Focused on the future

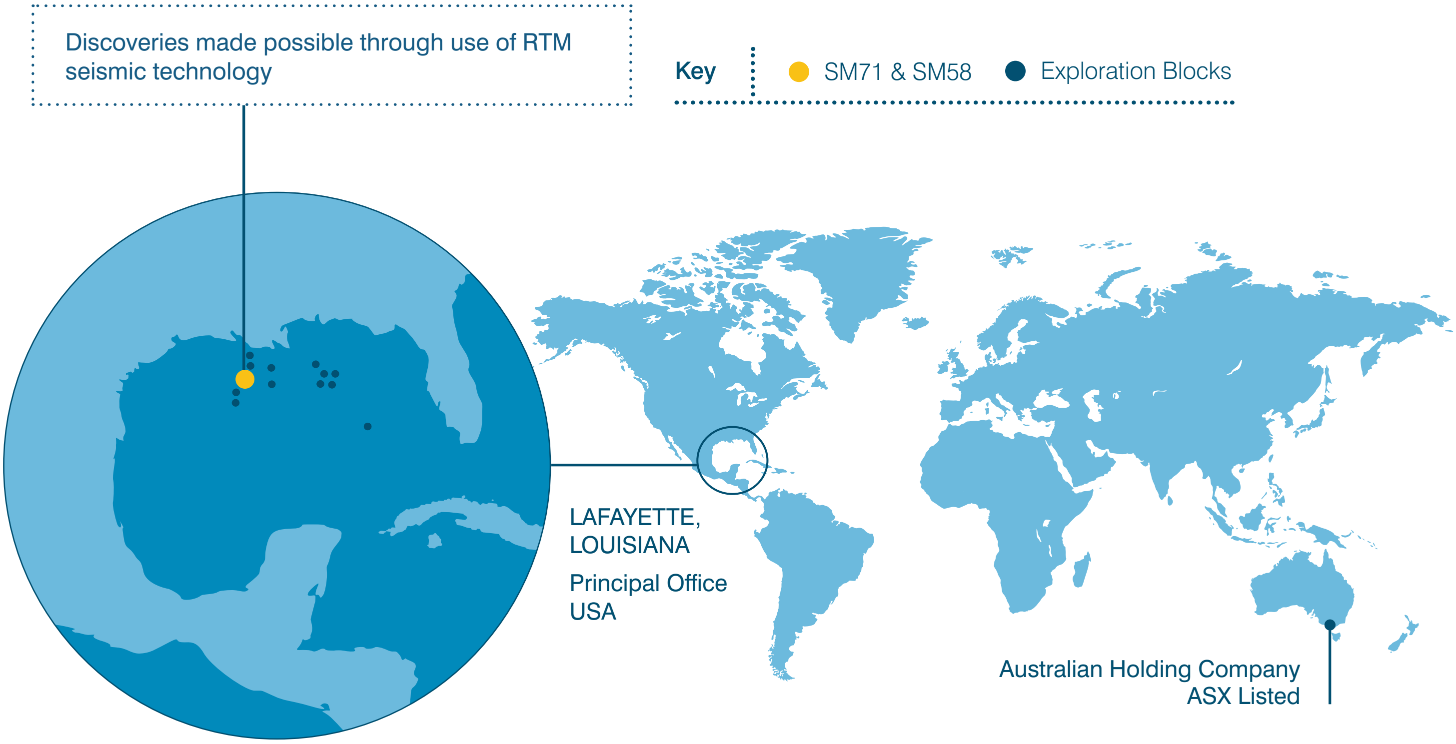
Annual Report 2020

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 Oil Fields



SM58 Discovery

SM58

August 2019 discovery
301 feet net pay in SM58 G1
Upper O Sands

SM71 Production

2,522 Bopd

Production (gross)
SM71 2,522 Bopd and
4.2 Mmcfpd average 2020

Reserves

2P 17.5 Mmbo

Reserves
2P (net) 17.5 Mmbo
2P (net) 105.3 Bcf
2P (net) 35.0 Mmboe

Chairman's Letter

Oil prices continued to improve after 30 June 2020 trading around US$40 as crude stock levels were drawn down from the peak levels reached during the June 2020 quarter

Dear Shareholder,

2020 has been a very difficult year for all of us. The World Health Organization declared the COVID-19 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 resulted in a sharp fall in oil prices.

West Texas Intermediate ('WTI'), the USA marker oil price, dropped from around US$61 per barrel in early January 2020 to around US$20 by early April 2020. The crude oil price decline started in early March 2020 after Saudi Arabia initiated a price war with Russia and accelerated after the COVID-19 outbreak around the world. The WTI spot price actually 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 improved reaching just over US$39 on 30 June 2020 for WTI spot. Oil prices continued to improve after 30 June 2020 trading around US$40 as crude stock levels were drawn down from the peak levels reached during the June 2020 quarter.

While COVID-19 had less of an impact on USA natural gas prices, it has adversely impacted industrial use of natural gas. In addition, volumes flowing to LNG export plants have dropped substantially due to weak international demand associated with the COVID-19 imposed lockdowns. All of this came at a time when the commodity was already struggling with weak consumption because of a warmer-than-usual USA winter 2019–2020.

The Henry Hub natural gas mmbtu spot price has been volatile declining from US$2.42 on 28 June 2019 to US$1.76 on 30 June 2020. Natural gas prices began to improve after 30 June 2020 exceeding US$2.50 by late August 2020.

The Byron operated SM71 project continued to perform strongly during the 2019/20 year producing 375,906 barrels of oil and 878,811 mmbtu of gas (net to Byron), generating net sales revenue of US$20.6 million.

During 2019/20 Byron's primary focus was on our SM58 project where we completed the platform construction and installation, installation of oil and gas pipelines and completion of the SM58 G1 well, all on time and under budget. Drilling of the SM58 G2 well commenced on 6 August 2019 and unfortunately did not encounter commercial hydrocarbons and was plugged back to be sidetracked to evaluate the Brown Trout prospect. The SM58 G1 well commenced production in September 2020 at 375 barrels of condensate per day and 19.4 mmcfd of gas on a gross basis.

In early October 2020, the SM58 G2ST well reached a final, total depth of 7,720 MD/7,035 TVD feet. 280 gross feet of hydrocarbon was logged with LWD gamma ray/resistivity tools. No water contact was observed within the interval. Good mudlog hydrocarbon seven shows with fluorescence and heavy gasses were also observed. Seven inch casing was run with completion operations expected to be completed around the end of October 2020.

SM58 G Platform and Enterprise Offshore 264 drilling rig.

The targeted O Sand in the SM58 G2ST well was intersected at the expected depth and with the expected thickness. Adding a second producing well to our SM58 G Platform will provide Byron with additional income and reduces the concentration risk to our producing assets in the South Marsh Island Project Area.

The current plan is to release the Enterprise Offshore drilling rig during the winter months and renew drilling operations in early March 2021. This should avoid the worst weather months in the GOM and ensure that the Company can fund the future drilling program though cash flow.

Byron funded the development of SM58 through a combination of debt and equity. The debt, comprising initially US$15 million and increased to US$18.5 million, was sourced from Crimson Midstream Holdings LLC (Crimson Midstream). Crimson Midstream is a portfolio company of The Carlyle Group and provides Byron with crude oil pipeline transportation services for our SM71 and SM58 oil production. The equity component of the funding in November 2019 and May 2020 was sourced from our existing shareholders, including directors, and several new substantial investors, through a combination of placements, an entitlement issue and share purchase plan which raised a combined A$53.4 million before costs. The strong support we received for our placement and the share purchase plan, in May 2020, after the oil price fall induced by COVID-19, allowed the Company to continue with its SM58 development uninterrupted.

On 10 September 2020, we released our 30 June 2020 reserves and resources statement. Our reserves and resources position as at 30 June 2020 is very strong. Remaining 2P reserves as of 30 June 2020, net to Byron, were 17.5 Mmbbl of oil and 105.3 Bcf of gas, an increase of 0.6% on a boe basis over the 2019 year, replacing our production and after adjusting for the GI95 lease relinquishment.

Our South Marsh Island area leases account for more than 60% of our 2P reserves, with SM58 being the main contributor. Our Eugene Island 77 area leases account for the remaining percentage.

Pleasingly we managed to increase our prospective resources substantially over the year to 43.6 mmbl of oil and 617.3 bcf of gas (net to Byron) up from 31.6 mmbl and 551.1 bcf, with SM60 prospective resources, included for the first time this year, more than offsetting the removal of GI95 prospective resources.

Again we have taken decisive steps to upgrade our portfolio of drillable prospects, relinquishing GI95, a relatively dry gas project, and adding the SM60 prospective gas and oil resources.

Our successful development of SM58, has added another Byron operated producing asset, significantly increasing our production and cash-generating capacity thus enabling the Company to continue exploration and development of the South Marsh Island area prospects and also our EI77 area opportunities.

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 guidance and support, in what has been a very challenging year for all. With production platforms and producing wells at SM71, SM58 and SM69 and an inventory of first-rate exploration and development opportunities, we believe that Byron is well positioned to continue creating substantial additional shareholder value.

Doug Battersby
Chairman

Net Revenue 2020

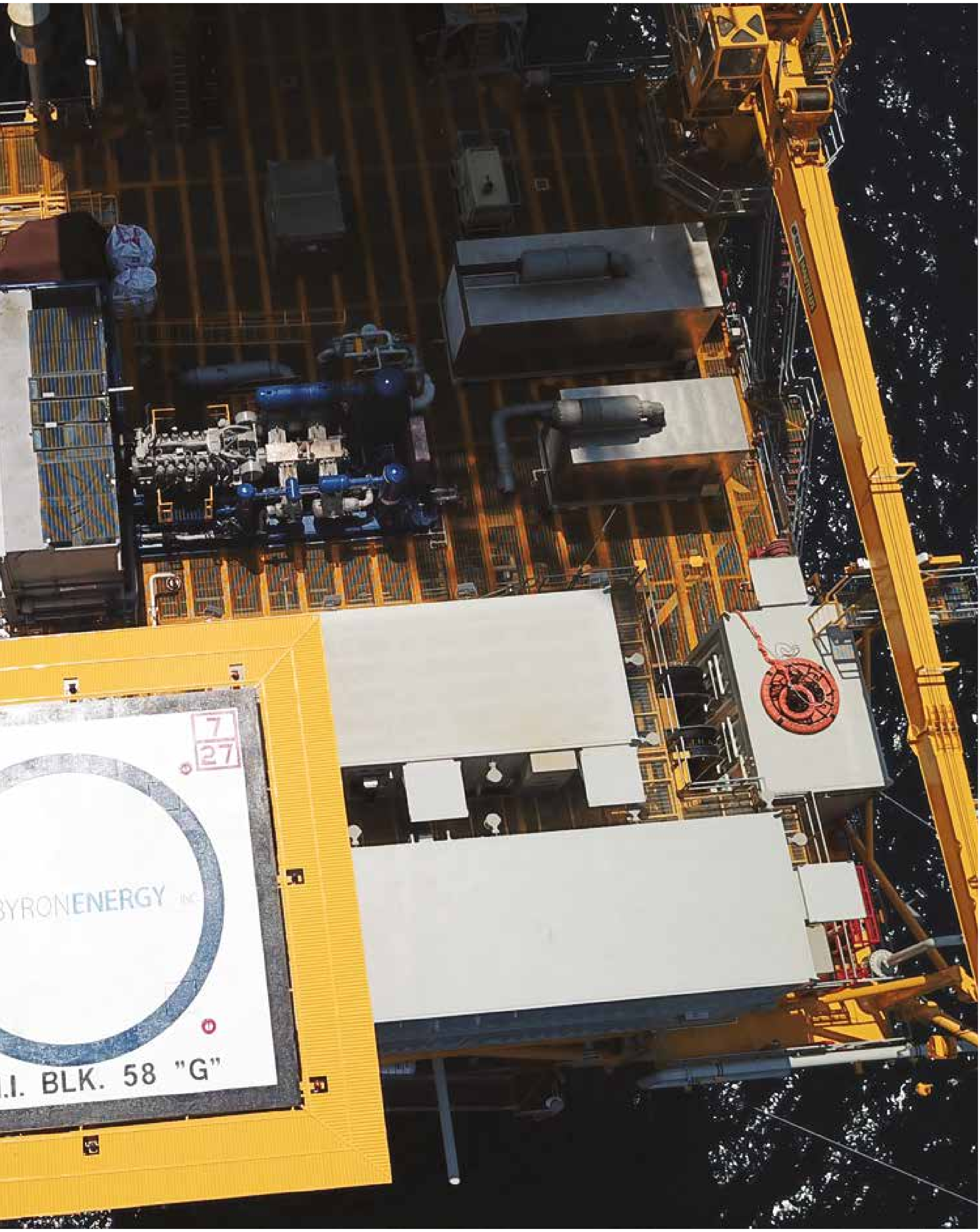
US$21.4m
SM71 and
SM58 E#1

3P Reserves

25.3 Mmbbl
130.0 Bcf

Prospective Resources

43.6 Mmbbl
617.3 Bcf
(before SM58 update for SM58 G2)


7
27
BYRONENERGY INC
.I. BLK. 58 "G"

Message from the CEO

Risk management in 2020, building a strong foundation for significant shareholder growth in 2021

By any measure, 2020 has presented Byron with one of the most difficult and challenging operating environments for a small oil and gas company that I have ever experienced. Due to the COVID-19 pandemic and the resultant impact on world oil consumption, the current economic circumstances are undoubtedly a black swan event. Early in 2020, daily world oil consumption was close to 100 million barrels of oil per day and set to climb further on the back of sustained world economic growth. Currently, the best estimate for average daily demand for 2020 is now closer to 90 million barrels per day, with the expectation that consumption will need a couple of years to return to pre COVID-19 levels. While demand is expected to recover, US shale production is likely to continue to decline through 2021 and potentially beyond, primarily due to its high cost and low margin nature. Byron, on the other hand, as a low cost high margin producer, has a significant advantage in the current economic environment.

Before the pandemic, it would have been hard to imagine any event outside of a world conflict, leading to such a dramatic collapse in oil demand and price. This event reinforces and highlights how critically important it is for a small oil company, such as Byron, to have a comprehensive risk management strategy to survive and prosper in these times of great uncertainty. Despite the unimaginable challenges that Byron has faced in 2020, the Byron team has remained focused and determined to adapt to the current circumstances. In doing so, the Company has not only further improved its risk minimization strategies but has also succeeded in building a foundation on which to grow the Company for many years to come.

In 2020, our business's primary risk factors are oil price volatility, cost overruns associated with drilling, non-commercial wells due to geological risk, the regulatory risk associated with changing political environment, and funding risk.

Byron has produced net to the Company this financial year, 394,000 barrels of oil, 0.8 billion cubic feet of gas, and received US$21.4 million in net revenue (after royalties and transportation charges). I expect this to increase steadily and substantially over the next 12 months. To get the best possible return for our product and, at the same time, minimize future price risk, Byron has employed the services of an expert advisor in this field to help guide our decision making. As a result of this, Byron instituted a timely defensive hedging strategy last year and again in June this year to smooth out the oil price volatility created by the COVID-19 pandemic. Byron's approach to locking in a portion of production revenue, to better predict future cash flows, provides the Company with the flexibility to plan the level and timing of future drilling and development. Byron's hedging strategy is a crucial plank in risk management and remains under continuous review as our production volumes increase.

Drilling risk and the associated cost overruns, when facing challenging conditions, is another serious concern that can adversely impact the Company. Drilling risk is a troublesome issue for all oil companies and must be continually assessed and mitigated. Following a careful review of this issue, in 2019 Byron decided to seek out and hire the best possible available talent to plan and manage all future drilling and completions and has succeeded in attracting and hiring one of the most senior and experienced teams of drilling and completion engineers available to the industry. This team has experience across many geographical locations and basins and has worked on some of the most challenging wells ever drilled. The results speak for themselves as the Company has not had any cost overruns associated with drilling or completion operations since this team began managing our wells.

To help minimize geological risk, while developing the SM58 area, future wells will incorporate a fully engineered, sidetrack option as a low risk fall back to the original prospect hole. This strategy has been part of our approach for many years and was recently employed on the G2 exploration well. While we were very enthusiastic about the Lower O section at the Cutthroat prospect, we were aware that this section had an element of trap risk. Before the drilling of the G2, we engineered a detailed sidetrack plan to test the Brown Trout prospect should the original G2 well fail. The G2ST1 tested Brown Trout at the cost of less than US$2.0 million, far cheaper than a stand-alone well from the surface, and provided Byron a low-risk option that delivered a good result for the Company. The Company's SM58 project is in a very complex area, with 123 wells drilled within the 9 square mile area of SM58 by previous operators. Thus far, the Byron proprietary seismic has been very accurate in identifying hydrocarbon, but one of the geophysical limits of all seismic data, due to a quirk of physics, is that the enhanced reflectivity associated with hydrocarbon on seismic data is the same for 5% gas saturation as it is for 90% gas saturation. This is true for any seismic data set used by the industry. Therefore, the only way to positively identify a commercial accumulation is through the drill bit. By employing pre-planned sidetracks for our wells, we will ensure that SM58 is developed both cost-effectively and efficiently.

Message from the CEO continued

To minimize the risk associated with the potential change in the regulatory environment post the 2020 election in the US, we have accelerated the permitting for the remaining seven wells at SM58/57, two wells at SM60, and four wells at SM70. Preliminary well planning has also started at our Eugene Island 77 project. These permits are generally valid for the life of the lease, and given the mentioned uncertainties, we think it is prudent to have the core of our program permitted. This permitting effort is a significant undertaking requiring many hundreds of working hours.

As I have mentioned in the past, Byron, as the operator, is in complete control of its expenditure. As our production and subsequent cashflow increases to a self-sustaining level, we will pace all our exploration, drilling, and construction efforts so that it can be funded entirely by internally generated cash flows and subsequent modest increases in our borrowing base. While making this statement, no one can accurately predict the future, and all I can say is our clear intention is to avoid further share market capital raisings if at all possible.

Since last year's CEO letter, Byron has drilled four wells and completed three. All four wells and the three completions were done on, or under, budget. Furthermore, we have installed a 100% owned nine-slot platform and 15 kilometers of oil and gas pipelines, which is, without a doubt, a significant milestone event for the Company. The complex SM58 platform design and construction project was completed almost two months ahead of schedule and nearly US$1.0 million under budget. This is a remarkable achievement, particularly given the adverse weather conditions we faced in one of the Gulf of Mexico's most active hurricane seasons on record. The SM58 platform and pipeline

SM58 G Platform and Enterprise Offshore 264 drilling rig.

gathering systems and the SM71 F4, SM58 G2, and SM58 G2 ST1 wells are all 100% designed, owned, and managed by Byron. This is a significant achievement, given the small number of professional staff currently employed and a testament to our ongoing commitment to minimize operating overheads in these challenging times.

Before finishing, it would be remiss of me not discuss the goal that I set out for our company last year. At that time, I expected a substantial appreciation in our share price by April of 2021. As discussed above, I believe we are now well into building a solid foundation for Byron through its increasing production and revenue and while I'm confident this will ultimately lead to significant share price appreciation, I suspect that it may take a little longer to achieve than last year's forecast.

Lastly, I want to thank all our fellow shareholders for your continued support. I know it's been a difficult year for many of you, but I have been humbled by the positive response and support that we received during our last capital raising, which was done during the depths of the COVID-19 pandemic. You can rest assured that the Byron management team, who, as you know, maintain a significant shareholding, will continue to work in the best interest of all shareholders to grow our company's value.

Maynard Smith
CEO

Review of Operations

Introduction

Notwithstanding a severe price decline in March/April 2020, as a result of a reduction in demand for oil following the onset of COVID-19 Byron successfully brought the SM58 project into production less than one year after the drilling of the discovery well, SM58 G1, in October 2019.

2P oil reserves	Annual oil production	Net revenue
UP by 0.6% to 17.5 MMbo	**DOWN by 15% to 393,703 bbls**	**DOWN by 32% to US$21.4m**

During the year, West Texas Intermediate ('WTI'), the USA marker price, dropped from US$61.17 per barrel on 2 January 2020 to US$20.28 on 1 April 2020. The crude oil price decline started in early March 2020 after Saudi Arabia initiated a price war with Russia and accelerated after the COVID-19 outbreak around the world. The WTI spot price actually 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 improved reaching US$39.27 on 30 June 2020 for WTI spot.

COVID-19 also impacted natural gas prices through curtailed industrial use and weaker international demand associated with the COVID-19 imposed lockdowns. The Henry Hub natural gas mmbtu spot price was US$2.42 on 28 June 2019, declining to US$1.76 on 30 June 2020.

The decline in oil and gas prices had a material adverse effect on the industry as well as Byron's oil and gas revenues.

Production for the year ended 30 June 2020 was approximately 394,000 bbls of oil and 0.9 bcf of gas net to Byron, generating net sales revenue of US$21.4 million.

Notwithstanding lower oil and gas price assumptions, Byron's 1P reserves as of 30 June 2020 increased by approximately 7%, from 30 June 2019, on a BOE basis. The Company's 2P reserves, excluding the effects of GI95, generally remained flat, with an increase of approximately 1% on a BOE basis with a small increase in 2P oil reserves of 240 Mbo and a slight decrease in the 2P gas component of 0.2 Bcf. The inclusion of GI95, a non-salt dome pure gas play deemed uneconomic and relinquished, results in a decrease of approximately 17% on a BOE basis.

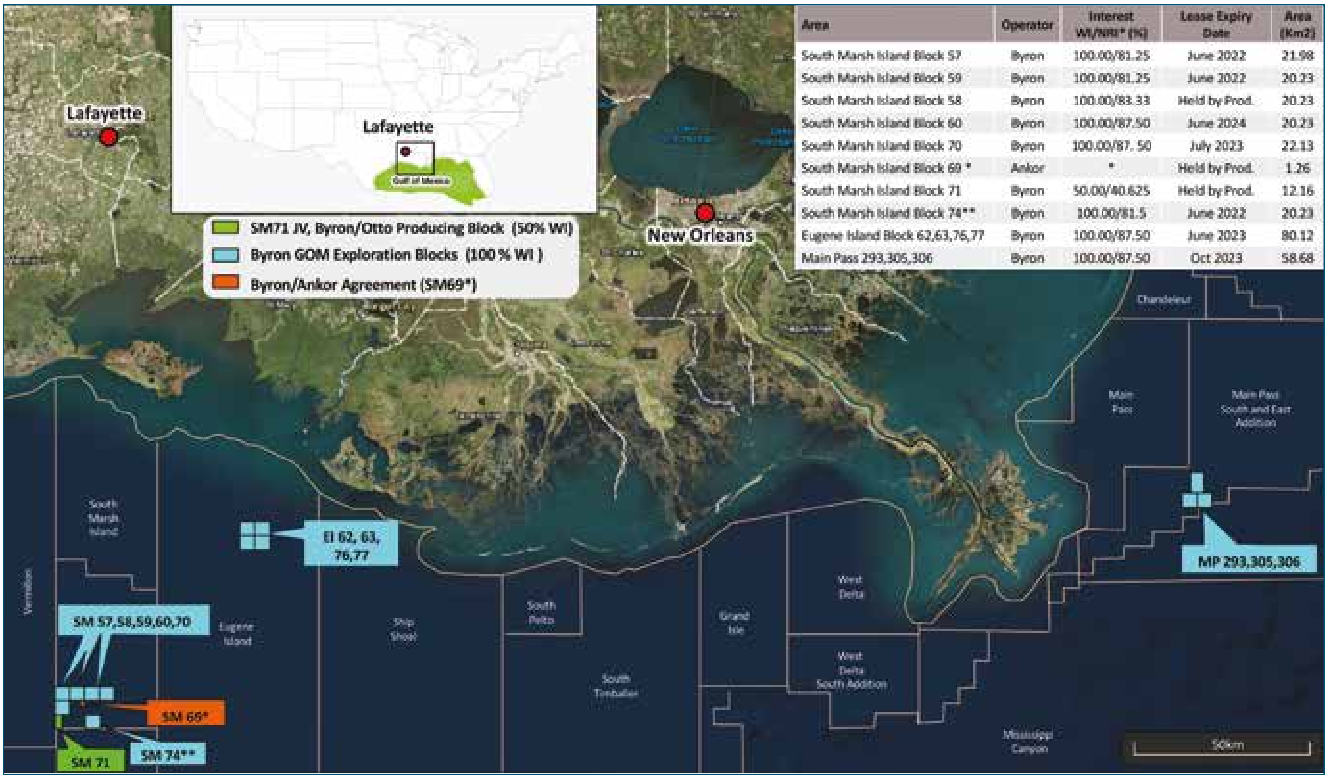
Production/sales statistics (net to Byron)	2020	2019	% change
Oil (bbls)	**393,703**	462,220	-14.8
Gas (mmbtu)	**883,055**	904,069	-2.3
Net revenue after royalties and transportation charges (US$ million)	**21.4**	31.3	-31.7
Lease operating expenses (cash)(US$ million)	**3.4**	2.6	-29.7
Realised oil price after transport charges (US$/bbl)	**50.05**	62.03	-19.3
Realised gas price after transport charges (US$/mmbtu)	**1.55**	2.79	-44.4

Byron Energy Limited – Reserves and Resources

Gulf of Mexico, Offshore Louisiana, USA

Remaining as at 30 June 2020 (net to Byron)	Oil Mbbl	Gas MMcf	Mboe (6:1)	change % 2020 v 2019 incl GI95	change % 2020 v 2019 excl GI95
Reserves (developed and undeveloped)					
Proved (1P)	**8,060**	**58,518**	**17,813**	**6.8%**	**6.8%**
Probable Reserves	9,409	46,732	17,198	-33.1%	-5.2%
Proved and Probable (2P)	**17,469**	**105,250**	**35,011**	**-17.4%**	**0.6%**
Possible Reserves	7,832	24,707	11,949	-24.8%	1.8%
Proved, Probable & Possible (3P)	**25,301**	**129,957**	**46,960**	**-19.4%**	**0.9%**
Total Prospective Resources					
Best Estimate (unrisked)	**43,612**	**617,296**	**146,495**	**18.7%**	**26.6%**

Outer Continental Shelf in the Gulf of Mexico



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 74**	Byron	100.00/81.5	June 2022	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	Oct 2023	58.68

* Refer ASX release 1st April 2019 for details.

** Metgasco Limited retains a 30% WI right to the SM74 lease which to date, has not been formally assigned.

Oil and gas properties

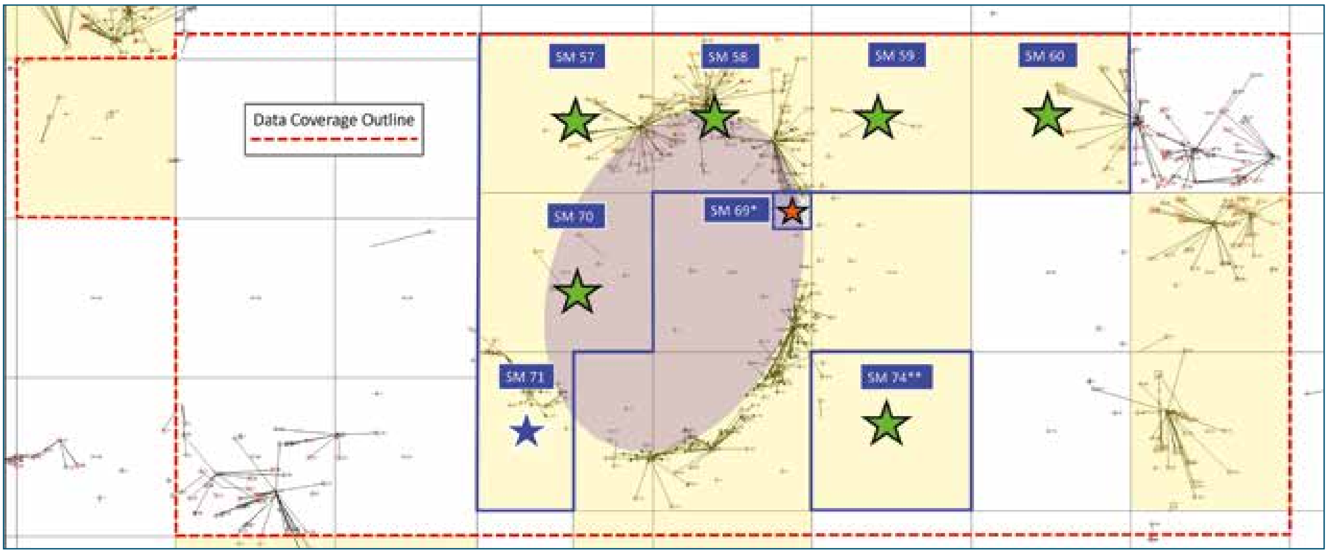
Byron is focused on the shallow waters of the Outer Continental Shelf ('OCS') in the Gulf of Mexico ('GOM'), with a portfolio of leases, as shown below.

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 six areas of interest around the SM73 field, comprising SM57/58/59/60/70 and north-east portion of SM69, as shown below. Byron is also the operator of SM71 and SM74, where it has less than a 100% working interest.

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



* Refer ASX release 1st April 2019.

** Metgasco Limited retains a 30% WI right to the SM74 lease which to date, has not been formally assigned.

(a) South Marsh Island 71

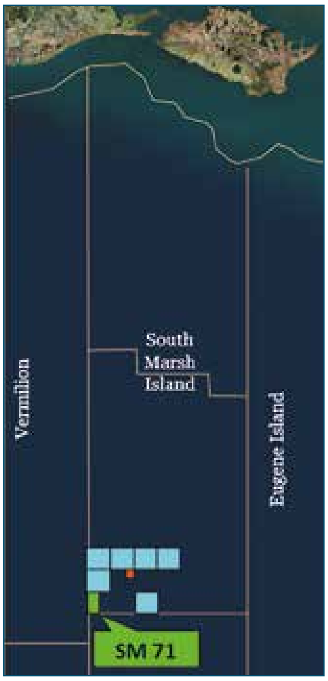
Byron owns the South Marsh Island block 71 ('SM71') a lease in the South Marsh Island Block 73 ('SM73') field. Byron is the designated operator of SM71 and owns a 50% Working Interest ('WI') and a 40.625% Net Revenue Interest ('NRI') in the block, with Otto Energy Limited ('Otto') group holding an equivalent 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 in SM71 F4 well, until payout.

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

Joint Venture Partners	**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
Subsequent Wells (F4 producer) and F5 (temporarily abandoned for future side-track)	F4 first prod. March 2020
Total Gross Project Oil and Gas Produced from March 2018 to June 2020	2.4 mmbo + 3.7 Bcf
Net 2P Remaining Reserves*	4.1 mmbo + 2.9 Bcf

* Collarini and Associates report as of 30 June 2020; refer ASX release 10/09/2020.



SM71 Reserve Summary	Gross Reserves Remaining 30/6/20		Net Reserves Remaining 30/6/20	
	mbo	mmcf	mbo	mmcf
1P Proved	**4,865**	**3,193**	**1,992**	**1,341**
Probable	5,052	3,870	2,079	1,590
2P	**9,917**	**7,063**	**4,071**	**2,931**
Possible	2,923	2,179	1,275	963
3P	**12,840**	**9,242**	**5,346**	**3,894**
	Gross Prospective Resource		Net Prospective Resource	
Prospective	**2,402**	**48,769**	**976**	**19,813**

(i) SM71 production

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

As of 30 June 2020, the SM71 F facility has produced 2.4 million barrels of oil (gross) since initial production began. The facility has also produced over 3.7 billion cubic feet of gas (gross).

Byron's share of SM71 production for the year ended 30 June 2020 is shown in the table below.

Production (sales)	YTD 30 June 2020	YTD 30 June 2019
Gross production		
Oil (bbls)	**923,027**	1,116,375
Gas (mmbtu)	**1,532,750**	2,213,706
Byron share of gross production (WI basis)		
Oil (bbls)	**462,653**	558,188
Gas (mmbtu)	**1,081,614**	1,106,853
Net production (Byron share (NRI basis)		
Oil (bbls)	**375,906**	453,527
Gas (mmbtu)	**878,811**	899,318

Oil production for the year ended 30 June 2020 was below the volumes achieved for the 2019 year mainly due to Byron's decision to shut in the SM71 F1 well and reduce production from the F3 well to 1,850 bopd, effective 31 March 2020, to maximise long-term value by linking production to volume commitments under the Company's forward sale agreement, during a period of depressed prices.

Sales revenue and lease operating expenses (US$ million)	YTD 30 June 2020	YTD 30 June 2019
Net sales revenue (Byron share after royalties and transportation costs)	**20.6**	31.0
Lease operating expenses (cash)	**2.7**	2.5

For the year ended 30 June 2020, Byron's share of net revenue was approximately US$20.6 million compared to US$31.0 million for the 2019 year, mainly due to lower average realised oil and gas prices and lower oil production, as a result of Byron's decision to shut in the SM71 F1 well and reduce production from the F3 well to 1,850 bopd, effective 31 March 2020, to maximise long-term value by linking production to volume commitments under the Company's forward sale agreement, during a period of depressed prices.

During the year ended 30 June 2020, Byron realised an average oil price after uplift for LLS price differentials and deductions for transportation, oil shrinkage and other applicable adjustments of US$50.32 per bbl compared to US$62.14 per bbl for the year ended 30 June 2019.

Byron realised an average gas price after transportation deductions of approximately US$1.55 per mmbtu during the year ended 30 June 2020 compared to US$2.79 per mmbtu for the 2019 year.

(ii) SM71 F4 well

The Enterprise Offshore Drilling 264 rig spudded the SM71 F4 well from the Byron operated SM71 F Platform in late January 2020.

The SM71 F4 well was designed to test the D5 Upper Sand outboard of the main D5 field area on SM71 where the F1 and F3 wells have combined to produce more than 2.2 million barrels of oil and 2.8 billion cubic feet of gas from the main D5 Sand since production began in March 2018.

The SM71 F4 well reached final, total depth of 8,130 feet measured depth (MD) (7,570 feet true vertical depth (TVD)) on 12 February 2020.

The primary target D5 Upper Sand was penetrated exactly on predicted depth and Log While Drilling ('LWD') Triple Combo (Gamma Ray, Resistivity and Neutron-Density) tools logged a total of 91 feet MD of net hydrocarbon pay (87 feet true vertical thickness (TVT) net hydrocarbon pay) which was at the upper end of pre-drill expectations. The D5 Upper Sand was penetrated high on structure and exhibited high-quality reservoir characteristics with an average porosity of 30%, a low water saturation and no water contacts were observed on the LWD logs. The LWD logs indicated the D5 Upper Sand contains gas in the higher porosity upper section and oil in the lesser-quality lower section.

Additionally, 11 feet MD (10 feet TVT) of hydrocarbons were logged in the SM71 F4 well in the J1 Sand. This result was entirely consistent with the current understanding of the J1 Sand as encountered in the SM71 F2 well where it is a behind pipe production opportunity when the current B55 Sand completion is fully produced in that wellbore. The SM71 F4 well was cemented in a manner that allows the J1 Sand to be produced should it be deemed necessary to efficiently produce the reserves attributed it.

The SM71 F4 well was turned over to production in mid-March 2020. Throughout the June 2020 quarter, the F4 continued to decline in reservoir pressure indicating a very weak water drive for the D5 Upper Sand reservoir. The well is being produced through the platform compressor and as of 30 June 2020, the F4 well was producing approximately 2.8 million cubic feet of gas and 53 barrels of oil, accompanied by two barrels of water (gross basis) per day. Byron's internal mapping and volumetrics indicates a potential gas cap of between 0.5 and 1.0 Bcf.

Ultimately, the oil recovery from the D5 Upper Sand will depend on the strength of the reservoir water drive mechanism, but that support appears to be weak.

As Otto declined to participate in the SM71 F4 well, Byron decided to drill the F4 well on a 100% basis. The SM71 Offshore Operating Agreement provides for participation in proposed operations by fewer than all parties, including the right for the non-participating party to revert to their working interest after the participating party has recouped, out of 100% of production, an amount of 600% of all costs associated with drilling and completion.

(iii) SM71 F5 well

The Byron operated SM71 F5 well was spud on 8 March 2020. The objective of the F5 well was to test a portion of the D5 Sand reservoir that may be poorly drained, if at all, by the SM71 F3 well.

The primary D5 Sand target was penetrated within 50 feet of the predicted depth based on RTM data at 8,225 feet MD (7,330 feet TVD) and LWD Triple Combo (Gamma Ray, Resistivity and Neutron-Density) tools logged a total of 39 feet MD of net gas pay, equivalent to 36 feet TVT. This zone was deemed Show #3 by Mudloggers and the well was drilled to a final total depth of 8,505 feet MD (7,591 feet TVD) where hole conditions deteriorated and, although another hydrocarbon show was encountered (Show #4), it was decided to stop and temporarily plug the F5 well for use as future side-track wellbore. Because of uncertainty related to the potential impact of COVID-19 on operations, Byron and Otto elected to defer a sidetrack operation at this time. The SM71 F5 wellbore was temporarily abandoned in a manner that allows it to be efficiently sidetracked in the future when the uncertainty relating to the COVID-19 epidemic has dissipated and also at a time where oil prices are higher.

Subsequent to drilling operations, Byron has done extensive internal work on the results of the F5 well and now believes that the well was drilling in the upper-most portion of the actual D5 Sand at total depth. However at the time, deteriorating hole conditions due to wellbore stability would not allow any drilling below total depth of 8,505 feet MD (7,591 feet TVD).

Between 8,484 feet and the total depth of 8,505 feet MD, 21 feet MD (20 feet TVT) of very fine to finegrained sand was encountered and hydrocarbon shows were recorded on mudlogs. The upper 10' of the interval was partially logged by LWD Gamma Ray and Resistivity tools. This zone was deemed Show #4 and coincided with the upper-most portion of a strong anomaly on Byron's FWI data. Show #4 was described by the Mudlogger as 'probably productive' gas/oil based on the presence of heavy gases (Ethane through Isopentane) with maximum gas over 1000 units recorded. No fluorescence was observed most likely due to the use of synthetic oil base muds.

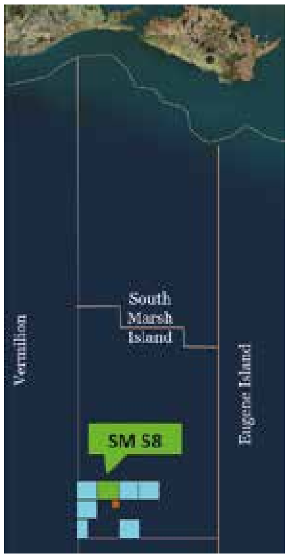
(b) South Marsh Island 58

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% 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.

South Marsh Island 58 (SM58) Project Summary

Joint venture partners	Byron Energy
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$4.25 million (including interest in SM58 E1 well and SM69E platform)
Byron Interest	100% WI, 83.33% NRI
Byron SM58 G1 discovery well	September 2019, 301' TVT Hydrocarbon Pay
G Platform Installation Completed	July 2020
SM58 G1 and G2ST	G1 first prod. September 2020 G2ST first prod. expected November 2020
G Platform Capacity	8,000 bopd + 80 mmcfgpd + 8,000 bwpd
Net 2P Remaining Reserves*	10.9 Mmbo + 33.4 bcf*

* Collarini and Associates report as of 30 June 2020; refer ASX release 10/09/2020.



SM58 Reserve Summary	Gross Reserves Remaining 30/6/20		Net Reserves Remaining 30/6/20	
	mbo	mmcf	mbo	mmcf
1P Proved	**5,619**	**28,662**	**4,682**	**23,884**
Probable	7,402	11,405	6,168	9,504
2P	**13,021**	**40,067**	**10,850**	**33,388**
Possible	4,717	6,064	3,931	5,053
3P	**17,738**	**46,131**	**14,781**	**38,441**
	Gross Prospective Resource		Net Prospective Resource	
Prospective	**14,680**	**35,296**	**12,233**	**29,412**

In early October 2019 Byron completed the drilling of SM58 G1 well which successfully tested Byron's Cutthroat Prospect, identified and evaluated using high-tech Reverse Time Migration (RTM), Vector Image Processing (VIP) and Full Waveform Inversion (FWI) 3D seismic processing.

The SM58 G1 well encountered a true vertical thickness net pay of 301 feet in the Upper O Sands. Mud log data indicated a total hydrocarbon bearing interval thickness in the Lower O section of between 180 and 250 feet. Due to hole conditions, the Lower O Sand interval was not logged in the SM58 G1 well and was the primary target of the SM58 92 well. The SM58 G1 well was mudline suspended so that it could be completed and placed on production when the G platform was completed.

(i) SM58 G development

Byron's final Development Operations Coordination Document ('DOCD') was approved on 4 June 2020. The DOCD allowed the Company to set the production platform, lay oil and gas pipelines and drill up to four wells.

Load out of the SM58 G platform jacket pilings began in early June 2020. On location, the jacket was set in place over the existing SM58 G1 well, pinned to the sea floor and then the deck was lifted into place on top of the jacket and welded down. With some weather delays, the entire operation was completed in early July. By salvaging and refurbishing a high-quality structure already in good condition, the Company realised a saving in the range of US$8–10 million and expedited cycle time to first production by nine to 12 months compared to a new-build facility.

The SM58 G platform is capable of handling 8,000 barrels of oil per day, 80 million cubic feet of natural gas per day and 8,000 barrels of water per day.

The pipeline lay barge was mobilised early in July 2020. Operations comprising the installation of the 4-inch diameter 1,000-foot (305 metre) oil sales line and the laying of the 8-inch diameter 39,000-foot (12km) gas sales line and tie-in operations were completed in mid-August 2020.

On 13 August 2020 (USCDT), the Company finished completion operations on the Upper O Sand in the SM58 G1 well. The Upper O Sand logged 331 measured depth ('MD') gross feet of hydrocarbon (301 feet true vertical thickness net pay) in the SM58 G1 well in September 2019. Consistent with the pre-job plan, a total of 217 feet MD of the Upper O Sand was perforated, and sand control measures were implemented to maximise production rate and recovery. The completion job was conducted without any operational issues and was completed about five days ahead of schedule.

Gas and oil production from the SM58 G platform was initiated on 7 September 2020 (USCDT) when the SM58 G1 ('G1') well was opened to sales. Initial test rates from the Upper O Sand are 19.4 million cubic feet of gas per day, 375 barrels of condensate per day, no formation water and a flowing tubing pressure of 1,375 psi. The flowing tubing pressure matched pre-production nodal models for the gas and condensate rates from the tests.

The drilling of the G2 well followed immediately after completion of the G1 well. The G2 well drilled through the primary target section of the Lower O Sand; however, no commercial hydrocarbons were logged with Log While Drilling (LWD) tools. LWD logs across the Lower O Sand section indicated the presence of two sand bodies totalling a gross 310 feet of true vertical thickness. Like the Lower O Sands observed on Mud logs from the SM58 G1 well drilled in 2019, the Lower O Sands in the G2 well had strong gas shows consisting of both light and heavy gasses while drilling. Non-commercial low saturation residual hydrocarbon-bearing sands and several wet sands were observed across the Lower O Sand section based on LWD logs.

The low-level residual hydrocarbon saturation of the Lower O Sand section is responsible for the bright seismic amplitude observed across the Lower O Sand trap and is indistinguishable from higher hydrocarbon saturations on seismic data. The results of the G2 are indicative of a failed geologic seal for the fault trap at the depth of the Lower O Sands. There were no Proved, Probable or Possible Reserves attributed to the Lower O Sand in the G2 well, in the Company's 30 June 2020 Net Reserves and Resources Report released to the ASX on 10 September 2020, which was a Prospective Resource play driven by shows in the 2019 SM58 Byron G1 well that Byron was unable to log at the time due to hole conditions. The Company will reassess its Prospective Resources in this portion of the SM58 project in due course.

The Lower O Sand section of the wellbore was plugged and abandoned as per government regulations. A section of 9 5/8" casing was cut and pulled from the wellbore, and after a cement kick off plug was set, the well was sidetracked to Byron's SM58 Brown Trout prospect. The SM58 G2 ST was drilled to a depth of 8,152 feet MD (7,506 feet TVD) and targeted the Upper O Sand in an attic position, updip from two wells that produced over two million barrels of oil from the Upper O Sand with a water drive mechanism. The SM58 G2 ST well will gain approximately 150 feet of structure to those wells.

SM58 G2ST reached final total depth at 0230 hours on 4 October 2020 (USCDT). The well was drilled to a total depth of 7,720 feet measured depth ('MD')/7,035 feet true vertical depth ('TVD'). Logging While Drilling ('LWD') gamma ray and resistivity tools indicate the SM58 G2ST penetrated a 280 foot gross thickness hydrocarbon section in the targeted Upper O Sand with no water contact in the interval. Additionally, mud-log analysis showed dull yellow streaming oil cuts with associated fluorescence throughout a large portion of the O Sand interval along with heavier gas fractions on the mudlog gas chromatograph.

A final net pay count cannot be provided until porosity logs are obtained using Pulse Neutron Logs ('PNL') after casing is run and cemented. However, LWD gamma ray and resistivity tools indicate an approximate 50–60% net to gross sand ratio which is typical for the Upper O Sand in this area of SM58. The LWD logs also indicate two, or possibly three, distinct sand lobes. The thickness and presence of multiple lobes of sand is in line with pre-drill expectations and the Company made the decision to run production casing.

The SM58 G2ST wellbore will be conditioned to run and cement 7" casing before completion operations can begin. Final perforation intervals and sand control measures will be designed on the basis of the cased hole logs. Completion operations will be followed by topside flowline hook up work before the well can be placed into production through Byron's SM58 Platform.

(c) SM58E1/69E platform

Byron also owns a 53.00% WI (44.167% NRI) in the SM58 E1 producing well and the SM69 E Platform and Flowlines. ANKOR Energy LLC is the designated operator.

(i) SM58E1/69E platform production

Byron's share of production for the year ended 30 June 2020 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 2020	YTD 30 June 2019
Gross production		
Oil (bbls)	**40,294**	19,683
Gas (mmbtu)	**9,610**	10,756
Byron share of gross production (53% WI)		
Oil (bbls)	**21,356**	10,497
Gas (mmbtu)	**5,093**	5,736
Net production (Byron share 44.167% (after royalty))		
Oil (bbls)	**17,797**	8,693
Gas (mmbtu)	**4,244**	4,751

Net sales revenue US$ million	YTD 30 June 2020	YTD 30 June 2019
Net sales revenue (Byron share 44.167% NRI)	**0.8**	0.5

(d) South Marsh Island 57, 59 and 60

Byron holds a 100% WI and an 81.25% NRI in SM57 and SM59 and 100% WI and an 87.5% NRI in SM60. Theses leases are in close proximity to Byron's newly set SM58 Platform and increase Byron's footprint in the South Marsh Island 73 Field. Water depth in the area is approximately 125 feet.

The SM57, 59 and 60 blocks were part of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites.

South Marsh Island 57/59/60 (SM57/59/60) Project Summary

Joint Venture Partners	Byron Energy
Operator	Byron Energy Inc.
Water Depth	~37 meters (121')
Previous SM57 Production	850 mbo + 14.6 bcf
Previous SM59 Production	283 mbo + 16.4 bcf
Previous SM60 Production	787 mbo + 385.2 bcf
SM57 acquired at Lease Sale 247, March 2017 SM59 acquired at Lease Sale 247, March 2017 SM60 acquired at Lease Sale 252, March 2019	Combined bid cost of US$0.5 million
Byron Interest	SM57 – 100% WI, 81.25% NRI SM59 – 100% WI, 81.25% NRI SM60 – 100% WI, 87.50% NRI
Status	Two prospects drill ready; Initial permitting at SM60 underway
Prospective Resources (Net to Byron)*	20.1 Mmbo + 346.8 bcf*

* Collarini and Associates report as of 30 June 2020; refer ASX release 10/09/2020.

SM57/59/60 Summary	Gross Prospective Resources Remaining 30/6/20		Net Prospective Resources Remaining 30/6/20	
	mbo	mmcf	mbo	mmcf
SM57	**1,884**	**92,607**	**1,531**	**75,243**
SM59	20,032	77,255	16,276	62,770
SM60	**2,881**	**257,028**	**2,341**	**208,835**
Total	**24,797**	**426,890**	**20,148**	**346,848**

SM57, 59 and 60 carry large prospective resources. Byron acquired the SM60 lease in 2019 and as a result of extensive mapping has advanced two prospects to drill ready status and determined that prospects previously identified on SM59 extend updip on to SM60, the most likely location for drilling. Because of this, a portion of prospective resources from SM59, in the Company's 2019 report, have been transferred to SM60 in 2020. Initial permitting for the SM60 project is underway.

(e) South Marsh Island 69

Byron is a party to the Joint Exploration Agreement ('JEA') and a related Production Handling Agreement with SM69 leaseholders. Byron has the right to drill a SM69 E2 development well and to earn interest in the north-east portion of the SM69 lease block.

By funding 100% of the well Byron can earn 100% WI and 80.33% NRI until E2 Project Payout, at which time and at the leaseholder's election, Byron's NRI would either adjust to 77.33% or the leaseholders can convert to a 30% WI and Byron's interest in the project would adjust to 70% WI with an unburdened 58.33% NRI.

The SM69 E2 wellbore would be drilled to a depth of approximately 8,750 feet MD (8,120 feet TVD). This fault block is interpreted to be an up-dip pool potentially fault separated from analogous production in the immediately adjacent fault block 'A' on SM58. Fault block A has to date produced a combined gross total of approximately 3.4 Mmbo + 4.3 Bcfg from two wellbores completed in zones equivalent to these six target sands. The primary target of the E2 well, the B65 (K4) Sand, has to date produced approximately 13 Mmbo in the SM73 Field.

If the Company elects to drill the E2 well, Byron will operate the E2 well and produce it back to the SM58 G Platform through the new pipeline laid in July 2020. Hydrocarbons from the E2 well would be processed and sold through the SM58 G Platform.

(f) South Marsh Island 70

Byron has a 100% WI and 87.5% NRI (royalty rate of 12.5%) South Marsh Island 70 ('SM 70'), acquired at the Gulf of Mexico OCS Lease Sale 250 held on 21 March 2018 in New Orleans, Louisiana.

Byron has identified several higher-risk exploratory leads on SM70. These leads are being evaluated following completion of Byron's South Marsh Island project seismic reprocessing work in late 2018.

(g) South Marsh Island 74

The SM74 D-14 well spudded on 15 May 2019 and after encountering drilling difficulties, requiring a bypass well with SM74 D-14 BP1 well ultimately drilled to a depth of 14,933 feet MD/13,591 TVD having drilled through the 13,000 Sand and also the 13,500 Sand which was the primary objective. Through the use of real-time gamma and resistivity logging tools, the well bore was deemed uncommercial and was plugged and abandoned. Because the first two primary objectives were wet and due to difficult hole conditions, it was decided not to drill deeper. The well was plugged and abandoned during the September quarter 2019.

Metgasco Limited ('Metgasco') paid 40% (US$4.5 million), of the initially estimated drilling costs of SM74 D14 to earn a 30% WI in SM74. On 18 July 2019 Byron announced that agreement had been reached with Metgasco to limit Metgasco's financial exposure to the SM74 project. Byron capped Metgasco's additional costs for the drilling of SM74 D-14 well and SM74 D-14 BPI well at A$1.75 million (in addition to the US$4.5 million previously contributed by Metgasco).

2. Eugene Island 77

Byron acquired Eugene Island blocks 62, 63, 76 and 77 ('EI77 Field'), at the 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.

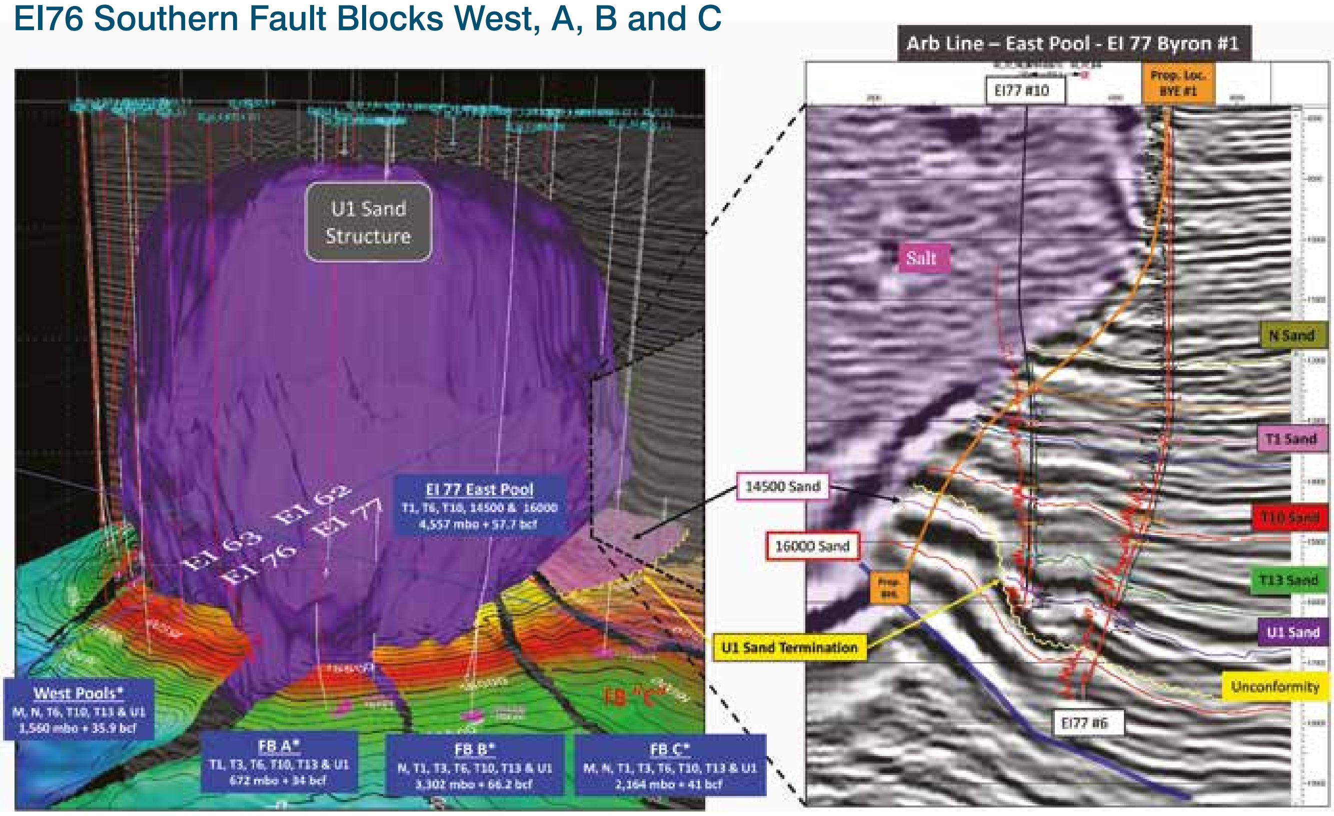
Byron currently holds a 100% WI and an 87.5% NRI in the EI77 Field, reflecting the reduced Federal Government Royalty of 12.5% versus pre-2017 rate of 18.75%.

EI77 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 EI62/63/76/77 at the OCS Lease Sale 250.

Discussion with several drilling contractors for drilling of EI77 commenced during the December 2018 quarter but were deferred until after mid-2021, with SM58 projects brought forward ahead of the EI77 Field wells.

EI76 Southern Fault Blocks West, A, B and C



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, Outer Continental Shelf ('OCS') Lease Sale 251 ('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 ('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.

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.

Non-salt dome projects (Byron operated)

1. Grand Isle Block 95

Grand Isle Block 95 ('GI95') is located in USA Federal waters, approximately 100 miles south-east of New Orleans, Louisiana, at a water depth of approximately 201 feet. The Company has a 100% operated WI and an 87.5% NRI, reflecting the recently reduced Federal Government Royalty of 12.5% versus pre-2017 rate of 18.75%. Water depth in the area is approximately 197 feet.

Byron acquired the GI95 lease at the Central Gulf of Mexico OCS Lease Sale 249 held on 16 August 2017 in New Orleans, Louisiana.

No material activity was undertaken on GI95 during the year ended 30 June 2020. GI95 was relinquished subsequent to year end.

Properties

As at 30 June 2020 Byron's portfolio of properties, all in the shallow waters of the Gulf of Mexico, 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	20.23
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		
SM69 (NE ¼ of NE ¼)	Byron	100.00/77.33-80.33	Production	1.3
Block 74***	Byron	100.00/81.25	June 2022	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
Grand Isle				
Block 95#	Byron	100.00/87.50	September 2022	18.37

* 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.
*** Metgasco Limited ('Metgasco') a 30% WI right in SM74 lease which to date has not been formally assigned.
# Relinquished on 1 September 2020.

Review of Operations continued

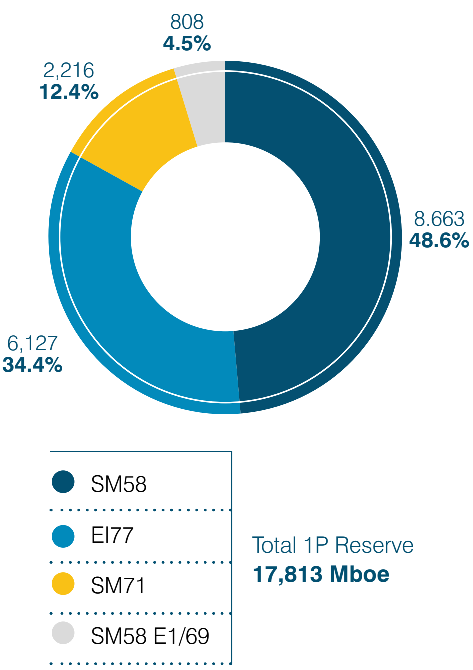
Reserves and resources

The Company's reserves and resources estimate as at 30 June 2020 was released to the ASX on 10 September 2020 and is summarised below:

- **Proved Reserves (1P): 8.1 Mmbbl of oil and 58.5 Bcf of gas.**
- **Proved and Probable Reserves (2P): 17.5 Mmbbl of oil and 105.3 Bcf of gas.**
- **Proved, Probable and Possible Reserves (3P): 25.3 Mmbbl of oil and 130 Bcf of gas.**
- **Prospective Resources: 43.6 Mmbbl of oil and 617.3 Bcf of gas.**

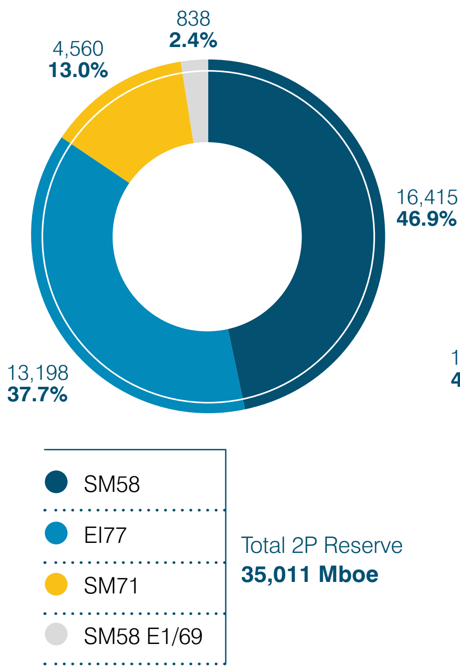
The combined remaining reserves and prospective resources, net to Byron, as of 30 June 2020 are as follows:

Byron net 1P Reserve by Project
Mboe and % of total



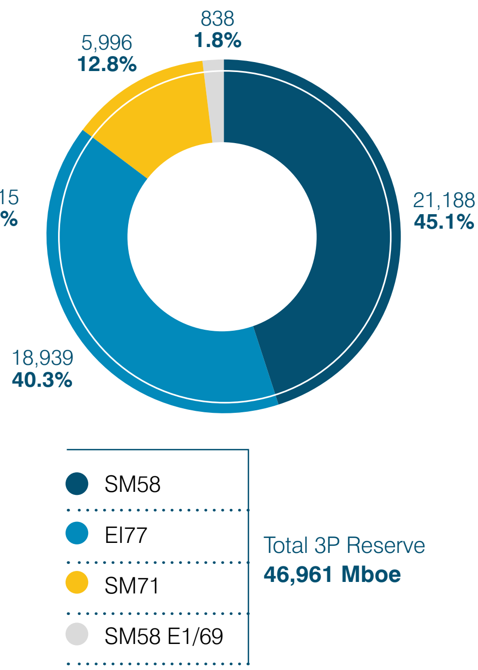
Total 1P Reserve
17,813 Mboe

Byron net 2P Reserve by Project
Mboe and % of total



Total 2P Reserve
35,011 Mboe

Byron net 3P Reserve by Project
Mboe and % of total



Total 3P Reserve
46,961 Mboe

Byron Energy Limited – reserves and resources

Gulf of Mexico, Offshore Louisiana, USA

Remaining as at 30 June 2020 (net to Byron)	Oil Mbbl	Gas MMcf	Mboe (6:1)	change % 2020 v 2019 incl GI95	change % 2020 v 2019 excl GI95
Reserves (developed and undeveloped)					
Proved (1P)	**8,060**	**58,518**	**17,813**	**6.8%**	**6.8%**
Probable reserves	9,409	46,732	17,198	-33.1%	-5.2%
Proved and probable (2P)	**17,469**	**105,250**	**35,011**	**-17.4%**	**0.6%**
Possible reserves	7,832	24,707	11,949	-24.8%	1.8%
Proved, probable and possible (3P)	**25,301**	**129,957**	**46,960**	**-19.4%**	**0.9%**
Total prospective resources					
Best estimate (unrisked)	**43,612**	**617,296**	**146,495**	**18.7%**	**26.6%**

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 split of Byron's remaining reserves, as at 30 June 2020, into developed and undeveloped categories by project and by product. 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 2020	Oil Mbbl	Gas MMcf	Oil Mbbl	Gas MMcf	Boe Mboe (6:1)
SM71					
Proved (1P)	**1,334**	**951**	**658**	**390**	**2,216**
Probable reserves	886	565	1,193	1,025	2,344
Proved and probable (2P)	**2,220**	**1,516**	**1,851**	**1,415**	**4,560**
Possible reserves	-	-	1,275	963	1,436
Proved, probable and possible (3P)	**2,220**	**1,516**	**3,126**	**2,378**	**5,996**
SM58 (100%WI)					
Proved (1P)	**-**	**-**	**4,682**	**23,884**	**8,663**
Probable reserves	-	-	6,168	9,504	7,752
Proved and probable (2P)	**-**	**-**	**10,850**	**33,388**	**16,415**
Possible reserves	-	-	3,931	5,053	4,773
Proved, probable and possible (3P)	**-**	**-**	**14,781**	**38,441**	**21,188**
SM58 E1					
Proved (1P)	**174**	**149**	**468**	**849**	**808**
Probable reserves	26	23	-	-	30
Proved and probable (2P)	**200**	**172**	**468**	**849**	**838**
Possible reserves	-	-	-	-	-
Proved, probable and possible (3P)	**200**	**172**	**468**	**849**	**838**
EI77					
Proved (1P)	**-**	**-**	**744**	**32,295**	**6,127**
Probable reserves	-	-	1,136	35,615	7,072
Proved and probable (2P)	**-**	**-**	**1,880**	**67,910**	**13,198**
Possible reserves	-	-	2,626	18,691	5,741
Proved, probable and possible (3P)	**-**	**-**	**4,506**	**86,601**	**18,939**
Total					
Proved (1P)	**1,508**	**1,100**	**6,552**	**57,418**	**17,813**
Probable reserves	912	588	8,497	46,144	17,198
Proved and probable (2P)	**2,420**	**1,688**	**15,049**	**103,562**	**35,011**
Possible	-	-	7,832	24,707	11,950
Proved, probable and possible (3P)	**2,420**	**1,688**	**22,881**	**128,269**	**46,961**

Review of Operations continued

The following table reconciles the movement in Byron's reserves between 30 June 2019 and 30 June 2020.

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

	Oil (Mbbl)				Gas (MMcf)			
Reserves reconciliation	**Remaining 30/6/19**	**Production 2020**	**Additions and revisions 2020**	**Remaining 30/6/20**	**Remaining 30/6/19**	**Production 2020**	**Additions and revisions 2020**	**Remaining 30/6/20**
SM71 (Developed and undeveloped)								
Proved (1P)	**2,082**	-376	286	**1,992**	**1,583**	-797	555	**1,341**
Probable reserves	2,277	0	-198	2,079	1,473	0	117	1,590
Proved and probable (2P)	**4,359**	-376	88	**4,071**	**3,056**	**-797**	672	**2,931**
Possible reserves	1,094	0	181	1,275	759	0	204	963
Proved, probable and possible (3P)	**5,453**	-376	269	**5,346**	**3,815**	-797	876	**3,894**
SM58 (Undeveloped)								
Proved (1P)	**4,068**	0	614	**4,682**	**23,888**	0	-4	**23,884**
Probable reserves	6,237	0	-69	6,168	9,610	0	-106	9,504
Proved and probable (2P)	**10,305**	0	545	**10,850**	**33,498**	0	-110	**33,388**
Possible reserves	3,931	0	0	3,931	5,052	0	1	5,053
Proved, probable and possible (3P)	**14,236**	0	545	**14,781**	**38,550**	0	-109	**38,441**
SM58 E1/69 (Developed)								
Proved (1P)	**652**	-26	16	**642**	**990**	-21	29	**998**
Probable reserves	26	0	0	26	23	0	0	23
Proved and probable (2P)	**678**	-26	16	**668**	**1,013**	-21	29	**1,021**
Possible reserves	0	0	0	0	0	0	0	0
Proved, probable and possible (3P)	**678**	-26	16	**668**	**1,013**	-21	29	**1,021**
EI77 (Undeveloped)								
Proved (1P)	**699**	0	45	**744**	**28,571**	0	3,724	**32,295**
Probable reserves	1,188	0	-52	1,136	39,338	0	-3,723	35,615
Proved and probable (2P)	**1,887**	0	-7	**1,880**	**67,909**	0	1	**67,910**
Possible reserves	2,625	0	1	2,626	18,704	0	-13	18,691
Proved, probable and possible (3P)	**4,512**	0	-6	**4,506**	**86,613**	0	-12	**86,601**
GI95 (Undeveloped)								
Proved (1P)	**0**	0	0	**0**	**0**	0	0	**0**
Probable reserves	145	0	-145	0	44,621	0	-44,621	0
Proved and probable (2P)	**145**	0	-145	**0**	**44,621**	0	-44,621	**0**
Possible reserves	57	0	-57	0	24,607	0	-24,607	0
Proved, probable and possible (3P)	**202**	0	-202	**0**	**69,228**	0	-69,228	**0**
Grand total								
Proved (1P)	**7,501**	**-402**	**961**	**8,060**	**55,032**	-818	**4,304**	**58,518**
Probable reserves	9,873	0	-464	9,409	95,065	0	-48,332	46,733
Proved and probable (2P)	**17,374**	**-402**	**497**	**17,469**	**150,097**	-818	**-44,029**	**105,251**
Possible reserves	7,707	0	125	7,832	49,122	0	-24,415	24,707
Proved, probable and possible (3P)	**25,081**	**-402**	**622**	**25,301**	**199,219**	-818	**-68,444**	**129,958**

Material changes to reserves

Oil

Proved and probable reserves

No material change in overall 2P oil reserves.

Possible reserves

No material change in overall possible oil reserves.

Gas

Proved and probable reserves

Overall 2P gas reserves as of 30 June 2020 are 30% below the 30 June 2019 2P gas reserves, mainly due to removal of 2P gas reserves previously attributed to GI95 as a result of lower gas prices.

Possible reserves

Overall possible gas reserves as of 30 June 2020 are 50% below the 30 June 2019 possible gas reserves, mainly due to removal of possible gas reserves, previously attributed to GI95, as a result of lower gas prices.

Prospective resources as at 30 June 2020

The following table shows Byron's prospective resources as at 30 June 2020 compared to 30 June 2019.

Byron Energy Limited prospective resources (net to Byron)

Gulf of Mexico, offshore Louisiana, USA

Best estimate enrisked 30 June 2020	Oil Mbbl	Gas MMcf	Mboe (6:1)
SM71	976	19,813	4,278
SMI57	1,531	75,243	14,072
SMI58*	12,233	29,412	17,135
SMI58E1/SM69	2,264	1,979	2,594
SMI59	16,276	62,770	26,738
SM60	2,341	208,835	37,147
EI77	7,991	219,244	44,532
Total prospective resources (2020)	**43,612**	**617,296**	**146,496**
Total prospective resources (2019)	**31,575**	**551,114**	**123,427**

* Subsequent to the 30 June 2020 year end Byron drilled the SM58 G2 well, which was targeting prospective resources in SM58. The well was deemed sub-commercial and was side tracked to test the Upper O Sand in the Brown Trout prospect where 280 gross feet of hydrocarbon was logged with LWD gamma ray/resistivity tool. The Company will reassess its prospective resources in this portion of the SM58 project in due course.

Material changes to prospective resources in 2020

- Addition of 11.7 Mmbbl to SM58 primarily reflecting the Lower O Sand objectives seen in the deeper portion of the G1 well drilled in September 2019 following the release of the 30 June 2019 Reserve Report.
- Addition of SM60 prospective oil and gas resources (approximately 1.3 Mmbbl and 107.2 Bcfg net to Byron of newly mapped resources plus a transfer of 1.0 Mmbbl and 101.6 Bcfg from SM59 to reflect likely takepoint).
- Removal of GI95 prospective dry gas resources (44.4 Bcf net) due to lower gas prices.
- Lower EI77 gas prospective resources due to lower gas prices.

Notes to Reserves and Resources Statement

Reserves and resources governance

Byron's reserves estimates are compiled annually. Byron engages Collarini Associates, a qualified external petroleum engineering consultant, to conduct an independent assessment of the Company's reserves. Collarini Associates is an independent petroleum engineering consulting firm that has been providing petroleum consulting services in the USA for more than 15 years. Collarini Associates does not have any financial interest or own any shares in the Company. The fees paid to Collarini 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 Associates, under the supervision of Mr Mitch Reece BSc PE. Mr Reece is the President of Collarini 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

Nominal oil prices used in this report represent consensus (30 June 2020 Bloomberg Street Consensus), starting on 1 July 2020, of $35.45 per barrel, with a final price of $60.51 per barrel on 1 January 2024, and held constant thereafter. Nominal gas prices used in this report represent a Henry Hub base, starting on 1 July 2020, of $2.08 per MMBtu, rising to $2.64 per MMBtu in January 2021 then declining to $2.56 per MMBtu on 1 January 2022, with a final price of $2.67 per MMBtu on 1 January 2024 and held constant thereafter. These prices were adjusted to account for transportation cost, basis difference, and oil gravity in order to arrive at realised prices.

ASX reserves and resources reporting notes

(i) The reserves and prospective resources information in this document is effective as at 30 June 2020 (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 2020

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 2020.

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

- Ambition Group Limited.
- Left Field Printing Group Limited ('Left Field'), a Hong Kong listed company.

Former directorships of listed companies in last three years

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 both technical 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 was co-founder/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.

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 2020, the Company had 1,023,549,331 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 2020, the Company issued 328,175,914 fully paid ordinary shares and no share options as detailed below:

(a) on 25 July 2019, Metgasco Limited (ASX: MEL) elected to convert 10,000,000 share options to equity at a share price of A$0.25 per share, resulting in the issue of 10,000,000 ordinary shares;

(b) on 21 November 2019, 51,961,055 shares were issued through a placement to institutional and sophisticated investors at A$0.27 per share, raising approximately A$14.0 million;

(c) on 18 December 2019, 42,075,806 shares were issued through a fully underwritten 1 for 18 pro-rata non-renounceable entitlement offer at A$0.27 per share, raising approximately A$11.4 million;

(d) on 7 January 2020, Byron issued 9,500,000 new shares to executive directors, senior staff and consultants following exercise of 9,500,000 unlisted options at $A0.25 each; the Company provided 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;

(e) on 28 January 2020, Byron issued 2,000,000 fully paid ordinary shares at A$0.27 each, the same as the issue price for the share placement completed by the Company on 21 November 2019, to Douglas Battersby and Paul Young, both Non-Executive Directors, as approved by the Company's shareholders on 20 January 2020 at a general meeting of the Company;

(f) on 26 May 2020, 106,331,150 shares were issued through a placement to institutional and sophisticated investors at A$0.13 per share, raising approximately A$13.8 million; and

(g) on 19 June 2020, 106,307,903 shares were issued under a share purchase plan at A$0.13 per share, raising approximately A$13.8 million.

Subsequent to 30 June 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.

Apart from the above July 2020 allotment of shares, no other ordinary shares, nor share options were issued and no share options were exercised subsequent to 30 June 2020 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 G Battersby	57,250,568	-	-	-
M V Smith	40,625,664	-	-	-
M V Smith	-	6,300,000	A$0.12	31 December 2021
M V Smith	-	2,100,000	A$0.40	31 December 2021
P H Kallenberger	4,408,762	-	-	-
P H Kallenberger	-	6,300,000	A$0.12	31 December 2021
P H Kallenberger	-	2,100,000	A$0.40	31 December 2021
C J Sands	24,710,783	-	-	-
P A Young	27,352,773	-	-	-
W R Sack	6,900,001	-	-	-
W R Sack	-	6,300,000	A$0.12	31 December 2021
W R Sack	-	2,100,000	A$0.40	31 December 2021
N Filipovic	3,041,359	-	-	-
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 other than:

(i) on 7 January 2020, Byron issued 9,500,000 new shares to executive directors and key management personnel as well as senior staff and consultants following exercise of 9,500,000 unlisted options at A$0.25 each; the Company provided 3-year interest-free loans to the option holders to fund the acquisition of the shares issued as a consequence of the exercise of options; and

(ii) on 28 January 2020, Byron issued 2,000,000 fully paid ordinary shares at A$0.27 each, the same as the issue price for the share placement completed by the Company on 21 November 2019, to Douglas Battersby and Paul Young, both Non-Executive Directors, as approved by the Company's shareholders on 20 January 2020 at a general meeting of the Company.

Company Secretary

Nick Filipovic

Appointed 18 March 2013

Nick is a qualified accountant with over 35 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$68,348 (2019: US$5,718,988).

Review of operations

Financial review

The Group recorded a net profit of US$68,348 for the year ended 30 June 2020, compared to a net profit of US$5,718,988 for the year ended 30 June 2019. The lower profit is primarily due to lower net revenue partly offset by lower impairment charges.

For the year ended 30 June 2020 Byron's share of net revenue, after transport costs and royalties was US$21,402,255 compared to US$31,324,061 in 2019. The decrease in net revenue was primarily due to lower realised oil and gas prices and lower production volumes.

Cost of sales were US$8,915,892 for the year ended 30 June 2020 compared to US$7,261,616 for the comparable period in 2019, mainly due to a full year of SM58 E-1 well operating costs and lease amortisation expenses.

For the year ended 30 June 2020, impairment charges were US$5,397,975 compared US$12,915,955 in 2019.

The impairment charge for 2020 financial year reflects the write-off of the drilling cost of the SM74 D14 well dry hole and the relinquishment of the Grand Isle 95 lease subsequent to 30 June 2020.

The impairment charge for the previous year reflects the write-off of unsuccessful exploration drilling in relation to the Weiss-Adler, et. al. No. 1 well, on the Bivouac Peak leases, part of the SM74 D14 well on the SM74 lease, and relinquishment of VR232, VR251 and EI18 leases during the 2019 year.

Share-based payment expenses in the 2020 financial year of US$940,671 were greater than the share-based payment expenses of US$670,141 in the 2019 final year. Share-based payment expenses in the 2020 financial year comprise expenses in relation to the interest free loans granted to executive directors, senior staff and contractors to be used solely for the funding of conversion of 9,500,000 A$0.25 options over unissued shares in the Company which expired on 31 December 2019. Share-based payment expenses in the 2019 financial year comprise expenses in relation to granting of 9,500,000 options to executive directors, senior staff and contractors exercisable at A$0.40 on or before 31 December 2021.

At 30 June 2020, the consolidated entity had total assets of US$105,107,449 (2019: US$53,493,510) and total liabilities of US$31,056,428 (2019: US$16,781,752) resulting in net assets of US$74,051,021 (2019: US$36,711,758), reflecting an increase of US$37,339,263. The increase was mainly due to the higher cash balances, following the completion of equity raisings in May and June 2020, higher oil and gas properties, reflecting expenditure on SM58, and lower creditors as a result of a lower level of exploration and development activity as of 30 June 2020. These factors were partly offset by increase in borrowings following the issue of promissory notes to Crimson Midstream Operating, LLC.

At 30 June 2020, the consolidated entity held cash and cash equivalents of US$16,644,701 (2019: US$6,783,320). During the financial year, the consolidated entity drew down loans totalling US$15,000,000 from Crimson Midstream Operating, LLC with total borrowings outstanding as of 30 June 2020 of US$19,935,047 (2019: US$5,747,990).

Corporate review

Cash equity raisings

During the financial year ended 30 June 2020 the Company issued 308,675,914 ordinary shares raising A$53,573,029 before costs, through a combination of two placements, an entitlement issue and share purchase plan.

In addition, 19,500,000 options were converted, at A$0.25 each, into 19,500,000 ordinary shares raising an additional A$4,875,000.

Issued capital

As at 30 June 2020, Byron's issued capital comprised:

Securities	Total issued	Quoted	Unquoted
Shares (ASX:BYE)	1,023,549,331	1,023,549,331	Nil
Options	41,100,000	Nil	41,100,000

Borrowings

Crimson Midstream Promissory Note

In the December 2019 quarter, Byron signed a binding Secured Promissory Note ('Promissory Note') with Crimson Midstream Operating, LLC ('Crimson Midstream'), a portfolio company of The Carlyle Group, to borrow an initial amount of US$15.0 million, 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 Crimson Midstream Promissory Note facility in June 2020, on the same terms and conditions as the initial US$15.0 million, being interest only until December 2020. The additional US$3.5 million Promissory Note had not been drawn down as of 30 June 2020 but has been drawn down at the date of this report. The Promissory Note is secured over Byron's SM71 and SM58 assets and guaranteed by the Company.

Loans from directors and shareholders

During the 2020 financial year the Company restructured the loans from directors and shareholders. Five of the lenders, for US$2.0 million and A$2.1 million, agreed to extend the repayment date of the loans, with no changes to interest rate or security from 30 November 2019 to 31 March 2022, while the remaining A$1.0 million was repaid in December 2019.

As at 30 June 2020, Byron's borrowings comprised:

Lender	US$	A$	US$ equivalent (@A$1=US$0.6863)
Directors	2,000,000	1,750,000	3,201,025
Shareholders	-	350,000	240,205
Crimson Midstream	15,000,000	-	15,000,000
Insurance premiums financed	1,493,817	-	1,493,817
Total	**18,493,817**	**2,100,000**	**19,935,047**

COVID-19 and oil and gas prices

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 cashflows.

West Texas Intermediate (WTI), the USA marker price, dropped from US$61.17 on 2 January 2020 to US$20.28 on 1 April 2020. The crude oil price decline started in early March 2020 after Saudi Arabia initiated a price war with Russia and accelerated after the COVID-19 outbreak around the world. The WTI spot price actually 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 improved reaching US$39.27 on 30 June 2020 for WTI spot.

While COVID-19 has had less of an impact on USA natural gas prices, COVID-19 has significantly curtailed industrial use of natural gas. In addition, volumes flowing to LNG export plants have dropped substantially due to weak international demand associated with the COVID-19 imposed lockdowns. Moreover, increasing downward pressure on European and Asian gas prices have made American fuel less competitive, lowering LNG demand in the process. All of this comes at a time when the commodity was already struggling with weak consumption because of a warmer-than-expected winter 2019-2020.

The Henry Hub natural gas mmbtu spot price was US$2.42 on 28 June 2019, declining to US$1.76 on 30 June 2020.
During the year ended 30 June 2020 Byron has not experienced any COVID-19 related interruptions to the Byron operated SM71 platform in the Gulf of Mexico, or the construction and installation of Byron's SM58 G platform.

Byron's office in Lafayette, Louisiana based worked in line with recommendations of Louisiana State, which included a stay-at-home period. Byron's Australian-based team worked as advised by the Australian government(s), to comply with COVID-19 regulations.

During drilling operations for the SM71 F5 well, the Company and Enterprise Offshore Drilling instituted temperature screening processes for any person boarding the rig via either the shorebase or through air transportation. Byron also provides a daily COVID-19 update to the Bureau of Safety and Environmental Enforcement ('BSEE') which is accomplished with the use of BSEE approved code detailing the screening processes in effect and any occurrence of illness on a Byron operated facility. There have been no reportable incidents on either the SM71 F platform or the EOD 264 drilling rig.

Island Operating Company, Inc., responsible for day-to-day operations of Byron's SM71 platform implemented various initiatives to comply with Louisiana State's Interim Guidance for Businesses and Employers to Plan and Respond to Coronavirus Disease 2019 ('LA COVID-19 Guidance'). Byron's third party contractors also implemented initiatives to comply with Louisiana COVID-19 guidance during construction and installation of the SM58 G platform.

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 put options ('Put Options') which provides Byron as the buyer of the Put Option with a hedge against potentially declining prices. Hedging with Put Options provides oil and gas producers with the 'best of both worlds' as Put Options provide a hedge against potentially declining crude oil prices while allowing the producer to potentially benefit from higher prices as well.

The hedging under the Forward Sale Agreement meets the 'own use' exemption and is accounted for as a normal sales contract whereas the Put Options hedges are treated as financial instruments relating to the Company's hedging activities to hedge against cash flow risks from movements in oil price for which hedge accounting has been applied. The Put Options are accounted for at fair value through other comprehensive income.

The hedging counterparty for the Forward Sale Agreement and the Put Options, 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.

In December 2019, under the Forward Sale Agreement Byron entered into an oil hedging program as follows:

Daily volume hedged (barrels of oil per day)	Period	Fixed base price (West Texas Intermediate)*
400	Jan-Mar 2020	US$52.70
670	Apr-Dec 2020	US$54.78
450	Jan-Dec 2021	US$52.86
400	Jan-Dec 2022	US$52.70

* Final realised prices are adjusted for Louisiana Light Sweet price differentials and deductions for transportation.

In response to the dislocation in the global and local crude oil markets and unusual volatility in prices, Byron placed the following hedges on two previously floating components:

(i) a fixed price hedge on the Louisiana Light Sweet/West Texas Intermediate ('LLS/WTI') differential for 1 May through 31 December 2020 on 670 barrels of oil per day ('bopd') @ minus US$2.78 per barrel; and

(ii) a fixed price hedge on the Calendar Month Average ('CMA') Roll for 1 June 2020 through 31 December, 2020 on 670 bopd @ minus US$1.80 per barrel.

In June 2020 Byron added a further derivative hedge, through acquisition of Put Options, at a cost of US$338,560 on 400 barrels bopd of production covering the period from 1 July to 31 December 2020.

Byron's hedged oil production as at 30 June 2020 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 2020 (Put Options)	400	73,600	US$39.00**	Unhedged	Unhedged	To be determined
Jul-Dec 2020 (Forward Sale Agreement)	670	122,897	US$54.78	-US$1.80 (fixed)	-US$2.78 (fixed)	US$50.20
Jan-Dec 2021 (Forward Sale Agreement)	450	164,250	US$52.86	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.

** Minimum WTI CMA base price prior to NYMEX roll adjust and/or LLS/WTI differential.

Producing oil and gas properties

South Marsh Island 71 and SM58 E1 well

Byron owns a 50% Working Interest ('WI') and a 40.625% Net Revenue Interest ('NRI') in the South Marsh Island ('SM71'). Byron is the designated operator of SM71 with Otto Energy Limited ('Otto') (ASX: OEL) holding an equivalent WI and NRI. Water depth in the area is approximately 137 feet.

Byron also owns a 53.00% WI (44.167% NRI) in the SM58 E1 well and the SM69 E platform and flowlines. ANKOR Energy LLC is the designated operator.

Both SM71 and SM58 E1 well are located in the South Marsh Island Block 73 ('SM73') field which encompasses nine Outer Continental Shelf ('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.

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.

During the March quarter 2020, Byron drilled the SM71 F5 well on a 50/50 basis with Otto. Post-drill evaluation of the SM71 F5 well indicates the well encountered a stray 40-foot-thick gas sand above the primary D5 Sand target and may have penetrated the upper 20 feet of the D5 Sand before hole conditions prevented the well to be drilled any deeper. Additionally, Log While Drilling ('LWD') logs indicate the well encountered 12 feet True vertical Thickness ('TVT') net oil pay in the I3 Sand, and 20 feet TVT net oil pay in the J Sand with the well temporarily abandoned for use as a future side-track.

Byron acquired its interest in SM58 E1 well and 69 E platform and flowlines effective 1 January 2019.

Byron's share of production (net of royalties) for the year ended 30 June 2020 is shown in the table below.

Production/sales statistics (net to Byron)	2020	2019	% change
Oil (bbls)	**393,703**	462,220	-14.8
Gas (mmbtu)	**883,055**	904,069	-2.3
Net revenue after royalties and transportation charges (US$ '000)	**21,402**	31,324	-31.7
Lease operating expenses (cash) (US$ '000)	**3,407**	2,626	-29.7
Realised oil price after transport charges (US$/bbl)	**50.05**	62.03	-19.3
Realised gas price after transport charges (US$/mmbtu)	**1.55**	2.79	-44.4

Oil and gas properties under development

South Marsh Island 58

Byron owns 100% WI (83.33% NRI) in the SM58 lease to a depth of 13,639 feet (total vertical depth) and 50% WI (41.67% NRI) below 13,639 feet with a third party currently holding the remaining 50% WI under an existing joint exploration agreement.

In May 2019 Byron purchased a production platform consisting of two decks, a jacket and production equipment from a private company for a total price of US$1.0 million.

The platform was offloaded at Acadian Contractors in Abbeville, Louisiana in May 2019, where modifications and build-out to Byron specifications were carried out during the 2020 financial year. Installation of the jacket and decks comprising the SM58 G platform commenced in June 2020 and was successfully completed in early July 2020.

By salvaging and refurbishing a high-quality structure already in good condition, the Company has realised a saving in the range of US$8–10 million and has expedited cycle time to first production by nine to 12 months compared to a new-build facility.

The next phase of the SM58 project, to lay the oil and gas sales pipelines needed to transport produced hydrocarbons to market, commenced early July 2020 and was completed in early August 2020.

In mid-July 2020, the Enterprise Offshore Drilling 264 ('EOD 264') jack up rig began the process of tying back the SM58 G1 well, drilled and logged in September 2019. The completion operations on the Upper O Sand in the SM58 G1 well finished in mid-August 2020. The 300-foot-thick hydrocarbon column logged across the Upper O Sand of the G1 well, drilled in September 2019, was perforated and sand control measures were implemented to maximise production rate and recovery. The G1 well was placed into production after all pipelines became operational and were tied into the production facility.

Upon completion of the SM58 G1 well, EOD 264 commenced operations on the Byron SM58 G2 well expected to be drilled to a total depth of 11,565 feet Measured Depth/10,555 feet True Vertical Depth with the primary goal to test the Lower O Sand section.

Exploration leases – salt dome leases

In addition to SM71 producing property and SM58 property under development, Byron is the operator and 100% working interest holder in six areas of interest around the SM73 field, comprising SM57/58/59/60/70 and north-east portion of SM69, as shown below. Byron is also the operator of SM74, where it has less than a 100% working interest. These areas were subject of the Company's South Marsh Island WesternGeco RTM Seismic Reprocessing Project undertaken in 2018.

While interpretation work continued through 2019 and into 2020, Byron has already seen the benefits of this processing work in the generation of several new prospect opportunities on its existing leasehold acreage, especially SM58, where multiple prospects were generated and including the Cutthroat prospect in SM58 successfully drilled by the G1 well during the September quarter of 2019.

South Marsh Island 57 and 59

Byron currently holds a 100% WI and an 81.25% NRI in SM57/59. Water depth in the area is approximately 125 feet.

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

South Marsh Island 69

In April 2019, Byron entered into a Joint Exploration Agreement ('JEA') and a related Production Handling Agreement with SM69 leaseholders to drill a SM69 E2 development well off the recently acquired E platform to earn interest in the north-east portion of the SM69 lease block. Byron and SM69 leaseholders have finalised a JEA for the proposed E2 well and the north-east ¼ of the north-east ¼ of SM69.

By funding 100% of the well Byron will earn a 100% WI and 80.33% NRI until E2 Project Payout, at which time and at the leaseholder's election, Byron's NRI will either adjust to 77.33% or the leaseholders can convert to a 30% WI and Byron's interest in the project would adjust to 70% WI with an unburdened 58.33% NRI.

If the SM58 G1 and G2 wells are successful, Byron will be positioned to drill SM69 E2 well soon after under the JEA.

Byron will operate the E2 well and produce it back to the SM58 G platform through a new pipeline which was laid in July 2020. Hydrocarbons from the E2 well would be processed and sold through the SM58 G platform. It is expected that the E2 well will begin production in January 2021, assuming drilling commences in October 2020 and is successful.

South Marsh Island 60

Byron acquired the South Marsh Island 60 lease ('SM60') at the Gulf of Mexico OCS Lease Sale 252 held in New Orleans, Louisiana on 20 March 2019.

From 1978 through 2006, nine wells completed for production on SM60 produced a combined total of 385 billion cubic feet of gas and 787,000 barrels of oil. SM60 lies within the area of Byron's RTM reprocessing project which was used to evaluate the prospect potential on the block.

South Marsh Island 70

Byron has a 100% WI and 87.5% NRI (royalty rate of 12.5%) South Marsh Island 70 ('SM70') at the Gulf of Mexico OCS Lease Sale 250 held on 21 March 2018 in New Orleans, Louisiana.

Byron has identified several higher-risk exploratory leads on SM70. These leads are being evaluated following completion Byron's South Marsh Island project seismic reprocessing work in 2018.

Eugene Island blocks 62, 63, 76 and 77

Byron acquired Eugene Island blocks 62, 63, 76 and 77 ('EI62/63/76/77'), 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 EI62/63/76/77, reflecting the recently reduced Federal Government Royalty of 12.5% versus pre-2017 rate of 18.75%.

EI62/63/76/77 were designated as the EI77 field in the 1960s and has produced 362 billion cubic feet of gas and 6.5 million barrels of oil from sands trapped by the EI77 salt dome. Initial production from the field began in 1957. There is no production on these blocks currently.

On the basis of proprietary RTM, undertaken by WesternGeco (a Schlumberger group company) in 2014 of 3D seismic data over the entire four block EI77 field. As a result of this detailed work Byron significantly upgraded the reserve potential of the EI77 field.

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. Final deliverables were received during the June 2019 quarter. Analysis of the reprocessed data continued during the 2020 financial year.

Drilling plans for EI77 have been paused, with the focus during the 2020 financial year on bringing SM58 into production.

Main Pass 293, 305 and 306

Byron currently holds a 100% WI and an 87.50% NRI in Main Pass 293, 305 & 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 ('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.

While no material activity was undertaken during the 2020 financial year, the Company will shortly start scoping an RTM seismic imaging project over the MP306 field.

South Marsh Island 74

The Byron operated SM74 D-14 well, the first test well on the South Marsh Island 74 block, spudded on 15 May 2019 and was plugged and abandoned in July 2019.

Non-salt dome projects (Byron operated)

No material activity was undertaken on the Company's non-salt dome projects during the 2020 financial year.

Grand Isle Block 95

Grand Isle Block 95 ('GI95') is located in US Federal waters, approximately 100 miles south-east of New Orleans, Louisiana, at a water depth of approximately 201 feet. The Company has a 100% operated WI and an 87.5% NRI, reflecting the recently reduced Federal Government Royalty of 12.5% versus pre-2017 rate of 18.75%. Water depth in the area is approximately 197 feet.

Byron acquired the GI95 lease at Central Gulf of Mexico OCS Lease Sale 249 held on 16 August 2017 in New Orleans, Louisiana. The GI95 lease was relinquished subsequent to year end with cumulative exploration expenditure of US$241,147 written off as of 30 June 2020.

Bivouac Peak leases

The Bivouac Peak state leases were relinquished in 2018 and the private leases were relinquished during the September quarter 2019.

Properties

As at 30 June 2020, 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 (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	20.23
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		
Block 69 (NE ¼ of NE ¼)	Byron	100.00/77.33-80.33	Production	1.30
Block 74***	Byron	100.00/81.25	June 2022	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
Grand Isle				
Block 95 (relinquished subsequent to year end)	Byron	100.00/87.50	September 2022	18.37

* 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.

*** Metgasco Limited ('Metgasco') agreed to earn a 30% WI in SM74 by paying a disproportionate share of the drilling costs of the SM74 D14 well. Metgasco paid 40% (US$4.5 million), of the initially estimated drilling costs of SM74 D14. On 18 July 2019, Byron announced that agreement had been reached with Metgasco to limit Metgasco's financial exposure to the SM74 D14 well whereby Byron capped Metgasco's additional costs for the drilling of SM74 D14 well at A$1.75 million (in addition to US$4.5 million already contributed by Metgasco). As a result Metgasco is entitled to a 30% WI (24.375% NRI) in SM74.

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;
- has a well-established and stable administration with one landowner for the shallow waters, BOEM; and
- the GOM shallow waters have regular lease sales conducted by BOEM with 5,000 acre blocks available, generally to the highest bidder, to lease for five years at US$7 per acre per annum.

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;
- a producing and cash-generating asset, SM71;
- a newly developed project which commenced production in the September 2020 quarter;
- 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 primarily through the annual Federal Government lease sale process in the GOM; 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 (xv) 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, various 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'). Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on the Company's business, financial condition and results of operations.

While the United States of America Congress has not taken any legislative action to reduce emissions of GHGs, many states have established GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

Additionally, the USA is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country uses to achieve its GHG emissions targets. The Paris Agreement entered into force on 4 November 2016. However, in August 2017, the U.S. State Department officially informed the United Nations of the intent of the USA to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The USA's adherence to the exit process is uncertain and/or the terms on which the USA may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The Company's oil and gas asset carrying values may be affected by any resulting adverse impacts to reserve estimates and the Company's inability to produce such reserves may also negatively impact its financial condition and results.

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.

The physical effects of climate change on the Company's assets may include changes in rainfall patterns, water shortages, rising sea levels, increased storm intensities and higher temperatures. These effects could have an adverse effect on the Company's business, financial condition and results of operations.

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; and (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 USA-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 USA with costs incurred in United States dollars.

As all Byron's operating assets are in the USA, 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.

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 US 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.

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.

Other risks

There are a number of other risks which may impact on the operating and financial performance of the Company, including but not limited to:

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.

Profitability and impairment write-downs risk

Byron may incur no-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.

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.

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.

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.

Cyber-security risk

The oil and gas industry is increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and distribution activities. The industry faces various security threats, including cyber-security threats. Cyber-security attacks in particular are increasing. Although to date Byron, has not experienced any material losses related to cyber-security attacks, it may suffer such losses in the future. If any of these events were to materialise, they could lead to losses of intellectual property and other sensitive information essential to the Company's business and could have a material adverse effect on its business prospects, reputation and financial position.

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 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 on certain cases.

Epidemic or outbreak of an infectious disease risk

The Company 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 its financial condition. For example, the recent outbreak of COVID-19, which has spread across the globe and impacted financial markets and worldwide economic activity, may adversely affect the Company's operations or the health of its workforce by rendering employees or contractors unable to work or unable to access the Company's facilities for an indefinite period of time. In addition, the effects of COVID-19 and concerns regarding its global spread have and could continue to 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 its production.

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 2020 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 6 July 2020, Byron announced to the ASX that the SM58 'G' Platform installation had been completed;
- on 20 July 2020, Byron announced to the ASX that SM58 G1 well completion operations had begun;
- on 21 July 2020, Byron announced to the ASX that 16,745,771 shares were issued to directors and/or their nominees to raise approximately A$ 2.2 million as approved by shareholders at a general meeting held on 9 July 2020;
- on 9 September 2020, Byron announced that production had commenced from the SM58 G1 well;
- on 10 September 2020, Byron announced its 2020 Independent Reserves and Resources Report; and
- on 21 September 2020, Byron announced that (i) that the SM58 G2 well has been drilled to a final total depth of 11,237 feet measured depth (10,233 feet true vertical depth) and has been deemed non-commercial, and (ii) preparations were underway to sidetrack the SM58 G2 well to test the Upper O Sand in the Brown Trout Prospect.

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 (2019: 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 six 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	6	6	-	-
Maynard V Smith	6	6	-	-
Prent H Kallenberger	6	6	-	-
Charles J Sands	6	6	3	3
Paul A Young	6	6	3	3
William R Sack	6	6	-	-

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 2020. 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 2016 US$	30 June 2017 US$	30 June 2018 US$	30 June 2019 US$	30 June 2020 US$
Revenue (net of royalties)	-	-	9,544,507	31,324,061	**21,402,255**
Net profit (loss) before tax	(30,944,243)	(5,357,583)	1,298,968	5,718,988	**68,348**
Net profit (loss) after tax	(30,944,243)	(5,357,583)	1,298,968	5,718,988	**68,348**
Share price at start of year	A$0.23	A$0.15	A$0.095	A$0.335	**A$0.29**
Share price at end of year	A$0.15	A$0.095	A$0.355	A$0.29	**A$0.14**
Basic earnings per share	(US$0.147)	(US$0.02)	US$0.0022	US$0.0083	**US$0.000088**
Diluted earnings per share	(US$0.147)	(US$0.02)	US$0.0022	US$0.0080	**US$0.000086**

(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.

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.

Remuneration Report – audited continued

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 having regard to: (a) the level of remuneration for comparable roles; (b) the service fee was last increased effectively two years ago and the Company has since made a substantial oil discovery at SM58, continued with trouble-free production at SM71 and has generated an excellent portfolio of prospects for future drilling; and (c) successful debt and equity raisings in 2019/20.

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

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 having regard to: (a) the level of remuneration for comparable roles; (b) salary was last reviewed more than two years ago and the Company has since made a substantial oil discovery at SM58, continued with trouble-free production at SM71 and has generated an excellent portfolio of prospects for future drilling; and (c) successful debt and equity raisings in 2019/20.

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

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 having regard to: (a) the level of remuneration for comparable roles; (b) salary was last reviewed more than two years ago and the Company has since made a substantial oil discovery at SM58, continued with trouble free production at SM71 and has generated an excellent portfolio of prospects for future drilling; and (c) successful debt and equity raisings in 2019/20.

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

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 having regard to: (a) the level of remuneration for comparable roles; (b) salary was last reviewed more than two years ago and the Company has since made a substantial oil discovery at SM58, continued with trouble-free production at SM71 and has generated an excellent portfolio of prospects for future drilling; and (c) successful debt and equity raisings in 2019/20.

In addition, Mr Filipovic is be 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 2020 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 #1

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 2020 was A$164,548, plus A$11,507 has been accrued as at 30 June 2020.
- 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 2020 was A$20,664, plus A$1,438 has been accrued as at 30 June 2020.
- 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 2020 was A$20,664, plus A$1,438 has been accrued as at 30 June 2020.
- 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 2020 was US$117,534, plus US$8,219 has been accrued as at 30 June 2020.
- 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 2020 was US$105,991 (net of withholding taxes), plus US$7,433 (net of withholding taxes) has been accrued as at 30 June 2020.

Remuneration Report – Audited continued

Loans #2

In September 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$1,500,000 and A$1,100,000. The loans were repaid in December 2019 with applicable interest, except for the Geogeny Pty Ltd US$500,000 loan which was repaid in early January 2020. During the year ended 30 June 2020, the Company made the following loan repayments and interest payments to related parties:

- Veruse Pty Ltd, a company controlled by Mr Douglas Battersby, a director of the Company, was repaid A$750,000, plus interest of A$20,959.
- Geogeny Pty Ltd, a company controlled by Mr Maynard Smith, a director of the Company, was repaid US$500,000, plus interest of US$15,068.
- Poal Pty Limited, a company controlled by Mr Paul Young, a director of the Company, was repaid A$175,000, plus interest of A$5,034.
- A related party of Mr Paul Young, a director of the Company, was repaid A$175,000, plus interest of A$5,034.
- Charles Sands, a director of the Company, was repaid US$1,000,000, plus interest of US$27,123 (net of withholding taxes).

Other

Corporate advisory services at normal commercial rates totalling A$525,930 (2019: A$ nil) excluding GST were provided by Henslow Pty Ltd, of which Paul Young is a managing director.

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 2019 number	Granted as compensation number	Received on exercise of options number	Via share placement, SPP or purchase number	Balance on 30 June 2020 number
D Battersby	48,123,203	-	-	4,511,980	**52,635,183**
M Smith	32,313,583	-	2,500,000	1,965,927	**36,779,510**
P Kallenberger	1,732,223	-	2,500,000	-	**4,232,223**
C Sands	19,765,997	-	-	2,052,478	**21,818,475**
P Young	18,655,631	-	-	4,081,757	**22,737,388**
W Sack	3,600,000	-	2,500,000	200,001	**6,300,001**
N Filipovic	634,788	-	1,000,000	1,406,571	**3,041,359**

During the financial year, no shares or share options were granted to directors or other key management personnel of the Company. Subsequent to 30 June 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 2019 number	Granted as compensation number	Exercise of options number	Expired options number	Balance on 30 June 2020 number
M Smith	10,900,000	-	(2,500,000)	-	**8,400,000**
P Kallenberger	10,900,000	-	(2,500,000)	-	**8,400,000**
W Sack	10,900,000	-	(2,500,000)	-	**8,400,000**
N Filipovic	5,780,000	-	(1,000,000)	-	**4,780,000**

During the financial year, Messers Smith, Kallenberger and Sack each converted 2,500,000 share options at A$0.25 cents per share and Nick Filipovic converted 1,000,000 share options at A$0.25 cents per share. The Company provided three-year interest-free loans to the option holders to fund the acquisition of the shares.

	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$
2020							
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**
Key management personnel							
N Filipovic	**211,491**	**-**	**-**	**-**	**20,092**	**99,018**	**330,601**
	1,000,203	**-**	**58,574**	**441,446**	**22,643**	**841,653**	**2,364,519**

	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$
2019							
Directors							
D Battersby	-	-	-	57,248	-	-	57,248
M Smith	-	357,800	-	393,580	-	125,793	877,173
P Kallenberger	350,000	275,333	27,350	-	-	125,793	778,476
C Sands	28,624	-	-	-	-	-	28,624
P Young	28,624	-	-	-	2,719	-	31,343
W Sack	350,000	275,333	29,798	-	-	125,793	780,924
Key management personnel							
N Filipovic	214,680	178,900	-	-	20,395	59,901	473,876
	971,928	1,087,366	57,148	450,828	23,114	437,280	3,027,664

Bonuses

Nil bonuses were granted to executive directors and the key management personnel during the financial year ended 30 June 2020 (2019: US$1,087,366).

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 2020

Auditor's Independence Declaration

Deloitte.

Deloitte Touche Tohmatsu
ABN 74 490 121 060

477 Collins Street
Melbourne VIC 3000
GPO Box 78
Melbourne VIC 3001 Australia

DX 111
Tel: +61 (0) 3 9671 7000
Fax: +61 (0) 3 9671 7001
www.deloitte.com.au

30 September 2020

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 2020, 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
Melbourne

Consolidated Statement of Profit or Loss and Other Comprehensive Income

For the Financial Year Ended 30 June 2020

	Note	Consolidated 2020 US$	Consolidated 2019 US$
Continuing operations			
Revenues from sale of oil and gas		**24,368,696**	38,572,362
Royalty expense		**(2,966,441)**	(7,248,301)
Cost of sales	2	**(8,915,892)**	(7,261,616)
Gross profit		**12,486,363**	24,062,445
Fair value adjustment on embedded derivative element of convertible note		**-**	397,215
Recoupment of operator overheads		**299,269**	200,499
Corporate and administration costs		**(2,507,071)**	(2,874,346)
Impairment expense and dry hole expense	8(a)	**(5,397,975)**	(12,915,955)
Share-based payments		**(940,671)**	(670,141)
Depreciation/amortisation of property, plant and equipment		**(359,334)**	(96,598)
Other expenses		**(1,715,463)**	(1,925,845)
Financial income	3	**19,355**	48,420
Financial expense	3	**(1,816,125)**	(506,706)
Profit before tax		**68,348**	5,718,988
Income tax expense	4	**-**	-
Profit for the year from continuing operations		**68,348**	5,718,988
Other comprehensive income, net of income tax			
Items that may subsequently be reclassified to profit and loss			
Oil price cash flow hedge written down to fair value	16	**(123,570)**	-
Exchange differences on translating the parent entity group		**(15,174)**	21,187
Total comprehensive (loss)/profit for the year		**(70,396)**	5,740,175
Earnings per share			
Basic (cents per share)	5	**0.0088**	0.83
Diluted (cents per share)	5	**0.0086**	0.80

The accompanying notes form part of these financial statements.

Consolidated Statement of Financial Position

As at 30 June 2020

	Note	Consolidated 2020 US$	Consolidated 2019 US$
Assets			
Current assets			
Cash and cash equivalents	21(b)	**16,644,701**	6,783,320
Trade and other receivables	6	**1,851,462**	5,068,725
Derivative financial instruments	16	**214,990**	-
Restricted cash and cash equivalents		**-**	4,377,250
Other	7	**3,137,974**	1,633,986
Total current assets		**21,849,127**	17,863,281
Non-current assets			
Exploration and evaluation assets	8(a)	**4,695,861**	6,587,670
Oil and gas properties	8(b)	**75,191,591**	27,192,032
Other (refundable bonds)	7	**1,925,000**	1,488,177
Right-of-use assets	9	**988,700**	-
Trade and other receivables	6	**251,365**	-
Property, plant and equipment	11	**40,476**	50,162
Other intangible assets	12	**165,329**	312,188
Total non-current assets		**83,258,322**	35,630,229
Total assets		**105,107,449**	53,493,510
Liabilities			
Current liabilities			
Trade and other payables	13	**4,545,285**	8,925,339
Provisions	14	**144,462**	124,361
Lease liabilities	10	**309,440**	-
Borrowings	15	**5,868,817**	5,747,990
Total current liabilities		**10,868,004**	14,797,690
Non-current liabilities			
Provisions	14	**5,080,192**	1,984,062
Lease liabilities	10	**1,042,002**	-
Borrowings	15	**14,066,230**	-
Total non-current liabilities		**20,188,424**	1,984,062
Total liabilities		**31,056,428**	16,781,752
Net assets		**74,051,021**	36,711,758
Equity			
Issued capital	17	**137,560,738**	101,091,750
Foreign currency translation reserve	18	**(146,640)**	(131,466)
Cash flow hedge reserve	18	**(123,570)**	-
Share option reserve	18	**6,305,069**	5,364,398
Accumulated losses		**(69,544,576)**	(69,612,924)
Total equity		**74,051,021**	36,711,758

The accompanying notes form part of these financial statements.

Consolidated Statement of Changes in Equity

For the Financial Year Ended 30 June 2020

Consolidated entity	Ordinary share capital US$	Share option reserve US$	Other reserves US$	Accumulated losses US$	Total US$
Balance at 1 July 2018	99,296,931	4,694,257	(152,653)	(75,331,912)	28,506,623
Profit for the year	-	-	-	5,718,988	5,718,988
Exchange differences arising on translation of the parent entity group	-	-	21,187	-	21,187
Total comprehensive profit for the year	-	-	21,187	5,718,988	5,740,175
The issue of 3,766,479 shares at A$0.2655 per share upon conversion of A$1,000,000 convertible notes	724,400	-	-	-	724,400
The exercise of 1,950,000 share options at A$0.25 per share	344,419	-	-	-	344,419
The issue of 4,669,904 shares at A$0.2141 per share upon conversion of A$1,000,000 convertible notes	726,000	-	-	-	726,000
Recognition of share-based payments	-	670,141	-	-	670,141
Balance at 30 June 2019	101,091,750	5,364,398	(131,466)	(69,612,924)	36,711,758
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**

The accompanying notes form part of these financial statements.

Consolidated Statement of Cash Flows
For the Financial Year Ended 30 June 2020

	Note	Consolidated 2020 US$	2019 US$
Cash flows from operating activities			
Receipts from customers		**25,797,729**	39,368,406
Payments to suppliers and employees		**(10,365,944)**	(15,823,182)
Interest paid		**(1,764,529)**	(321,899)
Interest received		**12,815**	10,333
Net cash flows from operating activities	21(a)	**13,680,071**	23,233,658
Cash flows from investing activities			
Payments for development of oil and gas properties		**(50,934,070)**	(5,118,734)
Payments for exploration and evaluation assets		**(3,033,962)**	(14,132,274)
Purchases of oil price hedge instruments designated at FVTOCI		**(338,560)**	-
Payments for intangible assets (software)		**-**	(366,488)
Payments for property, plant and equipment		**(840)**	(21,087)
Net cash flows used in investing activities		**(54,307,432)**	(19,638,583)
Cash flows from financing activities			
Proceeds from issues of ordinary shares		**36,268,595**	-
Proceeds from exercise of share options		**1,742,000**	344,419
Payment of equity raising costs		**(1,505,688)**	-
Redemption of convertible notes		**-**	(2,181,800)
Repayment of lease liabilities		**(248,103)**	-
Repayment of borrowings		**(3,690,500)**	(1,373,776)
Proceeds from borrowings		**17,990,210**	4,195,110
Net cash flows from financing activities		**50,556,514**	983,953
Net increase in cash and cash equivalents held		**9,929,153**	4,579,028
Cash and cash equivalents at the beginning of the year		**6,783,320**	2,256,958
Effect of exchange rate changes on the balance of cash held in foreign currencies		**(67,772)**	(52,666)
Cash and cash equivalents at the end of the year	21(b)	**16,644,701**	6,783,320

The accompanying notes form part of these financial statements.

Notes to the Financial Statements
For the Financial Year Ended 30 June 2020

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 2020.

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 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 effected.

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.

Notwithstanding the fluctuations in the oil and gas prices due to the impact of COVID-19 amongst other events in the second half of the financial year ended 30 June 2020, the consolidated entity reported a profit before tax of US$68,348 after recognising impairment and dry hole expenses of US$5,397,975 and generated net cash inflows from operating activities of US$13,680,071 for the year ended 30 June 2020. The consolidated entity reported a surplus of current assets over current liabilities of US$10,981,123 as at 30 June 2020.

The consolidated entity has prepared a Board approved forecast for the 12 months ending 30 September 2021 which highlights that the consolidated entity has sufficient cash reserves to continue normal business operations as planned, notwithstanding the recently announced unsuccessful drilling of the SM58 G2 well. The cashflow forecast is based on certain key assumptions including the cost to plug and abandon the SM58 G2 well, the volume of oil and gas production from recently completed production wells, the successful drilling and completion and production of additional wells, the additional volumes of oil and gas generated by the additional wells to be drilled over the forecast period 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.

1. Summary of significant accounting policies continued

For the year ended 30 June 2020 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; and
(iii) Extended terms of trade with certain key service industry suppliers.

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 16 Leases

AASB 16 *Leases* was effective for financial years commencing on or after 1 July 2019. AASB 16 eliminates the classification of leases as either operating leases or finance leases for lessees as required by AASB 117 *Leases* and instead, introduces a single lessee accounting model. Applying that model, a lessee is required to recognise:

On initial application of AASB 16, for all leases (except for short-term leases under one year), the entity has:

(a) recognise right-of-use assets and lease liabilities in the statement of financial position, initially measured at the present value of the future lease payments;

(b) recognise depreciation of right-of-use assets and interest on lease liabilities in the statement of profit or loss; and

(c) separated the total amount of cash paid into a principal portion (presented within financing activities) and interest (presented within operating activities) in the cash flow statement.

The Group has elected to apply the modified retrospective approach for leases. For leases, which were classified as operating leases under AASB 117, the Group has recognised right-of-use assets and lease liabilities as at the transition date (1 July 2019). The Group did not have any leases previously classified as finance leases on the adoption date.

Specifically, under AASB 16, the Group has recognised a right-of-use asset and a corresponding lease liability in relation to the non-cancellable operating leases of the USA office premises and the compressor on the SM71 F platform. Upon transition as at 1 July 2019, a right-of-use asset was recognised at an amount equal to the corresponding lease liability with the Group recognising a right-of-use asset and lease liability as detailed below for an office rental lease.

Statement of financial position	AASB 117 1 July 2019 US$	Adjustments US$	AASB 16 1 July 2019 US$
Right-of-use assets	-	631,765	631,765
Lease liability – current	-	109,095	109,095
Lease liability – non current	-	522,670	522,670

Leases to explore for or use oil and natural gas are specifically excluded from AASB 16.

In the future, the Group will assess whether future contracts contain 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. 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.

The lease liability is presented as a separate line with a corresponding right-of-use asset in the consolidated statement of financial position.

IFRIC 23 Uncertainty Over Income Tax Treatments

The Group has adopted IFRIC 23 for the first time in the current year. IFRIC 23 sets out how to determine the accounting tax position when there is uncertainty over income tax treatments. The Interpretation requires the Group to:

- determine whether uncertain tax positions are assessed separately or as a group; and
- assess whether it is probable that a tax authority will accept an uncertain tax treatment used, or proposed to be used, by an entity in its income tax filings:
  - If yes, the Group should determine its accounting tax position consistently with the tax treatment used or planned to be used in its income tax filings.
  - If no, the Group should reflect the effect of uncertainty in determining its accounting tax position using either the most likely amount or the expected value method.

As of 30 June 2020, the consolidated entity does not expect any financial material impact on its consolidated financial statements resulting from the application of IFRIC 23.

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 2019-1 Amendments to Australian Accounting Standards – References to the Conceptual Framework in IFRS Standards	1 January 2020	30 June 2021
AASB 2018-7 Amendments to Australian Accounting Standards – Definition of Material	1 January 2020	30 June 2021
AASB 2019-5 Amendments to Australian Accounting Standards – Disclosure of the Effect of New IFRS Standards Not Yet Issued in Australia	1 January 2020	30 June 2021
AASB 2020-1 Amendments to Australian Accounting Standards – Classification of Liabilities as Current or Non-current	1 January 2022	30 June 2023

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.

1. Summary of significant accounting policies continued

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.

Farm-in and farm-outs

In the case of farm-outs, the Group does not record any expenditure made by the farm-inee 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 farm-inee 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 as 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 as 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 and are recognised directly in equity in the foreign currency translation reserve.

1. Summary of significant accounting policies continued

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

Equity settled 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.

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 FVTOCI
- Equity instruments at FVTOCI
- 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.

1. Summary of significant accounting policies continued

(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.

(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. 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.

1. Summary of significant accounting policies continued

(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 cashflow hedges is made in Note 1(r).

(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 Group did make such an adjustments during the period presented for an additional office lease.

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 of 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 contracts 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.

2. Profit for the year

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

	Consolidated	
	2020 US$	**2019 US$**
Cost of sales		
Lease operating costs	**3,406,510**	2,625,889
Amortisation of oil and gas properties	**5,509,382**	4,635,727
	8,915,892	7,261,616
Professional and consulting costs	**1,229,622**	1,447,051
Insurance	**115,825**	97,230
Office lease rental expense including outgoings (short-term leases)	**142,787**	232,239
Employee benefits expense		
Salaries and wages	**1,628,484**	1,959,226
Share-based payments (loans made to staff for the conversion of share options to fully paid ordinary shares)	**623,813**	452,251
Defined contribution superannuation expense	**28,338**	28,765
	2,280,635	2,440,242

3. Financial income and expenses

Financial income		
Interest income	**12,815**	10,333
Foreign exchange gain on A$ denominated loans	**6,540**	38,087
	19,355	48,420
Financial expense		
Interest expense non-related parties	**1,294,301**	327,460
Lease finance costs	**82,860**	-
Unwinding of discount on rehabilitation of oil and gas properties	**38,605**	34,235
Interest expense paid or accrued on loans from related parties	**400,359**	145,011
	1,816,125	506,706

4. Income tax

	Consolidated	
	2020 US$	**2019 US$**
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	**68,348**	5,718,988
Income tax expense calculated at 27.5% (2019: 27.5%)	**18,796**	1,572,722
Effect of expenses that are not deductible in determining taxable profit	**260,774**	96,428
Effect of income that are not assessable in determining taxable profit	**(11,078)**	-
Effect of different tax rates of subsidiaries operating in other jurisdictions	**(44,934)**	(168,274)
Effect of unused tax losses and tax offsets not recognised as deferred tax assets	**(223,558)**	(1,500,876)
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	**3,380,123**	2,851,532
USA tax losses	**32,992,123**	15,012,898
Temporary differences	**(23,542,262)**	(5,234,519)
Total deferred tax assets not recognised	**12,829,984**	12,629,911

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	
	2020 US$	**2019 US$**
Net profit for the year	**68,348**	5,718,988
Basic profit per share	**0.000088**	0.0083
Diluted profit per share	**0.000086**	0.0080
Weighted average number of ordinary shares	**777,410,613**	691,142,698
Shares deemed to be issued for no consideration in respect of share options	**15,249,908**	20,459,212
Weighted average number of ordinary shares used in the calculation of diluted earnings per share	**792,660,521**	711,601,910
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	**1,634,481**	3,201,223
Joint operating arrangements receivables	**193,796**	1,848,434
GST receivable	**23,185**	19,068
	1,851,462	5,068,725
Non-current		
Joint operating arrangements receivables	**251,365**	-

Current trade and other receivables are non-interest bearing and are settled within 30 days. Consequently, the amounts referred to in this note are less than 30 days to collection, except for one debtor amounting to US$124,091 which is currently in excess of 30 days, but is expected to be received within the next financial year.

7. Other assets

	Consolidated 2020 US$	Consolidated 2019 US$
Current		
Prepayments	**3,131,989**	1,034,386
Security deposits	**5,985**	599,600
	3,137,974	1,633,986
Non-current		
Security deposits	**1,925,000**	1,488,177

8. (a) Exploration and evaluation assets

	2020 US$	2019 US$
Costs carried forward in respect of areas in the exploration and/or evaluation phase at cost:	**4,695,861**	6,587,670
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**6,587,670**	3,937,828
Additions at cost	**24,238,915**	14,956,165
Acquisition of an exploration property	**-**	609,632
Transfers of exploration and evaluations assets to oil and gas properties	**(20,732,749)**	-
Impairment expense	**(5,397,975)**	(12,915,955)
Carrying amount at the end of the financial year	**4,695,861**	6,587,670

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 2020, impairment charges were US$5,397,975 covering (i) write-off of unsuccessful exploration drilling expenses in relation to the SM74 D14 well dry hole on the SM 74 block; (ii) residual costs of the relinquishment of the Bivouac Peak and Eugene Island 18 leases; and (iii) relinquishment of the Grand Isle 95 lease subsequent to 30 June 2020.

8. (b) Oil and gas properties

(i) Oil and gas properties – Producing

	2020 US$	2019 US$
Costs carried forward in respect of areas in the oil and gas properties:	**37,224,157**	27,192,032
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**27,192,032**	26,174,962
Additions at cost	**14,753,450**	1,320,212
Additions for site restoration	**788,057**	203,152
Acquisition of producing properties	**-**	4,129,433
Amortisation of oil and gas properties included in cost of sales	**(5,509,382)**	(4,635,727)
Carrying amount at the end of the financial year	**37,224,157**	27,192,032

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 2020 financial year, the following assumptions were used in the assessment of recoverable amounts: (i) Oil prices (nominal) used represent consensus (June 30, 2020 Bloomberg Street Consensus), starting on July 1, 2020, of US$35.45 per barrel, with a final price of US$60.51 per barrel on January 1, 2024, and held constant thereafter; (ii) Gas prices (nominal) used in this report represent a Henry Hub base, starting on July 1, 2020, of US$2.08 per MMBtu, rising to US$2.64 per MMBtu in January 2021 then declining to US$2.56 per MMBtu on January 1, 2022, with a final price of US$2.67 per MMBtu on January 1, 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 2020 financial year.

(ii) Oil and gas properties – Non-producing

	Consolidated	
	2020 US$	**2019 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	**-**	-
Additions at cost	**14,976,251**	-
Additions for site restoration	**2,258,434**	-
Transfers from exploration and evaluation see Note 8(a)	**20,732,749**	-
Carrying amount at the end of the financial year	**37,967,434**	-

SM58 was reclassified from exploration and evaluation assets to oil and gas properties – non-producing effective 1 January 2020 reflecting the decision to commit to the full development of SM58 including platform and pipelines installation and completion of the SM58 G1 well drilled in the September 2019 quarter.

9. Right-of-use assets

	Consolidated 2020 US$	2019 US$
Office lease		
Opening balance 1 July 2019	**631,765**	-
Additions	**200,877**	-
Amortisation	**(158,764)**	-
Carrying amount at the end of the financial period	**673,878**	-
Compressor lease		
Opening balance 1 December 2019	**361,711**	-
Amortisation for seven months	**(46,889)**	-
Carrying amount at the end of the financial period	**314,822**	-
Total right-of-use assets	**988,700**	-
Amounts recognised in profit and loss		
Depreciation expense on right-of-use assets	**205,653**	-
Interest expense on lease liabilities	**82,860**	-
Expense relating to short-term leases including outgoings	**142,787**	-

10. Lease liabilities

Not later than one year	**432,573**	-
Later than one year and not later than five years	**1,208,620**	-
Minimum lease payments	**1,641,193**	-
Less: Future finance charges	**(289,751)**	-
Provided for in the financial statements	**1,351,442**	-
Representing lease liabilities:		
Current	**309,440**	-
Non-current	**1,042,002**	-
	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.

Notes to the Financial Statements continued

For the Financial Year Ended 30 June 2020

11. Property, plant and equipment

	Consolidated	
	2020 US$	**2019 US$**
Buildings at cost	**10,026**	10,245
Accumulated depreciation	**(3,523)**	(3,343)
	6,503	6,902
Reconciliation of movements:		
Carry amount at the beginning of the financial year	**6,902**	7,543
Depreciation for year	**(246)**	(261)
Foreign currency translation movements	**(153)**	(380)
Carrying amount at the end of the financial year	**6,503**	6,902
Plant and equipment at cost	**134,999**	135,920
Accumulated depreciation	**(101,026)**	(92,660)
	33,973	43,260
Reconciliation of movements:		
Carry amount at the beginning of the financial year	**43,260**	31,575
Additions at cost	**840**	21,087
Depreciation for year	**(10,082)**	(9,296)
Foreign currency translation movements	**(45)**	(106)
Carrying amount at the end of the financial year	**33,973**	43,260
Total property, plant and equipment	**40,476**	50,162

12. Other intangible assets

Capitalised software costs at cost	**465,172**	468,432
Accumulated amortisation	**(299,843)**	(156,244)
	165,329	312,188
Reconciliation of movements:		
Carry amount at the beginning of the financial year	**312,188**	32,082
Additions at cost	**-**	366,488
Amortisation for year	**(143,353)**	(87,041)
Foreign currency translation movements	**(3,506)**	659
Carrying amount at the end of the financial year	**165,329**	312,188

13. Trade and other payables

	Consolidated 2020 US$	2019 US$
Current		
Trade payables	**4,200,222**	8,217,459
Oil and gas royalties payable	**303,448**	590,212
Accrued interest on loans	**27,462**	104,963
Other payables	**14,153**	12,705
	4,545,285	8,925,339

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

	2020 US$	2019 US$
Current		
Accumulated employee entitlements	**144,462**	124,361
	144,462	124,361
Non-current		
Accumulated employee entitlements	**75,280**	64,246
Site restoration SM71 wells, pipelines and platform, SM58 E-1 well, SM69 pipelines and platform, SM58 G1 well and SM58 platform	**5,004,912**	1,919,816
	5,080,192	1,984,062

	2020 US$	2019 US$
Site restoration provisions		
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**1,919,816**	1,122,464
Net additions to site restoration	**3,046,491**	203,152
Additions to site restoration upon acquisition of a producing property	**-**	559,965
Unwinding of discount on site restoration	**38,605**	34,235
Carrying amount at the end of the financial year	**5,004,912**	1,919,816

Provisions are recognised for the Group's restoration obligations at SM71, the SM58 E-1 and G1 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 2020 were within the range of 0.74% to 1.18% (2019 within the range of 1.97% to 2.15%), 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 2020 US$	2019 US$
Current unsecured		
Loans from directors and shareholders*	**-**	4,174,030
Insurance premium financing (interest bearing)**	**1,493,817**	1,573,960
Current secured		
Promissory note – debt liability	**4,375,000**	-
Total current borrowings	**5,868,817**	5,747,990
Non-current unsecured		
Loans from directors and shareholders*	**3,441,230**	-
Non-current secured		
Promissory note – debt liability***	**10,625,000**	-
Total non-current borrowings	**14,066,230**	-

* During the March 2019 quarter, Byron established a short-term loan facility for US$2.0 million and A$3.1 million, equivalent to approximately US$4.2 million, with US$3.2 million sourced from four of the Company's directors (for additional details refer to the Related party transactions note). The loan facility, fully drawn during the March 2019 quarter, is unsecured, repayable by 31 March 2022 (as agreed and amended) and will bear interest, from time of drawdown, at a rate of 10% per annum payable every quarter and A$1.0 million was repaid on 31 December 2019 to a non-director.

** The insurance premium financing bears an average 3.43% fixed interest rate, refer Note 30(c).

*** Crimson Promissory Note: key terms of the Promissory Note include: (i) facility amount US$15 million; (ii) senior secured debt over the Company's SM71 and SM58 assets and guaranteed by the Company; and (iii) interest rate of 15% p.a., over a three-year term, with a first-year interest-only.

16. Derivative financial assets

	2020	2019
Oil price cash flow hedges at fair value	**214,990**	-
Total cash flow hedges	**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.

Oil price cash flow hedges

	2020	2019
Cash premium paid	**338,560**	
Write-down of oil price cash flow hedges to fair value through other comprehensive income	**(123,570)**	-
Net amount	**214,990**	-

17. Issued capital

	Consolidated	
	2020 US$	**2019 US$**
(a) Issued and paid up capital	**137,560,738**	101,091,750

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

	2020		2019	
	Number	**US$**	**Number**	**US$**
Fully paid ordinary shares				
Balance at beginning of the financial year	**695,373,417**	**101,091,750**	684,987,034	99,296,931
Shares issued				
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)**		
The issue of 3,766,479 shares at A$0.2655 per share upon conversion of A$1,000,000 convertible notes			3,766,479	724,400
The exercise of 1,950,000 share options at A$0.25 per share			1,950,000	344,419
The issue of 4,669,904 shares at A$0.2141 per share upon conversion of A$1,000,000 convertible notes			4,669,904	726,000
Balance at end of financial year	**1,023,549,331**	**137,560,738**	695,373,417	101,091,750

(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 1,023,549,331 ordinary shares (2019: 695,373,417). 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 (2019: 60,600,000) 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 and (i) 10,000,000 share options with an expiry date 21 July 2019 and an exercise price of A$0.25 per option were converted to ordinary fully paid shares; and (ii) 9,500,000 share options with an expiry date of 31 December 2019 and an exercise price of A$0.25 per option were converted to ordinary fully paid shares. No share options expired, unexercised during the financial year.

18. Reserves

	Consolidated	
Foreign currency translation reserve	**2020 US$**	**2019 US$**
Balance at beginning of financial year	**(131,466)**	(152,653)
Currency translation movements for the year	**(15,174)**	21,187
Balance at end of financial year	**(146,640)**	(131,466)

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	**-**	-
Changes in derivative financial instruments at fair value through other comprehensive income	**(123,570)**	-
Balance at end of financial year	**(123,570)**	-

The reserve arises out of the movement in mark-to-market value of oil price hedges as at 30 June 2020.

Share option reserve		
Balance at beginning of financial year	**5,364,398**	4,694,257
Loans made to executive directors, staff and consultants for the conversion of 9,500,000 share options to fully paid ordinary shares*	**940,671**	-
9,500,000 options issued to directors, staff and consultants as approved by shareholders	**-**	569,062
1,250,000 options issued to staff and consultants	**-**	101,079
Balance at end of financial year	**6,305,069**	5,364,398

* 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. 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.

19. Franking credits

There are no franking credits available for distribution (2019: 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 2020, has resulted in a significant decrease in office rental lease commitment as at 30 June 2020.

(a) Commitments for office lease rental payments

	Consolidated	
	2020 US$	**2019 US$**
Not longer than one year	**21,770**	273,143
Between one and five years	**-**	843,066
	21,770	1,116,209

(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 SM58 G1 well completion and tie back.

Commitments for well drilling/completion expenditures		
Not longer than 1 year	**2,072,500**	9,122,216

(d) Platform and pipeline expenditure commitments

The Group has a financial commitment as at balance date for the SM58 platform and pipelines expenditures.

Commitments for platform and pipeline expenditures		
Not longer than one year	**5,114,804**	-

(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	**204,730**	**54.0161**	**11,058,725**
Between one and five years	**228,800**	**52.7579**	**12,071,008**
	433,530	**53.3521**	**23,129,733**

Notes to the Financial Statements continued

For the Financial Year Ended 30 June 2020

21. Cash flow reconciliation

	Consolidated	
	2020 US$	2019 US$
(a) Reconciliation of profit from ordinary activities after tax to net cashflows from operations		
Profit for the year	**68,348**	**5,718,988**
Non-cash flows in operating result:		
Amortisation oil and gas properties	**5,509,382**	4,635,727
Depreciation and amortisation of property, plant and equipment	**153,681**	96,598
Depreciation of right-of-use assets	**205,653**	-
Impairment expense	**5,397,975**	12,915,955
Equity settled share-based payments	**940,671**	670,141
Finance cost of leased assets	**82,860**	-
Net foreign exchange (gain)/loss on A$ loans	**(6,540)**	(38,087)
Unwinding of discount on rehabilitation of oil and gas properties	**38,605**	34,235
Fair value adjustment on embedded derivative element of convertible note	**-**	(397,215)
Foreign exchange differences arising on translation of the parent entity group	**23,587**	23,295
	12,414,222	23,659,637
Movements in working capital		
(Increase)/decrease in assets:		
Trade and other receivables	**1,562,086**	791,110
Other assets	**(445,960)**	(1,568,950)
Increase/(decrease) in liabilities:		
Trade and other payables	**114,553**	346,219
Provisions	**35,170**	5,642
Net cash from operating activities	**13,680,071**	23,233,658
(b) Reconciliation of cash		
Cash and cash equivalents comprise:		
Cash and bank balances	**16,644,701**	6,783,320

(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, of which US$3.5 million is undrawn at 30 June 2020 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 rate utilised in the translation of the parent entity group Australia dollar figures to United States dollars are as follow:-

	2020	2019
Spot rate at 30 June	**0.6863**	0.7013
Average rate for year	**0.6714**	0.7156

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) Byran 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 Crimson 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 2019 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 2020, Byron had collateral bond holdings of US$3,549,618 (2019: US$2,474,600), of which US$1,925,000 (2019: US$2,074,600) was cash collateralised; and

(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	
	2020 US$	**2019 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**	-
Fair value of options granted to directors, staff and consultants	**-**	670,141
Expense arising from share-based payments paid as remuneration	**940,671**	670,141

9,500,000 share options were exercised during the financial year (2019: 1,950,000). There are no Employee Share Option plans in place.

	2020		2019	
	Number	**Exercise price**	**Number**	**Exercise price**
Balance at beginning of year	**50,600,000**		41,800,000	
Granted during the year	**-**		9,500,000	A$0.40c
Granted during the year	**-**		1,250,000	A$0.40c
Exercised during the year	**(9,500,000)**		(1,950,000)	
Balance at end of year	**41,100,000**		50,600,000	
Exercisable at end of year			9,500,000	A$0.25c
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$0.25c

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 549 days (2019: 915 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

Calculation of the fair value of a loan funded conversion of equity share options into fully paid shares

The total fair value of the loan funded conversion of share options into fully paid ordinary shares was US$940,671 and the total fair value of all share options granted and issued during the 2019 financial year was US$670,141. The fair value was calculated by an independent external consultant entity that determined the share option conversions should be valued as synthetic options using the Binomial option pricing model.

Inputs into the model	9,500,000 share options converted to fully paid ordinary shares to directors, staff and consultants as at 31 December 2019
Share option exercise price	A$0.25
Share price 31 December 2019	A$0.30
Number of options	9,500,000
Volatility	81.365%
Time maturity of underlying option	2 years
Risk-free interest rate	0.905%

26. Employee benefits and superannuation commitments

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

27. Auditors' remuneration

	Consolidated	
	2020 US$	2019 US$
Amounts received or due and receivable by Deloitte Touche Tohmatsu:		
Audit or review of the financial statements of the Group	**63,578**	56,518
	63,578	56,518

The auditors did not receive any other benefits (2019: 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$	Short-term cash incentive US$	Other benefits US$	Service agreements US$	Super-annuation US$	Share options US$	Total US$
Year 2020	**1,000,203**	**-**	**58,574**	**441,446**	**22,643**	**841,653**	**2,364,519**
Year 2019	971,928	1,087,366	57,148	450,828	23,114	437,280	3,027,664

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 entered into during the financial year ended 30 June 2020:

(a) In September 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$1,500,000 and A$1,100,000. The loans were repaid in December 2019 with applicable interest, except for the Geogeny Pty Ltd US$500,000 loan which was repaid in early January 2020. During the year ended 30 June 2020, the Company made the following loan repayments and interest payments to related parties:

- Veruse Pty Ltd, a company controlled by Mr Douglas Battersby, a director of the Company, was repaid A$750,000, plus interest of A$20,959.
- Geogeny Pty Ltd, a company controlled by Mr Maynard Smith, a director of the Company, was repaid US$500,000, plus interest of US$15,068.
- Poal Pty Limited, a company controlled by Mr Paul Young, a director of the Company, was repaid A$175,000, plus interest of A$5,034.
- A related party of Mr Paul Young, a director of the Company, was repaid A$175,000, plus interest of A$5,034.
- Charles Sands, a director of the Company, was repaid US$1,000,000, plus interest of US$27,123 (net of withholding taxes).

(b) 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 2020 was A$164,548, plus A$11,507 has been accrued as at 30 June 2020.
- 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 2020 was A$20,664, plus A$1,438 has been accrued as at 30 June 2020.
- 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 2020 was A$20,664, plus A$1,438 has been accrued as at 30 June 2020.
- 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 2020 was US$117,534, plus US$8,219 has been accrued as at 30 June 2020.
- 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 2020 was US$105,991 (net of withholding taxes), plus US$7,433 (net of withholding taxes) has been accrued as at 30 June 2020.

(c) Corporate advisory services at normal commercial rates totalling A$525,930 (2019: A$nil) excluding GST were provided by Henslow Pty Ltd, of which Paul Young is a managing director.

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, commodity price 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	**2020 US$**	**2019 US$**
Financial assets at fair value		
Cash and cash equivalents	**16,644,701**	6,783,320
Trade and other receivables	**2,102,827**	5,068,725
Derivative financial instruments	**214,990**	-
Restricted cash and cash equivalents	**-**	4,377,250
Bonds and security deposits	**1,930,985**	2,087,777
	20,893,503	18,317,072
Financial liabilities at fair value		
Trade and other payables	**4,545,285**	8,925,340
Insurance premium financing	**1,493,817**	1,573,960
Loans from related parties	**3,441,230**	4,174,030
Crimson loans	**15,000,000**	-
	24,480,332	14,673,330

(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 2020 financial year, no dividends were paid (2019: 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.

(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.

30. Financial instruments continued

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$
2020					
Non-interest bearing	**-**	**1,769,509**	**112,048**	**190,880**	**2,176,365**
Variable interest rate instruments	**0.18%**	**16,644,701**	**-**	**-**	**-**
2019					
Non-interest bearing	-	4,420,646	1,098,079	155,715	1,482,062
Variable interest rate instruments	0.30%	10,660,570	500,000	-	-

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$
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**
2019					
Non-interest bearing	-	8,820,376	-	104,964	-
Fixed interest rate instruments	5.16%	207,352	414,704	951,904	-
Related party liabilities	10.00%	-	-	4,174,030	-

(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 2020, 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 have 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$58,570 (2019: US$22,601) for an increase of 50 basis points; conversely a decrease of 50 basis points would result in a decrease of US$58,570 (2019: US$22,601) 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 USA 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	**2020 $**	**2019 $**	**2020 $**	**2019 $**
USA currency denominated	**19,653,469**	16,120,188	**22,860,922**	12,337,112
Australian currency denominated	**1,806,840**	3,132,589	**2,359,625**	3,331,268

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	**2020 US$**	**2019 US$**
Profit or equity	**245,109**	32,230

(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$1,572,949 (2019: US$2,311,100) 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$1,572,949 (2019: US$2,311,100) 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$83,200,908 (2019: US$35,514,110) and Australia US$57,414 (2019: US$116,119).

32. Interests in joint operations

As at 30 June 2020, 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;

(ii) Otto Energy (Gulf One) LLC, Metgasco Limited and NOLA Oil and Gas Ventures LLC exercised options to earn a 40%, 10% and 7% WI, respectively, in Byron's Bivouac Peak project. Post earn-in Byron's WI and NRI reduced to 43% and 32.035% respectively. Byron is the operator with the leases relinquished during the previous financial year;

(iii) Metgasco Limited exercised its option to earn a 30% WI and 24.375% NRI in South Marsh Island, block 74 ('SM74') by agreeing to pay a disproportionate share of drilling costs of the SM74 D14 well. Upon completion of the earn-in, Byron's WI and NRI will be reduced to 70% and 56.875% respectively. Byron is the operator; and

(iv) 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	2020 US$	2019 US$
Assets		
Current assets	**505,495**	2,115,172
Non-current assets	**126,242,539**	90,588,876
Total assets	**126,748,034**	92,704,048
Liabilities		
Current liabilities	**132,040**	4,319,019
Non-current liabilities	**3,441,230**	-
Total liabilities	**3,573,270**	4,319,019
Net assets	**123,174,764**	88,385,029
Equity		
Issued capital	**136,896,995**	100,428,006
Accumulated losses	**(10,595,513)**	(8,501,348)
Foreign currency translation reserve	**(7,553,504)**	(7,027,744)
Share option reserve	**4,426,786**	3,486,115
Total equity	**123,174,764**	88,385,029
Financial performance		
Loss for the year	**(2,094,165)**	(1,128,312)
Other comprehensive income	**525,760**	(2,262,733)
Total comprehensive loss for the financial year	**(1,568,405)**	(3,391,045)

Expenditure commitments

The parent entity has no expenditure commitments at the end of the 2020 financial year (2019: 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 2019 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 2020 (2019: 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 6 July 2020, Byron announced to the ASX that the SM58 'G' Platform installation had been completed;

(ii) on 20 July 2020, Byron announced to the ASX that SM58 G1 well completion operations had begun;

(iii) on 21 July 2020, Byron announced to the ASX that 16,745,771 shares were issued to directors and/or their nominees to raise approximately A$2.2 million as approved by shareholders at a general meeting held on 9 July 2020;

(iv) on 9 September 2020, Byron announced that production had commenced from the SM58 G1 well;

(v) on 10 September 2020, Byron announced its 2020 Independent Reserves and Resources Report; and

(vi) on 21 September 2020, Byron announced that (i) that the SM58 G2 well has been drilled to a final total depth of 11,237 feet measured depth (10,233 feet true vertical depth) and has been deemed non-commercial, and (ii) preparations were underway to sidetrack the SM58 G2 well to test the Upper O Sand in the Brown Trout Prospect.

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 2020

Deloitte Touche Tohmatsu
ABN 74 490 121 060

477 Collins Street
Melbourne VIC 3000
GPO Box 78
Melbourne VIC 3001 Australia

Tel: +61 3 9671 7000
Fax: +61 3 9671 7001
www.deloitte.com.au

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 2020, 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 2020 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.

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 2021; and

- Assessing the adequacy of the disclosures related to going concern in Note 1.

Deloitte.

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 As at 30 June 2020 the Group amortised US$5.5 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.
Carrying amount of development and production assets As at 30 June 2020 the carrying value of oil and gas property assets under production amounts to US$37.2 million as disclosed in Note 8. Management reviewed both producing fields SM58 E-1 and SM71 for indicators of impairment. An indicator was identified for both fields due to the COVID-19 impact on future oil prices and future revenues as a result. Management therefore estimated each CGU's recoverable amount and compared it to its carrying value, and calculated that no impairment is required. The assessment requires significant judgement due to assumptions and estimates involved in preparing a value is use model to estimate recoverable amount, including: • Future commodity prices; • Reserves estimate and production profiles; • Discount rates; and • Future capital and operating expenditure.	In conjunction with our valuation specialists our 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; • Comparing the accuracy of the oil and gas prices against third party oil futures price curves; • Comparing future capital and operating expenditures and reserves to the latest approved long-term budgets. We assessed the Group's ability to budget accurately by comparing prior years' estimated cashflows to actual results; • Determining the appropriateness of the discount rate used in the fair value models; • Performing sensitivity analysis on the impairment model using varied discount rates and reserve projections to simulate alternative market conditions and outcomes; and • Testing the mathematical accuracy of the impairment model. We also assessed the appropriateness of the disclosures in Note 8 to the financial statements.

Deloitte.

Key Audit Matters	How the scope of our audit responded to the Key Audit Matters
Reclassification of exploration and evaluation assets As at 30 June 2020 the Group has exploration and evaluation assets of $4.7m capitalised in respect of a portfolio of leased properties as disclosed in note 8. During the year the Group has transferred $20.7m to Oil and Gas properties. Significant judgement is required in respect of the following criteria to determine the classification of these costs, as exploration and evaluation assets shall no longer be classified as such where they do not meet these criteria: • the technical feasibility and commercial viability of extracting a mineral resource are demonstrable; and • whether the assets value is recoverable or impaired. Exploration and evaluation assets shall be assessed for impairment, and any impairment loss recognised, before reclassification.	Our procedures included, but were not limited to: • Obtaining an understanding of the key controls and processes that management have in place to determine which expenditure to capitalise for exploration and evaluation assets; • Evaluating and challenging management's determination of the technical feasibility and commercial viability of the mineral resources; • Assessing management's process to measure fair value less costs of disposal for each exploration and evaluation asset and testing internal controls, including the preparation, review and board approval of forecasts supporting this process; and • In conjunction with our valuation specialists we evaluated and tested the key assumptions used in management's recoverable amount analysis including: o Assessing the basis for management's forecast revenue including the estimated reserves from which revenue is generated and cash flows; o Recalculating an expected discount rate and comparing this to the rate calculated by management; and o Performing sensitivity analysis on the impairment model using varied discount rates and reserve projections to simulate alternative market conditions and outcomes. Assessing the appropriateness of the disclosures in Note 8 of 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 2020, 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.

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.

Deloitte.

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 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.

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.

Deloitte.

Report on the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included in pages 44 to 49 of the Directors' Report for the year ended 30 June 2020.

In our opinion, the Remuneration Report of Byron Energy Limited, for the year ended 30 June 2020, 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 2020

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 9 October 2020.

Distribution of equity securities

As at 9 October 2020 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 4,050 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 23 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 9 October 2020 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	172	35,684
1,001 – 5,000	898	2,655,582
5,001 – 10,000	547	4,279,010
10,001 – 100,000	1,473	58,354,322
100,001 and over	960	974,970,504
Total holders	**4,050**	**1,040,295,102**

The number of security investors holding less than a marketable parcel of securities is 133 with a combined total of 7,185 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**

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 of share	Percentage
1.	VERUSE PTY LIMITED	44,385,985	4.27%
2.	BNP PARIBAS NOMINEES PTY LTD <IB AU NOMS RETAILCLIENT DRP>	30,565,901	2.94%
3.	ELMSLIE SUPERANNUATION COMPANY PTY LTD <ELMSLIE FAMILY S/F A/C>	28,269,844	2.72%
4.	METGASCO LTD	26,777,829	2.57%
5.	EQUITAS NOMINEES PTY LIMITED <PB-600387 A/C>	24,227,836	2.33%
6.	MR CHARLES SANDS	20,382,409	1.96%
7.	MR MATTHEW DOMINELLO	20,016,962	1.92%
8.	WALLEROO PTY LTD	18,828,791	1.81%
9.	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED	17,426,026	1.68%
10.	AGRICO PTY LTD <PALM SUPER FUND A/C>	14,415,928	1.39%
11.	CLAPSY PTY LTD <BARON SUPER FUND A/C>	13,854,350	1.33%
12.	BARRIJAG PTY LTD <HADLEY SUPER FUND A/C>	13,809,524	1.33%
13.	GEOGENY PTY LIMITED	13,214,045	1.27%
14.	DISCOVERY INVESTMENTS PTY LTD	12,716,103	1.22%
15.	FITZROY RIVER CORPORATION LIMITED	12,210,089	1.17%
16.	METGASCO LIMITED	12,101,792	1.16%
17.	MR JOHN SANDS	12,080,972	1.16%
18.	POAL PTY LTD <BARAIN SUPER FUND A/C>	11,341,298	1.09%
19.	CITICORP NOMINEES PTY LIMITED	11,014,247	1.06%
20.	BARRIJAG PTY LTD <HADLEY FAMILY A/C>	10,245,000	0.98%
Total Quted Shares Held by Top 20 Holders		367,884,931	35.36%
Total Quoted Shares Held by Other Shareholders		672,410,171	64.64%
Total Quoted Shares		**1,040,295,102**	**100.00%**

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