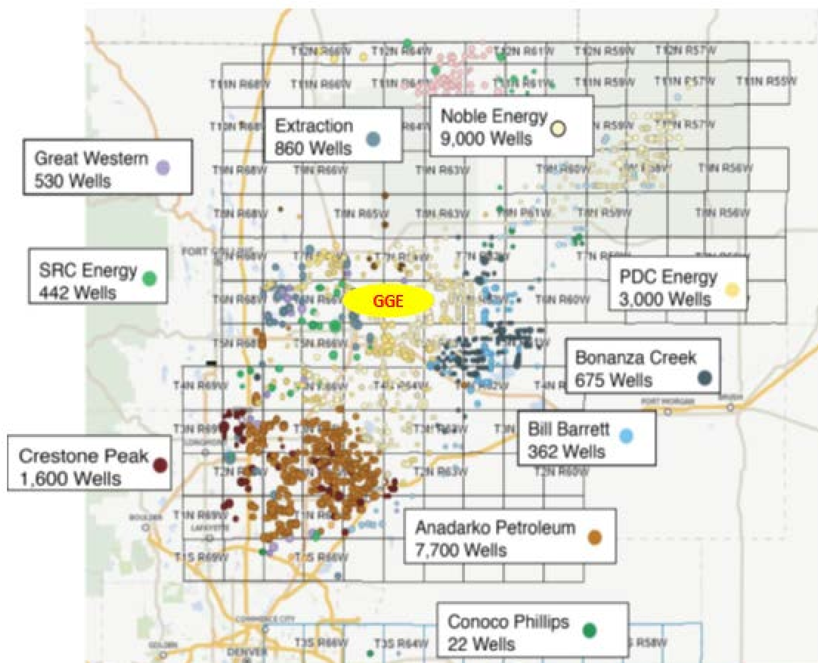
Grand Gulf estimates new wells with 8,000-10,000ft laterals to cost gross US$5m each. GGE's share of well costs is dependent on the level of participation by other parties in each DSU and on a well-by-well basis. This will be determined following the DSU process. However, under the farmin arrangement our minimum commitment is to participate in two wells with total exposure ~US$240,000. GGE will have the option to elect to increase its exposure in the event that other parties do not participate. The JV anticipates commencing drilling its first wells within 6 months following approval of the DSU's.

Background on the DJ Basin

The Energy Information Administration (EIA) projects that Niobrara production will rise 10,000 bo/d and 54 MMcf/d in 2019 to 679,000 bo/d and 5.209 Bcf/d. Colorado accounts for almost 4% of U.S. total crude oil production and also holds about 4% of the nation's economically recoverable crude oil reserves. Colorado's crude oil production has quadrupled since 2010, partly from the increased use of directional drilling and hydraulic fracturing technologies. Oil output declined somewhat in 2016 because of lower crude oil prices, but production rebounded and reached a record high in 2018 after oil prices rose. Substantial new production comes from the Niobrara Shale formation located in the Denver-Julesburg Basin in north-eastern Colorado, where oil production in one county, Weld, is the source of almost 9 out of every 10 barrels of crude oil drilled in Colorado. The Wattenberg field, much of which is in Weld County, is the fourth-largest U.S. oil field based on proved reserves.

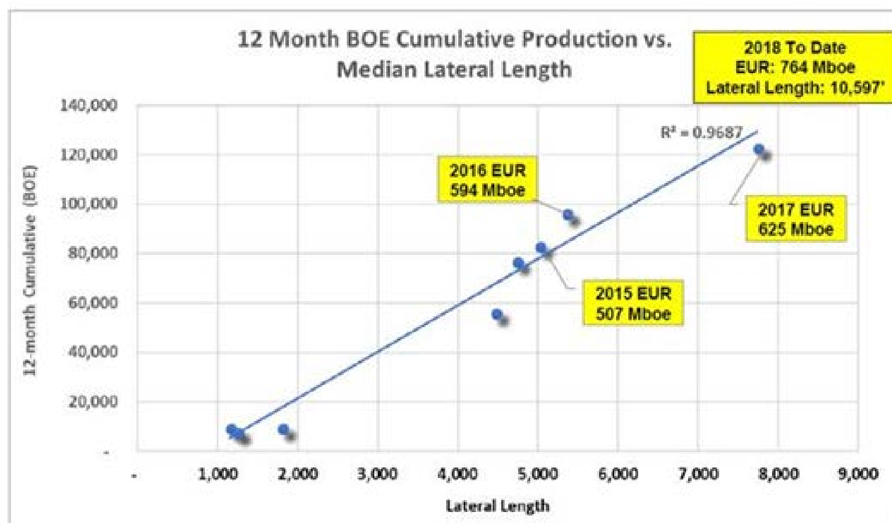
Some of the majors in the Basin are stepping up drilling with Anadarko recently announcing their drilling expenditure in the DJ Basin is expected to be ~US$1.3 billion during FY19. PDC Energy ("PDC") announced their Wattenberg production during the period grew 7% sequentially to 84,000 boe/d. PDC spudded 43 wells and turned 22 to sales in Wattenberg. During 2019, PDC plans to run three rigs in the Wattenberg.

During the period several political achievements occurred including Colorado proposition 112 being defeated. This proposal would have increased setbacks for new oil and gas developments.



Drilling and Completion Advance

Over the last 8 years unconventional basins in the USA have seen significant improvements in recoveries and the DJ Basin is one of the best performers. The Graph below shows the recovery improvements as measured by 12-month cumulative production as lateral lengths have increased from 2010 to 2018.



East Texas Prospect (50% WI) – Acquisition of 1,075 acres in the Eagle Ford

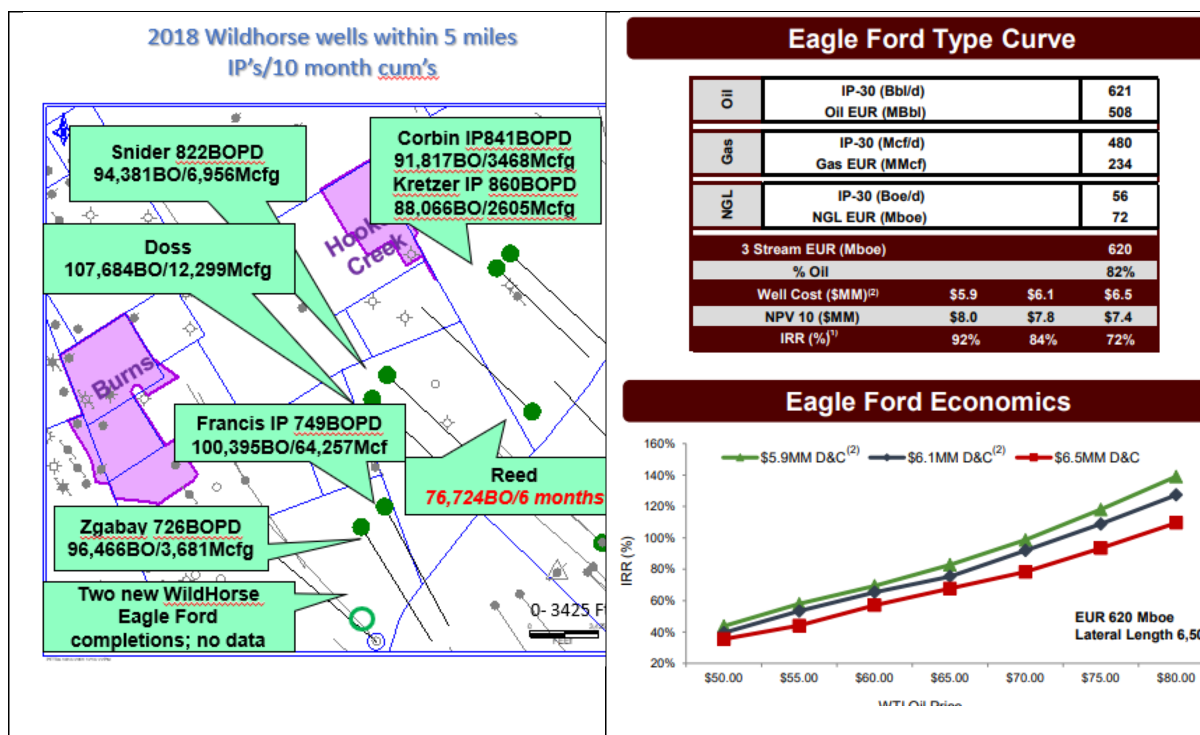
The Eagle Ford is the one of the most prolific oil and gas plays in North America and has the one of the lowest breakeven production costs . The Company has acquired a 50% interest in 1,117 net acres of 1,232 gross acres (558 acres net to GGE) in Burleson County, Texas as part of a 50/50 joint venture with a private Texas oil and gas company.

Wildhorse Resource Development has recently drilled and completed Eagle Ford wells with initial flowing rates of up to 840bo/d within one mile from GGE's proposed oil units. Wildhorse is the Eagle Ford play leader in Burleson, Lee and Brazos Counties with over 418,000 net acres. In September 2018, Chesapeake Energy announced a US$4 billion acquisition of Wildhorse.

Wildhorse drilled its first horizontal wells in the area in 2016. Its more recent "Gen 3" wells, are predicted to achieve significantly improved estimated ultimate recoveries (based on initial flow rates) of 620,000 boe/well, and with significantly reduced drilling costs, result in a NPV10 of $7.4 - $8m per well. All the Wildhorse wells drilled in a 5-mile radius of the GGE's acreage during 2018 are shown below. The map indicates the IP rates and cumulative 10-month oil and gas production. Using the improvements in drilling and completion techniques, 6 out of 7 of the "Gen 3" well's initial production results exceed the recoveries from older generation wells for the same period, irrespective of depth. Their decline rate is also less than for the older wells (which average 154,000 bo over 27 months) and Wildhorse expects the "Gen 3" wells to produce more oil over their lifetime.

Grand Gulf's proposed units (shown in purple on the map below) have the potential for up to 6 Eagle Ford and 1 Austin Chalk locations each with horizontal wells within the 5,000ft – 8,000ft range, similar to the wells being drilled by Wildhorse. The Company has spent ~US$660,000 in leasing costs and has the potential to add further adjacent land in H1, 2019.

The JV's strategy is to attract a third party to fund and operate the drilling and fraccing of a number of Eagle Ford horizontal wells. Well costs (drilled, fracced and completed) are anticipated to be US$4,500,000 each. GGE will reduce its interest to a manageable level as part of any farmin work program.



PRODUCTION

Desiree Field
Desiree, Assumption Parish, Louisiana, Non Operator 39.65%WI

The Hensarling #1 well (Desiree Field) produced a total for the period of 22,270 barrels of oil. The well averaged 190 bo/d. The well has produced 558,751 barrels of oil to 31 December 2018.

Desiree remains a substantial asset to the Company with significant long term reserves and cash flow.

Dugas & Leblanc Field
Napoleonville- Dugas & Leblanc #3 Well, Assumption Parish, Louisiana, Non Operator 55.5% WI*

The D&L#3 well (Dugas & Leblanc Field) produced a total for the period of 11,851 barrels of oil. The well is presently producing at 70 bo/d and has produced over 300,471 barrels of oil and 0.6 BCF gas. The D&L #3 well continues to outperform previous reserve estimates. During the period the well received an upgraded down-hole pump which has delivered substantially higher oil production rates.

Abita Field
Plaquemines Parish, Louisiana, Non Operator 20%WI

The Company disposed of its interests in the Abita field pre year end for US$100,000 net cash.

West Klondike Field
Wilbert Sons LLC #1 well, West Klondike, Iberville Parish, Louisiana, Non Operator 11.925% WI

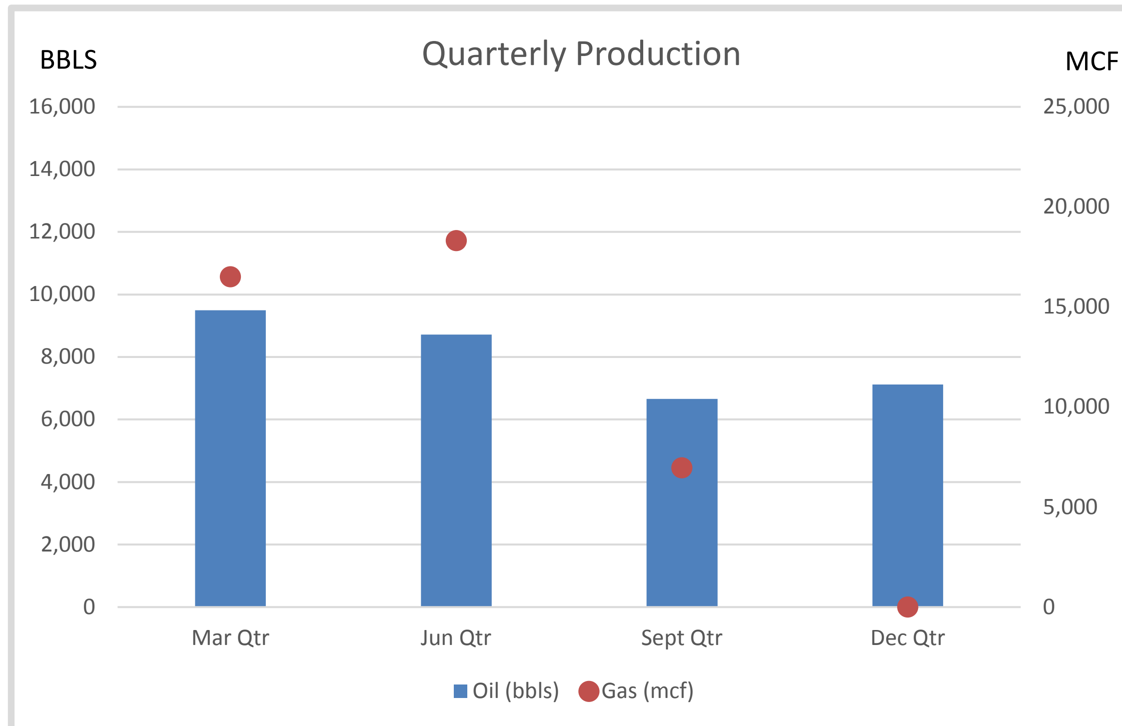
The Company disposed of its interests in the West Klondike field pre period end for a final payment of US$10,000. This clears all outstanding's and any obligations to plug and abandon the well.

RESULTS AND REVIEW OF OPERATIONS

Production

Total Net Quarterly Production

	Mar 18 Qtr	Jun 18 Qtr	Sept 18 Qtr	Dec 18 Qtr
Oil (bbls)	9,498	8,719	6,662	7,125
Gas (mcf)	16,500	18,306	6,954	0
% Oil Equ.	93%	92%	96%	100%



			Quarterly Bo		Daily Bo	
	Working interest	Parish	Gross	Net	Gross	Net
Desiree Field*	39.65%	Assumption	11,356	4,496	126	50
Dugas & Leblanc	55.5%	Assumption	6,334	2,629	70	29
Total			17,690	7,125	196	79

* Following the sale of Abita and West Klondike the Company is a presently a 100% oil producer.

Half Yearly Profit and Loss Summary

Cash Flow Analysis	Year to Dec 2018	Year to Date 2017
	$AUD '000	$AUD '000
Revenue from sales(i)	1,276	1,647
Cost of Sales	(381)	(745)
Net Operating Proceeds	895	902
Loss after income tax	304	718

(i) Revenue from sales are stated net of royalties for Current Period. See note 4.

Capital Structure and Financial Snapshot

ASX Codes	GGE	Shares	767m
Share Price	0.4 cents	Mkt Cap	$3.1m
Prod. Wells	2	Cash @ 31/12	$1.5m

EVENTS OCCURRING AFTER THE REPORTING PERIOD

The Company effective 31 January 2019 has changed its registered address to 1A/1 Alvan St, Subiaco WA 6008.

The Company has appointed Mr Craig Burton and Mr Chris Bath as Directors effective 5 March 2019, following the resignation on the same date of Mr Charles Morgan, Mr Stephen Keenihan and Mr Allan Boss.

No other matters or circumstances have arisen since the end of the financial period which significantly affected or may significantly affect the operations of the Group, the results of those operations, or the state of affairs of the Group in future financial years.

AUDITOR'S DECLARATION

The lead auditor's independence declaration under section 307C of the Corporations Act 2001 is set out on page 9 of the financial statements for the half year ended 31 December 2018.

This report is signed in accordance with a resolution of the Board of Directors.

Dated 13th March 2019

Mark Freeman
Managing Director

BDO

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DECLARATION OF INDEPENDENCE BY JARRAD PRUE TO THE DIRECTORS OF GRAND GULF ENERGY LIMITED

As lead auditor for the review of Grand Gulf Energy Limited for the half-year ended 31 December 2018, I declare that, to the best of my knowledge and belief, there have been:

1. No contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the review; and
2. No contraventions of any applicable code of professional conduct in relation to the review.

This declaration is in respect of Grand Gulf Energy Limited and the entities it controlled during the period.

Jarrad Prue

Director

BDO Audit (WA) Pty Ltd

Perth, 13 March 2019

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GRAND GULF ENERGY LIMITED
ABN 22 073 653 175

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME
FOR THE HALF YEAR ENDED 31 DECEMBER 2018

	Note	31 December 2018 $	31 December 2017 $
Revenue	4	1,276,059	1,646,816
Cost of sales		(380,495)	(744,014)
Amortisation of oil and gas properties	9	(141,510)	(282,165)
Gross profit		754,054	620,637
Other Income	5	484,894	15,075
Employee benefits expense		(244,190)	(221,410)
Professional and statutory fees		(75,339)	(46,997)
Corporate office expenses		(60,555)	(52,493)
Exploration Expenses	10	(1,116,325)	(996,656)
Foreign exchange gain/(loss)		(20,706)	(3)
Other expenses from ordinary activities		(24,878)	(34,150)
Depreciation		(484)	(1,720)
Profit/(Loss) before income tax		(303,529)	(717,717)
Income tax benefit/(expense)		-	-
Profit/(Loss) for the half year		(303,529)	(717,717)
Other Comprehensive Income/(loss)			
Items that may be reclassified to profit or loss			
Exchange differences on translation of foreign entities		190,989	(43,861)
Total comprehensive profit/loss for the half year		(112,540)	(761,577)
		Cents	**Cents**
Earnings/(Loss) per share			
Basic earnings/(loss) per share		(0.040)	(0.099)
Diluted earnings/(loss) per share		(0.040)	(0.099)

The Consolidated Statement of Profit or Loss and other Comprehensive Income is to be read in conjunction with the notes to the Consolidated Statements set out on pages 14 to 20.

GRAND GULF ENERGY LIMITED
ABN 22 073 653 175

CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS AT 31 DECEMBER 2018

	Note	31 December 2018 $	30 June 2018 $
ASSETS			
Current Assets			
Cash and cash equivalents		1,493,788	1,686,664
Trade and other receivables	8	589,130	533,689
Asset held for sale		-	65,574
Total Current Assets		2,082,918	2,285,927
Non-Current Assets			
Investment		2	2
Computer equipment		1,122	1,541
Oil and gas properties	9	2,303,658	2,307,526
Total Non-Current Assets		2,304,782	2,309,069
Total Assets		4,387,700	4,594,996
LIABILITIES			
Current Liabilities			
Trade and other payables		62,809	128,206
Total Current Liabilities		62,809	128,206
Non-Current Liabilities			
Provisions		291,150	320,509
Total Non-Current Liabilities		291,150	320,509
Total Liabilities		353,959	448,715
Net Assets		4,033,741	4,146,281
Equity			
Contributed equity	6	42,104,442	42,104,442
Reserves	7	5,355,940	5,164,951
Accumulated losses		(43,426,641)	(43,123,112)
Total Equity		4,033,741	4,146,281

The Consolidated Statement of Financial Position is to be read in conjunction with the notes to the Consolidated Financial Statements set out on pages 14 to 20.

GRAND GULF ENERGY LIMITED
ABN 22 073 653 175

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY FOR THE HALF YEAR ENDED 31 DECEMBER 2018

	Contributed Equity $	Share Option Reserve $	Option Premium Reserve $	Foreign Currency Translation Reserve $	Accumulated Losses $	Total Equity $
Balance at 01.07.2018	42,104,442	2,016,337	676,800	2,471,814	(43,123,112)	4,146,281
Loss for the half year	-	-	-	-	(303,529)	(303,529)
Other Comprehensive Income						
Exchange differences on translation of foreign operations	-	-	-	190,989	-	190,989
Total comprehensive income for the half year	**-**	**-**	**-**	**190,989**	**(303,529)**	**(112,540)**
Transactions with owners in their capacity as owners:						
Shares Issued	-	-	-	-	-	-
Share Options	-	-	-	-	-	-
Balance at 31.12.18	**42,104,442**	**2,016,337**	**676,800**	**2,662,803**	**(43,426,641)**	**4,033,741**
Balance at 01.07.2017	42,104,442	2,016,337	676,800	2,311,880	(42,580,019)	4,529,440
Loss for the half year	-	-	-	-	(717,717)	(717,717)
Other Comprehensive Income						
Exchange differences on translation of foreign operations	-	-	-	(43,861)	-	(43,861)
Total comprehensive income for the half year	-	-	-	(43,861)	(717,717)	(761,577)
Transactions with owners in their capacity as owners:	-	-	-	-	-	-
Shares Issued	-	-	-	-	-	-
Share Options	-	-	-	-	-	-
Balance at 31.12.17	**42,104,442**	**2,016,337**	**676,800**	**2,268,019**	**(43,297,736)**	**3,767,863**

The Consolidated Statement of Changes in Equity is to be read in conjunction with the notes to the Consolidated Financial Statements set out in pages 14 to 20.

GRAND GULF ENERGY LIMITED
ABN 22 073 653 175

CONSOLIDATED STATEMENT OF CASHFLOWS
FOR THE HALF YEAR ENDED 31 DECEMBER 2018

	31 December 2018 $	31 December 2017 $
Cash Flows From Operating Activities		
Proceeds from sales	1,228,143	1,559,345
Payments to suppliers and employees	(404,961)	(476,427)
Production costs	(448,543)	(680,096)
Other Income received	416,554	-
Interest received	111	388
Payments for exploration and evaluation	(1,116,325)	(665,356)
Net cash (outflow) from operating activities	(325,021)	(262,146)
Cash Flows From Investing Activities		
Payments for property plant and equipment	(18)	-
Proceeds from sale of oil & gas properties	89,498	-
Payments for development of oil & gas properties	(20,394)	-
Net cash inflow/(outflow) from investing activities	69,086	-
Cash Flows from financing activities		
	-	-
Net cash inflow/(outflow) from financing activities	-	-
Net increase/decrease in cash held	(255,935)	(262,146)
Cash and cash equivalents held at beginning of financial period	1,686,664	1,859,399
Effect of exchange rate changes on cash and cash equivalents	63,059	20,319
Cash and cash equivalents at end of the half year	1,493,788	1,617,572

The Consolidated Statement of Cash Flows is to be read in conjunction with the notes to the Consolidated Financial Statements set out in pages 14 to 20.

1. BASIS OF PREPARATION OF HALF YEAR FINANCIAL REPORT

(a) Reporting entity

Grand Gulf Energy Limited (the "Company") is a Company domiciled in Australia. The consolidated interim financial statements of the Company as at and for the half year ended 31 December 2018 comprise the Company and its controlled entities (together referred to as the "Group").

The consolidated financial statements of the Group as at and for the year ended 30 June 2018 are available upon request from the Company's registered office at 1 Alvan Street, Subiaco WA, 6008 or at www.grandgulfenergy.com

(b) Statement of Compliance

These consolidated interim financial statements have been prepared in accordance with the requirements of the Corporations Act 2001 and Australian Accounting Standards including AASB 134: Interim Financial Reporting. They do not include all of the information required for full annual financial statements, and should be read in conjunction with the consolidated financial statements of the Group as at and for the year ended 30 June 2018.

These consolidated interim financial statements were approved by the Board of Directors 14 March 2019.

(c) Basis of Preparation

The consolidated financial statements have been prepared on the basis of historical cost, except for the revaluation of certain non-current assets and financial instruments. Cost is based on the fair values of the consideration given in exchange for assets. All amounts are presented in Australian dollars, unless otherwise noted.

The accounting policies and methods of computation adopted in the preparation of the half-year financial report are consistent with those adopted and disclosed in the consolidated entity's 2018 annual financial report for the financial year ended 30 June 2018 except for those noted in 1(d). These accounting policies are consistent with Australian Accounting Standards and with International Financial Reporting Standards.

(d) New accounting standards and interpretations

A number of new or amended standards became applicable for the current reporting period for which the Company has adopted

- AASB 15 Revenue from Contracts with Customers; and
- AASB 9 Financial Instruments.

The new accounting policies are disclosed below. There is no material impact to the profit or loss of the Company for the period ended 31 December 2018.

Basis of preparation and changes to the Group's accounting policies

AASB 15 Revenue from contracts with Customers

AASB 15 Revenue from contracts with Customers replaces AASB 118 Revenue. AASB 15 was adopted by the Group on 1 July 2018. AASB 15 provides a single, principles-based five-step model to be applied to all contracts with customers.

The Group has considered AASB 15 in detail and determined that the impact on the Group's sales revenue is that revenue from the sale of produced hydrocarbons is to be presented net of royalties rather than gross of royalties. There is nil impact as a result of this change on the profit or loss for the Group for the period ended 31 December 2018.

The Group's new revenue accounting policy is detailed below:

Revenue is recognised when or as the Group transfers control of goods or services to a customer at the amount to which the Group expects to be entitled. If the consideration promised includes a variable component, the Group estimates the expected consideration for the estimated impact of the variable component at the point of recognition and re-estimated at every reporting period.

Revenue from the sale of produced hydrocarbons is recognised at a point in time when control of the product is transferred to the customer, which is typically on delivery. Revenue recognised is recorded net of royalties representing the net revenue interest which is receipted by the Group as non-operator of its producing wells.

AASB 9 Financial Instruments

AASB 9 Financial Instruments replaces the provisions of AASB 139 Financial Instruments: Recognition and Measurement that relate to the recognition, classification and measurement of financial assets and financial liabilities, derecognition of financial instruments, impairment of financial assets and hedge accounting.

The adoption of AASB 9 Financial Instruments from 1 July 2018 did not give rise to any material transitional adjustments. The new accounting policies (applicable from 1 July 2018) are set out below.
In accordance with the transitional provisions in AASB 9(7.2.15) and (7.2.26), comparative figures have not been restated.

Classification and measurement

Except for certain trade receivables the Group initially measures a financial asset at its fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs.
Under AASB 9 financial assets are subsequently measured at fair value through profit or loss (FVPL), amortised cost, or fair value through other comprehensive income (FVOCI). The classification is based on two criteria: the Group's business model for managing the assets; and whether the instruments' contractual cash flows represent 'solely payments of principal and interest' on the principal amount outstanding (the 'SPPI criterion').

Impairment

From 1 July 2018 the group assesses on a forward looking basis the expected credit losses (ECLs) associated with its debt instruments carried at amortised cost and FVOCI. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Group expects to receive. The shortfall is then discounted at an approximation to the asset's original effective interest rate.

The Group assesses at each balance date whether there is objective evidence that a financial asset or group of financial assets is impaired. For trade and other receivables, the Group applies the simplified approach permitted by AASB 9, which requires expected lifetime losses to be recognised from initial recognition of the receivables. The expected credit losses on these financial assets are estimated using a provision matrix based on the Group's historical credit loss experience.

2. SEGMENT REPORTING

Management has determined, based on reports reviewed by the Board of Directors that are used to make strategic decisions, that the Group has one reportable segment being oil and gas production and exploration.

The Board of Directors review internal management reports on a regular basis which reflect the information provided in the half year financial statements.

3. FAIR VALUES OF FINANCIAL INSTRUMENTS

Recurring fair value measurements
The Group does not have any financial instruments that are subject to recurring or non-recurring fair value measurements.

Fair values of financial instruments not measured at fair value
The Group did not have any financial instruments that are recognised in the financial statements where their carrying value differed from the fair value.

4. REVENUE FROM SALES

	31 December 2018 $	31 December 2017 $
Oil Sales	1,256,839	1,542,093
Gas Sales	19,220	104,723
Total Sales	1,276,059	1,646,816

The impact of the adoption of AASB 15 is disclosed in note 11.

5. OTHER INCOME

	31 December 2018 $	31 December 2017 $
Recovery of costs	7,010	14,687
Profit Sale of Abita	70,988	-
Unallocated Asset Recovery(i)	406,785	-
Interest Received	111	388
Total other income	484,894	15,075

(i) These monies are unclaimed insurance funds which were subsequently returned to the company from the US government.

6. CONTRIBUTED EQUITY

	31 December 2018 No.	30 June 2018 No.	31 December 2018 $	30 June 2018 $
Balance brought forward at the beginning of the period	767,498,870	767,498,870	42,104,442	42,104,442
Balance carried forward at the end of the period	**767,498,870**	**767,498,870**	**42,104,442**	**42,104,442**

7. RESERVES

	31 December 2018 $	30 June 2018 $
Foreign currency translation (a)	2,662,803	2,471,814
Share option reserve (b)	2,016,337	2,016,337
Option premium reserve (c)	676,800	676,800
	5,355,940	5,164,951

(a) Foreign currency translation reserve

The foreign currency translation reserve is used to record exchange differences arising from the translation of the financial statements of self-sustaining foreign operations.

	31 December 2018 $	30 June 2018 $
Balance at beginning of period	2,471,814	2,311,880
Gain / (loss) on translation of foreign controlled entities	190,989	159,934
Balance at end of period	2,662,803	2,471,814

(b) Share option reserve

The share option reserve is used to recognise the value of options issued to employees, Directors, consultants, and external finance companies.

	31 December 2018 $	30 June 2018 $
Balance at beginning of period	2,016,337	2,016,337
Balance at end of period	2,016,337	2,016,337

(c) Option premium reserve

The option premium reserve is used to recognise the options issued under a rights issue at 1 cent per option.

	31 December 2018 $	30 June 2018 $
Balance at beginning of period	676,800	676,800
Balance at end of period	676,800	676,800

8. TRADE AND OTHER RECEIVABLES AND OTHER CURRENT ASSETS

	31 December 2018 $	30 June 2018 $
Current		
Trade and other receivables (i)	548,521	497,449
Insurance claim receivables	40,609	36,240
	589,130	**533,689**

(i) Other receivables include trade debtors, sales revenue amounts outstanding for goods & services tax (GST). GST amounts are non-interest bearing and have repayment terms applicable under the relevant government authorities.

9. OIL AND GAS PROPERTIES

	31 December 2018 $	30 June 2018 $
Producing oil & gas assets	7,947,983	7,810,341
Provision for impairment and amortisation	(5,644,325)	(5,502,815)
	2,303,658	2,307,526
Capitalised oil and gas properties		
Carrying amount at beginning of period	2,307,526	2,736,479
Expenditure during the period	15,049	2,695
Foreign exchange difference	122,593	84,410
Amortisation	(141,510)	(383,016)
Transferred to Asset held for sale	-	(133,042)
Carrying amount at end of period	2,303,658	2,307,526

10. EXPLORATION EXPENSES

	31 December 2018 $	31 December 2017 $
Lease Acquisition Cost – Big River	76,582	659,532
Lease Acquisition Cost – Pleasant Homes	-	192,963
Lease Acquisition Cost – Iron Price	911,308	-
Miscellaneous Exploration Expenses	128,435	144,160
	1,116,325	996,655

11. CHANGES IN ACCOUNTING POLICIES

This note explains the impact of the adoption of AASB 15 Revenue from Contracts with Customers on the group's financial statements and also discloses the new accounting policies that have been applied from 1 July 2018, where they are different to those applied in prior periods.

11(a) Impact on the financial statements

The Company assessed the impact of adoption of new accounting standards. The cumulative method has been adopted, therefore comparatives are not restated.

The following table show the adjustments recognised for each individual line item.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME FOR THE HALF YEAR ENDED 31 DECEMBER 2017	As originally presented	AASB 15(i)	Restated
	$	$	$
Revenue	1,646,816	(181,623)	1,465,193
Cost of sales	(744,014)	181,623	(562,391)
Amortisation of oil and gas properties	(282,165)	-	(282,165)
Gross profit	620,637	-	620,637
Other Income	15,075	-	15,075
Employee benefits expense	(221,410)	-	(221,410)
Professional and statutory fees	(46,997)	-	(46,997)
Corporate office expenses	(52,493)	-	(52,493)
Exploration Expenses	(996,656)	-	(996,656)
Foreign exchange gain/(loss)	(3)	-	(3)
Other expenses from ordinary activities	(34,150)	-	(34,150)
Depreciation	(1,720)	-	(1,720)
Profit/(Loss) before income tax	(717,717)	-	(717,717)
Income tax benefit/(expense)	-	-	-
Profit/(Loss) for the half year	(717,717)	-	(717,717)
Other Comprehensive Income/(loss)			
Items that may be reclassified to profit or lo			
Exchange differences on translation of foreign entities	(43,861)	-	(43,861)
Total comprehensive profit/loss for the half year	(761,577)	-	(761,577)
	Cents		**Cents**
Earnings/(Loss) per share			
Basic earnings/(loss) per share	(0.099)		(0.099)
Diluted earnings/(loss) per share	(0.099)		(0.099)

(i) Revenue recognised is recorded net of royalties representing the net revenue interest which is receipted by the group as non-operator of its producing wells.

12. CONTINGENT LIABILITIES

NAPOLEONVILLE WELL CONTROL AND CONTINGENCIES

The JV partners continue to remain obligated to complete the remaining remediation of the land affected by the blowout. As most of the location has been remediated and handed back to the farmer the Company believes that the remaining remediation will be no more than US$250,000 in respect of the existing 40.5% WI the Company held prior to the acquisition of the additional 15.3% from Mustang Resources Limited. The Company confirms that the blowout insurances from Mustang are substantial and adequate to cover the cost of additional 15.3% WI of likely remaining remediation costs.

During the 6 months ended 31 December 2018, the Company incurred US$43,912 in respect of an annual department fee of which US$23,009 is recoverable from our insurers, leaving the Company liable for US$25,319. The Company does not anticipate any significant costs in the second half of 2018.

13. EVENTS SUBSEQUENT TO REPORTING DATE

The Company effective 31 January 2019 has changed its registered address to 1A/1 Alvan St, Subiaco WA 6008.

The Group have appointed Mr Craig Burton and Mr Chris Bath as Directors effective 5 March 2019, following the resignation on the same date of Mr Charles Morgan, Mr Stephen Keenihan and Mr Allan Boss.

No other matters or circumstances have arisen since the end of the financial period which significantly affected or may significantly affect the operations of the Group, the results of those operations, or the state of affairs of the Group in future financial years.

14. DIVIDENDS

No dividends have been paid or proposed during the financial period.

15. RELATED PARTIES

There were no changes to transactions with key management personnel during the period.

16. COMMITMENTS

There have been no changes to the commitments, from those disclosed in the 30 June 2018 financial statements.

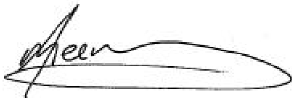
DIRECTORS' DECLARATION

The directors of the consolidated entity declare that:

1. The financial statements and notes, as set out on pages 10 to 20 are in accordance with the Corporations Act 2001:
   a. give a true and fair view of the consolidated entity's financial position as at 31 December 2018 and of its performance for the half-year ended on that date; and
   b. comply with Accounting Standard *AASB 134 Interim Financial Reporting*, *Corporations Regulations 2001 and* other mandatory professional reporting requirements
2. In the directors' opinion there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

This declaration is signed in accordance with a resolution of the Board of Directors made pursuant to s.303(5) of the *Corporations Act 2001*.

On behalf of the Directors



Mark Freeman
Managing Director

Perth, 13 March 2019

BDO

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INDEPENDENT AUDITOR'S REVIEW REPORT

To the members of Grand Gulf Energy Limited

Report on the Half-Year Financial Report

Conclusion

We have reviewed the half-year financial report of Grand Gulf Energy Limited (the Company) and its subsidiaries (the Group), which comprises the consolidated statement of financial position as at 31 December 2018, the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the half-year then ended, and notes comprising a statement of accounting policies and other explanatory information, and the directors' declaration.

Based on our review, which is not an audit, we have not become aware of any matter that makes us believe that the half-year financial report of the Group is not in accordance with the *Corporations Act 2001* including:

(i) Giving a true and fair view of the Group's financial position as at 31 December 2018 and of its financial performance for the half-year ended on that date; and

(ii) Complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001.*

Directors' responsibility for the Half-Year Financial Report

The directors of the company are responsible for the preparation of the half-year financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the half-year financial report that is free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express a conclusion on the half-year financial report based on our review. We conducted our review in accordance with Auditing Standard on Review Engagements ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity*, in order to state whether, on the basis of the procedures described, we have become aware of any matter that makes us believe that the half-year financial report is not in accordance with the *Corporations Act 2001* including giving a true and fair view of the Group's financial position as at 31 December 2018 and its financial performance for the half-year ended on that date and complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*. As the auditor of the Group, ASRE 2410 requires that we comply with the ethical requirements relevant to the audit of the annual financial report.

A review of a half-year financial report consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

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Independence

In conducting our review, we have complied with the independence requirements of the *Corporations Act 2001*. We confirm that the independence declaration required by the *Corporations Act 2001*, which has been given to the directors of the Group, would be in the same terms if given to the directors as at the time of this auditor's review report.

BDO Audit (WA) Pty Ltd

BDO

J Prue

Jarrad Prue

Director

Perth, 13 March 2019