At the forefront of geophysical technology

Annual Report
2021

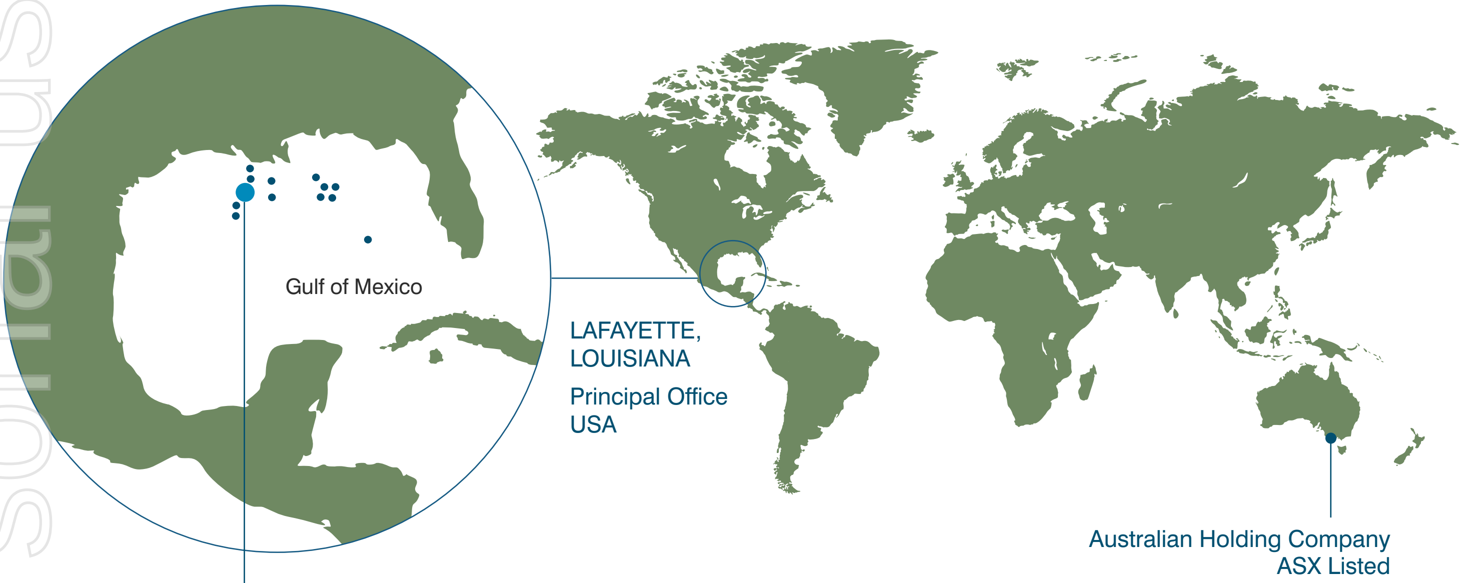
BYRONENERGY

Contents

Highlights

Byron is focused on the shallow waters of the Outer Continental Shelf in the Gulf of Mexico, with a portfolio of leases.

SM71, SM58 and SM69 E2 Oil and Gas Fields



SM71 and SM58 Field Discoveries and SM69 E2 Well Discovery made possible through use of RTM seismic technology

Key | SM71, SM58 and SM69 E2 | Exploration Blocks

SM58 Production	SM71 Production	Reserves (Net)
15.2 MMcfd	**2,450** Bopd	**2P 14.1** MMbo
Production (gross) Approximately 15.0 MMcfd and 280 Bopd average 2021 (production commenced in September 2020)	**Production (gross)** Approximately 2,450 Bopd and 2.1 MMcfd average 2021	**Reserves** 2P (net) 14.1 MMbo 2P (net) 97.5 Bcf 2P (net) 30.4 MMboe

Net Revenue 2021

US$34.2m

(net of royalties and oil and gas transportation charges)

3P Reserves

22.7 Mmbo
123.3 Bcf

Prospective Resources

33.3 Mmbo
572.2 Bcf

Chairman's Letter

Dear Shareholder,

After a very difficult year in 2020, there has been a vast improvement in 2021 with both oil and gas prices rallying strongly.

West Texas Intermediate ("WTI"), the US marker oil price, increased from US$39.27 on 30 June 2020 to US$73.52 on 30 June 2021, an increase of 87%. The Henry Hub natural gas mmbtu spot price rose from US$1.76 on 30 June 2020 to US$3.79 on 30 June 2021, an increase of 115%.

The lower 2020 year prices were attributable to the initial spread of the COVID-19 pandemic and its negative impact on the global demand for oil and natural gas. The subsequent increase in domestic vaccination programs have helped reduce the spread of COVID-19 in 2021, which has contributed to an improvement in the world economy and higher realised oil and gas price.

While oil and gas prices have rallied by 87% and 115% respectively over the year, oil and gas equities have not exhibited anywhere near the same strength with the ASX Energy index (ASX code XEJ) increasing by only 7% between 30 June 2020 and 30 June 2021. Historically, such a lack of correlation between energy prices and the price of energy sector equities would be viewed as very unusual. This disconnect between commodity prices and equity prices may be due to the world climate change and ESG narratives currently playing out.

Notwithstanding the volatility in oil and gas prices and the current disconnect between the commodity prices and share prices, Byron has continued to pursue its stated strategy.

The Byron operated SM71 project continued to perform strongly during the 2020/21 year producing approximately 365,000 barrels of oil and 400,000 mmbtu of gas, net to Byron. After royalties, oil and gas transportation charges and other customary price adjustments net revenue from SM71 was US$18.8 million while cash operating costs (lease operating expenses and insurance) were US$2.3 million.

As of 30 June 2021, the SM71 F facility has produced approximately 3.3 million barrels of oil (gross) since initial production began. The facility has also produced approximately 4.5 billion cubic feet of gas (gross). The SM71 lease ranks number 3 of all currently active oil producing leases on the US Gulf of Mexico shelf with the SM71 F3 and F1 ranked as the number 1 and number 2 active oil producing wells.

During the past year Byron's primary focus was on our SM58 project where we completed the platform construction and installation, the installation of oil and gas pipelines and completion of the SM58 G1 and SM58 G2ST wells.

Gas and oil production from the Byron Energy SM58 G platform was initiated on 7 September 2020 when the SM58 G1 well was opened up to sales.

As of 30 June 2021, the SM58 G facility has produced approximately 4.6 Bcf of gas (gross) and 86,000 barrels of oil and condensate (gross) from two wells since initial production began in the December 2020 quarter. The SM58 lease ranks number 5 of all currently active gas producing leases on the US Gulf of Mexico shelf with the SM58 G1 ranked as the number 5 active gas producing well.

For the year ended 30 June 2021, Byron's share of net revenue from SM58 after royalties, oil and gas transportation charges and other customary price adjustments was US$14.5 million while cash operating costs (lease operating expenses and insurance) were approximately US$3.4 million.

Byron's consistently low field level cash operating costs, currently at less than US$5.50 per BOE across SM71 and SM58, is a testament to the accomplishments and efficiency of our management and technical team and the quality of the producing assets.

On 29 September 2021, we released our 30 June 2021 reserves and resources statement. Our reserves and resources position as at 30 June 2021 shows remaining 1P reserves, net to Byron, of 8.7 Mmbbl of oil and 55.1 Bcf of gas with remaining 2P reserves, net to Byron, of 14.1 Mmbbl of oil and 97.5 Bcf of gas, a very solid reserve position.

With high-quality and modern infrastructure at SM71 and SM58 and a near-term planned program of low-risk exploration and development wells Byron is well positioned to continue executing its production growth strategy in the shallow waters of the Gulf of Mexico.

Byron uses highly sophisticated 3D seismic surveys and leading-edge processing technology such as reverse time migration to identify low-risk prospects as evidenced by the SM71 and SM58 discoveries and more recently by the SM69 E2 oil discovery well.

The Byron-operated SM69 E2 exploration well reached total depth of 8,157 feet Measured Depth (7,648 feet True Vertical Depth) on 9 September 2021. The three primary target sands were encountered and high-quality oil sands were logged across all three intervals with a total net oil true vertical thickness of approximately 80 feet.

Overall, our SM69 E2 well met or exceeded pre-drill pay and reserve expectations and is an excellent result for the Company. The E2 well is a good example of our strategy, and we expect it to provide a stable, low-cost, high-margin cash flow for several years to come.

Finally, I want to thank our management team, employees and contractors for their continued hard work, professionalism and dedication, as well as our non-executive directors for their continued support and guidance.

Doug Battersby
Chairman

Review of Operations

Introduction

During the year ended 30 June 2021, the West Texas Intermediate ("WTI"), the US marker price, staged a strong rally – from US$39.27 on 30 June 2020 to US$73.52 on 30 June 2021, an increase of approximately 87%. Natural gas prices also enjoyed a strong rise during the year. The Henry Hub natural gas mmbtu spot price was US$1.76 on 30 June 2020, increasing to US$3.79 on 30 June 2021.

Byron's ability to maintain operations at the SM71 F and SM58 G platforms in the Gulf of Mexico was not impacted by COVID-19 during the year ended 30 June 2021.

Byron's office in Lafayette, Louisiana worked in line with recommendations of Louisiana State and Byron's Australian-based team worked as advised by the Australian government(s) to comply with COVID-19 regulations. Byron's offshore contractors have continued to work within the Louisiana State's and the Bureau of Safety and Environmental Enforcement guidelines.

The increase in domestic vaccination programs have helped reduce the spread of COVID-19 in 2021, which has contributed to an improvement in the economy and higher realised oil and gas prices in 2021. Nevertheless, prices remain volatile, and there is still uncertainty regarding the long-term impact of the COVID-19 pandemic on global oil demand and prices.

Production for the year ended 30 June 2021 was approximately 453,100 bbls of oil and over 4,603,897 mmbtu of gas, net to Byron, generating net sales revenue of US$34.2 million.

1P Oil reserves	**UP by 8.1% to 8.7 MMbo**
Annual oil and gas production	**UP by 15.1% and 421.3% to 453 Mbo and 4.2 Bcf respectively**
Net revenue	**UP by 60.0% and to US$34.2 million** (after royalties and oil and gas transportation charges)

Production (sales) (net to Byron)	Year ended 30 June 2021	Year ended 30 June 2020
Total net production (NRI basis)		
Oil (bbls)	**453,098**	393,703
Gas (mmbtu)	**4,603,897**	883,055
Net revenue after royalties and transportation charges (US$ million)	**34.2**	21.4
Realised oil price before transport charges (US$/bbl)	**54.05**	54.74
Realised gas price before transport charges (US$/mmbtu)	**2.91**	1.93

Byron Energy Limited – Reserves and Resources

Gulf of Mexico, Offshore Louisiana, USA

Net remaining reserves as at 30/6/2021	Oil (MMbo)	Gas (Bcf)	MMboe (6:1)	% change 2021 v 2020
Proved	**8.7**	**55.1**	**17.9**	**0.4%**
Probable	5.4	42.4	12.5	(27.3%)
Proved and Probable (2P)	**14.1**	**97.5**	**30.4**	**(13.2%)**
Possible	8.6	25.8	12.9	8.1%
Proved, Probable and Possible (3P)	**22.7**	**123.3**	**43.3**	**(7.8%)**
Prospective Resources	**33.3**	**572.2**	**128.7**	**(12.1%)**

Reserves – The aggregate 1P may be a very conservative estimate and the aggregate 3P may be a very optimistic estimate due to the portfolio effects of arithmetic summation.

Conversion to boe – using a ratio of 6,000 cubic feet of natural gas to one barrel of oil – 6:1 conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency.

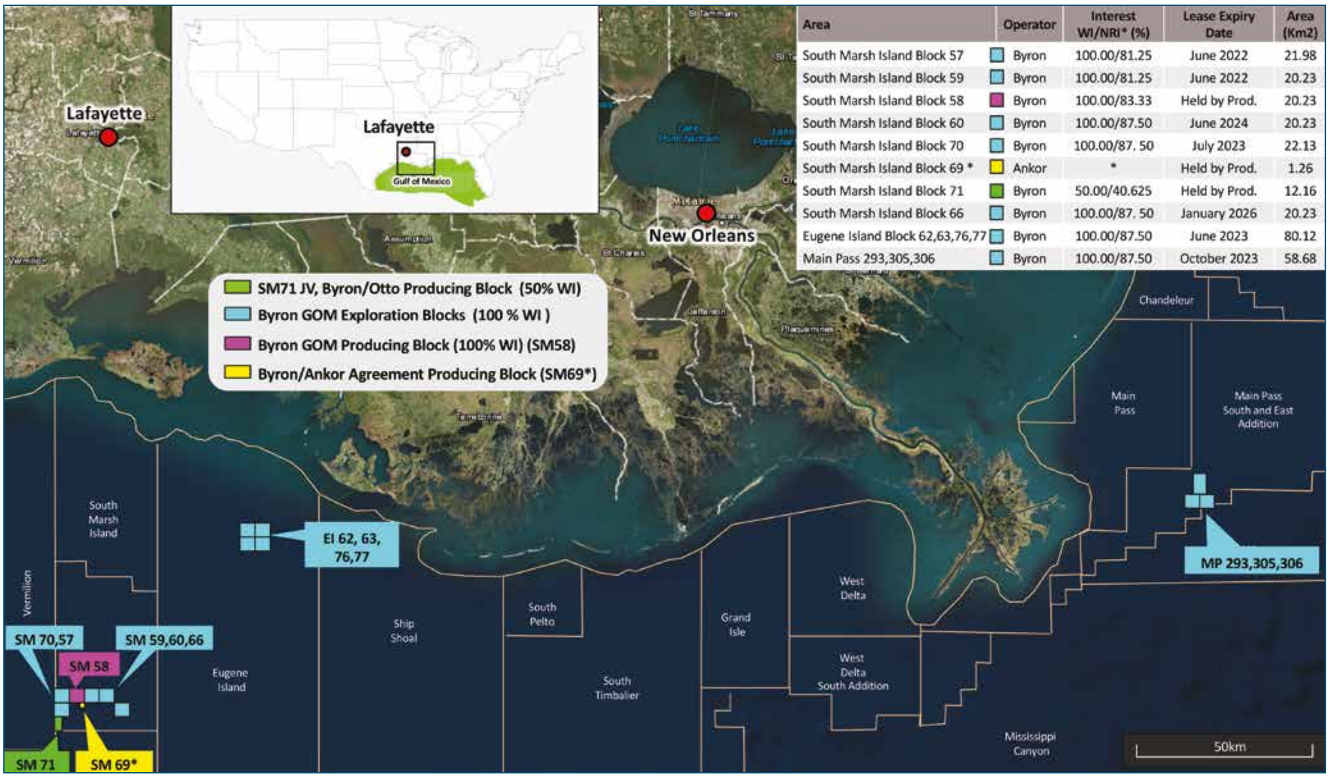
Prospective Resource – The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbon.

Byron's 1P reserves as of 30 June 2021 increased by approximately 0.4%, from 30 June 2020, on a BOE basis, mainly due to revisions based on the SM71 D5 reservoir water free and stable performance. The Company's 2P reserves were approximately 13.2% lower, on a BOE basis, due to a reduction of the SM58 Cutthroat G1 probable oil reserves.

Oil and gas properties

Byron is focused on the shallow waters of the Outer Continental Shelf ("OCS") in the Gulf of Mexico ("GOM"), with a portfolio of leases, as shown below.

Byron Energy Gulf of Mexico Lease Map as at 30 June 2021



Area	Operator	Interest WI/NRI* (%)	Lease Expiry Date	Area (Km2)
South Marsh Island Block 57	Byron	100.00/81.25	June 2022	21.98
South Marsh Island Block 59	Byron	100.00/81.25	June 2022	20.23
South Marsh Island Block 58	Byron	100.00/83.33	Held by Prod.	20.23
South Marsh Island Block 60	Byron	100.00/87.50	June 2024	20.23
South Marsh Island Block 70	Byron	100.00/87. 50	July 2023	22.13
South Marsh Island Block 69 *	Ankor	*	Held by Prod.	1.26
South Marsh Island Block 71	Byron	50.00/40.625	Held by Prod.	12.16
South Marsh Island Block 66	Byron	100.00/87. 50	January 2026	20.23
Eugene Island Block 62,63,76,77	Byron	100.00/87.50	June 2023	80.12
Main Pass 293,305,306	Byron	100.00/87.50	October 2023	58.68

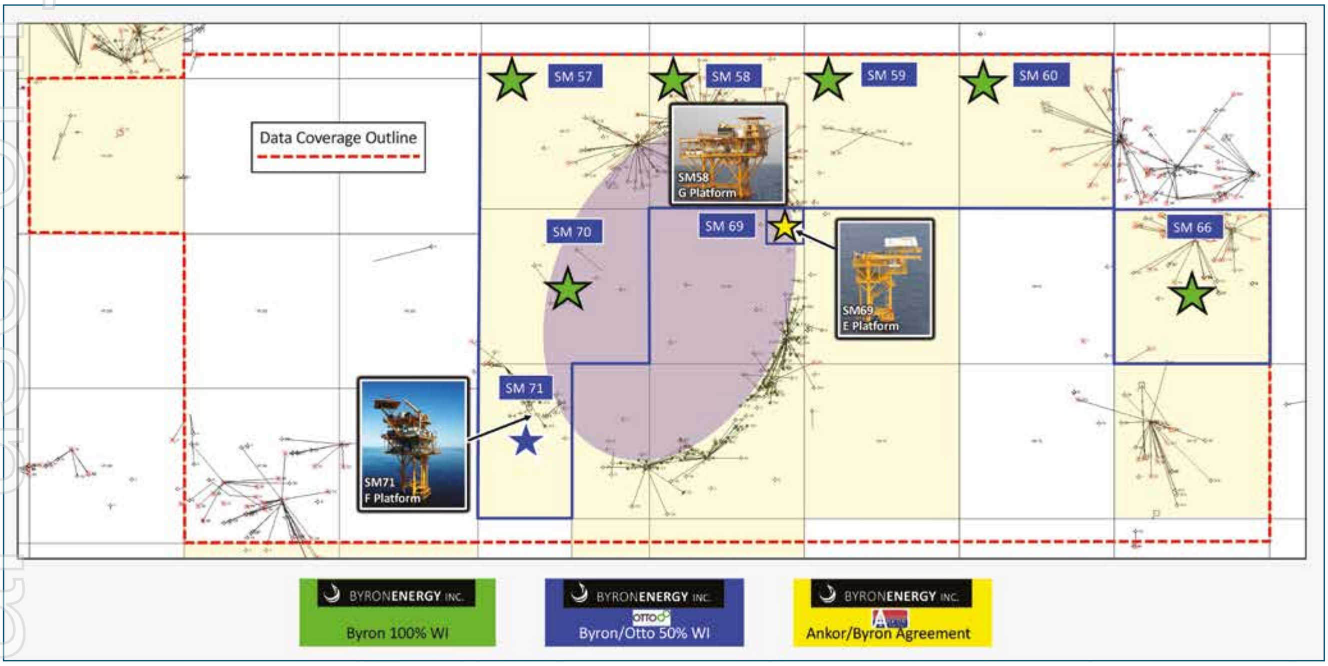
1. South Marsh Island 73 Salt Dome

The SM73 field encompasses nine OCS lease blocks (81 square miles) which overlie a large piercement salt dome. The salt dome is responsible for providing the trapping mechanism for production in all portions of the SM73 field. The SM73 field is productive from discrete hydrocarbon-bearing sandstone reservoirs which are primarily trapped in three-way structural closures bound either by salt or stratigraphic thinning, on their updip edge. These reservoirs are Pleistocene to Pliocene age sands ranging in depth from 5,000 feet to 8,800 feet Total Vertical Depth ("TVD"). The majority of the field production has come from depths less than 7,500 feet in high quality sandstone reservoirs.

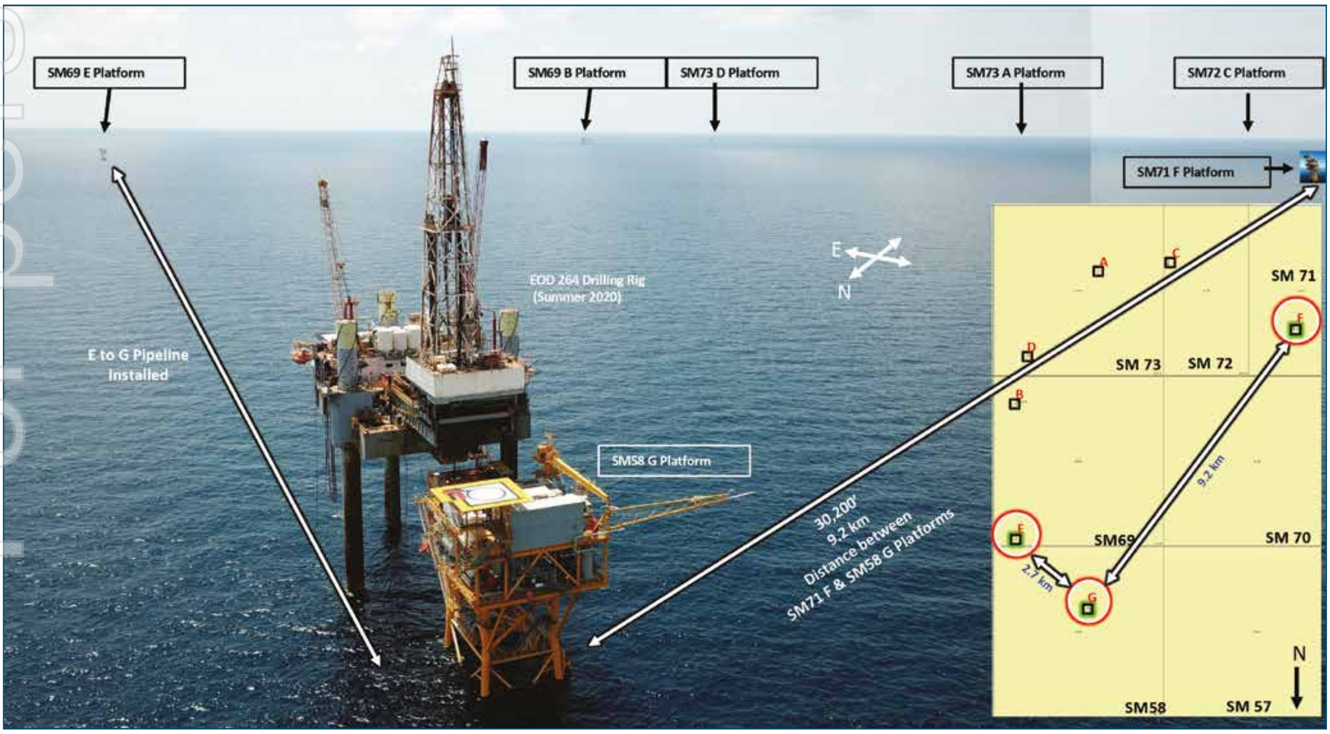
Byron is the operator and 100% working interest holder in 7 areas of interest around the SM73 field, comprising SM57/58/59/60/66/70 and north east portion of SM69, as shown in the map below. Byron is also the operator of SM71, where it has a 50% working interest.

In 2018/19 Byron undertook high effort seismic reprocessing of approximately 172 square miles (445 square kilometres) of high quality modern seismic data the Company previously licensed from WesternGeco, a Schlumberger group company.

Byron Energy GOM South Marsh Island Leases and RTM Data Coverage Area



South Marsh Island 71 F, 58 G and 69 E Platform Location




BYRONENERGY
BE S.M. 71 F
OCS-G-34266

(a) South Marsh Island 71 (WI 50%; NRI 40.625%; Operator, Byron)

Water depth in the area is approximately 137 feet.

Oil and gas production from the Byron-operated SM71 F platform began on 23 March 2018 from three wells, F1, F2 and F3. Production from the F4 well, successfully drilled and completed in March 2020, commenced production in mid-March 2020.

South Marsh Island 71 (SM71) Project Summary

Working Interest Holders	**Byron Energy 50% (Operator)** ***Otto Energy 50%***
Operator	Byron Energy Inc.
Water Depth	40 meters (131’)
Previous SM71 Production	3.9 mmbo + 10 Bcf (1995 to 2010)
Acquired	OCS Sale 222 June 2012 for US$166,620
Byron Interest	50% WI, 40.625% NRI
Byron #1 (F1) discovery well	April 2016, 132’ TVT NFO
F Platform Installation Completed	October 2017
Byron F2 and F3	F2 November 2017, 205 TVT NFO F3 January 2018, 175 TVT NFO
Initial Production (Three Wells) F1, F2 and F3	F1 first prod. March 2018 F2 and F3 first prod. April 2018
Net 2P Remaining Reserves*	3.3 mmbo + 2.4 Bcf

SM71 Reserve Summary*	**Gross Reserves Remaining 30/6/21**		**Net Reserves Remaining 30/6/21**	
	mbo	**MMcf**	**mbo**	**MMcf**
1P Proved	**5,312**	**3,402**	**2,173**	**1,390**
Probable	2,734	2,381	1,128	977
2P	**8,046**	**5,783**	**3,301**	**2,367**
Possible	2,634	1,905	1,078	778
3P	**10,680**	**7,688**	**4,379**	**3,145**
	Gross Prospective Resource		Net Prospective Resource	
Prospective	**2,406**	**48,948**	**977**	**19,885**

* Collarini and Associates reserves report as at 30 June 2021; refer ASX release 28 September 2021.

The F1 and F3 wells are producing in the primary D5 Sand reservoir and F2 well is producing from the B55 Sand.

Oil and gas production from the Byron operated SM71 F platform began on 23 March 2018 from three wells, F1, F2 and F3. Production from the F4 well, successfully drilled and completed in March 2020, commenced production in mid-March 2020 until it was shut in September 2020. The F4 well is expected to be recompleted up hole in late 2021 pending workboat availability.

The F1 and F3 wells are producing in the primary D5 Sand reservoir and the F2 well is producing from the B55 Sand.

As of 30 June 2021, the SM71 F facility has produced approximately 3.3 million barrels of oil ("MMbo") (gross) since initial production began. The facility has also produced approximately 4.5 billion cubic feet of gas (Bcfg) (gross). The SM71 lease ranks number 3 of all Gulf of Mexico currently active oil producing leases on the US Gulf of Mexico shelf with the SM71 F3 and F1 ranked as the number 1 and number 2 active oil producing wells. The D5 Sand completions in the SM71 F1 and F3 wells have total gross oil production of over 3.2 MMbo.

For the year ended 30 June 2021, Byron's share of net revenue after royalties, oil and gas transportation charges and other customary price adjustments from SM71 was US$18.8 million while cash operating costs (lease operating expenses and insurance) were US$2.3 million, or based on Byron's net production of 365 Mbo and 0.36 Bcfg a unit operating cost of approximately $5.52 per BOE, demonstrating Byron's continued operating efficiency and the project's strong cash generating capacity.

Byron's share of SM71 production for the quarter ended 30 June 2021 is shown in the table below.

Production (sales)	YTD 30 June 2021	YTD 30 June 2020
Gross production		
Oil (bbls)	**893,653**	923,027
Gas (mmbtu)	**851,143**	1,532,750
Byron share of gross production (WI basis)		
Oil (bbls)	**448,917**	462,653
Gas (mmbtu)	**490,873**	1,081,614
Net production (Byron share (NRI basis)		
Oil (bbls)	**364,748**	375,906
Gas (mmbtu)	**398,894**	878,811

Oil production for the year ended 30 June 2021 was below the volumes achieved for the 2020 year mainly due to natural decline, platform shut-ins necessitated by named windstorms.

For the year ended 30 June 2021, Byron's share of net revenue from SM71 was approximately US$20.6 million compared to US$22.2 million for the 2020 year, due to lower sales volumes partly offset by higher average realised gas prices.

(b) South Marsh Island 58 (WI 100%; NRI 83.333%; Operator, Byron)

Byron holds all the operator's rights, title, and interest in and to the SM58 lease block to a depth of 13,639 feet subsea with 100% Working Interest ("WI") and 83.33% Net Revenue Interest ("NRI"). Below 13,639 feet subsea, Byron has a 50% WI (41.67% NRI) under a pre-existing exploration agreement. To date, all identified drilling opportunities on the SM58 lease are above 13,639 feet subsea.

Gas and oil production from the Byron Energy SM58 G platform was initiated on 7 September 2020 when the SM58 G1 well was opened to sales.

As of 30 June 2021, the SM58 G facility has produced approximately 4.6 Bcf and 86,000 barrels of oil and condensate (gross) from two wells since initial production began. The SM58 lease ranks number 5 of all currently active gas producing leases on the US Gulf of Mexico shelf with the SM58 G1 ranked as the number 5 active gas producing well.

The SM58 G1 well produces from the Upper O Sand and as of 30 June 2021 has produced a gross total of approximately 4.0 Bcfg, 44,000 barrels of consistent 56.5-degree gravity condensate and no formation water.

For the year ended 30 June 2021, Byron's share of net revenue from SM58 after royalties, oil and gas transportation charges and other customary price adjustments was US$14.5 million while cash operating costs (lease operating expenses and insurance) were US$3.4 million, or based on Byron's net production of 72 Mbo and 3.8 Bcfg a unit cash operating cost of approximately $4.80 per BOE.

Gas and oil production from the G1 well has continued to follow a natural and predictable pressure decline. Based on performance to date, the production from O Sand in the G1 appears not to be connected to Byron's Steelhead Prospect and the two areas must be separated by stratigraphic boundaries in the O Sand.

South Marsh Island 58 Project Summary

Working Interest Holders	Byron Energy 50% (Operator) *Otto Energy 50%*
Operator	Byron Energy Inc.
Water Depth	~37 meters (121')
Previous SM58 Production	35.8 mmbo + 265 Bcf
Acquired 1 Jan 2019 from Fieldwood Energy	US$4,250,000
Byron Interest	100% WI, 83.33% NRI
Byron #1 (G1) discovery well	September 2019, 301' TVT Hydrocarbon Pay
G Platform Installation Completed and Installed	July 2020
Initial production SM58 G1 and G2ST	G1 fist production September 2020 G2 first production November 2020
Total Gross Project Oil and Gas Produced from Sept. 2020 to June 2021	4.6 Bcf and 86,000 bbls
G Platform Capacity	8,000 bopd + 80 MMcfgpd + 8,000 bwpd
Net 2P Remaining Reserves *	8,308 Mbo + 26,284 MMcf

SM58 Reserve Summary*	Gross Reserves Remaining 30/6/21		Net Reserves Remaining 30/6/21	
	mbo	**MMcf**	**mbo**	**MMcf**
1P Proved	**6,204**	**24,561**	**5,170**	**20,467**
Probable	3,766	6,981	3,138	5,817
2P	**9,970**	**31,542**	**8,308**	**26,284**
Possible	5,875	7,643	4,896	6,369
3P	**15,845**	**39,185**	**13,204**	**32,653**
	Gross Prospective Resource		Net Prospective Resource	
Prospective	**21,902**	**56,532**	**18,251**	**47,108**

* Collarini and Associates reserves report as at 30th June 2021; refer ASX releases 28/9/2021.

The SM58 G2ST well was tied into the SM58 G platform and the O Sand was opened to production on 29 October 2020 and has now produced approximately 0.64 Bcfg and 42,000 barrels of oil with an estimated 9,600 barrels of formation water.

The G2 well performance was negatively impacted by mechanical and reservoir issues. During wireline operations in August 2021, paraffin was discovered shallow in the well. The paraffin was cut and a bottom hole pressure was acquired which came in higher than expected and consistent with the effects attributable to paraffin. The gaslift was redesigned and the well is performing better with an increase in total liquids and oil rate. Eventually, the G2 will be recompleted uphole, in the J Sand interval above the current O Sand completion with through tubing completion methods which can be performed without a drilling rig. The J Sand was assigned gross proved behind pipe reserves of 0.25 MMbo and 0.21 Bcfg in the G2 well by the Company's third party reserve engineers in the 30 June 2021 year end reserve report.

As of 30 June 2021, Collarini has assigned proved reserves (net to Byron) of 5.2 Mmbbl and 20.5 Bcf. This represents an addition of 488 Mbo of proved reserves at SM58 which are due to addition of G2ST J Proved Developed Behind Pipe, and Proved Undeveloped in the following plays, Silver Trout Upper O1, Smoked Trout N2 and K4, and Steelhead South L2.

As of 30 June 2021, Collarini has assigned 2P reserves (net to Byron) of 8.3 Mmbbl and 26.3 Bcf to SM58. In comparison, 2P reserves (net to Byron) as at 30 June 2020 were 10.9 Mmbbl and 33.4 Bcf. The reduction in 2P reserves is primarily due to the transfer of G1 Upper O 2P oil reserves to prospective and the removal of G2ST O Sand Lobe 2 2P oil reserves.

Reduction of the SM58 Cutthroat G1 Incremental Probable oil reserves of 2.2 MMbo and 2.9 Bcfg, and Incremental Possible oil reserves of 1.8 MMbo and 2.3 Bcfg (net to Byron) was due to the reclassification of these G1 Upper O oil reserves to Prospective Resources due to performance indicating separate reservoir containers and the necessity for a future well or sidetrack to access such reserves. Other additions to 2P reserves include the G2ST J ProbBP, Smoked Trout N2, K4, and J ProbUDs, and Steelhead South L2 ProbUD reserves.

Collarini has also assigned 4.9 Mmbbl and 6.4 Bcf (net to Byron) in possible reserves and aggregate net Prospective Resources of 18.3 Mmbbl and 47.1 Bcf to SM58.

Byron's share of SM58 production for the quarter ended 30 June 2021 is shown in the table below.

Production (sales)	YTD 30 June 2021	YTD 30 June 2020
Gross production		
Oil (bbls)	**85,873**	nil
Gas (mmbtu)	**5,043,006**	nil
Net production (Byron share (NRI basis)		
Oil (bbls)	**71,558**	nil
Gas (mmbtu)	**4,202,475**	nil

There was no production or revenue from SM58 in the 2020 year, as production commenced after 1 July 2020.

(c) SM 58E1/69E platform

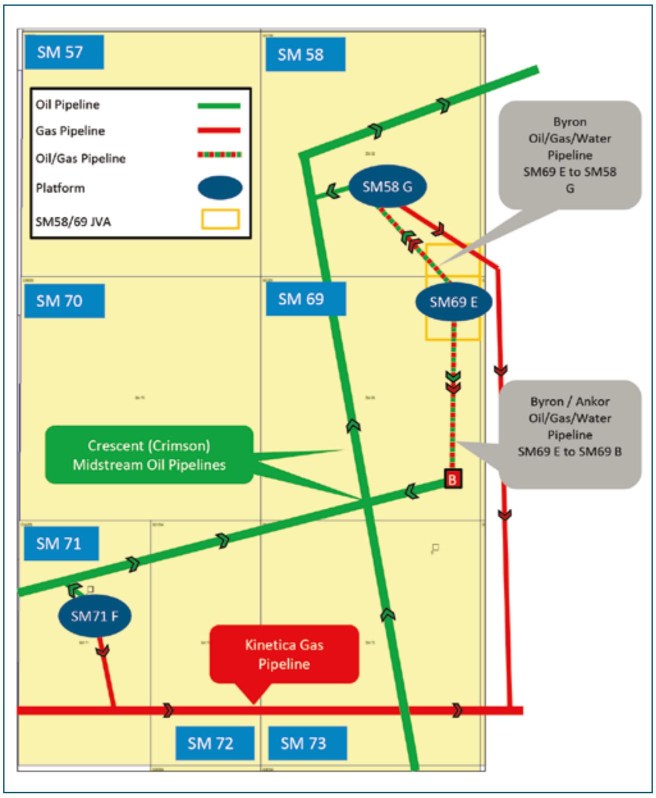
Byron owns a 53% WI and a 44.17% NRI in the joint area reservoirs from the surface to a depth of 7,490 feet TVD, located in the S1/2 of the SE1/4 of the SE1/4 of SM58, as well as a 53% working interest in the SM69 E platform. Ankor Energy, LLC (ANKOR) is the designated operator of this portion of the block to facilitate the surface operatorship of the jointly owned SM58 E1 well and E platform which is located in the NE corner of the SM69 block. Byron also holds a farm-in right under the Joint Exploration Agreement (JEA) with ANKOR group which provides for the drilling of a SM69 E2 exploration well with Byron owning a 100% WI less a 3.0% overriding royalty interest ("ORRI"), converting to a 6% ORRI after payout.

The SM58 E1 was recompleted during the March 2021 quarter, by sliding a sleeve covering the existing perforations in the K4 Sand and opening those across the K Sand (B55 Sand), a completion which also benefits from sand control. Because the wellbore completion work was already in place, the cost of recompletion was less than US$60,000 net to Byron. In addition to increased oil production, the elimination of water production from the E1 well and the associated reduction in production handling fees due to water has saved Byron significant operating costs and improved operating income at the field.

Collarini has assigned 2P reserves (net to Byron) of 0.66 Mmbbl and 0.9 Bcf to the SM58 E1 and future E1 ST wellbores in the S1/2 of the SE1/4 of the SE1/4 of SM58. A total of 2.3 Mmbbl and 2.0 Bcf (net to Byron), same as 30 June 2020, in prospective resources is allocated to Fault Block B and had been assigned by Collarini to the SM69 E2 well drilled In August/September 2021.

As announced on 13 September 2021, the Byron-operated South Marsh Island 69 E2 well reached total depth of 8,157 feet Measured Depth 7,648 feet True Vertical Depth. The SM69 E2 well logged three productive oil sands, including the primary target K (B55), K4 (B65) and L2 (C10) Sands and tested an apparent oil water contact near the seismic amplitude limit in the M6 (D5) Sand, as planned. The three primary targets encountered and logged high-quality oil sands, consistent with pre-drill expectations. Pre-drill Collarini Prospective Resources assigned to these three sands equalled a total of 1,275 Mbo and 1.07 Bcfg Gross, or 1,001 Mbo and 0.83 Bcfg Net, to Byron. An additional 907 Mbo and 859 Mmcfg of pre-drill Gross prospective resources (or 702 Mbo + 667 Mmcfg Net) were assigned to the fourth sand encountered in the E2 well with observed sand quality consistent with expectations. An updated post-drill Collarini reserve assessment will be provided once completion operations and all post-drill technical work are completed and production commences, expected in late October to early November 2021.

Byron will produce the SM69 E2 well back to the SM58 G platform through a new flowline laid in July 2020. Hydrocarbons from the E2 well would then be processed and sold through the SM58 G platform.



Byron's share of production for the year ended 30 June 2021 is shown in the table below. Byron acquired its interest in SM58 E1 well and 69 E platform and Flowlines, effective 1 January 2019.

Production (sales)	YTD 30 June 2021	YTD 30 June 2019
Gross production		
Oil (bbls)	**38,018**	40,294
Gas (mmbtu)	**5,858**	9,610
Byron share of gross production (53% WI)		
Oil (bbls)	**20,149**	21,356
Gas (mmbtu)	**3,015**	5,093
Net production (Byron share 44.167% (after royalty))		
Oil (bbls)	**16,791**	17,797
Gas (mmbtu)	**3,105**	4,244

Net sales revenue US$ million	YTD 30 June 2021	YTD 30 June 2020
Net sales revenue (Byron share 44.167% NRI)	**0.9**	0.8

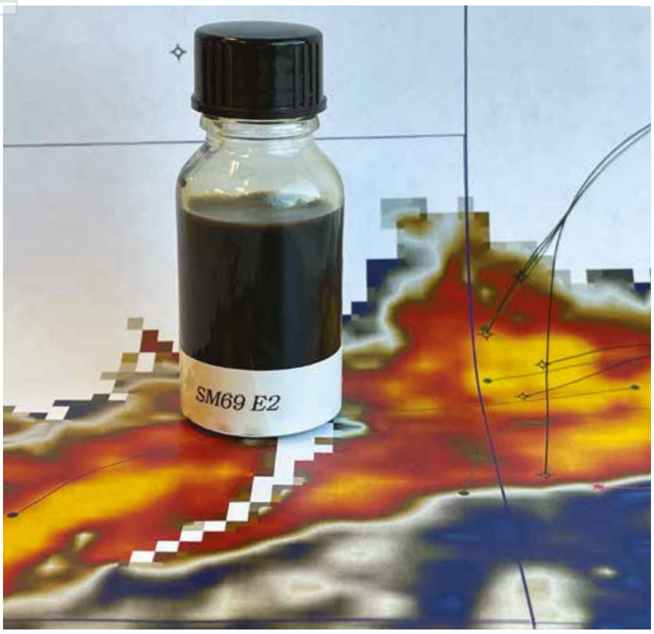
South Marsh Island 69 (SM58 E1 and SM69 E2) Project Summary

Working Interest Holders	Byron Energy
Operator SM69 E2 well Operator SM58 E1/SM69 E Platform	Byron Energy Inc. ANKOR
Water Depth	38 meters (125')
Previous Production (Fault Block A)	3.4 mmbo + 4.3 Bcf
Acquired SM58 E1/SM69 E Platform/SM58 Lease 1 Jan 2019 from Fieldwood Energy; Farmed into SM69 E2 via JEA with ANKOR	US$4.25 million 100% WI/83.33% NRI for funding 100% of SM69 E2 well
Byron SM69 E2 discovery well	September 2021, 81' TVT Hydrocarbon Pay
SM58 G Platform Installation and Pipeline to SM69 E Platform completed	July 2020; (SM69 E2 well will be produced back to SM58 G platform through pipeline laid in July 2020)
Initial production SM69 E2	Expected late October, early November 2021
Net 2P Remaining Reserves*	656 Mbo + 992 MMcf
Net Prospective Resources*#	2,252 Mbo + 2.0 Bcf

SM58 E1/SM69 E2 Reserve Summary*	Gross Reserves Remaining 30/6/21		Net Reserves Remaining 30/6/21	
	mbo	MMcf	mbo	MMcf
1P Proved	**1,430**	**2,071**	**631**	**915**
Probable	56	15	25	7
2P	**1,486**	**2,086**	**656**	**922**
Possible	-	-	-	-
3P	**1,486**	**2,086**	**656**	**922**
	Gross Prospective Resources		Net Prospective Resources	
Prospective	**2,905**	**2,540**	**2,252**	**1,969**

* Collarini and Associates reserves report as at 30 June 2021; refer ASX releases 28/9/2021.

\# As announced on 13 September 2021, the Byron operated SM69 E2 well reached total depth of 8,157 feet Measured Depth 7,648 feet True Vertical Depth. The well logged three productive oil sands and tested an apparent oil water contact near the seismic amplitude limit in the M6 (D5) Sand, as planned. The three primary targets encountered and logged high-quality oil sands, consistent with pre-drill expectations. Pre-drill Collarini Prospective Resources assigned to these three sands equalled a total of 1,275 Mbo and 1.07 Bcfg Gross, or 1,001 Mbo and 0.83 Bcfg Net, to Byron. An updated post-drill Collarini reserve assessment will be provided once all post-drill technical work is completed and production commences, expected in late October to early November 2021.



(d) South Marsh Island Area permitting status

Byron has spent considerable time pursuing key regulatory permits in the South Marsh Island Project Area. Executive Order 3395 went into effect on 20 January 2021 and has had no material effect on the process for permits on existing leases. Byron was granted approval for a revised Development Operations Coordination Document ("DOCD") on 10 February 2021 which allows the use of slots G5 through G9 from the South Marsh 58 G platform. Byron has submitted DOCD permits for wells on SM57, SM60 and SM70 and each permit is under review by the Bureau of Ocean Energy Management ("BOEM") Gulf of Mexico Region office in New Orleans, Louisiana. Byron has no reason to believe these permits will not be approved in the normal course of the approval process.

The scheduling of the SM58 G3 and G4 wells will be finalised later this calendar year or early next year.

To drill any well offshore, an operator must also file an Application for Permit to Drill ("APD") with the Bureau of Safety and Environmental Enforcement ("BSEE"). Byron has filed APDs for the next phase of drilling at SM69 and SM58. The APD for the SM69 E2 well is fully approved and the APDs for the proposed SM58 G3 and G4 wells have also been filed and are under review. Byron does not anticipate any delays in the approval process and expects approval in the normal course of business.

2. Eugene Island 77

Byron acquired Eugene Island blocks 62, 63, 76 and 77 ("EI77 field"), at Gulf of Mexico OCS Lease Sale 250 held on 21 March 2018 in New Orleans, Louisiana. Water depth in the area is approximately 20 feet.

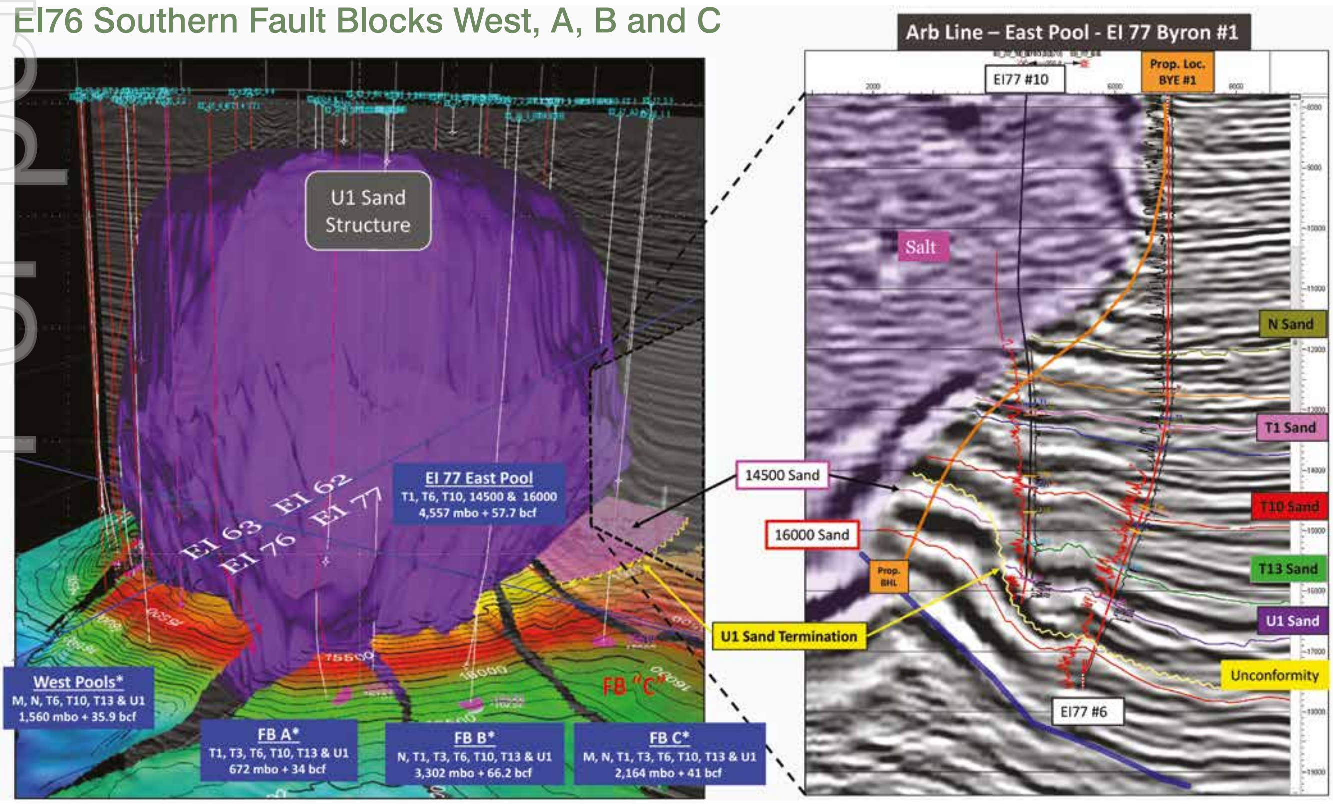
Byron currently holds a 100% WI and an 87.5% NRI in EI77 field, reflecting the reduced Federal Government Royalty of 12.5% versus pre-2017 rate of 18.75%.

EI77 blocks were designated as the Eugene Island 77 field in the 1960s and have produced 362 billion cubic feet of gas and 6.5 million barrels of oil from sands trapped by the Eugene Island 77 salt dome. Initial production from the field began in 1957. There is no production on these blocks currently.

In 2017 and 2018 Byron undertook a detailed year-long reservoir analysis which resulted in the identification of a number of low-risk development opportunities which are updip from previously productive reservoirs. On the basis of this work, Byron acquired EI 62/63/76/77 at the OCS Lease Sale 250.

Discussion with several drilling contractors for drilling of EI77 commenced during the December 2018 quarter but were delayed until after mid-2021, with SM58 projects brought forward ahead of the EI77 field wells. Byron has identified at least two active GOM rigs capable of mobilising into and drilling in these shallow waters although timing will be dictated by rig availability.

Collarini has assigned 1P net reserves of 0.7 Mmbl and 32.3 Bcfg, 2P net reserves of 1.9 Mmbl and 67.9 Bcfg, and 3P net reserves of 4.5 Mmbbl and 86.6 Bcf to EI77. Collarini has also assigned aggregate net prospective resources of 8.0 Mmbbl and 219.2 Bcf to EI77.



3. Main Pass 306

Byron currently holds a 100% WI and an 87.50% NRI in Main Pass 293, 305 and 306 ("MP306 field") acquired at the Gulf of Mexico, OCS Lease Sale 251 held in New Orleans, Louisiana on 15 August 2018.

The three leases comprise the MP306 field as formerly designated by the Bureau of Ocean Energy Management. The MP306 field was discovered in 1969 and lies in approximately 200 feet of water. Total produced hydrocarbons from the field are 96 million barrels of oil and 107 Bcf of gas from 172 of the 249 total wells drilled. The field ceased production in late 2009 and the last well drilled on any of these blocks was in 2004. The production was from a number of sands ranging from a depth of 4,000 to 9,000 feet.

The structural complexity of the salt dome combined with the stratigraphic variation of the trapping sands and possible deeper stratigraphic targets makes this salt dome an ideal candidate for RTM seismic imaging, similar to Byron's operated SM71 salt dome project.

While no material activity was undertaken during the year ended 30 June 2020, the Company has started scoping an RTM seismic imaging project over the MP306 field.

Properties

As at 30 June 2021, Byron's portfolio of properties, all in the shallow waters of the Gulf of Mexico, and coastal marshlands of Louisiana, USA comprised:

Properties	Operator	Interest WI/NRI (%)*	Lease expiry date	Lease area (Km²)
South Marsh Island				
Block 71	Byron	50.00/40.625	Production	12.16
Block 57	Byron	100.00/81.25	June 2022	21.98
Block 59	Byron	100.00/81.25	June 2022	20.23
Block 60	Byron	100.00/87.50	June 2024	20.23
Block 58 (excluding E1 well)	Byron	100.00/83.33**	Production	
Block 58 (E1 well in S ½ of SE ¼ of SE ¼ and associated production infrastructure in NE ¼ of NE ¼ of SM69)	Ankor	53.00/44.16667		20.23
SM69 (NE ¼ of NE ¼)	Byron	100.00/77.33-80.33	Production	1.3
Block 66	Byron	100.00/87.50	December 2025	20.23
Block 70	Byron	100.00/87.50	July 2023	22.13
Eugene Island				
Block 62	Byron	100.00/87.50	June 2023	20.23
Block 63	Byron	100.00/87.50	June 2023	20.23
Block 76	Byron	100.00/87.50	June 2023	20.23
Block 77	Byron	100.00/87.50	June 2023	20.23
Main Pass				
Block 293	Byron	100.00/87.50	October 2023	18.46
Block 305	Byron	100.00/87.50	October 2023	20.23
Block 306	Byron	100.00/87.50	October 2023	20.23

* Working Interest ("WI") and Net Revenue Interest ("NRI").

** 100.00% WI to a depth of 13,639 feet TVD and 50% WI below 13,639 feet TVD.

Reserves and resources

The Company's reserves and resources estimate as at 30 June 2021 was released to the ASX on 28 September 2021 and is summarised below:

- **Proved Reserves (1P): 8.7 Mmbbl of oil and 55.1 Bcf of gas**
- **Proved and Probable Reserves (2P): 14.1 Mmbbl of oil and 97.5 Bcf of gas**
- **Proved, Probable and Possible Reserves (3P): 22.7 Mmbbl of oil and 123.3 Bcf of gas**
- **Prospective Resources: 33.3 Mmbbl of oil and 572.2 Bcf of gas**

The combined remaining reserves and prospective resources, net to Byron, of 30 June 2020 and relinquished subsequent to 30 June 2021 are as follows:

Byron Energy Limited – reserves and resources

Gulf of Mexico, Offshore Louisiana, USA

Remaining as at 30 June 2021 (net to Byron)	Oil Mbbl	Gas MMcf	Mboe (6:1)
Reserves (developed and undeveloped)			
Proved (1P)	**8,715**	**55,063**	**17,893**
Probable reserves	5,427	42,406	12,495
Proved and probable (2P)	**14,142**	**97,469**	**30,388**
Possible reserves	8,606	25,853	12,916
Proved, probable and possible (3P)	**22,748**	**123,322**	**43,304**
Total prospective resources			
Best estimate (unrisked)	**33,341**	**572,198**	**128,707**

Reserves – The aggregate 1P may be a very conservative estimate and the aggregate 3P may be a very optimistic estimate due to the portfolio effects of arithmetic summation.

Conversion to boe – using a ratio of 6,000 cubic feet of natural gas to one barrel of oil – 6:1 conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency.

Prospective Resource – The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbon.

The following table shows a spilt of Byron's remaining reserves, as at 30 June 2021, into developed and undeveloped categories by project and byproduct. All of the projects in this table are located in the shallow water in the Gulf of Mexico, offshore Louisiana.

Byron Energy Limited – remaining reserves

Net to Byron

	Developed		Undeveloped		Total
30 June 2021	**Oil Mbbl**	**Gas MMcf**	**Oil Mbbl**	**Gas MMcf**	**Boe Mboe (6:1)**
SM71					
Proved (1P)	**1,438**	**978**	**735**	**412**	**2,405**
Probable reserves	509	275	619	702	1,291
Proved and probable (2P)	**1,947**	**1,253**	**1,354**	**1,114**	**3,696**
Possible reserves	-	-	1,078	778	1,208
Proved, probable and possible (3P)	**1,947**	**1,253**	**2,432**	**1,892**	**4,904**
SM58					
Proved (1P)	**243**	**3,640**	**4,927**	**16,827**	**8,581**
Probable reserves	112	143	3,026	5,674	4,108
Proved and probable (2P)	**355**	**3,783**	**7,953**	**22,501**	**12,689**
Possible reserves	-	-	4,896	6,369	5,958
Proved, probable and possible (3P)	**355**	**3,783**	**12,849**	**28,870**	**18,647**
SM58 E1					
Proved (1P)	**163**	**66**	**468**	**849**	**784**
Probable reserves	25	7	-	-	26
Proved and probable (2P)	**188**	**73**	**468**	**849**	**810**
Possible reserves	-	-	-	-	-
Proved, probable and possible (3P)	**188**	**73**	**468**	**849**	**810**
EI77					
Proved (1P)	**-**	**-**	**741**	**32,291**	**6,123**
Probable reserves	-	-	1,136	35,605	7,070
Proved and probable (2P)	**-**	**-**	**1,877**	**67,896**	**13,193**
Possible reserves	-	-	2,632	18,706	5,750
Proved, probable and possible (3P)	**-**	**-**	**4,509**	**86,602**	**18,943**
Total					
Proved (1P)	**1,844**	**4,684**	**6,871**	**50,379**	**17,893**
Probable reserves	646	425	4,781	41,981	12,495
Proved and probable (2P)	**2,490**	**5,109**	**11,652**	**92,360**	**30,388**
Possible	-	-	8,606	25,853	12,916
Proved, probable and possible (3P)	**2,490**	**5,109**	**20,258**	**118,213**	**43,304**

The following table reconciles the movement in Byron's reserves between 30 June 2020 and 30 June 2021.

Byron Energy Limited reserves (net to Byron)
Gulf of Mexico, offshore Louisiana, USA

	Oil (Mbbl)				Gas (MMcf)			
Reserves reconciliation	**Remaining 30/6/20**	**Production 2021**	**Additions and revisions 2021**	**Remaining 30/6/21**	**Remaining 30/6/20**	**Production 2021**	**Additions and revisions 2021**	**Remaining 30/6/21**
SM71 (Developed and undeveloped)								
Proved (1P)	**1,992**	-366	547	**2,173**	**1,341**	-358	407	**1,390**
Probable reserves	2,079	0	-951	1,128	1,590	0	-613	977
Proved and probable (2P)	**4,071**	-366	-404	**3,301**	**2,931**	-358	-206	**2,367**
Possible reserves	1,275	0	-197	1,078	963	0	-185	778
Proved, probable and possible (3P)	**5,346**	-366	-601	**4,379**	**3,894**	-358	-391	**3,145**
SM58 (Developed and undeveloped)								
Proved (1P)	**4,682**	-72	560	**5,170**	**23,884**	-3,832	415	**20,467**
Probable reserves	6,168	0	-3,030	3,138	9,504	0	-3,687	5,817
Proved and probable (2P)	**10,850**	-72	-2,470	**8,308**	**33,388**	-3,832	-3,272	**26,284**
Possible reserves	3,931	0	965	4,896	5,053	0	1,316	6,369
Proved, probable and possible (3P)	**14,781**	-72	-1,505	**13,204**	**38,441**	-3,832	-1,956	**32,653**
SM58 E1/69 (Developed)								
Proved (1P)	**642**	-16	5	**631**	**998**	-8	-75	**915**
Probable reserves	26	0	-1	25	23	0	-16	7
Proved and probable (2P)	**668**	-16	4	**656**	**1,021**	-8	-91	**922**
Possible reserves	0	0	0	0	0	0	0	0
Proved, probable and possible (3P)	**668**	-16	4	**656**	**1,021**	-8	-91	**922**
EI77 (Undeveloped)								
Proved (1P)	**744**	0	-3	**741**	**32,295**	0	-4	**32,291**
Probable reserves	1,136	0	0	1,136	35,615	0	-10	35,605
Proved and probable (2P)	**1,880**	0	-3	**1,877**	**67,910**	0	-14	**67,896**
Possible reserves	2,626	0	6	2,632	18,691	0	15	18,706
Proved, probable and possible (3P)	**4,506**	0	3	**4,509**	**86,601**	0	1	**86,602**
Grand total								
Proved (1P)	**8,060**	**-454**	**1,109**	**8,715**	**58,518**	**-4,198**	**743**	**55,063**
Probable reserves	9,409	0	-3,982	5,427	46,732	0	-4,326	42,406
Proved and probable (2P)	**17,469**	**-454**	**-2,873**	**14,142**	**105,250**	**-4,198**	**-3,583**	**97,469**
Possible reserves	7,832	0	774	8,606	24,707	0	1,146	25,853
Proved, probable and possible (3P)	**25,301**	**-454**	**-2,099**	**22,748**	**129,957**	**-4,198**	**-2,437**	**123,322**

Material changes to reserves

Oil

Proved and probable (2P) reserves

2P oil reserves down year on year mainly due to a reduction in probable reserves at SM58 while SM71 oil production was largely replaced by reallocations from possible reserves.

Possible reserves

Possible oil reserves up year on year mainly due to revisions of SM58 from probable to possible reserves.

Gas

Proved and probable (2P) reserves

2P gas reserves down year on year mainly due to a combination of a reduction in probable reserves at SM58 and gas production at SM58.

Possible reserves

Possible gas reserves up year on year mainly due to reallocations of SM58 probable reserves to possible reserves.

Prospective resources as at 30 June 2021

The following table shows Byron's prospective resources as at 30 June 2021 compared to 30 June 2020.

Byron Energy Limited prospective resources (net to Byron)

Gulf of Mexico, offshore Louisiana, USA

Best estimate enrisked 30 June 2021	Oil Mbbl	Gas MMcf	Mboe (6:1)
Total prospective resources (2021)	**33,341**	**572,198**	**128,707**
Total prospective resources (2020)	**43,612**	**617, 276**	**146,491**

Material changes to prospective resources

- Addition of SM60 prospective oil and SM59 removed from prospective resources as it's not planned to be drilled as of 30 June 2021 (removal of 16.3 Mmbl and 62.8 Bcf (net to Byron)).
- Addition of 6.0 Mmbbl and 17.7 Bcf to SM58 primarily reflecting the following additions: Rainbow Trout K4 PR, Tiger Trout K6 and L2 PRs, River Trout L2 PR, Silver Trout Upper O2 PR and Lower O PR, Steelhead South O PR, Smoked Trout South N2 and O PRs, and Cutthroat Oil Upper O PR.

Notes to Reserves and Resources Statement

Reserves and resources governance

Byron's reserves estimates are compiled annually. Byron engages Collarini and Associates, a qualified external petroleum engineering consultant, to conduct an independent assessment of the Company's reserves. Collarini and Associates is an independent petroleum engineering consulting firm that has been providing petroleum consulting services in the USA for more than 15 years. Collarini and Associates does not have any financial interest or own any shares in the Company. The fees paid to Collarini and Associates are not contingent on the reserves outcome of the Reserves Report.

Competent persons statement

The information in this report that relates to oil and gas reserves and resources was compiled by technical employees of independent consultants Collarini and Associates, under the supervision of Mr Mitch Reece BSc PE. Mr Reece is the President of Collarini and Associates and is a registered professional engineer in the State of Texas and a member of the Society of Petroleum Evaluation Engineers (SPEE), Society of Petroleum Engineers (SPE), and American Petroleum Institute (API). The reserves and resources included in this report have been prepared using definitions and guidelines consistent with the 2007 Society of Petroleum Engineers (SPE)/World Petroleum Council (WPC)/American Association of Petroleum Geologists (AAPG)/Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management System (PRMS). The reserves and resources information reported in this statement are based on, and fairly represents, information and supporting documentation prepared by, or under the supervision of, Mr Reece. Mr Reece is qualified in accordance with the requirements of ASX Listing Rule 5.41 and consents to the inclusion of the information in this report of the matters based on this information in the form and context in which it appears.

Reserves cautionary statement

Oil and gas reserves estimates are expressions of judgement based on knowledge, experience and industry practice. Estimates that were valid when originally calculated may alter significantly when new information or techniques become available. Additionally, by their very nature, reserve and resource estimates are imprecise and depend to some extent on interpretations, which may prove to be inaccurate. As further information becomes available through additional drilling and analysis, the estimates are likely to change. They may result in alterations to development and production plans which may, in turn, adversely impact the Company's operations. Reserves estimates and estimates of future net revenues are, by nature, forward-looking statements and subject to the same risks as other forward-looking statements.

Prospective resources cautionary statement

The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.

Forward-looking statements

This document may contain forward-looking information. Forward-looking information is generally identifiable by the terminology used, such as "expect", "believe", "estimate", "should", "anticipate" and "potential" or other similar wording. Forward-looking information in this document includes, but is not limited to, references to: well drilling programs and drilling plans, estimates of potentially recoverable resources, and information on future production and project start-ups. By their very nature, the forward-looking statements contained in this document require Byron and its management to make assumptions that may not materialise or that may not be accurate. Although Byron believes its expectations reflected in these statements are reasonable, such statements involve risks and uncertainties, and no assurance can be given that actual results will be consistent with these forward-looking statements.

Pricing assumptions

Oil prices used in this report represent 12 July 2021 NYMEX West Texas Intermediate (WTI) Strip prices through 2023 and Reuters consensus for 2024, starting on 1 July 2021, of $72.98 per barrel, with a final price of $60.00 per barrel on 1 January 2024, and held constant thereafter. Gas prices used in this report represent a Henry Hub base 15 July NYMEX Strip prices through 2023 and Reuters consensus for 2024, starting on 1 July 2021, of $3.411 per MMBtu, declining to $2.750 per MMBtu on 12 July 2021, then held constant thereafter. These prices were then adjusted to account for transportation cost, basis difference, Light Louisiana Sweet (LLS) vs WTI oil gravity.

ASX reserves and resources reporting notes

(i) The reserves and prospective resources information in this document is effective as at 30 June 2021 (Listing Rule (LR) 5.25.1).

(ii) The reserves and prospective resources information in this document has been estimated and is classified in accordance with SPE-PRMS (Society of Petroleum Engineers Petroleum Resources Management System) (LR 5.25.2).

(iii) The reserves and prospective resources information in this document is reported according to the Company's economic interest in each of the reserves and prospective resource net of royalties (LR 5.25.5).

(iv) The reserves and prospective resources information in this document has been estimated and prepared using the deterministic method (LR 5.25.6).

(v) The reserves and prospective resources information in this document has been estimated using a 6:1 BOE conversion ratio for gas to oil; 6:1 conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency (LR 5.25.7).

(vi) The reserves and prospective resources information in this document has been estimated on the basis that products are sold on the spot market with delivery at the sales point on the production facilities (LR 5.26.5).

(vii) The method of aggregation used in calculating estimated reserves was the arithmetic summation by category of reserves. As a result of the arithmetic aggregation of the field totals, the aggregate 1P may be a very conservative estimate and the aggregate 3P may be a very optimistic estimate due to the portfolio effects of arithmetic summation (LR 5.26.7 and 5.26.8).

(viii) Prospective resources are reported on a best estimate basis (LR 5.28.1).

(ix) For prospective resources, the estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons (LR 5.28.2).

(x) All of Byron's reserves and prospective resources are located in the shallow waters of the Gulf of Mexico, offshore Louisiana.

Financial Report

For the year ended 30 June 2021

Directors' Report

Your directors submit herewith their report together with the Financial Report of Byron Energy Limited ("the consolidated entity" or "Group"), being Byron Energy Limited ("Byron" or the "Company") and its subsidiaries for the financial year ended 30 June 2021.

Directors

The names and details of the Company's directors in office during the financial year and until the date of this report are as follows:

Douglas G Battersby

Maynard V Smith

Prent H Kallenberger

Charles J Sands

Paul A Young

William R Sack

All directors have held office for the whole year unless otherwise stated.

Names, qualifications, experience and special responsibilities

Douglas G Battersby

Non-Executive Chairman

Appointed 18 March 2013

Doug is a petroleum geologist with over 40 years' technical and managerial experience in the Australian and international oil and gas industry.

Doug co-founded two ASX listed companies (Eastern Star Gas Limited, which was taken over by Santos Limited in November 2011, and SAPEX Limited, which was taken over by Linc Energy Limited in October 2008), and two private oil and gas exploration/development companies, Darcy Energy Limited, which was sold to I B Daiwa Corporation in 2005, and Byron Energy (Australia) Pty Ltd where he was Executive Chairman until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Between 1990 and 1999 Doug was Technical Director at Petsec Energy Limited, an ASX listed operator in the shallow waters of the Gulf of Mexico with production reaching 100 MMcf per day of gas and 9,000 barrels of oil per day in 1997.

Doug holds a Master of Science degree in Petroleum Geology and Geochemistry from Melbourne University.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

Maynard V Smith

Executive Director and Chief Executive Officer

Appointed 18 March 2013

Maynard is a geophysicist with over 30 years' technical and managerial experience in the oil and gas industry with a particular focus on the Gulf of Mexico.

Maynard co-founded Darcy Energy Limited, sold to I B Daiwa Corporation in 2005, and Byron Energy (Australia) Pty Ltd where he has been Chief Executive until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Prior to that, Maynard was Chief Operating Officer with Petsec Energy Limited (1989-2000). In the late 1970s and early 1980s Maynard held senior exploration positions with Tenneco Oil Company, based in Bakersfield, California.

Maynard holds a Bachelor of Science degree in Geophysics from California State University at San Diego.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

Prent H Kallenberger

Executive Director and Chief Operating Officer

Appointed 18 March 2013

Prent is a geoscientist with over 30 years' experience in the oil and gas industry with extensive exploration and development experience in the Gulf of Mexico, having generated prospects which have led to the drilling of over 125 wells in the Gulf of Mexico and California. He was Vice President of Exploration with Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited.

Between 2000 and 2006, Prent was Vice President of Exploration with Petsec Energy Inc, where he was responsible for a team of seven people and generated projects leading to the drilling of 10 successful wells in 12 attempts in the shallow waters of the Gulf of Mexico. These wells produced 32 Bcf and 1.5 MMBbls of oil. Between 1992 and 1998 Prent was Geophysical Manager with Petsec Energy Inc, a wholly owned subsidiary of Petsec Energy Limited. He holds a Bachelor of Science degree in Geology from Boise State University and Master of Science degree in Geophysics from Colorado School of Mines.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

Charles J Sands

Non-Executive Director

Appointed 18 March 2013

Charles was a Non-Executive Director of Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Charles was also a director of Darcy Energy Limited.

Charles has over 30 years' of broad based business and management experience in the USA and is President of A. Santini Storage Company of New Jersey Inc, enabling him to advise on the general business operating environment and practices in the USA. He holds a Bachelor of Science degree from Monmouth University.

Charles is currently a member of the Audit and Risk Management Committee.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

Paul A Young

Non-Executive Director

Appointed 18 March 2013

Paul is a Managing Director of Henslow Corporate and country head for Oaklins, a global mid-market corporate advisory firm. He has been in merchant banking for more than 30 years. He has extensive experience in the provision of corporate advice to a wide range of Australian and international listed and unlisted companies including restructurings, capital raisings, initial public offerings and mergers and acquisitions.

Paul is an Honours Graduate in Economics (University of Cambridge) and has an Advanced Diploma in Corporate Finance. He is a Fellow of the Institute of Chartered Accountants in England and Wales and a Fellow of the Australian Institute of Company Directors.

Paul is currently Chairman of the Audit and Risk Management Committee.

Other current directorships of listed companies

Left Field Printing Group Limited ("Left Field"), a Hong Kong listed company.

Former directorships of listed companies in last three years

- Ambition Group Limited, voluntarily delisted 30 September 2020 but a continuing director; and
- Opus Group Limited (which entered into a scheme of arrangement with Left Field in October 2018).

William R Sack

Executive Director

Appointed 3 October 2014

Bill is an explorationist with more than 30 years' experience in the Gulf of Mexico region in technical, commercial and executive roles. He was appointed to the Board of Directors on 3 October 2014.

Bill's qualifications comprise BSc. Earth Sci./Physics, MSc. Geology and an MBA. He co-founded and served as Managing Partner of Aurora Exploration, LLC, a private entity focused on generating and drilling Gulf of Mexico exploration opportunities that has drilled more than 80 wells with a success rate in excess of 80%, and under his leadership has created substantial growth and monetised investments via multiple corporate level asset sales. Prior to 2000 he served in a variety of exploration and executive roles for Petsec Energy and Shell Offshore.

Bill holds a Bachelor of Science degree in Earth Science/Physics from St. Cloud State University, a Master of Science degree in Geology from Michigan State University and a Master of Business Administration from Tulane University.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

Summary of shares and options on issue

At 30 June 2021, the Company had 1,040,295,102 ordinary shares and 41,100,000 options on issue. Details of the options are as follows:

Issuing entity	Number of shares under option	Class of shares	Exercise price	Expiry date
Byron Energy Limited	28,350,000	Ordinary	A$0.12	31 December 2021
Byron Energy Limited	2,000,000	Ordinary	A$0.16	31 December 2021
Byron Energy Limited	9,500,000	Ordinary	A$0.40	31 December 2021
Byron Energy Limited	1,250,000	Ordinary	A$0.40	31 December 2021
	41,100,000			

During the year ended 30 June 2021, the Company issued 16,745,771 fully paid ordinary shares and no share options. The 16,745,771 ordinary shares were issued on 21 July 2020 at A$0.13 per share to directors and/or their associates. This issue was approved at a shareholders' meeting on 9 July 2020 and was part of the placement of shares by the Company announced on 19 May 2020.

Post 30 June 2021, no other ordinary shares, nor share options were issued and no share options were exercised subsequent to 30 June 2021 through to the date of this report.

Shareholdings and option holdings of directors and other key management personnel

The interests of each director and other key management personnel, directly and indirectly, in the shares and options of Byron Energy Limited at the date of this report are as follows:

Director/key management personnel	Ordinary shares	Options over ordinary shares	Exercise price	Option expiry date
D Battersby	57,250,568	-	-	-
M Smith	40,625,664	-	-	-
M Smith	-	6,300,000	A$0.12	31 December 2021
M Smith	-	2,100,000	A$0.40	31 December 2021
P Kallenberger	4,408,762	-	-	-
P Kallenberger	-	6,300,000	A$0.12	31 December 2021
P Kallenberger	-	2,100,000	A$0.40	31 December 2021
C Sands	24,710,783	-	-	-
P Young	27,352,773	-	-	-
W Sack	6,900,001	-	-	-
W Sack	-	6,300,000	A$0.12	31 December 2021
W Sack	-	2,100,000	A$0.40	31 December 2021
N Filipovic	2,721,359	-	-	-
N Filipovic	-	3,780,000	A$0.12	31 December 2021
N Filipovic	-	1,000,000	A$0.40	31 December 2021

Summary of shares and options on issue

During the financial year, no shares or share options were granted to directors or key management personnel of the Company.

Company Secretary

Nick Filipovic

Appointed 18 March 2013

Nick is a qualified accountant with over 40 years' experience in the financial services and natural resources industries, including oil and gas, where he has held a range of senior financial and commercial management positions. He was the Chief Financial Officer and Company Secretary of Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited.

Principal activities

The principal activities of the consolidated entity during the financial year were oil and gas exploration, development and production in the shallow waters in the Gulf of Mexico ("GOM"), USA.

Consolidated results

The profit for the consolidated entity after income tax was US$5,854,375 (2020: US$68,348).

Review of operations

Financial review

The Group recorded a net profit of US$5,854,375 for the year ended 30 June 2021, compared to a net profit of US$68,348 for the year ended 30 June 2020.

For the year ended 30 June 2021 Byron's share of net revenue was US$35,837,228 compared to US$21,402,255 for the year to 30 June 2020. The increase in net revenue was primarily due to higher natural gas and oil sales as a result of commencement of production from the SM58 G1 and G2 wells, and higher realised gas prices.

Cost of sales were US$20,793,128 for the year ended 30 June 2021 compared to US$8,915,892 for the comparable period in 2020. The increase is due to higher lease operating expenses, amortisation and gas transportation charges as a result of commencement of the SM58 G platform production during the December 2020 quarter.

Impairment charges were US$595,951 for the year ended 30 June 2021 reflecting the disposal of the Bivouac pipe/casing proceeds and the write-down to $nil of the SM59 lease were significantly lower in comparison to the year ended 30 June 2020 of US$5,397,975. The impairment charge for the 2020 year largely reflected the write-off of the drilling cost of the SM74 D14 well dry hole.

There were no share-based payment expenses in the year to 30 June 2021, compared to the year ended 30 June 2020 share-based payment expense of US$940,671.

At 30 June 2020, the consolidated entity had total assets of US$114,832,843 (30 June 2020: US$105,107,449) and total liabilities of US$33,599,978 (30 June 2020: US$31,056,428) resulting in net assets of US$81,232,865 (30 June 2020: US$74,051,021). The increase in net assets was mainly to due to the completion of the SM58 G1 well and the drilling and completion of the G2ST well, plus completion and commissioning of the SM58 G platform and associated pipelines, partly offset by lower cash and cash equivalents.

At 30 June 2021, the consolidated entity held cash and cash equivalents of US$4,143,411 (30 June 2020: US$16,644,701).

Corporate review

Cash equity raisings

Following approval at an Extraordinary General Meeting held in July 2020, the Company issued 16,745,771 ordinary shares at A$0.13 cents per share raising A$2,176,950 before costs, from directors and/or their associates, as part of a share placement announced in May 2020.

No share options were converted during the year ended 30 June 2021.

Issued capital

As at 30 June 2021, Byron's issued capital comprised:

Securities	Total issued	Quoted	Unquoted
Shares (ASX:BYE)	1,040,295,102	1,040,295,102	Nil
Options	41,100,000	Nil	41,100,000

Borrowings

Crescent Midstream Promissory Note

In the December 2019 quarter, Byron signed a binding Secured Promissory Note ("Promissory Note") with Crescent (formerly Crimson) Midstream Operating, LLC ("Crescent Midstream"), a portfolio company of The Carlyle Group, to borrow an initial amount of US$15.0 million, (fully drawn down by Byron during the 2020 financial year), bearing interest at a rate of 15% p.a., over a three-year term and being interest only until December 2020. Byron secured an additional US$3.5 million under the Crescent Midstream Promissory Note facility in June 2020, drawn down in August 2020, on the same terms and conditions as the initial US$15.0 million, including interest only until December 2020. The Promissory Note is secured over Byron's SM71 and SM58 assets and guaranteed by the Company.

In December 2020 Byron commenced making principal repayments under the Promissory Note. As at 30 June 2021 the remaining balance of the Promissory Note was US$15.1 million with US$3.4 million repaid over the period 1 December 2020 to 30 June 2021. The balance of the Promissory Note is due to be repaid over the period 1 July 2021 to 30 November 2022.

Loans from directors and shareholders

Byron's outstanding loans of approximately US$3.6 million, as at 30 June 2021, from entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young (all directors of the Company), and a longstanding shareholder are due to be repaid on 31 March 2022, unless otherwise agreed.

As at 30 June 2021, Byron's borrowings comprised:

Lender	US$ million	A$ million	US$ million equivalent (@A$1=US$0.7518)
Directors	2.00	1.75	3.32
Shareholder	8.00	0.35	0.26
Crescent Midstream	15.08	-	15.08
Insurance premium funding	1.53	-	1.53
Total*	**18.61**	**2.10**	**20.19**

* Does not include an oil revenue prepayment of US$1.75 million.

Hedging

Byron's realised prices for oil are a combination of hedged and unhedged volumes. The Company's current oil hedging position is governed by a forward sale agreement ("Forward Sale Agreement"), which specifies a price per barrel in advance for each delivery period during the term of the contract and a derivative hedge in the form of swaps ("Swaps") which provide Byron with a hedge against potentially declining prices.

The hedging counterparty for the Forward Sale Agreement and the Swaps is one of the global oil industry's "supermajors" and is also the purchaser of Byron's oil production under a mutually agreed long-term purchase arrangement, which provides Byron with a stable, aligned counterparty.

Byron's hedged oil production as at 30 June 2021 is as follows:

Period	Daily hedged volume (bopd)	Period hedged volume (bbl)	NYMEX WTI fixed base price crude oil*	NYMEX roll adjust	LLS/WTI price differential	Realised price on hedged production prior to transportation charges
July-Dec 2021 (Forward sale agreement)	450	82,800	US$52.86	unhedged	unhedged	To be determined
July-Dec 2021 (Swaps)	200	36,800	US$60.78	unhedged	unhedged	To be determined
Jan-Dec 2022 (Forward sale agreement)	400	146,000	US$52.70	unhedged	unhedged	To be determined

* WTI CMA base price is adjusted for NYMEX Roll, LLS/WTI price differentials. Transportation (estimated at US$4.70/barrel +-0.20) to arrive at a realised price.

Review of operations

COVID-19

The World Health Organization declared the COVID-19 coronavirus outbreak a pandemic on 11 March 2020. COVID-19 was first identified in China, where it caused an economic slowdown for the world's largest energy consumer. The decrease in demand led to fears of over-supply for fuel and oil products, and a resulting fall in prices.

The decline in demand for oil across the world and the resulting price decline had a material adverse effect on the industry as well as Byron's oil revenues and cash flows in 2020.

West Texas Intermediate ("WTI"), the US marker price, finished the 31 December 2020 half year at US$48.24 having crashed to an unprecedented minus US$36.98 on 20 April 2020. Following large cuts in production by OPEC and Non-OPEC producers, prices gradually increased from US$39.27 on 30 June 2020 to US$48.24 on 31 December 2020. The increase in vaccination programs have helped reduce the spread of COVID-19 in 2021, which has contributed to an improvement in the economy and higher realised oil and gas prices in 2021 with the WTI spot price closing at US$73.52 on 30 June 2021.

The Henry Hub natural gas mmbtu spot price improved from US$1.76 on 30 June 2020 to US$2.36 on 31 December 2020 and US$3.65 on 30 June 2021.

While there has been an improvement in oil and gas prices since April 2020, prices remain volatile, and there is still significant uncertainty regarding the long-term impact of the COVID-19 pandemic on global oil demand and prices.

Byron's ability to maintain operations at the SM71 F and SM58 G platforms in the Gulf of Mexico was not impacted by COVID-19 during the year ended 30 June 2021. Byron's office in Lafayette, Louisiana worked in line with recommendations of Louisiana State and Byron's Australian-based team worked as advised by the Australian government(s) to comply with COVID-19 regulations.

Byron's offshore contractors have continued to work within the Louisiana State's and the Bureau of Safety and Environmental Enforcement guidelines.

Producing oil and gas properties

Oil and gas production and sales

Byron's share of oil and gas production and sales for the year ended 30 June 2021 is summarised in the table below.

Production (sales)	Year ended 30 June 2021	Year ended 30 June 2020
Net production Byron share (NRI basis 40.625%) SM71		
Oil (bbls)	**364,748**	375,906
Gas (mmbtu)	**398,834**	878,811
Net production Byron share (NRI basis 83.333%) SM58		
Oil (bbls)	**71,558**	0
Gas (mmbtu)	**4,202,475**	0
Net production Byron share (NRI basis 44.167%) SM58 E1 well		
Oil (bbls)	**16,791**	17,797
Gas (mmbtu)	**2,588**	4,244
Total net production (NRI basis)		
Oil (bbls)	**453,098**	393,703
Gas (mmbtu)	**4,603,897**	883,055

Byron's share of net oil production for the year ended 30 June 2021 was approximately 15% above the corresponding period last year due to oil production from SM58 G platform which commenced in September 2020 from the SM58 G1 well and the SM58 G2ST well which commenced in November 2020, partly offset by production from SM71F platform reflecting natural decline and production shut-ins due to hurricanes.

Byron's share of net gas production for the year ended 30 June 2021 was approximately 521% above the corresponding period last year due to gas production from the SM58 G platform commencing in September 2020 from the SM58 G1 well followed by the SM58 G2ST well in November 2020, both significant gas producing wells for the year partly offset by lower gas production from SM71 F platform.

Sale revenue and realised prices (accrual basis) US$ million	Year ended 30 June 2021	Year ended 30 June 2020
Net sales revenue (Byron share on NRI basis) US$ million	**35.8**	21.4

Net sales revenue for the year ended 30 June 2021 was US$35.8 million compared to US$21.4 million for the corresponding period last year. Net sales revenue was boosted by oil and gas production from SM58 G1 and SM58 G2ST wells and higher realised gas prices.

During the year ended 30 June 2021, Byron realised an average oil price after adjustment for LLS price differentials and deductions for transportation, oil shrinkage and other applicable adjustments of US$49.50 per bbl (US$54.05 excluding transportation) compared to US$50.32 per bbl and US$54.74 per bbl respectively for the 30 June 2020 year.

Byron realised an average gas price after transportation deductions of approximately US$2.56 per mmbtu during the year ended 30 June 2021 (US$2.91 excluding transportation) compared to US$1.55 per mmbtu and US$1.93 per mmbtu respectively for the 30 June 2020 year.

South Marsh Island 71

The South Marsh Island block 71 ("SM71") is a lease in the South Marsh Island 73 field ("SM73"). Byron is the designated operator of SM71 and owns a 50% Working Interest ("WI") and a 40.625% Net Revenue Interest ("NRI") in the block, with Otto Energy Limited ("Otto") group holding an equivalent WI and NRI in the block. As Otto did not participate in the drilling of the SM71 F4 well, Byron is entitled to 100% WI/81.25% NRI.

Water depth in the area is approximately 137 feet.

Oil and gas production from the Byron-operated SM71 F platform began on 23 March 2018 from three wells, F1, F2 and F3. Production from the F4 well, successfully drilled and completed in March 2020, commenced production in mid-March 2020.

The F1 and F3 wells are producing in the primary D5 Sand reservoir and the F2 well is producing from the B55 Sand reservoir. The F4 well is producing from the upper D5 Sand reservoir.

Total gross production/sales volumes for all wells on the SM71 F platform totalled approximately 364,748 barrels of oil and 398,834 mmbtu for the year ended 30 June 2021, with only minor amounts of water produced by the SM71 F2 well, compared to 375,906 barrels of oil and 878,811 mmbtu for the year ended 30 June 2020. The F1 and F3 wells continue to produce water-free from the D5 Sand.

As at 30 June 2021, the SM71 F facility has produced approximately 3.4 million barrels of oil (gross) since initial production began. The facility has also produced approximately 4.3 billion cubic feet ("bcf") of gas (gross).

South Marsh Island 58

Byron holds all the operator's rights, title, and interest in and to the SM58 lease block to a depth of 13,639 feet subsea with 100% WI and 83.33% NRI. Below 13,639 feet subsea, Byron has a 50% WI (41.67% NRI) under a pre-existing exploration agreement. To date, all identified drilling opportunities on the SM58 lease are above 13,639 feet subsea.

Gas and oil production from the Byron Energy SM58 G platform was initiated on 7 September 2020 when the SM58 G1 well commenced production.

The SM58 G2ST well is also completed in the Upper O Sand, but was drilled into a different fault block than the SM58 G1 well.

As of 30 June 2021, the SM58 G facility has produced approximately 4.7 Bcf and 88,000 barrels of oil and condensate (gross) from two wells since initial production began. Effective 30 June 2021, the SM58 lease ranks number 5 of all currently active gas producing leases on the US Gulf of Mexico shelf with the SM58 G1 ranked as the number 5 active gas producing well.

The SM58 G1 well produces from the Upper O Sand and as of 30 June 2021, has produced a gross total of approximately 4.1 Bcf of gas, 45,000 barrels of consistent 56.5-degree gravity condensate and no formation water.

The SM58 G2ST well was tied into the SM58 G platform and the O Sand was opened to production on 29 October 2020 and has now produced approximately gross 0.65 billion cubic feet of gas and 43,000 barrels of oil with an estimated 12,000 barrels of formation water.

The G2 well performance was negatively impacted by mechanical and reservoir issues. Byron will acquire bottom hole pressure data from the G2 well in the second half of calendar 2021 year. Based on that data, a wireline tubing punch operation may also be performed to move the effective depth of the gas lift system deeper in the well bore. If performance does not improve, the G2 will eventually be recompleted uphole, in the J Sand interval above the current O Sand completion with through tubing completion methods. That type of completion operation can be performed without a drilling rig. The J Sand was assigned gross 2P reserves of 0.379 mmbo and 0.379 Bcfg in the G2 well by the Company's third party reserve engineers in the 30 June 2021 reserve report

Production issues at SM58 G2ST well started being experienced very soon after the well commenced production. The SM58 G2ST well production is below the forecasts of the Byron's third-party reserve engineers, Collarini Associates, and its performance has been taken into account in the Company's 30 June 2021 reserve report.

South Marsh Island 58 E1 well bore and SM69 E platform

Byron holds a non-operated 53% WI (44.167% NRI) in the South Marsh Island 69 E platform with one active producing well, the SM58 E1 well. The SM58 was drilled from a surface location in SM69 to a bottom hole location in SM58 in 2011 and is completed in the K4 Sand (B65 Sand) and has produced a total of 630,000 barrels of oil, 0.185 bcf of gas and 800,000 barrels of formation water.

For the 12 months ended 30 June 2021, Byron's share of net revenue from SM58 E1 well was US$0.9 million and Byron's net production was approximately 16,791 barrels of oil and 2.6 million cubic feet of gas.

The well was recompleted during the March 2021 quarter, by sliding a sleeve covering existing perforations with sand control across the K Sand (B55 Sand). For the month of June 2021, SM58 E1 well produced 180 bopd on a gross basis.

Ankor Energy, LLC ("ANKOR") is the designated operator of this portion of the block to facilitate the surface operatorship of the jointly owned SM58 E1 well and SM69 E platform which is located in the NE corner of the SM69 block. Byron also holds a farm-in right under the Joint Exploration Agreement ("JEA") with ANKOR group which provides for the drilling of a SM69 E2 exploration well with Byron owning a 100% WI less a 3.0% overriding royalty interest ("ORRI"), converting to a 6% ORRI after payout.

Exploration and evaluation leases

In addition to the SM71, SM58 and SM58 E1 / SM69 E platform producing properties, Byron is the operator and 100% working interest holder in 12 other blocks as shown in the table below.

Properties

As at 30 June 2021, Byron's portfolio of properties in the shallow waters of the Gulf of Mexico, USA, comprised:

Properties	Operator	Interest WI/NRI (%)*	Lease expiry date	Lease area (Km^2)
South Marsh Island				
Block 71	Byron	50.00/40.625	Production	12.16
Block 57	Byron	100.00/81.25	June 2022	21.98
Block 59	Byron	100.00/81.25	June 2022	20.23
Block 60	Byron	100.00/87.50	June 2024	20.23
Block 58 (excluding E1 well)	Byron	100.00/83.33**		
Block 58 (E1 well in S ½ of SE ¼ of SE ¼ and associated production infrastructure in NE ¼ of NE ¼ of SM69)	Ankor	53.00/44.17	Production	20.23
Block 69 (NE ¼ of NE ¼)	Byron	100.00/77.33-80.33	Production	1.30
Block 66	Byron	100.00/87.50	December 2025	20.23
Block 70	Byron	100.00/87.50	June 2023	22.13
Eugene Island				
Block 62	Byron	100.00/87.50	June 2023	20.23
Block 63	Byron	100.00/87.50	June 2023	20.23
Block 76	Byron	100.00/87.50	June 2023	20.23
Block 77	Byron	100.00/87.50	June 2023	20.23
Main Pass				
Block 293	Byron	100.00/87.50	October 2023	18.46
Block 305	Byron	100.00/87.50	October 2023	20.23
Block 306	Byron	100.00/87.50	October 2023	20.23

* Working Interest ("WI") and Net Revenue Interest ("NRI").

** 100.00% WI to a depth of 13,639 ft TVD and 50% WI below 13,639 ft TVD.

South Marsh Island Area leases

The SM57/59/60/66/70 blocks, as part of the larger SM71 project area, are the focus areas of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites.

Byron has spent considerable time pursuing key regulatory permits in the South Marsh Island Project Area. During the year ended 30 June 2021, Executive Order 3395 went into effect on 20 January 2021 and has had no material effect on the process for permits on existing leases. Executive Order 3395 suspends new leasing activities for oil and gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and gas permitting and leasing practices but does not apply to existing leases.

Byron was granted approval for a revised Development Operations Coordination Document ("DOCD") on 10 February 2021 which allows the use of slots G5 through G9 from the South Marsh 58 G platform. Byron has submitted DOCD permits for wells on SM57, SM60 and SM70 and each permit is under review by the Bureau of Ocean Energy Management ("BOEM") Gulf of Mexico Region office in New Orleans, Louisiana. Byron has no reason to believe these permits will not be approved in the normal course of the approval process.

The scheduling of the SM58 G3 and G4 wells will be finalised once the results of the SM69 E2 well are known.

To drill any well offshore, an operator must also file an Application for Permit to Drill ("APD") with the Bureau of Safety and Environmental Enforcement ("BSEE"). Byron has filed APDs for the next phase of drilling at SM69 and SM58. The APD for the SM69 E2 well is fully approved and the APDs for the proposed SM58 G3 and G4 wells have also been filed and are under review. Byron does not anticipate any delays in the approval process and expects approval in the normal course of business.

Eugene Island Area leases

Byron owns and operates the Eugene Island blocks 62, 63, 76 and 77 ("EI62/63/76/77"), in water depth of approximately 20 feet. Byron currently holds a 100% WI and an 87.5% NRI in EI62/63/76/77.

EI62/63/76/77 were designated as the Eugene Island 77 field in the 1960s and have produced 362 billion cubic feet of gas and 6.5 million barrels of oil from sands trapped by the Eugene Island 77 salt dome. Initial production from the field began in 1957. There is no production on these blocks currently.

On the basis of proprietary Reverse Time Migrated seismic data ("RTM"), undertaken by WesternGeco (a Schlumberger group company) in 2014 of 3D seismic data over the entire four block Eugene Island 77 field, Byron acquired EI62/63/76/77 at the OCS Lease Sale 250. As a result of this detailed work Byron significantly upgraded the reserve potential of EI62/63/76/77.

In the September 2018 quarter, Byron began a reprocessing effort similar to that undertaken on the SM71 Project Area with WesternGeco over all four Eugene Island blocks leased by the Company. Analysis of the reprocessed data is almost complete while preliminary well planning is also underway.

Main Pass Area leases

Byron also currently holds a 100% WI and an 87.50% NRI in Main Pass 293, 305 and 306 ("MP 306 field"). The three leases comprise the MP306 field as formerly designated by the Bureau of Ocean Energy Management ("BOEM"). The MP306 field was discovered in 1969 and lies in approximately 200 feet of water. Total produced hydrocarbons from the field are 96 million barrels of oil and 107 bcf of gas from 172 of the 249 total wells drilled. The field ceased production in late 2009 and the last well drilled on any of these blocks was in 2004. The production was from a number of sands ranging from a depth of 4,000 to 9,000 feet.

The structural complexity of the salt dome combined with the stratigraphic variation of the trapping sands and possible deeper stratigraphic targets makes this salt dome an ideal candidate for RTM seismic imaging, similar to Byron's operated SM71 salt dome project.

During the year ended 30 June 2021, the Company commenced scoping an RTM seismic imaging project over the MP306 field.

Portfolio optimisation

Byron further optimised its portfolio of properties by acquiring a 100% WI in South Marsh Island 66 lease ("SM66") and relinquishing South Marsh Island 74 lease ("SM74") during the year ended 30 June 2021.

In the December 2020 quarter Byron was awarded the SM66 lease, having been the successful bidder at the Gulf of Mexico OCS Lease Sale 256 held on Wednesday 18 November 2020.

Byron bid US$143k as a bonus bid. Byron has a 100% WI and an 87.50% NRI in the block.

SM66 was evaluated using the same reprocessed RTM seismic data used to make the discoveries on SM71 and SM58. Historical production from SM66 has totalled 1.4 million barrels of oil and 238 billion cubic feet of gas from 1969 to 2018.

The SM66 lease enhances the Company's prospect inventory and is a block expected to move up in Byron's drilling program as it is considered to have significant hydrocarbon potential.

Byron relinquished SM74 during the December 2020 quarter, prior to the June 2021 lease renewal, having completed all evaluation work and consulted Metgasco Limited, which had a residual right to a 30% WI.

Byron impaired the carrying value of SM59 (US$655k) as at 30 June 2021, as the Company does not plan to drill these prospects.

Review of strategy, principal risks and uncertainties facing the Company

Strategy

Since inception Byron has focused on the shallow waters of the OCS in the GOM. The directors believe that the shallow waters of the GOM offer significant advantages to Byron, as the GOM:

- is a prolific producer of oil and gas;
- has significant proved and unproved reserves of low-cost oil and gas as well as significant potential for further hydrocarbon discoveries;
- has extensive, established and accessible oil and gas exploration, development and production infrastructure;
- offers a short development cycle and rapid payback;
- has modern 3D seismic coverage, suitable for improved imaging, over fields and prospects, available for purchase from third party providers;
- advanced seismic processing techniques have allowed the industry to better distinguish hydrocarbon traps and identify previously unknown prospects; and
- has a well-established and stable administration with one landowner for the shallow waters, BOEM.

Byron is well positioned to exploit the competitive advantages of the GOM as the Company has:

- an experienced team of oil and gas exploration, development and production personnel with a successful track record in the GOM, with significant experience utilising advanced seismic image processing techniques, including reverse time migration, in Byron's area of focus;
- two Byron operated, producing and cash-generating assets, SM71 and SM58;
- an inventory of relatively low-risk, ready to drill prospects, including several prospects with significant oil potential; and
- the capacity to grow its asset portfolio in the shallow waters and transition zone of the GOM.

Byron's strategy in the GOM comprises three key elements:

- to identify highly prospective oil and gas plays, aided by leading edge seismic technology such as RTM, which is particularly effective in the shallow waters of the GOM;
- to secure the leases, usually on a 100% or majority working interest basis; and
- Byron will either 'drill test' the play as operator holding a 100% working interest or seek to farm out up to 50% of its WI to a non-operator or another operator with a proven track record of drilling and producing wells in the GOM, retaining a 40-50% WI in the block.

Principal risks and uncertainties

The key areas of risk, uncertainty and material issues facing the Company in executing its strategy and delivering on its targets are described below.

Risks relating to the Company's industry, business and financial condition

There are a number of risks which may impact on the operating and financial performance of the Company and therefore, on the value of its shares. Some of these risks can be mitigated by the Company's systems and internal controls, but many are outside of the control of the Company and the Board. There can be no guarantee that the Company will achieve its stated objectives or that any forward-looking statements will eventuate.

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to the Company and the oil and gas industry could materially impact the Company's future performance and results of operations. Below is a list of known material risk factors that should be reviewed when considering buying or selling Byron's shares. These are not all the risks the Company faces and other factors currently considered immaterial or unknown may impact future operations.

Oil and natural gas price risk

The Company's revenues, profitability and future growth depend significantly on crude oil and natural gas prices. Oil and natural gas prices are volatile and low prices could have a material adverse impact on cash flow and on Byron's business. Among the factors that can cause these fluctuations are: (i) changes in global supply and demand for oil and natural gas, (ii) the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls, (iii) the price and volume of imports into the USA of foreign oil and natural gas, (iv) political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity, (v) the level of global oil and gas exploration and production activity, (vi) weather conditions, (vii) technological advances affecting energy consumption, (viii) USA domestic and foreign governmental regulations and taxes, (ix) proximity and capacity of oil and gas pipelines and other transportation facilities, (x) the price and availability of competitors' supplies of oil and gas in captive market areas, (xi) the introduction, price and availability of alternative forms of fuel to replace or compete with oil and natural gas, (xii) import and export regulations for LNG and/or refined products derived from oil and gas production from the USA, (xiii) speculation in the price of commodities in the commodity futures market, (xiv) the availability of drilling rigs and completion equipment; and the overall economic environment.

Financing risk

Byron's business plan, which includes participation in seismic data purchases, lease acquisitions and the drilling of exploration and development prospects, has required and is expected to continue to require capital expenditures. Byron may require additional financing to fund its planned growth. This additional financing may be in the form of equity, debt or a combination thereof. Byron may also obtain capital by farming out part of its working interest in one or more of its oil and gas properties. Byron's ability to raise additional capital will depend on the results of its operations and the status of various capital and industry markets at the time it seeks such capital. Accordingly, additional financing may not be available on acceptable terms, if at all. In the event additional capital resources are unavailable, Byron may be required to curtail its exploration and development activities. It is difficult to quantify the amount of financing Byron may need to fund its planned growth in the longer term. The amount of funding Byron may need in the future depends on various factors, including but not limited to: (i) the Company's financial condition, and (ii) the success or otherwise of its exploration and development program. Further, the availability of such funding may depend on various factors, including but not limited to, the liquidity of the Company's shares at the time the Company seeks to raise funds and the prevailing and forecast market price of oil and natural gas. If Byron raises additional funds through the issue of equity securities, this may dilute the holdings of existing shareholders. If Byron obtains additional capital by farming out part of its working interest in one or more of its oil and gas properties, the Company's share of reserves, future production and therefore oil and/or and gas revenues, if any, from those properties will be reduced.

Third party pipelines and operators risk

Byron may from time to time, depend on third party platforms and pipelines that provide processing and delivery options from its facilities. As these platforms and pipelines are not owned or operated by Byron, their continued operation is not within Byron's control. Revenues in the future may be adversely affected if Byron's ability to process and transport oil or natural gas through those platforms and pipelines is impaired. If any of these platform operators ceases to operate their processing equipment, Byron may be required to shut in the associated wells, construct additional facilities or assume additional liability to re-establish production.

Oil and gas reserves estimation risk

There are numerous uncertainties in estimating crude oil and natural gas reserves and their value, including many factors that are beyond the control of the Company. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves. In order to prepare these estimates, Byron's independent third party petroleum engineers must project production rates and timing of development expenditures as well as analyse available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control and may prove to be incorrect over time. As a result, estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in the Company's reserve report have produced for a relatively short period of time. Accordingly, some of the Company's reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect the Company's financial condition, future prospects and market value.

Oil and gas reserves depletion risk

Byron's future oil and natural gas production depends on its success in finding or acquiring new reserves. If Byron fails to replace reserves, its level of production and cash flows will be adversely impacted. Production from oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Byron's total proved reserves will decline as reserves are produced unless it can conduct other successful exploration and development activities or acquire properties containing proved reserves, or both.

Further, all of Byron's proved reserves are proved developed producing or behind pipe. Accordingly, Byron does not have significant opportunities to increase production from its existing proved reserves. Byron's ability to make the necessary capital investment to maintain or expand its asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. Byron may not be successful in exploring for, developing or acquiring additional reserves. If Byron is not successful, its future production and revenues will be adversely affected.

Oil and gas drilling risk

Drilling for crude oil, natural gas and natural gas liquids are high-risk activities with many uncertainties that could adversely affect the Company's business, financial condition or results of operations.

The drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for crude oil, natural gas and natural gas liquids can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, Byron's drilling and producing operations may be curtailed, delayed or cancelled as a result of other factors, including, unusual or unexpected geological formations and miscalculations; pressures; fires; explosions and blowouts; pipe or cement failures; environmental hazards; such as natural gas leaks; oil spills; pipeline and tank ruptures; encountering naturally occurring radioactive materials and unauthorised discharges of toxic gases, brine, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment; loss of drilling fluid circulation; title problems; facility or equipment malfunctions; unexpected operational events; shortages of skilled personnel; shortages or delivery delays of equipment and services; compliance with environmental and other regulatory requirements; natural disasters; and adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, clean-up responsibilities, loss of wells, repairs to resume operations; and regulatory fines or penalties.

Operating risk

The oil and natural gas business, including production activities, involves a variety of operating risks, including blowouts, fires and explosions; surface cratering; uncontrollable flows of underground natural gas, oil or formation water; natural disasters; pipe and cement failures; casing collapses; stuck drilling and service tools; reservoir compaction; abnormal pressure formation; environmental hazards such as natural gas leaks, oil spills, pipeline and tank ruptures or unauthorised discharges of brine, toxic gases or well fluids; capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which Byron has no control; repeated shut-ins of Byron's well bores could significantly damage the Company's well bores; required workovers of existing wells that may not be successful.

If any of the above events occur, Byron could incur substantial losses as a result of injury or loss of life; reservoir damage; severe damage to and destruction of property or equipment; pollution and other environmental and natural resources damage; restoration, decommissioning or clean-up responsibilities; regulatory investigations and penalties; suspension of our operations or repairs necessary to resume operations.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, and in some instances operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, the Company could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

If Byron was to experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, any one of which could adversely affect its ability to conduct operations. In accordance with customary industry practices, Byron maintains insurance against some, but not all, of these risks. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The Company may not be able to maintain adequate insurance in the future at rates we consider reasonable, and particular types of coverage may not be available. An event that is not fully covered by insurance could have a material adverse effect on the Company's financial position and results of operations.

Execution risk (drilling and operating programs)

Shortages or increases in the cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect Byron's operations which could have a material adverse effect on its business, financial condition and results. Where Byron is the operator it assumes additional responsibilities and risks. As the designated operator, Byron, under the BOEM regulations, will be required to post bonds for exploration and development activities as well as for production activities and future decommissioning obligations. There is the risk that the Company may not be able to obtain sufficient bonding and may have to collateralise obligations with cash. If the Company was unable to provide such bonds, it would not be able to proceed with its operating plans. In addition, as the designated operator Byron will have to demonstrate the required oil spill financial responsibility ("OSFR") under the *Oil Pollution Act of 1990*. The OSFR is based on worst-case oil-spill discharge volume. Byron expects to demonstrate OSFR requirement through the purchase of OSFR insurance coverage, a method of demonstrating OSFR acceptable to the BOEM. If the Company was unable to demonstrate OSFR as required by the BOEM, it would not be able to proceed with its operating plans.

Geographic concentration risk

The geographic concentration of Byron's properties in the shallow waters in the GOM means that some or all of the properties could be affected by the same event should the Gulf of Mexico experience severe weather, delays or decreases in production, changes in the status of pipelines, delays in the availability of transport and changes in the regulatory environment.

Because all of the Company's properties could experience the same condition at the same time, these conditions could have a relatively greater impact on results of operations than they might have on other operators who have properties over a wider geographic area.

Climate change risk

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of Greenhouse Gases ("GHG"). These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. At the federal level, the United States Congress has from time to time considered climate change legislation, but no comprehensive climate change legislation has been adopted. The Environmental Protection Authority ("EPA"), however, has adopted regulations under the existing Clean Air Act to restrict emissions of GHG. For example, the EPA imposes preconstruction and operating permit requirements on certain large stationary sources that are already potential sources of certain other significant pollutant emissions. The EPA also adopted rules requiring the monitoring and reporting of GHG emissions on an annual basis from specified large GHG emission sources in the United States, including onshore and offshore oil and natural gas production facilities. Federal agencies have also begun directly regulating emissions of methane, a GHG, from oil and natural gas operations as described above. Compliance with these rules or other could result in increased compliance costs on Byron's operations.

At the international level, the United Nations sponsored Paris Agreement requires member states to submit non-binding, individually determined emissions reduction goals every five years after 2020. On 20 January 2021 President Biden issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which became effective on 19 February 2021.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing federal political risks in the United States. On 27 January 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the elimination of subsidies provided to the fossil fuel industry, increased production of offshore wind energy and increased emphasis on climate-related risks across governmental agencies and economic sectors. The Biden Administration has also taken actions to limit oil and gas development activities on the OCS. Other actions that could be pursued by the Biden Administration include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquefied natural gas export facilities, as well as more stringent emissions standards for oil and gas facilities. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. While Byron's business is not a party to any such litigation, the Company could be named in actions making similar allegations. An unfavourable ruling in any such case could significantly impact Byron's operations and could have an adverse impact on its financial condition.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy-related sectors. Institutional lenders who provide financing to fossil fuel energy companies also have become more attentive to sustainable lending practices, and some of them may elect not to provide funding for fossil fuel energy companies. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption of legislation or regulatory programs to reduce or eliminate future emissions of GHG could require Byron to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas Byron produces. Consequently, legislation and regulatory programs to reduce or eliminate future emissions of GHG could have an adverse effect on Byron's business, financial condition and results of operations. Also, political, financial and litigation risks may result in Byron restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes or impairing the ability to continue to operate in an economic manner.

Some scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. Byron's offshore operations are particularly at risk from severe climatic events. If any such effects of climate changes were to occur, they could have an adverse effect on the Company's financial condition and results of operations.

Finally, the growth of alternative energy supply options, such as renewables and nuclear, could also present a change to the energy mix that may reduce the value of oil and gas assets.

Competition risk

Competition in the oil and natural gas industry is intense which may make it more difficult for Byron to acquire further properties, market oil and gas and secure trained personnel. There is also competition for capital available for investment, particularly since alternative forms of energy have become more prominent. Most competitors possess and employ financial, technical and personnel resources substantially greater than those available to Byron. As a result increased costs of capital could have an adverse effect on Byron's business.

Environmental risk

The natural gas and oil business involves a variety of operating risks, including but not limited to (i) blowouts, fires and explosions, (ii) surface cratering, (iii) uncontrollable flows of underground natural gas, oil or formation water and natural disasters. If any of the above events occur, Byron could incur losses as a result of injury or loss of life, reservoir damage, damage to and destruction of property or equipment, pollution and other environmental damage, clean-up responsibilities and regulatory investigations and penalties.

The operation of our future oil and gas properties will be subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of the operations of our properties, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons.

Among the environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and the Company's business are the following: Waste Discharges, Air Emissions and Climate Change, Oil Pollution Act, National Environmental Policy Act, Worker Safety, Safe Drinking Water Act, Offshore Drilling, Hazardous Substances and Wastes and Protected and Endangered Species.

Oil and gas transport and processing risk

All of Byron's oil and natural gas is transported through gathering systems, pipelines and processing plants. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilised by other natural gas or oil shippers that may have priority transportation agreements. If the gathering systems, processing plants, platforms or Byron's transportation capacity is materially restricted or is unavailable in the future, the Company's ability to market its oil and/or natural gas could be impaired and cash flow from the affected properties could be reduced, which could have a material adverse effect on its financial condition and results of operations. Further, repeated shut-ins of Byron's wells could result in damage to its well bores that would impair its ability to produce from these wells and could result in additional wells being required to produce existing reserves.

Exchange rate risk

The functional currency of Byron is Australian dollars and the functional currency of its United States-based subsidiaries is United States dollars. Byron has historically presented its financial statements in United States dollars, as the United States dollar is viewed as the best measure of performance for Byron because oil and gas, the dominant sources of revenue, are priced in United States dollars and its oil and gas operations are located in the United States with costs incurred in United States dollars.

As all Byron's operating assets are in the United States, the Company's presentation currency, the currency in which it reports its financial results, will be United States dollars. Accordingly, an Australian dollar investment in the Company is exposed to fluctuations between the Australian dollar and the United States dollar exchange rate. In particular, as most of the Company's capital and operating expenses will be in United States dollars any appreciation/depreciation in the Australian dollar against the United States dollar will effectively decrease/increase the quantum of those costs for shareholders. In addition, the Company's revenue is derived from United States dollar oil and gas sales. Any appreciation/depreciation of the Australian dollar against the United States dollar will effectively reduce/increase the value of that revenue for shareholders.

Adverse exchange rate variations between the Australian dollar and the United States dollar may impact upon cash balances held in Australian dollars. Since most of Byron's operations are conducted in United States dollars, Byron generally maintains a substantial portion of its cash balances in United States dollar accounts. From time to time the Company may have substantial cash deposits in Australian dollar accounts. Until these funds are converted into United States dollars, the United States dollar value of the deposits will change as the exchange rate between the two currencies fluctuates.

The Company does not currently have in place any foreign exchange hedging arrangements. However, foreign exchange hedging strategies will be reviewed by the Company from time to time, implementation of any strategy will depend, inter alia, upon the foreign exchange hedging options available to the Company from time to time, the cash cost of entering into hedging transactions and the Company's capacity to pay for such costs.

Key management risk

To a large extent, the Company depends on the services of its senior management. The loss of the services of any of the senior management team, could have a negative impact on the Company's operations. Byron does not maintain or plan to obtain for the benefit of the Company any insurance against the loss of any of these individuals.

Regulatory risk

Byron's oil and gas operations in the Gulf of Mexico, USA are subject to regulation at the USA federal, state and local level and some of the laws, rules and regulations that govern operations carry substantial penalties for non-compliance. Rules and regulations affecting the oil and gas industry are under constant review for amendment or expansion. In addition to possible increased costs, the imposition of increased regulatory based procedures may result in delays in being able to initiate or complete drilling programs.

Executive Order 3395 went into effect on 20 January 2021 and has had no material effect on the process for permits on existing leases. Executive Order 3395 suspends new leasing activities for oil and gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and gas permitting and leasing practices but does not apply to existing leases.

The Company continues to conduct operations on its existing leases in the OCS. However, uncertainty on future Biden Administration actions in relation to offshore oil and gas activities on the OCS together with the issuance of any future executive orders or adoption and implementation of laws, rules or initiatives that further restrict, delay or result in cancellation of existing oil and gas activities on the OCS could have a material adverse effect on business and operations.

Seismic risk

3D seismic data and visualisation techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically.

Lease termination risk

The failure to timely effect all lease-related payments could cause the leases to be terminated by the BOEM.

Working interest partners' risk

If partners are not able to fund their share of costs, it could result in the delay or cancellation of future projects, resulting in a reduction of Byron's reserves and production, which could have a materially adverse effect on its financial condition and results of operations.

Profitability and impairment write-downs risk

Byron may incur non-cash impairment charges in the future, which could have a material adverse effect on its results of operations for the periods in which such charges are taken.

Bonding risk

As an operator, Byron is required to post surety bonds of US$200,000 per lease for exploration and US$500,000 per lease for developmental activities as part of its general bonding requirements, as well as the posting of additional supplemental bonds to cover, among other things, decommissioning obligations. A failure by an operator to post required supplemental bonding or other financial assurances required by the BOEM could result in the BOEM assessing monetary penalties or requiring any operations on an operator's federal lease to be suspended or cancelled or otherwise subject an operator to monetary penalties. Any one or more such actions imposed on us could materially adversely affect Byron's financial condition and results of operations.

Cyber security risk

The oil and gas industry is increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and distribution activities. For example, companies depend on digital technologies to interpret seismic data, conduct reservoir modelling and record financial and other data. The Company also depends on digital technology, including information systems and related infrastructure as well as cloud application and services, to process and record financial and operating data, communicate with its employees and business partners, analyse seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to its business. The Company's business partners, including vendors, service providers, co-venturers, product purchasers, and financial institutions, are also dependent on digital technology. The complexity of the technologies needed to explore for and develop oil and gas, and global competition for oil and gas resources make certain information more attractive to thieves.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorised access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites.

The Company's technologies, systems, networks, and those of its business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorised release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of its business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. A cyber-incident involving our information systems and related infrastructure, or that of the Company's business partners, could disrupt its business plans and negatively impact operations. Although to date, Byron has not experienced any material cyber-attacks, there can be no assurance that the Company will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident. As cyber threats continue to evolve, Byron may be required to expend significant additional resources to continue to modify or enhance its protective measures or to investigate and remediate any information security vulnerabilities

Level of indebtedness risk

Byron's debt level and the covenants in current or future agreements governing the Company's debt including the Secured Promissory Note ("Promissory Note") issued to Crescent Midstream Operating, LLC (formerly Crimson Midstream Operating, LLC), could negatively impact the Company's financial condition, results of operations and business prospects. Byron's level of indebtedness could affect its operations in several ways, including the following:

- a significant portion or all of cash flows, when generated, could be used to service indebtedness;
- a high level of indebtedness could increase vulnerability to general adverse economic and industry conditions; and
- the covenants contained in the Promissory Note will inter-alia limit ability to borrow additional funds and dispose of assets.

Hedging activities risks

To achieve more predictable cash flows and to reduce exposure to adverse fluctuations in the prices of oil and natural gas, the Company has and may in the future enter into hedging arrangements for a portion of oil and natural gas production, including, forward sale agreements and derivatives such as puts, collars and fixed-price swaps. Changes in the fair value of derivative instruments are recognised in earnings. Accordingly, earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose the Company to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price and actual prices received in the derivative instrument.

In addition, hedging arrangements may limit the benefit the Company could receive from increases in the prices for oil and natural gas and may expose the Company to cash margin requirements in certain cases.

Asset retirement obligations (AROs) risk

Byron is required to record a liability for the present value of AROs to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment and to restore land and seabed when production finishes. Estimating future costs is uncertain because most obligations are many years in the future, regulatory requirements will change and technologies are evolving which may make it more expensive to meet these obligations.

Insurance risk

In accordance with industry practice Byron maintains insurance against some, but not all, of the operating risks to which its business is exposed. Byron will not be insured against all potential risks and liabilities. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable.

Epidemic or outbreak of an infectious disease risk

Byron faces risks related to epidemics, outbreaks or other public health events that are outside of its control, and could significantly disrupt operations and adversely affect the Company's financial condition. The global or national outbreak of an illness or other communicable disease, or any other public health crisis, such as COVID-19, may cause disruptions to the Company's business and operational plans, which may include but is not limited to (i) shortages of employees, (ii) unavailability of contractors or subcontractors, (iii) restrictions imposed by government and health authorities, including quarantines, to address an outbreak and (iv) restrictions imposed by the Company's contractors and customers, including facility shutdowns, to ensure the safety of employees. In addition, the effects of COVID-19 and concerns regarding its global spread could negatively impact the domestic and international demand for crude oil and natural gas, which could contribute to price volatility, impact the price Byron receives for oil and natural gas and materially and adversely affect the demand for and marketability of our production. The potential impact from COVID-19, both now and in the future, is difficult to predict, and the extent to which it may negatively affect Byron's operating results or the duration of any potential business disruption is uncertain. Any potential impact will depend on future developments and new information that may emerge regarding the COVID-19 infection rate or the efficacy and distribution of COVID-19 vaccines, and the actions taken by authorities to contain it or treat its impact, all of which are beyond the Company's control. These potential impacts, while uncertain, could adversely affect the Company's operating results.

Share market investment risk

The Company's shares are quoted on the ASX, where their price may rise or fall. The shares carry no guarantee in respect of profitability, dividends or return of capital, or the price at which they may trade on the ASX. The value of the shares will be subject to the market and hence a range of factors outside of the control of the Company and the directors and officers of the Company. Returns from an investment in the shares may also depend on general share market conditions, as well as the performance of the Company

Historically, the stock market has experienced significant price and volume fluctuations. Stock market volatility and volatility in commodity prices has had a significant impact on the market price of securities issued by many companies, including companies in the oil and gas industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of the Company's shares could fluctuate based upon factors that have little or nothing to do with Byron, and these fluctuations could materially reduce its share price.

The Company's board of directors presently intends to retain all of our earnings for the expansion of the business; therefore, there are no plans to pay regular dividends. Any payment of future dividends will be at the discretion of the board of directors and will depend on, among other things, earnings, financial condition, capital requirements, level of indebtedness and other considerations that the board of directors deems relevant.

Future sales or the availability for sale of substantial amounts of the Company's shares in the public market could adversely affect the prevailing market price of Byron's shares and could impair its ability to raise capital through future issues of equity securities.

Significant events after the balance date

There has been no matter or circumstance since 30 June 2021 which has significantly affected or may significantly affect the operations of the consolidated entity, the results of those operations or the state of affairs of the consolidated entity in subsequent financial years other than those described below:

- on 5 August 2021, Byron announced to the ASX that the Enterprise Offshore Drilling 351 jack-up drilling rig has passed all US Coast Guard and Bureau of Safety and Environmental Enforcement inspections, final drilling permits were approved and was ready to be towed to the South Marsh Island 69 E platform from which the SM69 E2 well will be drilled;
- on 30 August 2021, Byron announced that all platforms were safely evacuated on Friday 27 August 2021 (USCDT) with production shut-in at all platforms, ahead of Hurricane Ida. The Enterprise Offshore Drilling 351 ("EOD 351") jack-up drilling rig was also evacuated and drilling operations suspended;
- on 3 September 2021, Byron announced that the passage of Hurricane Ida, approximately 110 miles east of the Company's assets in the Gulf of Mexico and did not cause any damage to Byron's Gulf of Mexico production facilities or the EOD 351 rig;
- on 13 September 2021, Byron announced that oil pay was logged in South Marsh Island 69 E2 well and oil and gas production and sales had restarted from all wells on the Byron operated SM71 F and SM58 G platforms; and
- on 28 September 2021, Byron released its 2021 reserves and resources report.

Future developments

It is expected that the consolidated entity will continue its oil and gas exploration, development and production activities in the shallow waters of the Gulf of Mexico, USA.

Further information regarding likely developments are not included in this report. As the Company is listed on the Australian Securities Exchange ("ASX"), it is subject to the continuous disclosure requirements of the ASX Listing Rules which require immediate disclosure to the market of information that is likely to have a material effect on the price or value of Byron Energy Limited's securities.

Dividends

No dividends in respect of the current financial year have been paid, declared or recommended for payment (2020: nil).

Environmental regulation

The consolidated entity's operations are not regulated by any significant environmental regulation under a law of the Commonwealth or of any state or territory of Australia. The consolidated entity's oil and gas exploration activities are subject to significant environmental regulation under United States of America Federal and State legislation.

The directors are not aware of any breach of environmental compliance requirements relating to the consolidated entity's activities during the year.

Non-audit services

Deloitte Touche Tohmatsu did not provide non-audit services to the Company during the financial year.

Auditor independence declaration

A copy of the auditor's independence declaration under s.307C of the *Corporation Act 2001* in relation to the audit of the full year is included in this report.

Indemnification and insurance of officers and auditors

During the financial year the Company paid an insurance premium in respect of directors' and officers' liability for the current directors and officers including the Company Secretary. Under the terms of the policy the premium amount, coverage and other terms of the policy have been agreed to be confidential and not to be disclosed.

The Company has not otherwise, during or since the financial year, except to the extent permitted by law, indemnified or agreed to indemnify an officer or auditor of the Company or of any related body corporate against a liability incurred as such an officer or auditor.

Significant changes in the state of affairs

During the financial year, there were no significant changes in the state of affairs of the consolidated entity, other than those set out in the Review of Operations.

Directors' meetings

The charter for the Audit and Risk Management Committee was adopted on 12 July 2007 and most recently amended on 25 June 2014. The current members of the committee consist of Paul Young (Chairman) and Charles Sands.

During the year there was four Board meetings and three Audit and Risk Management Committee meetings held. The numbers of meetings attended by each director were as follows:

	Board of directors		Audit and Risk Management Committee	
Directors	**Entitled to attend**	**Attended**	**Entitled to attend**	**Attended**
Douglas G Battersby	4	4	-	-
Maynard V Smith	4	4	-	-
Prent H Kallenberger	4	4	-	-
Charles J Sands	4	4	3	3
Paul A Young	4	4	3	3
William R Sack	4	4	-	-

Remuneration Report – audited

This Remuneration Report, which forms part of the Directors' Report, sets out information about the remuneration of the Group's directors and other key management personnel for the financial year ended 30 June 2021. The prescribed details for each person covered by this report are detailed below.

Details of directors and other key management personnel

Directors and other key management personnel of the Company during and since the end of the financial year are as follows:

Directors

Douglas G Battersby

Maynard V Smith

Prent H Kallenberger

Charles J Sands

Paul A Young

William R Sack

Key management personnel

Nick Filipovic – Chief Financial Officer and Company Secretary

The Remuneration Report is set out below under the following main headings:

A. Principles and agreements; and

B. Remuneration of directors and other key management personnel

A. Principles and agreements

Remuneration levels are set to attract and retain appropriately qualified and experienced directors and executives. The Board is responsible for remuneration policies and practices. The Board may seek independent advice on remuneration policies and practices, including compensation packages and terms of employment.

The directors' and key management personnel remuneration levels are not directly dependent upon the Company or consolidated entity's performance or any other performance conditions.

Directors' remuneration is inclusive of committee fees.

Additional information

The Corporations Act requires disclosure of the Company's remuneration policy to contain a discussion of the Company's earnings and performance and the effect of the Company's performance on shareholder wealth in the reporting period and the four previous financial years. The table below provides a five-year financial summary.

	30 June 2017 US$	30 June 2018 US$	30 June 2019 US$	30 June 2020 'US$	30 June 2021 US$
Revenue (net of royalties)	-	9,544,507	31,324,061	21,402,255	**35,837,228**
Net profit (loss) before tax	(5,357,583)	1,298,968	5,718,988	68,348	**5,854,375**
Net profit (loss) after tax	(5,357,583)	1,298,968	5,718,988	68,348	**5,854,375**
Share price at start of year	A$0.15	A$0.095	A$0.335	A$0.29	**A$0.14**
Share price at end of year	A$0.095	A$0.355	A$0.29	A$0.14	**A$0.10**
Basic earnings per share	(US$0.02)	US$0.0022	US$0.0083	US$0.000088	**US$0.005633**
Diluted earnings per share	(US$0.02)	US$0.0022	US$0.0080	US$0.000086	**US$0.005587**

(i) Non-executive directors

The ASX Listing Rules provide that the aggregate remuneration of non-executive directors shall be determined from time to time by a general meeting of shareholders. The latest determination was at the Extraordinary General Meeting held on 22 April 2013 when shareholders approved an aggregate remuneration of A$300,000 per annum.

The amount of aggregate remuneration sought to be approved by shareholders and the fee structure is reviewed annually.

The Chairman, Douglas Battersby, is paid an annual non-executive director's fee of A$80,000, paid pro-rata on a quarterly basis, as well as reimbursement of costs relating incurred by him in his performance of his duties as a director.

Non-executive directors, Charles Sands and Paul Young, are paid an annual non-executive director's fee of A$40,000 each, paid pro-rata on a quarterly basis, as well as reimbursement of costs incurred by them relating to their performance as directors.

There are no termination or retirement benefits for non-executive directors (other than statutory superannuation where applicable).

(ii) Executive directors and key management personnel

Remuneration levels of executive directors and key management personnel are set to attract and retain appropriately qualified and experienced directors and executives. This involves assessing the appropriateness of the nature and amount of remuneration on a periodic basis by reference to market conditions, length of service and particular experience of the individual concerned.

While the remuneration packages may include a mix of fixed and variable remuneration, short and long-term performance-based incentives. The remuneration packages are reviewed annually by the Board as required.

Currently the remuneration package comprises fixed cash payments.

The Board may at its discretion, put in place short-term incentive scheme with amounts and basis to be determined by the Board. The Board may also issue options over unissued shares to executives from time to time, at the discretion of the Board and subject to shareholder approval as a form of a long-term incentive scheme.

Remuneration packages may include a mix of fixed and variable remuneration, short and long-term performance-based incentives. The remuneration packages are reviewed annually by the Board as required.

Remuneration and other terms of employment of the Chief Executive Officer (Maynard Smith), Executive Director and Chief Operating Officer (Prent Kallenberger), Executive Director (William Sack) and the CFO/Company Secretary (Nick Filipovic) are detailed below.

Fixed remuneration for executive directors and key management personnel

Maynard Smith

The Company entered into a new service agreement with Maynard Smith via a company of which Mr Smith is a director on 15 September 2017. Mr Smith's contract is for a period of three years, at an initial annual rate of A$160,000 plus reasonable and justifiable business expenses, with an automatic extension for a further one year unless the parties elect to terminate the contract at the end of three years. The contract is further terminable by either party "for cause" immediately on notice and otherwise "without cause" on 90 days' notice. On 26 June 2018 the Company announced that the annual service fee payable in respect of Mr Smith's services was increased from A$160,0000 to A$550,000 (excluding GST) per annum, effective 1 July 2018. All other terms and conditions of the service agreement remained unchanged.

Effective 1 January 2020, the annual service fee was increased from A$550,000 to A$605,000.

In addition, Mr Smith is eligible to participate in the Company's short and long-term incentive scheme as determined by the Board from time to time.

It is expected that Mr Smith will enter into a new service agreement prior to the Company's 2021 annual general meeting.

Prent Kallenberger

The Company entered into an employment agreement with Prent Kallenberger for three years commencing on 15 September 2017 with an automatic extension for a further one year unless the parties elect to terminate the contract at the end of three years. The contract is further terminable by the Company "for cause" immediately on notice and otherwise "without cause" on 90 days' notice. Under the agreement, Mr Kallenberger's remuneration is US$350,000 per annum in fixed remuneration plus medical insurance.

Effective 1 January 2020, Mr Kallenberger's remuneration was increased from US$350,000 to US$385,000.

In addition, Mr Kallenberger is eligible to participate in the Company's short and long-term incentive scheme as determined by the Board from time to time.

It is expected that Mr Kallenberger will enter into a new employment agreement prior to the Company's 2021 annual general meeting.

William Sack

The Company entered into an employment agreement with William Sack for three years commencing on 15 September 2017 with an automatic extension for a further one year unless the parties elect to terminate the contract at the end of three years. The contract is further terminable by the Company "for cause" immediately on notice and otherwise "without cause" on 90 days notice. Under the agreement Mr Sack's remuneration is US$350,000 plus medical insurance and reasonable and justifiable business expenses.

Effective 1 January 2020, Mr Sack's remuneration was increased from US$350,000 to US$385,000.

In addition, Mr Sack is eligible to participate in the Company's short and long term incentive scheme as determined by the Board from time to time.

It is expected that Mr Sack will enter into a new employment agreement prior to the Company's 2021 annual general meeting.

Nick Filipovic

The Company has a letter agreement with Nick Filipovic. Under Mr Filipovic's letter of engagement, he is entitled to a gross salary of A$300,000 per annum plus superannuation at the statutory rate. Byron may terminate Mr Filipovic's employment at any time by giving 90 days' notice or in case of serious misconduct employment may be terminated without notice. Should Mr Filipovic resign from Byron he will need to give 90 days' notice.

Effective 1 January 2020, Mr Filipovic's base remuneration was increased from A$300,000 to A$330,000.

In addition, Mr Filipovic is eligible to participate in the Company's short and long-term incentive scheme as determined by the Board from time to time.

B. Remuneration of directors and key management personnel

Options

No share options were granted to the executive directors or key management personnel during the financial year and there are no Employee Share Option plans in place.

In January 2020 Byron issued 9,500,000 new shares to key management personnel, other senior staff and consultants following exercise of 9,500,000 unlisted options at A$0.25 each. The issue of these options was approved by shareholders on 24 November 2016. The Company provided unsecured three-year interest-free loans to the option holders to fund the acquisition of the shares issued as a consequence of the exercise of options. The interest-free loans were approved by shareholders at the Company's 2019, annual general meeting held on 29 November 2019, and granted to key management personnel during the financial year. Loans outstanding as of 30 June 2021 are:

Key management personnel (borrower)	Principal sum (A$)	Interest rate %	Term
Maynard Smith	625,000	Nil	3 years
Prent Kallenberger	625,000	Nil	3 years
William Sack	625,000	Nil	3 years
Nick Filipovic	250,000	Nil	3 years

At the end of the term, each borrower is required to repay the amounts outstanding under the loans. If a borrower does not repay a loan, the Company may demand that a borrower dispose of sufficient loan funded shares to satisfy up to the total amount owing under the loan. The Company's recourse against each borrower for repayment of the loans is limited to the proceeds of the loan funded shares.

At the end of the financial year, the following share-based payment arrangements were in existence:

Grantee	Number	Grant date	Vesting date	Expiry date	Exercise price	Fair value at grant date
M Smith	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
M Smith	2,100,000	22 Nov 2018	22 Nov 2018	31 Dec 2021	A$0.40	A$0.0837
P Kallenberger	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
P Kallenberger	2,100,000	22 Nov 2018	22 Nov 2018	31 Dec 2021	A$0.40	A$0.0837
W Sack	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
W Sack	2,100,000	22 Nov 2018	22 Nov 2018	31 Dec 2021	A$0.40	A$0.0837
N Filipovic	3,780,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
N Filipovic	1,000,000	22 Nov 2018	22 Nov 2018	31 Dec 2021	A$0.40	A$0.0837

These options are transferrable and not quoted. They may be exercised at any time after vesting date.

Other transactions with key management personnel of the Group

Loans from directors and shareholders

Loans

In March 2019, the Company entered into unsecured loan agreements, bearing interest at 10% per annum, with four of the Company's directors, for a total drawdown of US$2,000,000 and A$1,750,000. The loans were due for repayment in November 2019, however the directors agreed to extend the loan repayment date to March 2022 and interest payments have been made on a quarterly basis. The individual directors' transactions and balances for these loans were:

- Veruse Pty Ltd, a company controlled by Mr Douglas Battersby, a director of the Company, provided an unsecured loan of A$1,400,000 to the Company and interest paid for the financial year to June 2021 was A$140,000, plus A$11,507 has been accrued as at 30 June 2021;
- Clapsy Pty Ltd, a company controlled by Mr Paul Young, a director of the Company, provided an unsecured loan of A$175,000 to the Company and interest paid for the financial year to June 2021 was A$17,500, plus A$1,438 has been accrued as at 30 June 2021;
- Poal Pty Ltd, a company controlled by Mr Paul Young, a director of the Company, provided an unsecured loan of A$175,000 to the Company and interest paid for the financial year to June 2021 was A$17,500, plus A$1,438 has been accrued as at 30 June 2021;
- Geogeny Pty Ltd, a company controlled by Mr Maynard Smith, a director of the Company, provided an unsecured loan of US$1,000,000 to the Company and interest paid for the financial year to June 2021 was US$100,000, plus US$8,219 has been accrued as at 30 June 2021; and
- Mr Charles Sands, a director of the Company, provided an unsecured loan of US$1,000,000 to the Company and interest paid for the financial year to 30 June 2021 was US$90,036 (net of withholding taxes), plus US$7,397 (net of withholding taxes) has been accrued as at 30 June 2021.

Additional information – key management personnel equity and share option holdings

The interests of each director and other key management personnel (directly and indirectly), in the shares and options of Byron Energy Limited are as follows:

Ordinary shares

Director/key management personnel	Balance on 30 June 2020 Number	Granted as compensation Number	Received on exercise of options Number	Via share placement Number	Shares purchased/ (sold) Number	Balance on 30 June 2021 Number
D Battersby	52,635,183	-	-	4,615,385	-	**57,250,568**
M Smith	36,779,510	-	-	3,846,154	-	**40,625,664**
P Kallenberger	4,232,223	-	-	176,539	-	**4,408,762**
C Sands	21,818,475	-	-	2,892,308	-	**24,710,783**
P Young	22,737,388	-	-	4,615,385	-	**27,352,773**
W Sack	6,300,001	-	-	600,000	-	**6,900,001**
N Filipovic	3,041,359	-	-	-	(320,000)	**2,721,359**

During the financial year, no shares or share options were granted to directors or other key management personnel of the Company. In July 2020 the Company issued 16,745,771 ordinary shares at A$0.13 per share to directors and/or their associates. This issue was approved at a shareholders' meeting on 9 July 2020 and was part of the placement of shares by the Company announced on 19 May 2020.

Share options over ordinary shares

Director/key management personnel	Balance on 30 June 2020 Number	Granted as compensation Number	Exercise of options Number	Expired options Number	Balance on 30 June 2021 Number
M. V. Smith	8,400,000	-	-	-	**8,400,000**
P. H. Kallenberger	8,400,000	-	-	-	**8,400,000**
W. R. Sack	8,400,000	-	-	-	**8,400,000**
N. Filipovic	4,780,000	-	-	-	**4,780,000**

During the financial year no share options were issued and none were converted to ordinary shares.

2021	Short-term employee benefits				Post-employment benefits	Share-based payments	
	Salaries and fees US$	Short-term cash incentive US$	Other benefits US$	Service agreements US$	Super-annuation US$	100% vested share options US$	Total US$
Directors							
D Battersby	-	-	-	59,744	-	-	59,744
M Smith	-	-	-	451,814	-	-	451,814
P Kallenberger	385,000	-	31,236	-	-	-	416,236
C Sands	29,872	-	-	-	-	-	29,872
P Young	29,872	-	-	-	2,838	-	32,710
W Sack	385,000	-	30,391	-	-	-	415,391
N Filipovic	246,444	-	-	-	23,412	-	269,856
	1,076,188	-	61,627	511,558	26,250	-	1,675,623

The above salaries and fees, other benefits and service agreement payments are not performance related.

2020	Short-term employee benefits				Post-employment benefits	Share-based payments	
	Salaries and fees US$	Short-term cash incentive US$	Other benefits US$	Service agreements US$	Super-annuation US$	100% vested share options US$	Total US$
Directors							
D Battersby	-	-	-	53,712	-	-	53,712
M Smith	-	-	-	387,734	-	247,545	635,279
P Kallenberger	367,500	-	28,658	-	-	247,545	643,703
C Sands	26,856	-	-	-	-	-	26,856
P Young	26,856	-	-	-	2,551	-	29,407
W Sack	367,500	-	29,916	-	-	247,545	644,961
N Filipovic	211,491	-	-	-	20,092	99,018	330,601
	1,000,203	-	58,574	441,446	22,643	841,653	2,364,519

Bonuses

Nil bonuses were granted to executive directors and the key management personnel during the financial year ended 30 June 2021 (2020: US$ nil).

End of Remuneration Report.

This Directors' Report is signed in accordance with a resolution of directors made pursuant to s.298(2) of the *Corporations Act 2001*.

On behalf of the directors

D Battersby
Chairman

30 September 2021

Auditor’s Independence Declaration

Deloitte.

Deloitte Touche Tohmatsu
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30 September 2021

The Board of Directors
Byron Energy Limited
Level 4, 480 Collins Street
MELBOURNE VIC 3000

Dear Board Members

Byron Energy Limited

In accordance with section 307C of the *Corporations Act 2001*, I am pleased to provide the following declaration of independence to the directors of Byron Energy Limited.

As lead audit partner for the audit of the financial statements of Byron Energy Limited for the financial year ended 30 June 2021, I declare that to the best of my knowledge and belief, there have been no contraventions of:

(i) the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and

(ii) any applicable code of professional conduct in relation to the audit.

Yours sincerely

Deloitte Touche Tohmatsu

DELOITTE TOUCHE TOHMATSU

Craig Bryan
Partner
Chartered Accountants

Consolidated Statement of Profit or Loss and Other Comprehensive Income

For the Financial Year Ended 30 June 2021

	Note	Consolidated 2021 US$	Consolidated 2020 US$
Continuing operations			
Revenues from sale of oil and gas		**43,260,597**	26,243,322
Royalty expense		**(7,423,369)**	(4,841,067)
Cost of sales	2	**(20,793,128)**	(8,915,892)
Gross profit		**15,044,100**	12,486,363
Recoupment of operator overheads		**297,799**	299,269
Realised loss on forward commodity price contracts	16	**(369,734)**	-
Corporate and administration costs		**(2,547,239)**	(2,507,071)
Impairment expense/dry hole expense	8(a)	**(595,951)**	(5,397,975)
Share-based payments		**-**	(940,671)
Depreciation/amortisation of property, plant and equipment		**(560,354)**	(359,334)
Other expenses		**(1,986,508)**	(1,715,463)
Financial income	3	**53,337**	19,355
Financial expense	3	**(3,481,075)**	(1,816,125)
Profit before tax		**5,854,375**	68,348
Income tax expense	4	**-**	-
Profit for the year from continuing operations		**5,854,375**	68,348
Other comprehensive income, net of income tax			
Items that may subsequently be reclassified to profit and loss			
Cumulative loss on oil price cash flow hedges reclassified to profit and loss	18	**123,570**	(123,570)
Oil price financially settled swaps written down to fair value	18	**(428,596)**	-
Exchange differences on translating the parent entity group		**99,922**	(15,174)
Total comprehensive profit/(loss) for the year		**5,649,271**	(70,396)
Earnings per share			
Basic (cents per share)	5	**0.5633**	0.0088
Diluted (cents per share)	5	**0.5587**	0.0086

The accompanying notes form part of these financial statements.

Consolidated Statement of Financial Position

At 30 June 2021

	Note	Consolidated 2021 US$	Consolidated 2020 US$
Assets			
Current assets			
Cash and cash equivalents	21(b)	**4,143,411**	16,644,701
Trade and other receivables	6	**4,197,380**	1,851,462
Derivative financial instruments	16(a)	**-**	214,990
Other	7	**2,291,909**	3,137,974
Total current assets		**10,632,700**	21,849,127
Non-current assets			
Exploration and evaluation assets	8(a)	**5,150,621**	4,695,861
Oil and gas properties	8(b)	**95,433,081**	75,191,591
Other (refundable bonds)	7	**1,925,000**	1,925,000
Right-of-use assets	9	**1,454,296**	988,700
Trade and other receivables	6	**180,398**	251,365
Property, plant and equipment	11	**31,472**	40,476
Other intangible assets	12	**25,275**	165,329
Total non-current assets		**104,200,143**	83,258,322
Total assets		**114,832,843**	105,107,449
Liabilities			
Current liabilities			
Trade and other payables	13	**2,022,359**	4,545,285
Provisions	14	**173,682**	144,462
Derivative financial instruments	16(b)	**476,913**	-
Lease liabilities	10	**509,143**	309,440
Borrowings	15	**16,302,006**	5,868,817
Total current liabilities		**19,484,103**	10,868,004
Non-current liabilities			
Provisions	14	**7,183,789**	5,080,192
Lease liabilities	10	**1,291,722**	1,042,002
Borrowings	15	**5,640,364**	14,066,230
Total non-current liabilities		**14,115,875**	20,188,424
Total liabilities		**33,599,978**	31,056,428
Net assets		**81,232,865**	74,051,021
Equity			
Issued capital	17	**139,093,311**	137,560,738
Foreign currency translation reserve	18	**(46,718)**	(146,640)
Cash flow hedge reserve	18	**(428,596)**	(123,570)
Share option reserve	18	**6,305,069**	6,305,069
Accumulated losses		**(63,690,201)**	(69,544,576)
Total equity		**81,232,865**	74,051,021

The accompanying notes form part of these financial statements.

Consolidated Statement of Changes In Equity

For the Financial Year Ended 30 June 2021

Consolidated entity	Ordinary share capital US$	Share option reserve US$	Other reserves US$	Accumulated losses US$	Total US$
Balance at 1 July 2019	101,091,750	5,364,398	(131,466)	(69,612,924)	36,711,758
Profit for the year	-	-	-	68,348	68,348
Change in value of cash flow hedges	-	-	(123,570)	-	(123,570)
Exchange differences arising on translation of the parent entity group	-	-	(15,174)	-	(15,174)
Total comprehensive profit for the year	-	-	(138,744)	68,348	(70,396)
The issue of 10,000,000 shares at A$0.25 per share upon conversion of 10,000,000 share options	1,742,000	-	-	-	1,742,000
The placement of 53,961,055 shares at a subscription price of A$0.27 cents per share	9,856,532	-	-	-	9,856,532
42,075,806 shares were issued at A$0.27 cents per share under an entitlement offer	7,838,723	-	-	-	7,838,723
The placement of 106,331,150 shares at a subscription price of A$0.13 cents per share	9,091,420	-	-	-	9,091,420
The issue of 106,307,903 shares under an SPP at a subscription price of A$0.13 cents per share	9,481,921	-	-	-	9,481,921
Equity raising costs	(1,541,608)	-	-	-	(1,541,608)
Recognition of share-based payments	-	940,671	-	-	940,671
Balance at 30 June 2020	137,560,738	6,305,069	(270,210)	(69,544,576)	74,051,021
Balance at 1 July 2020	**137,560,738**	**6,305,069**	**(270,210)**	**(69,544,576)**	**74,051,021**
Profit for the year	**-**	**-**	**-**	**5,854,375**	**5,854,375**
Change in value of financially settled swaps written down to fair value	**-**	**-**	**(428,596)**	**-**	**(428,596)**
Change in value of cash flow hedges	**-**	**-**	**123,570**	**-**	**123,570**
Exchange differences arising on translation of the parent entity group	**-**	**-**	**99,922**	**-**	**99,922**
Total comprehensive profit for the year	**-**	**-**	**(205,104)**	**5,854,375**	**5,649,271**
The placement of 16,745,771 shares at a subscription price of A$0.13 cents per share	**1,532,573**	**-**	**-**	**-**	**1,532,573**
Equity raising costs	**-**	**-**	**-**	**-**	**-**
Balance at 30 June 2021	**139,093,311**	**6,305,069**	**(475,314)**	**(63,690,201)**	**81,232,865**

The accompanying notes form part of these financial statements.

Consolidated Statement of Cash Flows

For the Financial Year Ended 30 June 2021

	Note	Consolidated 2021 US$	2020 US$
Cash flows from operating activities			
Receipts from customers		**42,674,868**	27,810,063
Payments to suppliers and employees		**(18,187,987)**	(12,378,278)
Interest paid		**(3,136,320)**	(1,764,529)
Interest received		**1,499**	12,815
Net cash flows from operating activities	21(a)	**21,352,060**	13,680,071
Cash flows from investing activities			
Payments for development of oil and gas properties		**(34,007,000)**	(50,934,070)
Payments for exploration and evaluation assets		**(1,034,993)**	(3,033,962)
Purchases of oil price hedge instruments designated at FVTOCI		**-**	(338,560)
Payments for property, plant and equipment		**-**	(840)
Net cash flows used in investing activities		**(35,041,993)**	(54,307,432)
Cash flows from financing activities			
Proceeds from issues of ordinary shares		**1,532,573**	36,268,595
Proceeds from exercise of share options		**-**	1,742,000
Payment of equity raising costs		**(35,919)**	(1,505,688)
Repayment of lease liabilities		**(499,828)**	(248,103)
Repayment of borrowings		**(3,417,003)**	(3,690,500)
Proceeds from borrowings		**3,500,000**	17,990,210
Net cash flows from financing activities		**1,079,823**	50,556,514
Net (decrease)/increase in cash and cash equivalents held		**(12,610,110)**	9,929,153
Cash and cash equivalents at the beginning of the year		**16,644,701**	6,783,320
Effect of exchange rate changes on the balance of cash held in foreign currencies		**108,820**	(67,772)
Cash and cash equivalents at the end of the year	21(b)	**4,143,411**	16,644,701

The accompanying notes form part of these financial statements.

Notes to the Financial Statements
For the Financial Year Ended 30 June 2021

1. Summary of significant accounting policies

Statement of compliance

These financial statements are general purpose financial statements which have been prepared in accordance with the *Corporations Act 2001*, Accounting Standards and Interpretations, and comply with other requirements of the law.

The financial statements comprise the consolidated financial statements of the Group. For the purposes of preparing the consolidated financial statements, the Company is a for-profit entity.

Accounting Standards include Australian Accounting Standards. Compliance with Australian Accounting Standards ensures that the financial statements and notes of the Company and Group comply with International Financial Reporting Standards ("IFRS").

The financial statements were authorised for issue by the directors on 30 September 2021.

The following significant policies have been adopted in the preparation and presentation of the financial statements:

Basis of preparation

The Financial Report has been prepared on the basis of historical cost. Historical cost is based on the fair values of the consideration given in exchange for goods and services. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. All amounts are presented in United States of America dollars, unless otherwise noted.

Critical accounting judgements and key sources of estimation uncertainty

The preparation of the consolidated financial statements requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expense. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised and in any future periods affected.

In particular, information about significant areas of estimation uncertainty and critical judgements in applying accounting policies that have the most significant effect on the amount recognised in the financial statements are described in notes 1(c) Oil and gas properties (amortisation based upon estimates of proved and probable reserves), 1(d) Impairment and on the amounts recognised in the financial statements are described in note 8 Exploration and evaluation assets / Oil and gas properties.

Another area of estimation uncertainty relates to the future cost to remove oil and gas production facilities, abandonment of wells and restoring the affected areas. The provision for future restoration is the best estimate of the present value of the expenditure required to settle the obligation at the reporting date, based on current legal requirements and technology. Please see notes 1(m) Provisions (site restoration) and note 14.

Going concern

The Financial Report has been prepared on the going concern basis which assumes the continuity of normal business activity and the realisation of assets and the settlement of liabilities in the normal course of business for a period of at least 12 months from the date of signing the Financial Report.

The primary activities of the consolidated entity comprise the exploration for and development and production of oil and gas in the shallow water offshore Louisiana in the Gulf of Mexico.

For the year ended 30 June 2021 the consolidated entity reported a profit before tax of US$5,854,375 after recognising impairment and dry hole expenses of US$595,951 and generated net cash inflows from operating activities of US$21,352,060. As at 30 June 2021 the consolidated entity reported a working capital deficiency of US$8,851,403. This deficiency principally arises from:

(i) existing borrowings from third parties totalling US$9,442,633 that are due for repayment in the next 12 months;

(ii) existing borrowings from certain directors totalling US$3,578,780 that are due for repayment in the next 12 months; and

(iii) excess cash flow generated by the Group over the year ended 30 June 2021 has been invested in various exploration and development activities which are presented as non-current assets at year end.

1. Summary of significant accounting policies continued

The consolidated entity has prepared a Board-approved forecast for the 12 months ending 30 September 2022 which highlights that the consolidated entity has sufficient cash reserves to continue normal business operations as planned. The cash flow forecast is based on certain key assumptions including the successful completion and production of additional wells over the forecast period, the up-front payment for future oil production from a key customer, as well as the sales prices to be realised on unhedged oil and gas sales. To the extent these assumptions do not occur as planned or the expected timings of the forecast events are delayed, the consolidated entity may be required to source additional funding to continue operations and settle its obligations with existing suppliers and financiers.

For the year ended 30 June 2021 and in prior periods the consolidated entity has raised sufficient funding to continue operating as planned through various means including:

(i) equity capital;

(ii) interest bearing debt finance;

(iii) extended terms of trade with certain key service industry suppliers; and

(iv) farm-outs.

Having considered all relevant facts the directors are satisfied that is appropriate to prepare the Financial Report on the going concern basis. However, in the event that the consolidated entity is unsuccessful in the matters set out above, a material uncertainty would exist that may cast significant doubt as to whether the consolidated entity will be able to continue as a going concern and therefore whether it will realise its assets and discharge its liabilities in the normal course of business and at the amounts stated in the Financial Report.

The financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts or to the amounts and classification of liabilities that might be necessary should the consolidated entity not continue as a going concern.

Adoption of new and revised Accounting Standards

The Group has adopted all of the new and revised Standards and Interpretations issued by the Australian Accounting Standards Board ("AASB") that are relevant to their operations and effective for the financial year.

New and revised Standards and amendments thereof and Interpretations effective for the current year that are relevant to the Group include:

Standard/Interpretation

- AASB 2019-1 Amendments to Australian Accounting Standards – References to the Conceptual Framework in IFRS Standards
- AASB 2018-7 Amendments to Australian Accounting Standards – Definition of Material
- AASB 2019-5 Amendments to Australian Accounting Standards – Disclosure of the Effect of New IFRS Standards Not Yet Issued in Australia

Their adoption has not had any material impact on the disclosures or on the amounts reported in these financial statements.

Standards and Interpretations issued not yet effective – IASB and IFRIC Interpretations

At the date of authorisation of the financial statements, the following IASB Standards and IFRIC Interpretations (for which Australian equivalent Standards and Interpretations have not yet been issued) were in issue but not yet effective:

Standard/Interpretation	Effective for annual reporting periods beginning on or after	Expected to be initially applied in the financial year ending
AASB 2020-1 Amendments to Australian Accounting Standards – Classification of Liabilities as Current or Non-current	1 January 2022	30 June 2023
AASB 2021-2 Amendments to Australian Accounting Standards – Disclosure of Accounting Policies and Definition of Accounting Estimates	1 January 2023	30 June 2024

The directors do not expect that the adoption of the Standards listed above will have a material impact on the financial statements of the Group in future periods.

The following significant accounting policies have been adopted in the preparation and presentation of the Financial Report:

(a) Basis of consolidation

Subsidiaries

The consolidated financial statements incorporate the financial statements of the Company and entities controlled by the Company (referred to as 'the consolidated entity' or 'the Group' in these financial statements). Control is achieved where the Company:

- has power over the investee;
- is exposed, or has rights, to variable returns from its involvement with the investee; and
- has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

The results of subsidiaries acquired or disposed of during the year are included in the consolidated income statement from the effective date of acquisition or up to the effective date of disposal, as appropriate. Where necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with those used by other members of the consolidated entity.

Joint operating arrangements

Joint operating arrangements are those legal entities over whose activities the consolidated entity has joint control, established by contractual agreement. The interest of the consolidated entity in unincorporated joint operating arrangements are brought to account by recognising in its financial statements, its respective share of the assets it controls, the liabilities and the expenses it incurs and its share of income that it earns from the sale of goods or services by the joint operating arrangements.

Transactions eliminated on consolidation

All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

(b) Exploration and evaluation expenditure

Exploration and evaluation costs, including the costs of acquiring leases, are intangible assets capitalised as exploration and evaluation assets on an area of interest basis. Costs incurred before the consolidated entity has obtained the legal rights to explore an area are recognised in the income statement.

Exploration and evaluation assets are only recognised if the rights of the area of interest are current and either:

(i) the expenditures are expected to be recouped through successful development and exploitation of the area of interest; or alternatively, by its sale; or

(ii) activities in the area of interest have not, at the reporting date, reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves, and active and significant operations in, or in relation to, the area of interest are continuing.

Exploration and evaluation assets are initially measured at cost and include acquisition of rights to explore, lease rental payments, seismic and other expenditure to provide legal tenure of the area of interest. When an area of interest is abandoned or the directors decide that it is not commercial, any capitalised costs in respect of that area are written off in the financial period the decision is made.

Exploration and evaluation assets are assessed for impairment if: (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

1. Summary of significant accounting policies continued

Farm-in and farm-outs

In the case of farm-outs, the Group does not record any expenditure made by the farminee on its account. It also does not recognise any gain or loss on its exploration and evaluation farm-out arrangements, but redesignates any costs previously capitalised in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farminee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for as a gain on disposal.

In the case of farm-ins, Byron accounts for its expenditures under a farm-in arrangement in the same way as directly incurred exploration and evaluation expenditure.

For the purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units to which the exploration activity relates. The cash-generating unit shall not be larger than the area of interest.

Once the technical feasibility and commercial viability of the extraction of oil and gas reserves relating to a prospect are demonstrable and development is proceeding, exploration and evaluation assets attributable to that prospect are first tested for impairment and then reclassified assets to oil and gas properties.

All other exploration and evaluation costs are expensed as incurred.

(c) Oil and gas properties

The cost of oil and gas producing assets include acquisition and capitalised development costs that are directly attributable to the accessing and production of the proved and probable oil and gas reserves.

In addition, costs include:

(i) the initial estimate at the time of installation or acquisition and during the period of use, when relevant of the costs of dismantling and removing the items and restoring the site on which they are located; and

(ii) changes in the measurement of existing liabilities recognised for these costs resulting from changes in the timing or outflow of resources required to settle the obligation or from changes in the discount rate.

Amortisation

When an oil and gas asset commences commercial production, all acquisition and/or costs carried forward will be amortised on a units of production of basis over the remaining proved and probable recoverable reserves (“2P”). The remaining 2P reserves are measured by external independent petroleum engineers.

Changes in factors that affect amortisation calculations do not give rise to prior financial period adjustments and are dealt with on a prospective basis.

(d) Impairment

The carrying amounts of the Company’s and the consolidated entity’s non-financial assets, except exploration and evaluation expenditure, are reviewed each balance date or when there is an indication of an impairment loss, to determine whether they are in excess of their recoverable amount. An impairment loss is recognised whenever the carrying amount of an asset or its cash-generating unit exceeds its recoverable amount.

Calculation of the recoverable amount

The recoverable amount of an asset is the greater of its fair value less cost to sell and value in use. In assessing the value in use, the estimated future cash flows are discounted to their present value using a post-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognised immediately in profit or loss. Refer to note 8 for further details.

Reversals of impairment

Impairment losses are reversed when there has been a change in the estimates used to determine recoverable amounts.

An impairment loss is reversed only to the extent that the asset’s carrying value does not exceed the carrying amount that would have been determined, net of depreciation or amortisation, if no impairment loss had been recognised.

(e) Foreign currency

Functional and presentation currency

Items included in the financial statements of each of the consolidated entity's subsidiaries are measured using the currency of the primary economic environment in which the subsidiaries operate ("the functional currency"). The functional currency of the Company is Australian dollars (A$) and the functional currency of the Company's overseas subsidiaries is United States dollars (US$).

The financial statements are presented in United States dollars. The consolidated entity believes the US dollar is the best measure of performance for the Group because oil and gas, the consolidated entity's dominant sources of revenue are priced in US$ and the consolidated entity's main operations are based in the USA with costs incurred in US$.

Prior to consolidation, the results and financial position of each entity within the consolidated entity are translated from the functional currency into the consolidated entity's presentation currency as follows:

- asset and liabilities of the non US$ denominated balance sheet are translated at the closing rate at the date of that balance sheet;
- income and expenses for the non US$ denominated income statement is translated at average exchange rates (unless this is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case the income and expenses are translated at the dates of the transactions);
- components of equity are translated at the historical rates; and
- all resulting exchange differences are recognised as a separate component of equity.

Foreign currency transactions and balances

Non-monetary asset and liabilities that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

Foreign exchange gains and losses arising from a monetary item receivable from or payable to a foreign operation, the settlement of which is neither nor likely in the foreseeable future, are considered to form part of the net investment in a foreign operation are recognised directly in equity in the foreign currency translation reserve.

Interest bearing loans and borrowings repayable in fixed currency denominations

Interest bearing loans and borrowings are initially measured at fair value, net of transaction costs. As some of the loans from shareholders are legally repayable in non-functional or non United States currency denominations, any unrealised foreign currency exchange gains and losses emanating from the recognition of the amounts required to settle these future obligations are recognised in the profit and loss.

(f) Cash and cash equivalents

Cash comprises cash on hand and deposits held at call with financial institutions. Cash equivalents are short-term, highly liquid investments that are readily convertible to known amounts of cash, which are subject to an insignificant risk of changes in value.

(g) Share-based payments

Equitysettled share-based payments with directors, employees and others providing similar services are measured at the fair value of the equity instrument at the grant date. Fair value is measured by use of an appropriate model. A share-based payment expense is recognised in profit and loss with a corresponding increase in equity at grant date where the share-based payment arrangements vest immediately.

(h) Revenue recognition

Oil and gas revenue

Revenue associated with the sale of crude oil, natural gas, condensate and natural gas liquids ("NGLs") owned by the Company is recognised when title is transferred from the Company to its customers under short-term contracts (less than 12 months). Revenue is measured at the fair value of the consideration received or receivable. Revenue from the sale of crude oil, natural gas, condensate and NGLs is recognised when all of the following conditions have been satisfied:

- Byron has transferred control of the goods to the buyer and revenue is recognised at that time;
- Byron retains no continuing managerial involvement to the degree usually associated with ownership or effective control over the goods sold;
- the amount of revenue can be measured reliably;
- it is probable that the economic benefits associated with the transaction will flow to Byron; and
- the costs incurred or to be incurred in respect of the transaction can be measured reliably.

The Company recognises oil, natural gas and NGL revenues based on its share of the quantities of production, solely owned or under joint ownership, sold to purchasers under short-term contracts at market prices.

1. Summary of significant accounting policies continued

Interest revenue

Interest revenue is accrued on a time basis, by reference to the principal outstanding and at the effective interest rate applicable, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount.

(i) Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognised in the profit or loss except to the extent that it relates to items recognised directly in equity, in which case it is recognised in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantially enacted at the balance sheet date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognised using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognised for the following temporary differences: the initial recognition of goodwill, the initial recognition of assets or liabilities in a transaction that is not a business combination and that affect neither accounting nor taxable profit/loss, and differences relating to investments in subsidiaries to the extent that they will not reverse in the foreseeable future. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the balance sheet date.

A deferred tax asset is recognised only to the extent that it is probable that future taxable profits will be available against which the asset can be utilised. Deferred tax assets are reviewed at each balance sheet date and are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

(j) Financial assets

Financial assets and financial liabilities are recognised when the Company becomes a party to the contractual provisions of the instrument.

Financial assets and financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of financial assets and financial liabilities (other than financial assets and financial liabilities at fair value through profit or loss) are added to, or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at fair value through profit or loss are recognised immediately in profit or loss.

Financial assets

Financial assets are measured subsequently in their entirety at either amortised cost or fair value, depending on the classification of the financial assets (this note is also applicable: note 1(r) Derivative financial instruments – cash flow hedges).

Classification of financial assets

Debt instruments that meet the following conditions are measured subsequently at amortised cost:

- the financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows; and
- the contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Debt instruments that meet the following conditions are measured subsequently at fair value through other comprehensive income (FVTOCI):

- the financial asset is held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets; and
- the contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

By default, all other financial assets are measured subsequently at fair value through profit or loss (FVTPL).

Despite the foregoing, the Company may make the following irrevocable election/designation at initial recognition of a financial asset:

- the Company may irrevocably elect to present subsequent changes in fair value of an equity investment in other comprehensive income if certain criteria are met; and
- the Company may irrevocably designate a debt investment that meets the amortised cost or FVTOCI criteria as measured at FVTPL if doing so eliminates or significantly reduces an accounting mismatch.

Initial measurement of financial assets

Financial assets are classified according to their business model and the characteristics of their contractual cash flows. Except for those trade receivables that do not contain a significant financing component and are measured at the transaction price in accordance with AASB 15, all financial assets are initially measured at fair value adjusted for transaction costs.

Subsequent measurement of financial assets

For the purpose of subsequent measurement, financial assets, other than those designated and effective as hedging instruments, are classified into the following four categories:

- financial assets at amortised cost;
- debt instruments at fair value through other comprehensive income (FVTOCI);
- equity instruments at FVTOCI; and
- financial assets at FVTPL.

(i) Amortised cost and effective interest method

The effective interest method is a method of calculating the amortised cost of a debt instrument and of allocating interest income over the relevant period.

(ii) Debt instruments at fair value through other comprehensive income (Debt FVTOCI)

Debt FVTOCI initially measured at fair value plus transaction costs. Subsequently, changes in the carrying amount of these as a result of foreign exchange gains and losses, impairment gains or losses, and interest income calculated using the effective interest method are recognised in profit or loss.

(iii) Equity instruments at fair value through other comprehensive income (Equity FVTOCI)

Investments in equity instruments at FVTOCI are initially measured at fair value plus transaction costs. Subsequently, they are measured at fair value with gains and losses arising from changes in fair value recognised in other comprehensive income and accumulated in the investments revaluation reserve. The cumulative gain or loss is not to be reclassified to profit or loss on disposal of the equity investments; instead, it is transferred to retained earnings.

(iv) Financial assets at fair value through profit or loss (FVTPL)

Financial assets at FVTPL are measured at fair value at the end of each reporting period, with any fair value gains or losses recognised in profit or loss to the extent they are not part of a designated hedging relationship. The net gain or loss recognised in profit or loss includes any dividend or interest earned on the financial asset and is included in the "Net gain/(loss) arising on financial assets measured at FVTPL" line.

Impairment of financial assets

The Company recognises a loss allowance for expected credit losses on investments in debt instruments that are measured at amortised cost or at FVTOCI, lease receivables, trade receivables and contract assets, as well as on financial guarantee contracts. The amount of expected credit losses is updated at each reporting date to reflect changes in credit risk since initial recognition of the respective financial instrument.

Trade and other receivables and contract assets

The Company makes use of a simplified approach in accounting for trade and other receivables as well as contract assets and records the loss allowance at the amount equal to the expected lifetime credit losses. In using this practical expedient, the Company uses its historical experience, external indicators and forward-looking information to calculate the expected credit losses using a provision matrix.

1. Summary of significant accounting policies continued

(k) Employee benefits

A liability is recognised for benefits accruing to employees in respect of wages and salaries, annual leave and long service leave when it is probable that settlement will be required and they are capable of being measured reliably.

Liabilities recognised in respect of employee benefits expected to be settled within 12 months, are measured at their nominal values using the remuneration rate expected to apply at the time of settlement.

Liabilities recognised in respect of employee benefits which are not expected to be settled within 12 months are measured as the present value of the estimated future cash outflows to be made by the consolidated entity in respect of services provided by employees up to reporting date.

Defined contribution plans

Contributions to defined contribution superannuation plans are expensed when employees have rendered service entitling them to the contributions.

(l) Property, plant and equipment (including software)

Buildings held for use in the production or supply of goods or services, or for administrative purposes, are carried in the statement of financial position at cost, less any subsequent accumulated depreciation and subsequent accumulated impairment losses.

Plant and equipment are stated at cost less accumulated depreciation and impairment. Construction in progress is stated at cost. Cost includes expenditure that is directly attributable to the acquisition or construction of the item. In the event that settlement of all or part of the purchase consideration is deferred, cost is determined by discounting the amounts payable in the future to their present value as at the date of acquisition.

Depreciation is provided on property, plant and equipment, including freehold buildings but excluding land. Depreciation is calculated on a straight-line basis so as to write off the net cost or other revalued amount of each asset over its expected useful life to its estimated residual value. The estimated useful lives, residual values and depreciation method are reviewed at the end of each annual reporting period, with the effect of any changes recognised on a prospective basis.

The gain or loss arising on disposal or retirement of an item of property, plant and equipment is determined as the difference between the sales proceeds and the carrying amount of the asset and is recognised in profit or loss.

The following useful lives are used in the calculation of depreciation:

Buildings	40 years
Plant and equipment	4 to 10 years
Intangible assets – software	2.5 to 3 years

(m) Provisions

Provisions are recognised when the consolidated entity has a present obligation (legal or constructive) as a result of a past event, it is probable that the consolidated entity will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at reporting date, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows.

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, the receivable is recognised as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

Site restoration and rehabilitation of oil and gas properties

Provisions made for environmental rehabilitation are recognised where there is a present obligation as a result of exploration, development or production activities having been undertaken and it is probable that an outflow of economic benefits will be required to settle the obligation, and the amount of the provision can be measured reliably. The estimated future obligations include the cost of removing the facilities, abandoning the well(s) and restoring the affected areas. The provision for future restoration is the best estimate of the present value of the expenditure required to settle the obligation at the reporting date, based on current legal requirements and technology. Future restoration costs are reviewed annually; and any changes are reflected in the present value of the restoration provision at the end of the reporting period. The amount of the provision for future restoration costs relating to exploration and producing activities is capitalised as a cost of these activities. The provisions are determined by discounting the expected future cash flows at a pre tax rate that reflects the time value of money. The unwinding of discounting on the provision is recognised as a finance cost rather than being capitalised into the cost of the related asset.

(n) Financial liabilities

Financial liabilities

Financial liabilities, including borrowings and trade and other payables, are initially measured at fair value, net of transaction costs (this note is also applicable note 1(r) Derivative financial instruments – cash flow hedges). All financial liabilities are subsequently measured at amortised cost using the effective interest method, with interest expense recognised on an effective yield basis.

The effective interest method is a method of calculating the amortised cost of a financial liability and of allocating interest expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash payments through the expected life of the financial liability, or (where appropriate) a shorter period, to the net carrying amount on initial recognition.

Borrowing, finance and interest costs

Borrowing, finance and interest costs comprise interest payable on borrowings calculated using the effective interest rate method, loans transactions costs, lease finance charges, amortisation of discounts or premiums related to the borrowings and the unwinding of discounts on the rehabilitation provisions.

Derecognition of financial liabilities

The Group derecognises financial liabilities when, and only when, the Group's obligations are discharged, cancelled or they expire. The difference between the carrying amount of the financial liability derecognised and the consideration paid and payable is recognised in profit or loss.

(o) Issued capital

Issued and paid up capital is recognised at the fair value of the consideration received by the Company.

Transaction costs on the issue of equity instruments

Transaction costs arising on the issue of equity instruments are recognised directly in equity as a reduction of the proceeds of the equity instrument to which the costs relate. Transaction costs are costs that are incurred directly in connection with the issue of those equity instruments and which would not have been incurred had those instruments not been issued.

(p) Reserves

Foreign currency translation reserve

Foreign currency exchange differences relating to the translation of Australian dollars, being the functional currency of the parent entity group into the presentational currency of US dollars for the consolidated entity are brought to account by entries made directly to the foreign currency translation reserve.

Share option reserve

The share option reserve arises on the grant of share options to directors, staff, consultants and other service providers to the Group. Amounts are transferred out of the reserve and into issued capital when the options are exercised. Further information about share-based payments is made in note 1(g).

Cash flow hedging reserve

The cash flow hedging reserve arises when the effective portion of changes in the fair value of derivatives and other qualifying hedging instruments that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated under the heading of cash flow hedging reserve. Further information about cash flow hedges is made in note 1(r) Derivative financial instruments – cash flow hedges.

1. Summary of significant accounting policies continued

(q) Goods and services tax

Revenues, expenses and assets are recognised net of the amount of goods and services tax ("GST"), except:

(i) where the amount of GST incurred is not recoverable from the taxation authority, it is recognised as part of the cost of acquisition of an asset or as part of an item of expense; or

(ii) for receivables and payables which are recognised inclusive of GST.

The net amount of GST recoverable from, or payable to, the taxation authority is included as part of receivables or payables.

Cash flows are included in the cash flow statement on a gross basis. The GST component of cash flows arising from investing and financing activities which is recoverable from, or payable to, the taxation authority is classified as operating cash flows.

(r) Derivative financial instruments

The Group enters into a variety of derivative financial instruments to manage its exposure to crude oil price risks, including cash flow hedges. Further details of derivative financial instruments are disclosed in note 16.

Cash flow hedges

The effective portion of changes in the fair value of derivatives and other qualifying hedging instruments that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated under the heading of cash flow hedging reserve, limited to the cumulative change in fair value of the hedged item from inception of the hedge.

Amounts previously recognised in other comprehensive income and accumulated in equity are reclassified to profit or loss in the periods when the hedged item affects profit or loss, in the same line as the recognised hedged item.

However, when the hedged forecast transaction results in the recognition of a non-financial asset or a non-financial liability, the gains and losses previously recognised in other comprehensive income and accumulated in equity are removed from equity and included in the initial measurement of the cost of the non-financial asset or non-financial liability. This transfer does not affect other comprehensive income. Furthermore, if the Group expects that some or all of the loss accumulated in the cash flow hedging reserve will not be recovered in the future, that amount is immediately reclassified to profit or loss.

The Group discontinues hedge accounting only when the hedging relationship (or a part thereof) ceases to meet the qualifying criteria (after rebalancing, if applicable). This includes instances when the hedging instrument expires or is sold, terminated or exercised. The discontinuation is accounted for prospectively. Any gain or loss recognised in other comprehensive income and accumulated in cash flow hedge reserve at that time remains in equity and is reclassified to profit or loss when the forecast transaction occurs. When a forecast transaction is no longer expected to occur, the gain or loss accumulated in the cash flow hedge reserve is reclassified immediately to profit or loss.

(s) Leases

The Group as lessee

The Group assesses whether a contract is or contains a lease, at inception of the contract. The Group recognises a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low value assets (such as tablets and personal computers, small items of office furniture and telephones). For these leases, the Group recognises the lease payments as an operating expense on a straight-line basis over the term of the lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate the Group uses for its incremental borrowing.

Lease payments included in the measurement of the lease liability comprise:

(i) fixed lease payments (including in-substance fixed payments), less any lease incentives receivable; and

(ii) variable lease payments that depend on an index or rate, initially measured using the index or rate at the commencement date.

The lease liability is presented as a separate line in the consolidated statement of financial position.

The lease liability is subsequently measured by increasing the carrying amount to reflect interest on the lease liability (using the effective interest method) and by reducing the carrying amount to reflect the lease payments made.

The Group remeasures the lease liability (and makes a corresponding adjustment to the related right-of-use asset) whenever:

A lease contract is modified and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured based on the lease term of the modified lease by discounting the revised lease payments using a revised discount rate at the effective date of the modification.

The right-of-use assets comprise the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day, less any lease incentives received and any initial direct costs. They are subsequently measured at cost less accumulated depreciation and impairment losses.

Right-of-use assets are depreciated over the shorter period of lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

The right-of-use assets are presented as a separate line in the consolidated statement of financial position.

The Group applies AASB 136 to determine whether a right-of-use asset is impaired and accounts for any identified impairment loss as described in the 'Property, Plant and Equipment' policy.

Variable rents that do not depend on an index or rate are not included in the measurement the lease liability and the right-of-use asset. The related payments are recognised as an expense in the period in which the event or condition that triggers those payments occurs and are included in the line "Corporate and administration costs" in profit or loss.

As a practical expedient, AASB 116 permits a lessee not to separate non-lease components, and instead account for any lease and associated non-lease components as a single arrangement. The Group has not used this practical expedient. For a contract that contain a lease component and one or more additional lease or non-lease components, the Group allocates the consideration in the contract to each lease component on the basis of the relative stand-alone price of the lease component and the aggregate stand-alone price of the non-lease components.

(t) Comparative figures

Where required by Accounting Standards, comparative figures have been adjusted to conform to changes in presentation for the current period.

2. Profit for the year

Profit for the year has been arrived at after charging the following items of expense:

	Consolidated	
	2021 US$	**2020 US$**
Cost of sales		
Lease operating costs	**5,959,274**	3,056,644
Gas transportation costs	**1,595,962**	349,866
Amortisation of oil and gas properties	**13,237,892**	5,509,382
	20,793,128	8,915,892
Professional and consulting costs	**1,489,788**	1,229,622
Insurance	**142,674**	115,825
Office lease rental expense including outgoings (short-term leases)	**136,258**	142,787
Employee benefits expense		
Salaries and wages	**1,791,962**	1,628,484
Share-based payments (loans made to staff for the conversion of share options to fully paid ordinary shares)	**-**	623,813
Defined contribution superannuation expense	**33,021**	28,338
	1,824,983	2,280,635

3. Financial income and expenses

	Consolidated	
	2021 US$	2020 US$
Financial income		
Interest income	**53,337**	12,815
Foreign exchange gain on A$ denominated loans	**-**	6,540
	53,337	19,355
Financial expense		
Interest expense non-related parties	**2,801,944**	1,294,301
Foreign exchange loss on A$ denominated loans	**137,550**	-
Lease finance costs	**148,547**	82,860
Unwinding of discount on rehabilitation of oil and gas properties	**42,455**	38,605
Interest expense paid or accrued on loans from related parties	**350,579**	400,359
	3,481,075	1,816,125

4. Income tax

Income tax recognised in profit and loss	**-**	-
The income tax expense for the year can be reconciled to the accounting profit as follows:		
Profit before tax from continuing operations	**5,854,375**	68,348
Income tax expense calculated at 26.0% (2020: 27.5%)	**1,522,138**	18,796
Effect of expenses that are not deductible in determining taxable profit	**3,730**	260,774
Effect of income that is not assessable in determining taxable profit	**(11,650)**	(11,078)
Effect of different tax rates of subsidiaries operating in other jurisdictions	**6,840**	(44,934)
Effect of unused tax losses and tax offsets not recognised as deferred tax assets	**(1,521,058)**	(223,558)
Income tax expense/(benefit) on continuing operations	**-**	-
Deferred tax assets not recognised		
Deferred tax assets not recognised comprises temporary differences and tax losses attributable to:		
Australian tax losses	**4,144,962**	3,380,123
USA tax losses	**36,011,315**	32,992,123
Temporary differences	**(22,884,322)**	(23,542,262)
Total deferred tax assets not recognised	**17,271,955**	12,829,984

The potential deferred tax asset will only be recognised if:

(i) the consolidated entity derives future assessable income of a nature and amount sufficient to enable the benefits to be realised in the jurisdiction in which the losses were incurred;

(ii) the consolidated entity continues to comply with conditions for tax deductibility imposed by law; and

(iii) no changes in tax legislation adversely affect the ability of the consolidated entity to realise the tax benefits.

Byron Energy Limited and its 100% owned Australian subsidiary, Byron Energy (Australia) Pty Ltd formed a tax consolidated group effective from 1 July 2013.

5. Earnings per share

The following reflects the profit and share data used in calculating basic and diluted earnings per share:

	Consolidated	
	2021 US$	**2020 US$**
Net profit for the year	**5,854,375**	68,348
Basic profit per share	**0.005633**	0.000088
Diluted profit per share	**0.005587**	0.000086
Weighted average number of ordinary shares	**1,039,331,647**	777,410,613
Shares deemed to be issued for no consideration in respect of share options	**8,543,288**	15,249,908
Weighted average number of ordinary shares used in the calculation of diluted earnings per share	**1,047,874,935**	792,660,521
Anti-dilutive options on issue not used in the dilutive earnings per share calculation	**32,200,000**	32,200,000

Options outstanding

There is partial dilution of shares due to some options issued or outstanding as the potential ordinary shares are anti-dilutive in accordance with AASB 133, paragraph 41 and are therefore not included in the calculation of diluted earnings per share.

6. Trade and other receivables

Current		
Oil and gas sales receivables	**3,970,390**	1,634,481
Joint operating arrangements receivables	**145,252**	193,796
Interest receivable	**51,858**	-
GST receivable	**29,880**	23,185
	4,197,380	1,851,462
Non-current		
Joint operating arrangements receivables	**180,398**	251,365

Current trade and other receivables are non-interest bearing and are settled within 45 days. Consequently, the amounts referred to in this note are less than 45 days to collection, except for a joint venture receivable that was reviewed for collectability as part of the year end review process and resulted in a partial write-off of US$33,243 to the profit and loss to reflect the revised debt payment plan.

7. Other assets

	Consolidated 2021 US$	Consolidated 2020 US$
Current		
Prepayments	**2,285,353**	3,131,989
Security deposits	**6,556**	5,985
	2,291,909	3,137,974
Non-current		
Security deposits	**1,925,000**	1,925,000

8. (a) Exploration and evaluation assets

	2021 US$	2020 US$
Costs carried forward in respect of areas in the exploration and/or evaluation phase at cost:	**5,150,621**	4,695,861
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**4,695,861**	6,587,670
Additions at cost	**1,050,711**	24,238,915
Transfers of exploration and evaluations assets to oil and gas properties	**-**	(20,732,749)
Impairment expense	**(595,951)**	(5,397,975)
Carrying amount at the end of the financial year	**5,150,621**	4,695,861

Ultimate recovery of deferred exploration and evaluation costs is dependent upon success in exploration and evaluation or the full or partial sale (including farm-out) of the exploration interests.

For the year ended 30 June 2021, impairment charges were US$595,951 covering (i) residual costs of the relinquishment of the Bivouac Peak and SM74 leases and (ii) the write-down to $nil of the SM59 lease carrying value as at 30 June 2021.

8. (b) (i) Oil and gas properties – Producing

	2021 US$	2020 US$
Costs carried forward in respect of areas in the oil and gas properties:	**95,433,081**	37,224,157
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**37,224,157**	27,192,032
Additions at cost	**31,432,130**	14,753,450
Additions for site restoration	**2,047,252**	788,057
Transfers from non-producing properties see note 8 (b) (ii)	**37,967,434**	-
Amortisation of oil and gas properties included in cost of sales	**(13,237,892)**	(5,509,382)
Carrying amount at the end of the financial year	**95,433,081**	37,224,157

Recoverable amount

The estimated recoverable amount of all cash-generating units in the development or production phase is determined by discounting the estimated future cash flows to their present value using a post-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the assets. The consolidated entity utilises future cash flows as estimated by independent petroleum engineers for this assessment. The key assumptions used include: (i) estimated future production based on proved and probable reserves (2P reserves), (ii) hydrocarbon prices that the consolidated entity estimates to be reasonable, taking into account historical prices, current prices, and prices used in making its exploration and development decisions, and (iii) future operating and development costs as estimated by the Company and reviewed for reasonableness by the independent petroleum engineers. The estimated recoverable amount of Byron's oil and gas properties is sensitive to a change in estimated recoverable reserves, oil and gas prices, discount rates and cost estimates.

For the 2021 financial year, the following assumptions were used in the assessment of recoverable amounts: (i) oil prices (nominal) used represent Reuters Consensus, starting on 1 July 2021 of US$72.98 per barrel, with a final price of US$60.00 per barrel on 1 January 2024 and held constant thereafter; (ii) gas prices (nominal) used in this report represent a Henry Hub base, starting on 1 July 2021 of US$3.411 per MMBtu, declining to US$2.75 per MMBtu on 1 January 2024 and held constant thereafter; (iii) post-tax nominal discount rate of 10%.

At year end, the Company's oil and gas properties were assessed for impairment indicators in accordance with AASB 136. Following this assessment, no impairment was required or recognised on the oil and gas properties during the 30 June 2021 financial year.

8. (b) (ii) Oil and gas properties – Non-producing

	Consolidated	
	2021 US$	**2020 US$**
Costs carried forward in respect of areas in the oil and gas properties at cost:	**-**	37,967,434
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**37,967,434**	-
Additions at cost	**-**	14,976,251
Additions for site restoration	**-**	2,258,434
Transfers to producing oil and gas properties see note 8 (b) (i)	**(37,967,434)**	
Transfers from exploration and evaluation see note 8 (a)	**-**	20,732,749
Carrying amount at the end of the financial year	**-**	37,967,434

During the financial year, SM58 was reclassified from non-producing to producing oil and gas properties reflecting the commencement of oil and gas production on the SM58 G platform from the SM58 G1 and G2ST wells.

9. Right-of-use assets

	Consolidated	
	2021 US$	2020 US$
Office lease		
Opening balance	673,878	631,765
Additions	-	200,877
Amortisation	(188,059)	(158,764)
Carrying amount at the end of the financial period	485,819	673,878
Compressor lease		
Opening balance	314,822	361,711
Additions	871,666	-
Amortisation	(218,011)	(46,889)
Carrying amount at the end of the financial period	968,477	314,822
Total right-of-use assets	1,454,296	988,700
Amounts recognised in profit and loss		
Amortisation expense on right-of-use assets	406,070	205,653
Interest expense on lease liabilities	148,547	82,860
Expense relating to short-term leases including outgoings	136,258	142,787

10. Lease liabilities

Not later than one year	664,821	432,573
Later than one year and not later than five years	1,452,871	1,208,620
Minimum lease payments	2,117,692	1,641,193
Less: Future finance charges	(316,827)	(289,751)
Provided for in the financial statements	1,800,865	1,351,442
Representing lease liabilities:		
Current	509,143	309,440
Non-current	1,291,722	1,042,002
	1,800,865	1,351,442

The Group does not face a significant liquidity risk with regard to its lease liabilities. Lease liabilities are monitored within the Group's treasury function.

11. Property, plant and equipment

	Consolidated	
	2021 US$	**2020 US$**
Buildings at cost	**10,983**	10,026
Accumulated depreciation	**(4,135)**	(3,523)
	6,848	6,503
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**6,503**	6,902
Depreciation for year	**(273)**	(246)
Foreign currency translation movements	**618**	(153)
Carrying amount at the end of the financial year	**6,848**	6,503
Plant and equipment at cost	**135,359**	134,999
Accumulated depreciation	**(110,735)**	(101,026)
	24,624	33,973
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**33,973**	43,260
Additions at cost	**-**	840
Depreciation for year	**(9,379)**	(10,082)
Foreign currency translation movements	**30**	(45)
Carrying amount at the end of the financial year	**24,624**	33,973
Total property, plant and equipment	**31,472**	40,476

12. Other intangible assets

Capitalised software costs at cost	**479,408**	465,172
Accumulated amortisation	**(454,133)**	(299,843)
	25,275	165,329
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**165,329**	312,188
Amortisation for year	**(144,514)**	(143,353)
Foreign currency translation movements	**4,460**	(3,506)
Carrying amount at the end of the financial year	**25,275**	165,329

13. Trade and other payables

	Consolidated 2021 US$	2020 US$
Trade payables	**1,281,781**	**4,200,222**
Oil and gas royalties payable	**694,461**	**303,448**
Accrued interest on loans	**28,593**	**27,462**
Other payables	**17,524**	**14,153**
	2,022,359	**4,545,285**

Terms and conditions relating to the above financial instruments:

(i) trade creditors are non-interest bearing and are usually settled on 30 day terms; and

(ii) some of the other payables are non-interest bearing and have an average term of 30 days.

14. Provisions

	2021 US$	2020 US$
Current		
Accumulated employee entitlements	**173,682**	144,462
	173,682	144,462
Non-current		
Accumulated employee entitlements	**89,170**	75,280
Site restoration SM71 wells, pipelines and platform, SM58 E-1 well, SM69 pipelines and platform, SM58 G1 & G2ST wells and SM58 platform	**7,094,619**	5,004,912
	7,183,789	5,080,192
Site restoration provisions		
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**5,004,912**	1,919,816
Additions to site restoration	**2,047,252**	3,046,491
Unwinding of discount on site restoration	**42,455**	38,605
Carrying amount at the end of the financial year	**7,094,619**	5,004,912

Provisions are recognised for the Group's restoration obligations for the SM71 wells and platform, SM58 E-1, G1 and G2ST wells, SM58 and SM69 pipelines and platforms. The estimation of future costs associated with the abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until a number of years into the future. Such cost estimates could be subject to revisions in subsequent years due to regulatory requirements, technological advances and other factors that are difficult to predict. Likewise the appropriate future discount rates used in the calculation are subject to change according to the risks inherent in the liability. The interest rates used to determine the restoration obligations at 30 June 2021 were within the range of 1.51% to 2.00% (2020 within the range of 0.74% to 1.18%), and were based on applicable government bond rates with a tenure aligned to the tenure of the liability. The measurement and recognition criteria relating to restoration obligations is described in note 1 (m).

15. Borrowings

	Consolidated 2021 US$	Consolidated 2020 US$
Current unsecured		
Loans from directors and shareholder*	**3,578,780**	-
Prepaid oil revenues**	**1,750,000**	-
Insurance premium financing (interest bearing)***	**1,530,593**	1,493,817
Current secured		
Promissory note – debt liability	**9,442,633**	4,375,000
Total current borrowings	**16,302,006**	5,868,817
Non-current unsecured		
Loans from directors and shareholder*	**-**	3,441,230
Non-current secured		
Promissory note – debt liability****	**5,640,364**	10,625,000
Total non-current borrowings	**5,640,364**	14,066,230

* The loan facility was fully drawn during the March 2019 quarter, is unsecured and repayable by 31 March 2022 (unless otherwise agreed) and bears interest from time of drawdown, at a rate of 10% per annum, payable every quarter. The increase in the loans for the period is solely due to the strength in the Australia dollar relative to the USA dollar.

** Prepaid oil revenues incur a US$0.72 cents a barrel charge on Byron's oil production from initial prepayment date to full repayment. The current prepayment balance will be repaid over a two-month period in equal instalments.

*** The insurance premium financing bears an average 3.87% fixed interest rate, refer note 30 (c).

**** Crescent (formerly Crimson) Promissory Note: key terms of the Promissory Note include: (i) facility amount US$18.5 million; and (ii) senior secured debt over the Company's SM71 and SM58 assets and guaranteed by the Company.

16. Derivative financial assets/liabilities

(a) Derivative financial assets

	2021 US$	2020 US$
Oil price cashflow hedges at fair value	**-**	214,990
Total cash flow hedge assets	**-**	214,990

In June 2020, Byron hedged 400 barrels of oil per day for the period July to December 2020 in the form of put options with a strike price of US$39 per barrel on the West Texas Intimidate (WTI) base price.

(b) Oil price cash flow hedges – Derivative financial assets

	2021 US$	2020 US$
Cash premium paid	**214,990**	338,560
Realised loss on oil price cash flow hedge	**(338,560)**	-
Reverse write-down of oil price cash flow hedges to fair value through other comprehensive income	**123,570**	(123,570)
Net amount	**-**	214,990

(c) Derivative financial liabilities

	2021 US$	2020 US$
Oil price financially settled hedges at fair value	**476,913**	-
Total oil price financially settled hedge liabilities	**476,913**	-

In March 2021, Byron hedged 200 barrels of oil per day for the period March to December 2021 in the form of financially settled swaps with an average strike price of US$62 per barrel on the West Texas Intimidate (WTI) base price.

16. Derivative financial assets/liabilities continued

Oil price financially cash settled swaps – unrealised loss

	Consolidated 2021 US$	Consolidated 2020 US$
Unrealised loss on oil price financially settled swaps to fair value on 30 June 2021 through other comprehensive income	**476,913**	-
Net loss through other comprehensive income	**476,913**	-
Oil price financially cash settled swaps – realised loss		
Realised loss on oil price cash flow hedges for the year ended 30 June 2021	**31,174**	-

17. Issued capital

	2021	2020
(a) Issued and paid up capital	**139,093,311**	137,560,738

Changes to the then Corporations Law abolished the authorised capital and par value concept in relation to share capital from 1 July 1998. Therefore, the Company does not have a limited amount of authorised capital and issued shares do not have a par value.

(b) Movement

	2021 Number	2021 US$	2020 Number	2020 US$
Fully paid ordinary shares				
Balance at beginning of the financial year	**1,023,549,331**	**137,560,738**	695,373,417	101,091,750
Shares issued				
The placement of 16,745,771 shares at a subscription price of A$0.13 cents per share	**16,745,771**	**1,532,573**		
The issue of 10,000,000 shares at A$0.25 per share upon conversion of 10,000,000 share options			10,000,000	1,742,000
The placement of 53,961,055 shares at a subscription price of A$0.27 cents per share			53,961,055	9,856,532
42,075,806 shares were issued at A$0.27 cents per share under an entitlement offer			42,075,806	7,838,723
The placement of 106,331,150 shares at a subscription price of A$0.13 cents per share			106,331,150	9,091,420
The issue of 106,307,903 shares under an SPP at a subscription price of A$0.13 cents per share			106,307,903	9,481,921
The issue of 9,500,000 shares at A$0.25 per share via interest-free loans for the conversion of 9,500,000 share options			9,500,000	-
Equity raising costs				(1,541,608)
Balance at end of financial year	**1,040,295,102**	**139,093,311**	1,023,549,331	137,560,738

(c) Terms and conditions of contributed equity

Ordinary shares

Ordinary shares have the right to receive dividends as declared and in the event of winding up of the Company, to participate in the proceeds from the sale of all surplus assets in proportion to the number of and amounts paid up on shares held. Ordinary shares entitle their holder to one vote, either in person or by proxy, at a meeting of the Company.

The issued capital of the Company comprises 1,040,295,102 ordinary shares (2020: 1,023,549,331). All of the shares are quoted on the ASX.

(d) Share options

Options over ordinary shares

At the end of the financial year, there were 41,100,000 (2020: 41,100,000) unissued ordinary shares in respect of which the following options were outstanding:

Expiry date	Number	Securities	Exercise price
31 December 2021	**28,350,000**	**Unlisted options**	**A$0.12**
31 December 2021	**2,000,000**	**Unlisted options**	**A$0.16**
31 December 2021	**9,500,000**	**Unlisted options**	**A$0.40**
31 December 2021	**1,250,000**	**Unlisted options**	**A$0.40**
Total	**41,100,000**		

During the financial year, no share options were issued, no share options were converted to ordinary share and no share options expired, unexercised during the financial year.

18. Reserves

	Consolidated	
Foreign currency translation reserve	**2021 US$**	**2020 US$**
Balance at beginning of financial year	**(146,640)**	(131,466)
Currency translation movements for the year	**99,922**	(15,174)
Balance at end of financial year	**(46,718)**	(146,640)

The reserve arises out of the translation of A$, being the functional currency of the parent entity group into the consolidated entity presentation currency of US$.

Cash flow hedging reserve		
Balance at beginning of financial year	**(123,570)**	-
Reverse write-down of oil price cash flow hedge assets to fair value through other comprehensive income	**123,570**	(123,570)
Write-down of oil price financially cash-settled swap hedge liabilities to fair value through other comprehensive income	**(428,596)**	(123,570)
Balance at end of financial year	**(428,596)**	(123,570)

The reserve arises out of the movement in mark-to-market value of oil price hedges as at 30 June 2021.

Share option reserve		
Balance at beginning of financial year	**6,305,069**	5,364,398
Loans made to executive directors, staff and consultants for the conversion of 9,500,000 share options to fully paid ordinary shares	**-**	940,671
Balance at end of financial year	**6,305,069**	6,305,069

19. Franking credits

There are no franking credits available for distribution (2020: nil).

20. Commitments

(i) Expenditure commitments

The Group has expenditure commitments at the end of the financial year for short-term non-cancellable operating lease office rental payments, not included as liabilities in the financial statements at note 10. The inclusion of long-term operating lease office rentals payments under AASB 16 now classified as liabilities for the year end 30 June 2021.

(a) Commitments for office lease rental payments

	Consolidated	
	2021 US$	**2020 US$**
Not longer than one year	**23,847**	21,770
	23,847	21,770

(b) Exploration lease expenditure commitments

The Group has no exploration lease commitments at the end of the financial year as the leasing arrangements of the Gulf of Mexico blocks do not require firm work program commitments.

(c) Well expenditure commitments

The Group has a financial commitment as at balance date for the drilling of the SM58 E-2 well.

Commitments for well drilling expenditures		
Not longer than one year	**2,025,000**	2,072,500

(ii) Oil sales delivery commitments

The Group has oil sales delivery commitments at the end of the financial year for fixed volumes of barrels of oil.

	Oil barrels	Average price US$ bbl	Value of committed sales US$
Not longer than one year	**155,200**	**52.7854**	**8,192,288**
Between one and five years	**73,600**	**52.7000**	**3,878,720**
	228,800	**52.7579**	**12,071,008**

21. Cash flow reconciliation

	Consolidated 2021 US$	Consolidated 2020 US$
(a) Reconciliation of profit from ordinary activities after tax to net cash flows from operations		
Profit for the year	**5,854,375**	68,348
Non-cash flows in operating result:		
Amortisation oil and gas properties	**13,237,892**	5,509,382
Depreciation and amortisation of property, plant and equipment	**154,282**	153,681
Depreciation of right-of-use assets	**406,071**	205,653
Impairment expense	**595,951**	5,397,975
Equity-settled share-based payments	**-**	940,671
Oil price hedges written down to zero	**386,878**	-
Finance cost of leased assets	**148,547**	82,860
Net foreign exchange (gain)/loss on A$ loans	**137,550**	(6,540)
Unwinding of discount on rehabilitation of oil and gas properties	**42,455**	38,605
Write-off joint venture bad debt	**33,243**	-
Foreign exchange differences arising on translation of the parent entity group	**15,732**	23,587
	21,012,976	12,414,222
Movements in working capital		
(Increase)/decrease in assets:		
Trade and other receivables	**(2,391,678)**	1,562,086
Other assets	**252,090**	(445,960)
Increase/(decrease) in liabilities:		
Trade and other payables	**706,535**	114,553
Prepaid oil revenue	**1,750,000**	-
Provisions	**22,137**	35,170
Net cash from operating activities	**21,352,060**	13,680,071
(b) Reconciliation of cash		
Cash and cash equivalents comprise:		
Cash and bank balances	**4,143,411**	16,644,701

(c) Financing facility

The Group had finance facilities at balance date consisting of loans from directors and shareholders that are fully drawn, loans from a third party provider and an insurance premium financing facility.

(d) Non-cash financing and investing activities

There were no non-cash financing or investing activities during the financial year.

22. Controlled entities

The following entities are controlled by Byron Energy Limited and they have been consolidated into the financial statements for the consolidated entity:

Name	Country of domicile	Class of share	Percentage beneficially owned
Byron Energy (Australia) Pty Ltd	Australia	Ordinary	100%
Byron Energy Inc	USA	Ordinary	100%
Byron Energy LLC	USA	Ordinary	100%

23. Foreign currency translation

The exchange rates utilised in the translation of the parent entity group Australia dollar amounts to United States of America dollars are as follows:

	2021	2020
Spot rate at 30 June	**0.7518**	0.6863
Average rate for year	**0.7468**	0.6714

24. Contingent liabilities

The directors are of the opinion that the recognition of a provision is not required in respect of the following matters, as it is not probable that a future sacrifice of economic benefits will be required or the amount is not capable of reliable measurement.

(a) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under the Participation Agreement dated 1 December 2015 between Byron Energy Inc and Otto Energy (Louisiana) LLC.

(b) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under the Secured Promissory Note between Byron Energy Inc and Crescent Midstream Operating, LLC. effective as of 3 December 2019.

(c) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under (i) an ISDA Master Agreement dated 21 May 2020 between Byron Energy Inc. and Shell Trading Risk Management, LLC and (ii) the Master Crude Purchase and Sale Agreement between dated 26 November 2020 between Byron Energy Inc. and Shell Trading (US) Company.

(d) Supplemental Bonding Requirements by the BOEM

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances to satisfy lease obligations, including decommissioning activities on the OCS. As of the date of this report, the Company is in compliance with its financial assurance obligations to the BOEM and has no outstanding BOEM orders related to assurance obligations. Byron and other offshore Gulf of Mexico producers may in the ordinary course receive future demands for financial assurances from the BOEM as the BOEM continues to re-evaluate its requirements for financial assurances.

(e) Surety Bond Issuers' Collateral Requirements

The issuers of surety bonds in some cases have requested and received additional collateral related to surety bonds for exploration and development drilling and plugging and abandonment activities. Byron may be required to post collateral at any time pursuant to the terms of its agreement with sureties under its existing bonds, if they so demand at their discretion. As at 30 June 2021, Byron had collateral bond holdings of US$4,918,356 (2020: US$3,549,618), of which US$1,925,000 (2020: US$1,925,000) was cash collateralised.

(f) Other Claims

Claims or contingencies may arise related to matters occurring prior to Byron's acquisition of properties or related to matters occurring subsequent to Byron's sale of properties. In certain cases, Byron has indemnified the sellers of properties it has acquired, and in other cases, it has indemnified the buyers of properties sold.

From time to time the Company may be involved in litigation arising out of the normal course of business. The Company is not involved in any ligation, the outcome of which would have a material effect on its consolidated financial position, results of operations or liquidity.

In addition, the Company and its oil and gas joint interest owners are subject to periodic audits of the joint interest accounts for leases which Byron operate and/or participate. As a result of these joint interest audits, amounts payable or receivable by the Company for costs incurred or revenue distributed by the operator or by the Company on a lease may be adjusted, resulting in adjustments to Byron's net costs or revenues and the related cash flows. When they occur, these adjustments are recorded in the current period, which generally is one or more years after the related cost or revenue was incurred or recognised by the joint account. Byron does not believe any such adjustments will be material.

25. Share-based payments

Movements in share-based payments options

The aggregate share-based payments paid as remuneration for the financial year are set out below:

	Consolidated	
	2021 US$	2020 US$
Details of share-based payments:		
Interest-free loans made to executives, staff and consultants for the conversion of share options to fully paid ordinary shares	-	940,671
Expense arising from share-based payments paid as remuneration	-	940,671

No share options were exercised during the financial year (2020: 9,500,000). There are no Employee Share Option plans in place.

	2021 Number	2021 Exercise price	2020 Number	2020 Exercise price
Balance at beginning of year	**41,100,000**		50,600,000	
Granted during the year	**-**		-	
Exercised during the year	**-**		(9,500,000)	
Balance at end of year	**41,100,000**		41,100,000	
Exercisable at end of year	**28,350,000**	**A$0.12c**	28,350,000	A$0.12c
Exercisable at end of year	**2,000,000**	**A$0.16c**	2,000,000	A$0.16c
Exercisable at end of year	**10,750,000**	**A$0.40c**	10,750,000	A$0.40c

Weighted average remaining contractual life

All three tranches of 28,350,000, 2,000,000 and 10,750,000 share options have an expiry of 184 days (2020: 549 days) remaining.

Director and key management personnel equity share options

Share-based payment options held at the end of the reporting year were as follows:

Grantee	Number	Grant date	Vesting date	Expiry date	Exercise price	Fair value at grant date
M Smith	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
M Smith	2,100,000	22 Nov 2018	22 Nov 2018	31 Dec 2021	A$0.40	A$0.0837
P Kallenberger	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
P Kallenberger	2,100,000	22 Nov 2018	22 Nov 2018	31 Dec 2021	A$0.40	A$0.0837
W Sack	2,100,000	22 Nov 2018	22 Nov 2018	31 Dec 2021	A$0.40	A$0.0837
W Sack	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
N Filipovic	3,780,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
N Filipovic	1,000,000	22 Nov 2018	22 Nov 2018	31 Dec 2021	A$0.40	A$0.0837

26. Employee benefits and superannuation commitments

The consolidated entity contributes in accordance with the Australian Government superannuation guarantee legislation.

27. Auditors' remuneration

	Consolidated 2021 US$	Consolidated 2020 US$
Amounts received or due and receivable by Deloitte Touche Tohmatsu:		
Audit or review of the financial statements of the Group	**70,834**	63,578
	70,834	63,578

The auditors did not receive any other benefits (2020: nil).

28. Key management personnel compensation

Total aggregate remuneration of directors and key management personnel.

	Short-term employee benefits				Post-employment benefits	Share-based payments	
	Salaries and fees US$	Other benefits US$	Service agreements US$	Short-term cash incentive US$	Super-annuation US$	Share options US$	Total US$
Year 2021	**1,076,188**	**-**	**61,627**	**511,558**	**26,250**	**-**	**1,675,623**
Year 2020	1,000,203	-	58,574	441,446	22,643	841,653	2,364,519

More detailed information on remuneration and retirement benefits of directors is disclosed in the Remuneration Report.

29. Related party transactions

The following related party transactions were made during the financial year ended 30 June 2021:

(a) In March 2019, the Company entered into unsecured loan agreements, bearing interest at 10% per annum, with four of the Company's directors, for a total drawdown of US$2,000,000 and A$1,750,000. The loans were due for repayment in November 2019, however the directors agreed to extend the loan repayment date to March 2022 and interest payments have been made on a quarterly basis. The individual directors' transactions and balances for these loans were:

- Veruse Pty Ltd, a company controlled by Mr Douglas Battersby, a director of the Company, provided an unsecured loan of A$1,400,000 to the Company and interest paid for the financial year to June 2021 was A$ 140,000, plus A$11,507 has been accrued as at 30 June 2021;
- Clapsy Pty Ltd, a company controlled by Mr Paul Young, a director of the Company, provided an unsecured loan of A$175,000 to the Company and interest paid for the financial year to June 2021 was A$17,500, plus A$1,438 has been accrued as at 30 June 2021;
- Poal Pty Ltd, a company controlled by Mr Paul Young, a director of the Company, provided an unsecured loan of A$175,000 to the Company and interest paid for the financial year to June 2021 was A$17,500, plus A$1,438 has been accrued as at 30 June 2021;
- Geogeny Pty Ltd, a company controlled by Mr Maynard Smith, a director of the Company, provided an unsecured loan of US$1,000,000 to the Company and interest paid for the financial year to June 2021 was US$100,000, plus US$8,219 has been accrued as at 30 June 2021; and
- Mr Charles Sands, a director of the Company, provided an unsecured loan of US$1,000,000 to the Company and interest paid for the financial year to 30 June 2021 was US$90,036 (net of withholding taxes), plus US$7,397 (net of withholding taxes) has been accrued as at 30 June 2021.

30. Financial instruments

The consolidated entity's financial instruments consist mainly of cash and cash equivalents, trade and other receivables, security deposits, trade and other payables and secured borrowings. The main risks the consolidated entity is exposed to through its financial instruments are interest rate risk, foreign currency risk, liquidity risk and credit risk.

This note presents information about the consolidated entity's exposure to each of the above risks and processes for measuring and managing the risks and the management of capital.

	Consolidated	
Categories of financial instruments	**2021 US$**	**2020 US$**
Financial assets at fair value		
Cash and cash equivalents	**4,143,411**	16,644,701
Trade and other receivables	**4,377,779**	2,102,827
Derivative financial instruments	**-**	214,990
Bonds and security deposits	**1,931,556**	1,930,985
	10,452,746	20,893,503
Financial liabilities at fair value		
Trade and other payables	**2,022,359**	4,545,285
Prepaid oil revenue	**1,750,000**	-
Derivative financial instruments	**476,913**	-
Insurance premium financing	**1,530,593**	1,493,817
Loans from related parties	**3,578,780**	3,441,230
Crescent loan	**15,082,996**	15,000,000
	24,441,641	24,480,332

(a) Capital risk management

The Group manages its capital to ensure that entities in the Group will be able to continue as a going concern while maximising the return to shareholders. The Group's capital structure consists of: (i) equity comprising issued capital, reserves and accumulated losses, (ii) as required, unsecured borrowings from related parties and shareholders and (iii) secured borrowings from independent third parties on commercial terms.

During the 2021 financial year, no dividends were paid (2020: nil).

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements.

(b) Credit risk exposure

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. The Group has adopted a policy of only dealing with creditworthy counterparties as a means of mitigating the risk of financial loss from defaults.

The Group has a material credit exposure to the party that purchases its oil production from the SM71 and SM58 leases. There are no risk mitigation strategies in place, however the purchasing company is a large global energy corporation, so the risk of financial default is considered low. Apart from this credit risk exposure, the Group does not have any significant credit risk exposure to any single counterparty or any group of counterparties having similar characteristics. The credit risk on liquid funds is limited as the counterparties are banks with high credit ratings assigned by international credit rating agencies.

The carrying amount of financial assets recorded in the financial statements, net of any allowances for losses, represent the Group's maximum exposure to credit risk.

30. Financial instruments continued

(c) Liquidity risk management

The Group manages liquidity risk by maintaining adequate cash reserves and if required, standby credit facilities to meet commitments when they fall due. Management continuously monitors cash forecasts to manage liquidity risk.

Liquidity, credit and interest risk tables

The following table details the Group's remaining contractual maturity for its financial assets.

Consolidated financial assets	Weighted average effective interest rate %	Less than 1 month US$	1 month to 3 months US$	3 months to 12 months US$	1-5 years US$
2021					
Non-interest bearing	**-**	**4,021,044**	**98,937**	**83,956**	**180,398**
Interest rate bearing bonds	**0.5 to 1.0%**	**-**	**-**	**-**	**1,925,000**
Variable interest rate instruments	**0.08%**	**4,143,411**	**-**	**-**	**-**
2020					
Non-interest bearing	-	1,769,509	112,048	190,880	251,365
Interest rate bearing bonds	0.5 to 1.0%	-	-	-	1,925,000
Variable interest rate instruments	0.18%	16,644,701	-	-	-

The table below details the Group's remaining contractual maturities for its financial liabilities. The following are future contractual cash payments of financial liabilities, including estimated interest payments.

Consolidated financial liabilities	Weighted average effective interest rate %	Less than 1 month US$	1 month to 3 months US$	3 months to 12 months US$	1-5 years US$
2021					
Non-interest bearing	**-**	**2,073,251**	**187,564**	**238,457**	**-**
Prepaid oil revenue	**11.80%**	**875,000**	**875,000**	**-**	**-**
Fixed interest rate instruments	**3.87%**	**210,677**	**429,373**	**890,543**	**-**
Related party liabilities	**10.00%**	**-**	**-**	**3,578,780**	**-**
Crimson loan	**15.00%**	**626,500**	**1,479,700**	**7,336,432**	**5,640,364**
2020					
Non-interest bearing	-	4,517,823	27,462	-	-
Fixed interest rate instruments	3.43%	204,400	408,800	880,617	-
Related party liabilities	10.00%	-	-	-	3,441,230
Crimson loan	15.00%	-	-	4,375,000	10,625,000

(d) Fair values

The directors consider that the carrying amounts of financial assets and financial liabilities recorded at cost less any accumulated impairments in the financial statements approximates their fair values.

The fair values of financial assets and financial liabilities are determined as follows:

(i) holdings in unlisted shares are measured at cost less any impairments. The directors consider that no other measure could be used reliably; and

(ii) other financial assets and financial liabilities are determined in accordance with generally accepted pricing models.

(e) Interest rate risk management

The Group's exposure to the risk of changes in market interest rates relates primarily to the Group's cash and cash equivalents with a floating interest rate. The Group is not currently engaged in any hedging or derivative transactions to manage interest rate risk. This risk is managed through the use of cash flow forecasts supplemented by sensitivity analysis.

As at 30 June 2021, the Group had no loans outstanding with a variable interest rate as the insurance premium funding, a secured third party loan and director/shareholder loans, all have applicable fixed interest rates. As such, the fixed interest rate loans have an interest risk if variable and/or new loan interest rates are below the fixed loan interest rates.

Interest rate sensitivity analysis

A sensitivity analysis has been determined based on the exposure to interest rates at reporting date with the stipulated change taking place at the beginning of the financial year and held constant throughout the reporting period.

At reporting date, if interest rates had been 50 basis points higher or lower and all other variables were held constant, the Group's net profit would increase by US$51,970 (2020: US$58,570) for an increase of 50 basis points, conversely a decrease of 50 basis points would result in a decrease of US$51,970 (2020: US$58,570) to the net profit. This is mainly due to the Group's exposure to variable interest rates on cash and cash equivalents.

(f) Foreign currency risk management

The Group incurs costs in US dollars and Australian dollars and holds the majority of liquid funds in US dollars.

Fluctuations in the Australian dollar/US dollar exchange rate can impact the performance of the consolidated entity. The consolidated entity is not currently engaged in any hedging or derivative transactions to manage foreign currency risk. As cash inflows and cash outflows are predominately denominated in US dollars, with the exception of Australian dollar denominated equity funding, surplus funds are primarily held in US dollars.

The carrying amounts of the Group's foreign currency denominated monetary assets and monetary liabilities at the end of the reporting period are as follows.

	Monetary assets		**Monetary liabilities**	
Consolidated	**2021 $**	**2020 $**	**2021 $**	**2020 $**
USA currency denominated	**10,202,416**	19,653,469	**22,698,195**	22,860,922
Australian currency denominated	**332,974**	1,806,840	**2,319,031**	2,359,625

The following table details the Group's sensitivity to a 10% increase and decrease in the US$ against the A$.

A positive number below indicates an increase in profit or equity where the US dollar strengthens 10% against the relevant currency. For a 10% weakening of the US dollar against the relevant currency, there would be a comparable negative impact on the profit or equity. The impact is mainly due to the Australian group of holding companies incurring and settling expenses and outgoings in Australian dollars.

	Australian dollar impact on profit/loss	
Consolidated	**2021 US$**	**2020 US$**
Profit or equity	**1,123,783**	245,109

30. Financial instruments continued

(g) Commodity price risk

The Group's exposure to the risk of changes in commodity price relates primarily to the Group's sales of crude oil. The Group currently manages these risks through US$ denominated oil price hedges. Changes in the fair value of these derivatives are recognised immediately in the profit and loss and other comprehensive income, having regard to whether they are defined as accounting hedges. At reporting date, if the West Texas Intermediate ("WTI") price per barrel had been US$5.00 per barrel higher or lower and excluding hedged price oil barrels, with all other variables were held constant, the Group's net profit would increase by US$1,433,769 (2020: US$1,572,949) for an increase of US$5.00 per WTI oil barrel, conversely a decrease of US$5.00 per WTI oil barrel would result in a decrease of US$1,433,769 (2020: US$1,572,949) to the net profit.

31. Segment information

Management has determined based on the reports reviewed by the executive management group (the chief operating decision makers) and used to make strategic decisions, that the Group operates within one business segment of oil and gas exploration, development and production; and one geographical segment, the shallow waters of the Gulf of Mexico, United States of America.

The geographical locations of the Group's non-current assets are United States of America US$104,193,107 (2020: US$83,200,908) and Australia US$7,036 (2020: US$57,414).

32. Interests in joint operations

As at 30 June 2021, Byron Energy Inc, a wholly owned subsidiary of the Company was a party, to the following joint operations:

(i) SM71 Offshore Operating Agreement with Otto Energy (Louisiana) LLC covering all of Block 71, South Marsh Island Area, to explore, develop, produce and operate the lease. Byron Energy Inc is the designated operator of SM71 and owns a 50% WI and a 40.625% NRI in the block, with Otto Energy (Louisiana) LLC holding an equivalent WI and NRI in the block. Byron is the operator; and

(ii) On 6 March 2019, Byron purchased from Fieldwood Energy LLC, a 53.00% non-operated WI/44.167% NRI in the SM58 Apache E1 well and E platform located on SM69. Ankor E&P Holdings Corporation is the operator and holds a 47.00% WI in the well and platform.

33. Parent entity information

Financial position	2021 US$	2020 US$
Assets		
Current assets	**87,972**	505,495
Non-current assets	**135,031,802**	126,242,539
Total assets	**135,119,774**	126,748,034
Liabilities		
Current liabilities	**3,679,922**	132,040
Non-current liabilities	**-**	3,441,230
Total liabilities	**3,679,922**	3,573,270
Net assets	**131,439,852**	123,174,764
Equity		
Issued capital	**138,429,568**	136,896,995
Accumulated losses	**(11,613,751)**	(10,595,513)
Foreign currency translation reserve	**197,249**	(7,553,504)
Share option reserve	**4,426,786**	4,426,786
Total equity	**131,439,852**	123,174,764
Financial performance		
Loss for the year	**(1,018,238)**	(2,094,165)
Other comprehensive income	**7,750,753**	525,760
Total comprehensive profit/(loss) for the financial year	**6,732,515**	(1,568,405)

Expenditure commitments

The parent entity has no expenditure commitments at the end of the 2021 financial year (2020: nil).

Guarantees

There were no guarantees entered into during the year by the parent entity in relation to the debts of its subsidiaries except for (i) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under the Secured Promissory Note between Byron Energy Inc and Crimson Midstream Operating, LLC, effective as of 3 December 2019; and (ii) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under an ISDA Master Agreement dated 21 May 2020 between Byron Energy Inc. and Shell Trading Risk Management, LLC and the Master Crude Purchase and Sale Agreement between dated 26 November 2020 between Byron Energy Inc. and Shell Trading (US) Company. In addition, Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under the Participation Agreement dated 1 December 2015 between Byron Energy Inc and Otto Energy (Louisiana) LLC.

Contingent liabilities

The parent entity had no contingent liabilities at 30 June 2021 (2020: nil), other than those listed in note 24 – Contingent liabilities.

34. Subsequent events

Subsequent to the end of the financial year the following has occurred:

(i) on 5 August 2021, Byron announced to the ASX that the Enterprise Offshore Drilling 351 jack-up drilling rig has passed all US Coast Guard and Bureau of Safety and Environmental Enforcement inspections, final drilling permits were approved and was ready to be towed to the South Marsh Island 69 E platform from which the SM69 E2 well will be drilled;

(ii) on 30 August 2021, Byron announced that all platforms were safely evacuated on Friday 27 August 2021 (USCDT) with production shut-in at all platforms, ahead of Hurricane Ida. The Enterprise Offshore Drilling 351 ("EOD 351") jack-up drilling rig was also evacuated and drilling operations suspended;

(iii) on 3 September 2021, Byron announced that the passage of Hurricane Ida, approximately 110 miles east of the Company's assets in the Gulf of Mexico and did not cause any damage to Byron's Gulf of Mexico production facilities or the EOD 351 rig;

(iv) on 13 September 2021, Byron announced that oil pay was logged in South Marsh Island 69 E2 well and oil and gas production and sales had restarted from all wells on the Byron operated SM71 F and SM58 G platforms; and

(v) on 28 September 2021, Byron released its 2021 reserves and resources report.

Except for the above, there have not been any other matters or circumstances occurring subsequent to the end of the financial year that have significantly affected, or may significantly affect the operations of the Group, the results of those operations, or the state of affairs of the company in future financial period.

Directors' Declaration

The directors of Byron Energy Limited declare that in the opinion of the directors:

(a) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable;

(b) the attached financial statements are in compliance with International Financial Reporting Standards as stated in note 1 to the financial statements;

(c) the attached financial statements and notes thereto are in accordance with the *Corporations Act 2001*, including compliance with accounting standards and giving a true and fair view of the financial position and performance of the consolidated entity; and

(d) the directors have been given the declarations required by section 295A of the *Corporations Act 2001*.

Signed in accordance with a resolution of the directors of Byron Energy Limited made pursuant to section 295(5) of the *Corporations Act 2001*.

On behalf of the directors

D Battersby
Chairman

30 September 2021

Deloitte.

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Independent Auditor's Report to the members of Byron Energy Limited

Report on the Audit of the Financial Report

Opinion

We have audited the consolidated financial report of Byron Energy Limited (the "Company") and its subsidiaries (the "Group") which comprises the consolidated statement of financial position as at 30 June 2021, 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 year then ended, and notes to the financial statements, including a summary of significant accounting policies, and the directors' declaration.

In our opinion the accompanying financial report of the Group, is in accordance with the *Corporations Act 2001*, including:

(i) giving a true and fair view of the Group's financial position as at 30 June 2021 and of its financial performance for the year then ended; and

(ii) complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

Basis for Opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Report* section of our report. We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We confirm that the independence declaration required by the *Corporations Act 2001*, which has been given to the directors of the Company, would be on the same terms if given to the directors as at the time of this auditor's report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Material Uncertainty Related to Going Concern

We draw attention to Note 1 in the financial report, where it is described that there are events or conditions which indicate that a material uncertainty exists that may cast significant doubt on the Group's ability to continue as a going concern. Our opinion is not modified in respect of this matter.

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Our audit procedures in relation to going concern included, but were not limited to:

- Reviewing management's cash flow forecasts for the next 12 months including understanding the rationale and reasonableness of the assumptions made including inflows from production activities, exploration and drilling commitments and the basis of the other operating expenditure requirements of the Group for the period ending 30 September 2022; and
- Assessing the adequacy of the disclosures related to going concern in Note 1.

Key Audit Matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report of the current period. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. In addition to the matter described in the Material Uncertainty Related to Going Concern section, we have determined the matter described below to be the key audit matters to be communicated in our report.

Key Audit Matters	How the scope of our audit responded to the Key Audit Matters
Amortisation of Oil and Gas properties For the year ended 30 June 2021 the Group amortised US$13.2 million of oil and gas properties as disclosed in Note 8(b). When an oil and gas asset commences commercial production, all acquisition and/or costs carried forward will be amortised on a units of production of basis over the remaining proved and probable recoverable reserves The remaining reserves are measured by external independent petroleum engineers. The measurement of this amortisation is subject to certain assumptions including: • The level of future proved and probable recoverable reserves; and • The future capital expenditure required to access the reserves.	Our audit procedures included, but were not limited to: • Obtaining and assessing management's external specialist report used to estimate the level of proven and probable oil and gas reserves and future development capital expenditure; • Assessing the objectivity, expertise and experience of management's external specialist to support the assumptions used; • Testing the metered production usage in the current year to independent third party reports; and • Recalculating the mathematical accuracy of the amortisation recognised. We also assessed the appropriateness of the disclosures in Note 8 to the financial statements.

Other Information

The directors are responsible for other information disclosed. The other information comprises the information included in the Group's annual report for the year ended 30 June 2021, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit or otherwise appears to be materially misstated. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

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Responsibilities of the Directors for the Financial Report

The directors of the Company are responsible for the preparation of the 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 financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

Auditor's Responsibilities for the Audit of the Financial Report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

As part of an audit in accordance with the Australian Auditing Standards, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial report, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the directors.

- Conclude on the appropriateness of the director's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial report or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial report, including the disclosures, and whether the financial report represents the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the financial report. We are responsible for the direction, supervision and performance of the Group's audit. We remain solely responsible for our audit opinion.

We communicate with the directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

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We also provide the directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, actions taken to eliminate threats or safeguards applied.

From the matters communicated with directors, we determine those matters that were of most significance in the audit of the financial report of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included in pages 41 to 46 of the Directors' Report for the year ended 30 June 2021.

In our opinion, the Remuneration Report of Byron Energy Limited, for the year ended 30 June 2021, complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the Remuneration Report in accordance with section 300A of the *Corporations Act 2001*. Our responsibility is to express an opinion on the Remuneration Report, based on our audit conducted in accordance with Australian Auditing Standards.

Deloitte Touche Tohmatsu

DELOITTE TOUCHE TOHMATSU

Craig Bryan
Partner
Chartered Accountants
Melbourne, 30 September 2021

ASX Additional Information

Additional information required by the Australian Securities Exchange Ltd. Listing Rules and not disclosed elsewhere in this report is as follows. The information is current as at 7 October 2021.

Distribution of equity securities

As at 7 October 2021 the Company had a total of 1,040,295,102 Ordinary Shares on issue and 41,100,000 Options on issue comprising:

Quoted Ordinary Shares

1,040,295,102 fully paid ordinary shares are held by 5,744 shareholders. All issued ordinary shares carry one vote per share without restriction. Every member at a meeting of shareholders shall have one vote and up on a poll each share shall have one vote.

Unquoted options on issue

41,100,000 options are held by 31 option holders. 28,350,000 options are exercisable on or before 31 December 2021 at an exercise price of A$0.12 cents each, 2,000,000 options are exercisable on or before 31 December 2021 at an exercise price of A$0.16 cents each and 10,750,000 options are exercisable on or before 31 December 2021 at an exercise price of A$0.40 cents each

There are no voting rights attached to these options.

Escrowed securities

As at 7 October 2021 there are no escrowed securities.

The number of shareholders, by size of holding and the total number of quoted shares on issue:

Size of holding	No. of holders	No. of shares
1 – 1,000	1,022	416,885
1,001 – 5,000	1,316	3,629,536
5,001 – 10,000	731	5,539,983
10,001 – 100,000	1,736	66,269,453
100,001 and over	939	964,439,245
Total holders	**5,744**	**1,040,295,102**

The number of security investors holding less than a marketable parcel of securities is 1,929 with a combined total of 2,307,628 securities.

The number of option holders, by size of holding and the total number of unquoted options on issue:

Size of holding	No. of holders	Exercise price A$0.12 expiry 31/12/2021	No. of holders	Exercise price A$0.16 expiry 31/12/2021	No. of holders	Exercise price A$0.40 expiry 31/12/2021
1 – 1,000	-	-	-	-	-	-
1,001 – 5,000	-	-	-	-	-	-
5,001 – 10,000	-	-	-	-	-	-
10,001 – 100,000	-	-	-	-	-	-
100,001 and over	12	28,350,000	1	2,000,000	10	10,750,000
Total	**12**	**28,350,000**	**1**	**2,000,000**	**10**	**10,750,000**

ASX Additional Information continued

Substantial shareholders

Set out below are the names of the substantial holders and the number of equity securities held by those substantial holders (including those equity securities held by their associates).

Name of holder	No. of ordinary shares held	Percentage of issued capital
Douglas Battersby (and associates)	57,250,568	5.5%

20 largest shareholders

Byron Energy Limited

Fully paid ordinary shares

	Name	Number	Percentage
1.	BNP PARIBAS NOMINEES PTY LTD <IB AU NOMS RETAILCLIENT DRP>	55,690,205	5.35%
2.	VERUSE PTY LIMITED	44,385,985	4.27%
3.	ELMSLIE SUPERANNUATION COMPANY PTY LTD <ELMSLIE FAMILY S/F A/C>	28,269,844	2.72%
4.	EQUITAS NOMINEES PTY LIMITED <PB-600387 A/C>	24,227,836	2.33%
5.	MR CHARLES SANDS	20,382,409	1.96%
6.	WALLEROO PTY LTD	18,828,791	1.81%
7.	J & A VAUGHAN SUPER PTY LTD <J & A VAUGHAN SUPER A/C>	17,262,212	1.66%
8.	MR MATTHEW DOMINELLO	16,020,000	1.54%
9.	AGRICO PTY LTD <PALM SUPER FUND A/C>	14,415,928	1.39%
10.	CLAPSY PTY LTD <BARON SUPER FUND A/C>	13,854,350	1.33%
11.	GEOGENY PTY LIMITED	13,214,045	1.27%
12.	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED	12,537,666	1.21%
13.	MR JOHN SANDS	12,080,972	1.16%
14.	DISCOVERY INVESTMENTS PTY LTD	12,000,000	1.15%
15.	POAL PTY LTD <BARAIN SUPER FUND A/C>	11,341,298	1.09%
16.	FITZROY RIVER CORPORATION LIMITED	11,210,089	1.08%
17.	BARRIJAG PTY LTD <HADLEY FAMILY A/C>	10,245,000	0.98%
18.	JETAN PTY LTD	10,050,001	0.97%
19.	DIXSON TRUST PTY LIMITED	9,788,400	0.94%
20.	BATTERSBY PTY LTD <VERUSE EMPLOYEES S/F A/C>	9,295,959	0.89%
Total securities of top 20 holdings		365,100,990	35.10%
Total of securities		**1,040,295,102**	

Corporate Directory

Directors

Doug Battersby (Non-Executive Chairman)

Maynard Smith (Executive Director and CEO)

Prent Kallenberger (Executive Director)

William Sack (Executive Director)

Charles Sands (Non-Executive)

Paul Young (Non-Executive)

Chief Executive Officer

Maynard Smith

Chief Financial Officer and Company Secretary

Nick Filipovic

Registered and principal Australian office

Level 4
480 Collins Street
MELBOURNE VIC 3000

Principal office (USA)

Suite 100
425 Settlers Trace Boulevard
LAFAYETTE LA 70508

Legal adviser

Piper Alderman

Level 23
Governor Macquarie Tower
1 Farrer Place
SYDNEY NSW 2000

Auditors

Deloitte Touche Tohmatsu

477 Collins Street
MELBOURNE VIC 3000

Website

www.byronenergy.com.au

Home Stock Exchange

ASX Limited

20 Bridge Street
SYDNEY NSW 2000
ASX Code: BYE

Share registry

Boardroom Pty Limited

Grosvenor Place,
Level 12, 225 George Street
SYDNEY NSW 2000
Tel: 1300 737 760
Fax: 1300 653 459

BYRONENERGY