

Quarterly Report for the Period Ended 31 December 2020

Summary

- Byron's share of oil and gas production (net sales volume) for the December 2020 quarter was 111,516 barrels of oil and 1,742,124 mmbtu of gas compared to the September 2020 quarter of 99,281 barrels of oil and 529,560 mmbtu of gas;
- Net revenue recorded for the December 2020 quarter, was approximately US\$9.2 million (net to Byron after quality adjustments, transportation charges and royalties) with realised net prices of US\$ 42.06 per barrel of oil and US\$ 2.25 per mmbtu of natural gas for the December quarter (September 2020 quarter: net revenue approximately US\$5.1 million with realised net prices of US\$ 41.51 per barrel of oil and US\$ 1.49 per mmbtu of natural gas)
- As of 31 December 2020 well test data indicates that the SM58 G1 is producing 15.7 million cubic feet of gas per day, 200 barrels of 56.5-degree condensate per day, and no formation water with flowing tubing pressure of 1,213 psi.
- SM58 G2ST well commenced production on 1 November 2020 (USCDT) with the SM58 G2ST test rates as of 31 December 2020 indicating that the SM58 G2ST is was producing 4.9 Mmcfgpd, 330 barrels of 38.8-degree API oil and no formation water.
- Byron further optimised its portfolio of properties by acquiring a 100% WI in SM66 and relinquishing SM74.

Name:	Byron Energy Limited
ASX code:	BYE
Shares on issue at 31 Dec 2020:	1,040.3 million
Quoted shares:	1,040.3 million
Options on issue (unquoted):	41.1 million
Cash at Bank 31 Dec 2020:	US\$1.5 million
Borrowings 31 Dec 2020:	US\$22.1 million
Market Capitalisation at 31 Dec 2020:	A\$167 million (@A\$0.16 per share)

Corporate

Issued Capital

As at 31 December 2020, Byron's issued capital comprised:-

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

Directors Doug Battersby (Non-Executive Chairman) Maynard Smith (Chief Executive Officer) Prent Kallenberger (Chief Operating Officer) Charles Sands (Non-Executive Director)	Directors (continued) Paul Young (Non-Executive Director) William Sack (Executive Director) Company Secretary and Chief Financial Officer Nick Filipovic
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Corporate (cont.)

Borrowings

As at 31 December 2020, Byron's outstanding loans comprised:-

Lender	US\$ M	A\$ M	US\$ Equivalent (@A\$1=US\$0.7702)
Directors	2.00	1.75	3.25
Shareholder	-	0.35	0.24
Crimson Midstream	18.50	-	18.50
Total	20.50	2.10	21.99

* as at 31 December 2020, Byron also had US\$ 0.5 million in insurance premium financing outstanding

Crimson Midstream

As announced on 19 May 2020, Crimson Midstream agreed to subscribe for an additional US\$3.5 million in the form of a promissory note ("Promissory Note") on the same terms and conditions as the initial US\$15.0 million facility. The additional Promissory Note of US\$3.5 million, taking the total to US\$18.5 million, was drawn down in August 2020.

The Promissory Note is secured over Byron's SM71 and SM58 assets and guaranteed by the Company, bearing interest at a rate of 15% p.a., over a 3-year term, being interest-only until December 2020.

Under the terms of the Promissory Note, after the interest only period ends, principal and interest is payable via a fee on production, based on monthly throughput of Byron's oil production.

In December 2020 Crimson agreed that notwithstanding the terms of the Promissory Note the parties agreed that the Production Handling Agreement ("PHA") Fee would be fixed at US\$15/bbl, instead of approximately US\$25/bbl under the original agreement, and will remain at that level until at least the next PHA Fee adjustment date, being March 2021. This effectively reduces the total amount of principal repayments by Byron in December 2020, January and February 2021 by deferring them beyond March 2021.

For further details of the Promissory Note refer to the Company's ASX release dated 4 December 2019.

Directors and Shareholder Loans

Byron's outstanding loans of approximately US\$3.6 million, as of 31 December 2020, from entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young, all directors of the Company, and another long standing shareholder are due to be repaid on 31 March 2022.

Appointment of Seaport Global

As announced to the ASX on 27 January 2021, Byron has appointed Seaport Global to pursue a more flexible debt finance package for the repayment of existing loans and fund multi-well development capital for SM58 area project.

Oil Price 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. The derivative hedge in the form of put options ("Put Options") which provided Byron as the buyer of the Put Options with a hedge against potentially declining prices expired on 31 December 2020.

The hedging counterparty for the Forward Sale Agreement and the Put Options, is one of the global oil industry's

Corporate (cont.)

“supermajors” and is also the purchaser of Byron’s oil production under a mutually agreed long term purchase arrangement, which provides Byron with a stable, aligned counterparty.

Byron’s hedged oil production as at 31 December 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
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.

For additional information on the Company’s oil price hedging activities, refer to ASX releases dated 22 April 2020 and 18 June 2020.

Oil and Gas Production/Sales

Byron’s share of oil and gas production and sales for the December 2020 quarter is summarised in the table below.

Production (sales)	Dec 2020 quarter	Sep 2020 quarter	YTD 31 Dec 2020	YTD 31 Dec 2019
Net production (Byron share (NRI basis) SM71)				
Oil (bbls)	89,522	91,761	181,282	210,688
Gas (mmbtu)	71,412	163,398	234,810	247,522
Net production (Byron share (NRI basis) SM58)				
Oil (bbls)	21,004	4,953	25,957	N/A
Gas (mmbtu)	1,670,316	365,290	2,035,606	N/A
Net production (Byron share (NRI basis) SM58 E1 well)				
Oil (bbls)	990	2,567	3,557	9,016
Gas (mmbtu)	396	872	1,268	1,990
Total Net production (NRI basis)				
Oil (bbls)	111,516	99,281	210,796	219,704
Gas (mmbtu)	1,742,124	529,560	2,271,684	249,512

Oil and Gas Production/Sales (cont.)

Oil and gas production and sales, net to Byron, were 111,516 bbls of oil and 1,742,124 mmbtu of gas for the December 2020 quarter compared to 99,281 bbls of oil and 529,560 mmbtu of gas for the September 2020 quarter.

The December quarter production of oil and gas was boosted by a full quarter's production from the SM58 G1 well and commencement of production from the SM58 G2 ST well in November 2020, partly offset by production shut-ins of the SM71 F and SM58 G platforms due to Hurricane Delta in early October and Hurricane Zeta in late October 2020.

Sale revenue and realised prices (accrual basis) US\$ million	Dec 2020 quarter	Sep 2020 quarter	YTD 31 Dec 2020	YTD 31 Dec 2019
Net sales revenue (Byron share on NRI basis)	9.2	5.1	14.3	13.0

Net sales revenue for the December quarter 2020 was US\$9.2 million compared to US\$5.1 million for the September 2020 quarter. Net sales revenue was boosted by a full quarter of production from SM58 G1 well, oil and gas sales from the SM58 G2ST well (commenced on 1 November 2020) and higher realised oil and gas prices during the December 2020 quarter.

During the December 2020 quarter, Byron realised an average oil price after adjustment for LLS price differentials and deductions for transportation, oil shrinkage and other applicable adjustments of US\$ 42.06 per bbl (US\$ 46.62 excluding transportation) compared to US\$ 41.51 per bbl and US\$ 46.03 per bbl respectively for the September 2020 quarter.

Byron realised an average gas price after transportation deductions of approximately US\$ 2.25 per mmbtu during the December quarter (US\$ 2.59 excluding transportation) compared to US\$ 1.49 per mmbtu and US\$ 1.85 per mmbtu respectively for the September 2020 quarter.

Project Updates

Salt Dome Projects

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. The majority of the field production has come from depths less than 7,500 feet in high quality sandstone reservoirs.

Byron is the operator and 100% working interest holder in 7 areas of interest around the SM73 field, comprising SM57/58/59/60/66/70 and north east portion of SM69, as shown in Attachment 1. Byron is also the operator of SM71, where it has less than a 100% working interest.

(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 SM 71 F4 well, until payout.

Water depth in the area is approximately 137 feet.

Project Updates

South Marsh Island 73 Salt Dome (cont)

(a) South Marsh Island 71 (cont)

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

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

As of 31 December 2020, the SM71 F facility has produced approximately 2.9 million barrels of oil (gross) since initial production began. The facility has also produced approximately 3.8 billion cubic feet of gas (gross).

As of 31 December 2020, the SM71 platform the gross production rate was approximately 2,690 barrels of oil per day and 2.2 million cubic feet of gas per day and no water from the F1 and F3 wells. F2 well was producing small amounts of water whilst the F4 well was shut in. The F4 has been shut-in since late September but is building pressure at very slow rate each day, indicating weak support from down-dip sands. The well will be opened to production in the future before an up-hole recompletion is performed.

(b) South Marsh Island 58

Gas and oil production from the Byron Energy 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 were 19.4 million cubic feet of gas per day ("Mmcfgpd"), 375 barrels of condensate per day ("Bcpd"), 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 SM58 G1 well produces from the Upper O Sand and as of 31 December 2020 has produced a gross total of approximately 1.8 Bcf of gas, 26,000 barrels of consistent 56.5-degree gravity condensate and no formation water. The SM58 G1 saw an early drop in flowing tubing pressure and rate but recently has shown signs of pressure support from the expected water drive mechanism of the Upper O Sands in this portion of the SM58 block. After the initial decline, the well has been stable with the 31 December 2020 well test data indicating the SM58 G1 is producing 15.7 Mmcfgpd, 200 barrels of 56.5-degree Bcpd and no formation water with flowing tubing pressure of 1,321 psi.

Following the completion of the SM58 G1 well Byron spudded the SM58 G2 ("G2") well to test the Lower O Sand.

On Saturday, 19 September 2020 (USCDT), the G2 well reached a final total depth of 11,237 feet Measured Depth ("MD")/ 10,233 feet True Vertical Depth ("TVD").

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 mudlogs 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 BP1 well that Byron was unable to log at the time due to hole conditions. The Company is reassessing its Prospective Resources in this portion of the SM58 project.

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

(b) South Marsh Island 58 (cont)

After plugging and abandoning the Lower O Sand section of the wellbore the well was sidetracked to Byron's SM58 Brown Trout prospect. The SM58 G2 ST targeted the Upper O Sand in an attic position, updip from two wells that produced over 2 million barrels of oil from the Upper O Sand with a water drive mechanism.

As announced on 5 October 2020, the Byron operated SM58 G2ST well reached total depth after logging 280 gross feet of hydrocarbons (150 net feet of true vertical net feet of pay based on cased hole logs) across the target O Sand and 7" casing was run to bottom and cemented with no operational issues. After that, the entire O Sand interval was perforated, and sand control measures were placed across the perforations. Following the passage of Hurricane Zeta, the well was tied in to the SM58 G Platform and the O Sand was opened to production on the afternoon of Thursday, 29 October 2020 (USCDT).

The Enterprise Offshore Drilling 264 jack up rig was demobilized off location on Friday, 30 October 2020 (USCDT).

As of Sunday, 1 November 2020 (USCDT) the SM58 G2ST was initially flowed at a controlled rate of 10.2 million cubic feet of gas per day ("Mmcfgpd"), 50 barrels of 60-degree API condensate per day ("bcpd") with no formation water at a flowing tubing pressure of 1,158 psi. The gas rate was consistent with the position of the G2 ST high on structure in the O Sand updip from two wells that produced over 2 million barrels of 36-degree API oil. Because of the strong water drive mechanism in the O Sand reservoir, it was anticipated that the SM58 G2ST production will transition to oil production as the gas cap is saturated and produced.

After three weeks of production, Byron ran a series of production logs (combination spinner, temperature, and pressure surveys) to confirm the complex flow regime in the wellbore. Through these logs it was determined that over 90% of the hydrocarbons entering the wellbore were from the lower pressure upper most, gassy lobe of the Upper O Sand with very little contribution from the lower, more oil prone lobes. This information confirmed a complex flow regime exists between the various lobes in the whole Upper O Sand section in the well.

As reported on 17 December 2020, The SM58 G2 ST well was placed into continuous compression in the first half of December to create more pressure drawdown across the perforations with a goal of moving more oil into the wellbore from the lower, oil prone lobes. At that time the oil rate had climbed from 20 bopd to 202 bopd as of 16 December 2020 and was still increasing daily as of 16 December 2020. Just as importantly, oil gravity dropped from its initial 60-degrees API of clear condensate to its 16 December 2020 gravity of 38.8-degrees API dark oil, a clear indication of feed-in from the lower lobes of the oily, water drive portion of the Upper O Sand.

Because of the complexity of the flow regime, the SM58 G2ST has been slower to stabilize, but is now showing continued improvements in oil rates and also in the gravity of oil it is producing indicating the wellbore may be seeing signs of aquifer support as expected. Initial rates from the SM58 G2ST were reported at 10.2 Mmcfgpd and 50 Bcpd of 60-degree API condensate. Well test rates on 31 December 2020, indicate the SM58 G2ST was producing 4.9 Mmcfgpd, 330 barrels of 38.8-degree API oil and no formation water.

The SM58 G2ST is being watched carefully and will be evaluated to see if any remedial work will be needed to increase flow from the oil prone lobes of the Upper O Sand. The well is continuing to increase its daily oil rate which is consistent with the Company's expectations.

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.

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

(b) South Marsh Island 58 (cont)

Byron has initiated permits for multiple new wells on SM58 and the Company's four adjacent South Marsh Island leases in anticipation of resuming drilling operations in 2021.

(c) South Marsh Island 57

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

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

(d) South Marsh Island 59

Byron holds a 100% WI and an 81.25% NRI in SM59. Water depth in the area is approximately 125 feet.

The SM59 block, as part of the larger SM71 project area, is also focus areas of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites.

(e) South Marsh Island 69

As previously reported, Byron entered into a Joint Exploration Agreement ("JEA") and a related Production Handling Agreement with SM69 leaseholders to drill a SM69 E2 well off the E Platform, acquired in early 2019, 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 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 6 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 SM69 E2 well is drilled and is successful Byron would produce it back to the SM58 G platform through a new pipeline laid in July 2020. Hydrocarbons from the E2 well would be processed and sold through the SM58 G Platform.

For additional information of the SM69 E2 development project, refer to the Company's ASX releases dated 1 April 2019 and 17 June 2020.

(f) South Marsh Island 60

Byron Energy Inc, a wholly owned subsidiary of the Company, acquired the South Marsh Island 60 lease ("SM60") at the Gulf of Mexico, Outer Continental Shelf ("OCS") Lease Sale 252 held in New Orleans, Louisiana on 20 March 2019. Byron has a 100% WI and 87.5% NRI (royalty rate of 12.5%) in SM 60.

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.

(g) South Marsh Island 70

Byron has a 100% WI and 87.5% NRI (royalty rate of 12.5%) in South Marsh Island 70 ("SM 70").

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

SM70 lies within the area of Byron's RTM reprocessing project.

(h) South Marsh Island 66

In December 2020 Byron Energy Inc., a wholly owned subsidiary of the Company, was advised by the Bureau of Ocean Energy Management ("BOEM") that its bid for South Marsh Island 66 lease ("SM66"), at the Gulf of Mexico OCS Lease Sale 256 held on Wednesday 18 November 2020, has been deemed acceptable by the BOEM and the lease was awarded to Byron.

As reported in the Company's ASX release as of 19 November 2020, Byron bid \$US143,000 as a bonus bid. Byron will have a 100% working interest and an 87.50% net revenue interest in the block.

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

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

(i) South Marsh Island 74

Byron relinquished SM 74 during the December 2020 quarter, prior to the June 2021 lease renewal, having completed all evaluation work and consulted Metgasco Limited, which had a residual right to a 30% WI.

(j) South Marsh Island Area permitting status

As reported in the September 2020 quarterly, to minimise the risk associated with the potential change in the regulatory environment post the 2020 election in the USA, Byron has accelerated its permitting efforts. Byron has submitted a revised Development Operations Co-ordination Document ("DOCD") to allow an additional 5 wells to be drilled from the SM58 G platform, a two well DOCD for SM60, a one well DOCD for SM57 and a one well DOCD for SM70. Byron has also submitted Applications for Permit to Drill ("APD") for the SM58 G3 and G4 wells and has an approved APD for the SM69 E2 well.

2. 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.

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

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

In 2018 Byron began a reprocessing effort similar that undertaken on the SM71 Project Area with WesternGeco over all four Eugene Island blocks leased by the Company. Analysis of the reprocessed data is continuing while preliminary well planning has also started.

Project Updates (cont)

3. Main Pass 293, 305 & 306

Byron currently holds a 100% WI and an 87.50% NRI in Main Pass 293, 305 & 306 ("MP 306 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 MP 306 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 December 2020 quarter, the Company expects to shortly start scoping an RTM seismic imaging project over the MP306 field.

Properties

As at 31 December 2020, Byron's portfolio of properties, all in the shallow waters of the Gulf of Mexico, and coastal marshlands of Louisiana, USA comprised:-

Properties	Operator	Interest WI/NRI* (%)	Lease Expiry Date	Area (Km ²)
South Marsh Island Block 71	Byron	50.00/40.625	Production	12.16
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 60	Byron	100.00/87.50	June 2024	20.23
South Marsh Island Block 58 (Excl. E1 well)	Byron	100.00/83.33**	Production	20.23
South Marsh Island 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	53.00/44.167		
South Marsh Island Block 69 (NE ¼ of NE ¼)	Byron	100.00/77.33-80.33	Production	1.3
South Marsh Island Block 66	Byron	100.00/87.50	December 2025	20.23
South Marsh Island Block 70	Byron	100.00/87.50	July 2023	22.13
Eugene Island Block 62	Byron	100.00/87.50	June 2023	20.23
Eugene Island Block 63	Byron	100.00/87.50	June 2023	20.23
Eugene Island Block 76	Byron	100.00/87.50	June 2023	20.23
Eugene Island Block 77	Byron	100.00/87.50	June 2023	20.23
Main Pass Block 293	Byron	100.00/87.50	October 2023	18.46
Main Pass Block 305	Byron	100.00/87.50	October 2023	20.23
Main Pass Block 306	Byron	100.00/87.50	October 2023	20.23

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

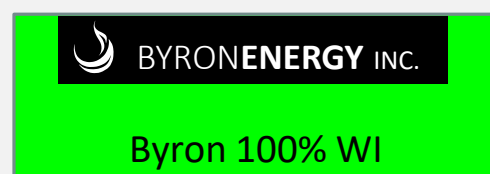
** 100.00% WI to a depth of 13,639 feet TVD and 50% WI below 13,639 feet TVD

Glossary

1P = Proved Reserves
2P = Proved and Probable Reserves
3P = Proved, Probable and Possible Reserves
Bbl = barrels
bcf = billion cubic feet
Bcpd = barrels of condensate per day
Bopd = barrels of oil per day
btu = British Thermal Units
mcfg = thousand cubic of gas
mcfgpd = thousand cubic feet of gas per day
Mmcfgpd = million cubic feet of gas per day
mcf = thousand cubic feet
mmcf = million cubic feet
mmbtu = million British Thermal Units
Mbo = thousand barrels of oil
Mmbbl = million barrels of oil
NGL = Natural gas Liquids, such as ethane, propane and butane
Tcf = trillion cubic feet

Conversions

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.



Appendix 5B

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

Name of entity

Byron Energy Limited

ABN

88 113 436 141

Quarter ended ("current quarter")

31 December 2020

<i>Consolidated statement of cash flows</i>		Current quarter US\$'000	Year to date (6.months) US\$'000
1.	Cash flows from operating activities		
1.1	Receipts from customers	7,702	11,982
1.2	Payments for		
	(a) exploration & evaluation	(31)	(66)
	(b) development	(14,224)	(25,702)
	(c) production	(1,187)	(2,264)
	(d) staff costs	(568)	(1,209)
	(e) administration and corporate costs	(306)	(798)
1.3	Dividends received (see note 3)	-	-
1.4	Interest received	-	1
1.5	Interest and other costs of finance paid	(791)	(1536)
1.6	Income taxes paid	-	-
1.7	Government grants and tax incentives	-	-
1.8	Other (provide details if material)	-	-
	- Cash Contributions from JV partners	23	192
1.9	Net cash from / (used in) operating activities	(9,382)	(19,400)

2.	Cash flows from investing activities		
2.1	Payments to acquire or for:		
	(a) entities		
	(b) tenements	(178)	(178)
	(c) property, plant and equipment		
	(d) exploration & evaluation	(191)	(342)
	(e) investments		
	(f) other non-current assets		

Consolidated statement of cash flows		Current quarter US\$'000	Year to date (6.months) US\$'000
2.2	Proceeds from the disposal of:		
	(a) entities		
	(b) tenements		
	(c) property, plant and equipment		
	(d) investments		
	(e) other non-current assets		
2.3	Cash flows from loans to other entities		
2.4	Dividends received (see note 3)		
2.5	Other (provide details if material)		
2.6	Net cash from / (used in) investing activities	(369)	(520)

3.	Cash flows from financing activities		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)	-	1,533
3.2	Proceeds from issue of convertible debt securities		
3.3	Proceeds from exercise of options		
3.4	Transaction costs related to issues of equity securities or convertible debt securities	-	(36)
3.5	Proceeds from borrowings	-	3,500
3.6	Repayment of borrowings	(351)	(351)
3.7	Transaction costs related to loans and borrowings		
3.8	Dividends paid		
3.9	Other (provide details if material)	-	(4)
3.10	Net cash from / (used in) financing activities	(351)	4,642

4.	Net increase / (decrease) in cash and cash equivalents for the period		
4.1	Cash and cash equivalents at beginning of period	11,527	16,645
4.2	Net cash from / (used in) operating activities (item 1.9 above)	(9,382)	(19,400)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(369)	(520)
4.4	Net cash from / (used in) financing activities (item 3.10 above)	(351)	4,642

Consolidated statement of cash flows		Current quarter US\$'000	Year to date (6.months) US\$'000
4.5	Effect of movement in exchange rates on cash held	73	131
4.6	Cash and cash equivalents at end of period	1,498	1,498

5.	Reconciliation of cash and cash equivalents at the end of the quarter (as shown in the consolidated statement of cash flows) to the related items in the accounts	Current quarter US\$'000	Previous quarter US\$'000
5.1	Bank balances	1,498	11,527
5.2	Call deposits	-	-
5.3	Bank overdrafts	-	-
5.4	Other (provide details)	-	-
5.5	Cash and cash equivalents at end of quarter (should equal item 4.6 above)	1,498	11,527

6.	Payments to related parties of the entity and their associates	Current quarter US\$'000
6.1	*Aggregate amount of payments to related parties and their associates included in item 1	361
6.2	Aggregate amount of payments to related parties and their associates included in item 2	-
<p>Note: if any amounts are shown in items 6.1 or 6.2, your quarterly activity report must include a description of, and an explanation for, such payments.</p> <p>*Payments to directors comprise: (i) Non-executive directors' fees of A\$ nil, (ii) Executive directors' salaries and service fees of US\$ 208k and A\$ 101k, and (iii) quarterly interest payments of US\$ 68k and A\$ 44k to certain directors on the loan facilities listed in 7.1a.</p>		

7.	Financing facilities <i>Note: the term “facility” includes all forms of financing arrangements available to the entity. Add notes as necessary for an understanding of the sources of finance available to the entity.</i>	Total facility amount at quarter end \$’000	Amount drawn at quarter end \$’000
7.1a	Loan facilities (unsecured and repayable by 31 March 2022, bearing 10% interest p.a.)	US\$ 2,000 & A\$ 2,100	US\$ 2,000 & A\$ 2,100
7.1b	Loan facilities (secured over the SM71 & SM58 assets on a 3 year fixed term, bearing 15% interest p.a. with loan repayments commencing in December 2020.)	US\$ 18,500	US\$ 18,500
7.2	Credit standby arrangements	-	-
7.3	Other (please specify)	-	-
7.4	Total financing facilities	US\$ 20,500 & A\$ 2,100	US\$ 20,000 & A\$ 2,100
7.5	Unused financing facilities available at quarter end	Nil	
7.6	Include in the box below a description of each facility above, including the lender, interest rate, maturity date and whether it is secured or unsecured. If any additional financing facilities have been entered into or are proposed to be entered into after quarter end, include a note providing details of those facilities as well.		

8. Estimated cash available for future operating activities	US\$'000
8.1 Net cash from / (used in) operating activities (item 1.9)	(9,382)
8.2 (Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	(191)
8.3 Total relevant outgoings (item 8.1 + item 8.2)	(9,573)
8.4 Cash and cash equivalents at quarter end (item 4.6)	1,498
8.5 Unused finance facilities available at quarter end (item 7.5)	-
8.6 Total available funding (item 8.4 + item 8.5)	1,498
8.7 Estimated quarters of funding available (item 8.6 divided by item 8.3)	0.2
<i>Note: if the entity has reported positive relevant outgoings (ie a net cash inflow) in item 8.3, answer item 8.7 as "N/A". Otherwise, a figure for the estimated quarters of funding available must be included in item 8.7.</i>	
8.8 If item 8.7 is less than 2 quarters, please provide answers to the following questions:	
8.8.1 Does the entity expect that it will continue to have the current level of net operating cash flows for the time being and, if not, why not?	
Answer: Receipts from customers are expected to improve further over the coming quarters, subject to oil and gas price movements, as production from SM58 G Platform stabilises and oil production increases. Payments for past development expenditure will taper off substantially given the completion of SM58 drilling in the December 2020 quarter.	

8.8.2 Has the entity taken any steps, or does it propose to take any steps, to raise further cash to fund its operations and, if so, what are those steps and how likely does it believe that they will be successful?

Answer: The Company has taken the following steps to raise further cash to fund its operations: (i) the Company has secured improved credit terms from key service providers which allows for delay of settlement in respect to SM58 drilling and completion costs incurred during the December 2020 quarter until cashflow from production has built up during the March 2021 quarter, (ii) the Company has obtained agreement from Crimson Midstream for lower repayments under the Crimson Promissory Note for December 2020, January 2021 and February 2021 and (iii) appointed Seaport Global to assist in pursuing debt financing in the US, as announced to the ASX on 27 January 2021

8.8.3 Does the entity expect to be able to continue its operations and to meet its business objectives and, if so, on what basis?

Answer: Yes, the entity is expect to be able to continue its operations and to meet its business objectives for the reasons outlined in 1 and 2 above.

Note: where item 8.7 is less than 2 quarters, all of questions 8.8.1, 8.8.2 and 8.8.3 above must be answered.

Compliance statement

- 1 This statement has been prepared in accordance with accounting standards and policies which comply with Listing Rule 19.11A.
- 2 This statement gives a true and fair view of the matters disclosed.

Date: 28 January 2021.....

Authorised by: The Board of Directors.....
(Name of body or officer authorising release – see note 4)

Notes

1. This quarterly cash flow report and the accompanying activity report provide a basis for informing the market about the entity's activities for the past quarter, how they have been financed and the effect this has had on its cash position. An entity that wishes to disclose additional information over and above the minimum required under the Listing Rules is encouraged to do so.
2. If this quarterly cash flow report has been prepared in accordance with Australian Accounting Standards, the definitions in, and provisions of, AASB 6: *Exploration for and Evaluation of Mineral Resources* and AASB 107: *Statement of Cash Flows* apply to this report. If this quarterly cash flow report has been prepared in accordance with other accounting standards agreed by ASX pursuant to Listing Rule 19.11A, the corresponding equivalent standards apply to this report.
3. Dividends received may be classified either as cash flows from operating activities or cash flows from investing activities, depending on the accounting policy of the entity.
4. If this report has been authorised for release to the market by your board of directors, you can insert here: "By the board". If it has been authorised for release to the market by a committee of your board of directors, you can insert here: "By the [name of board committee – eg Audit and Risk Committee]". If it has been authorised for release to the market by a disclosure committee, you can insert here: "By the Disclosure Committee".
5. If this report has been authorised for release to the market by your board of directors and you wish to hold yourself out as complying with recommendation 4.2 of the ASX Corporate Governance Council's *Corporate Governance Principles and Recommendations*, the board should have received a declaration from its CEO and CFO that, in their opinion, the financial records of the entity have been properly maintained, that this report complies with the appropriate accounting standards and gives a true and fair view of the cash flows of the entity, and that their opinion has been formed on the basis of a sound system of risk management and internal control which is operating effectively.