BYRONENERGY LIMITED

Quarterly Report for the Period Ended 30 September 2020

Summary

- Byron's share of oil and gas production (net sales volume) for the September 2020 quarter was 99,281 barrels of oil and 529,560 mmbtu of gas compared to the June 2020 quarter of 84,988 barrels of oil and 397,749 mmbtu of gas;

- Net revenue recorded for the September 2020 quarter, was approximately US$5.1 million (net to Byron after quality adjustments, transportation charges and royalties) with realised net prices of US$ 41.51 per barrel of oil and US$ 1.49 per mmbtu of natural gas for the September quarter;

- The SM58 G Platform installation was completed in July 2020 and commenced production on 7 September 2020 (USCDT) when the SM58 G1 well was opened to sales; initial test rates from the Upper O Sand were 19.4 million cubic feet of gas per day, 375 barrels of oil per day, no formation water and a flowing tubing pressure of 1,375 psi;

- The SM58 G2 well was drilled to a final total depth of 11,237 feet measured depth ("MD") (10,233 feet true vertical depth ("TVD")) in mid-September 2020 and was deemed non-commercial due to low hydrocarbon saturation in the targeted Lower O Sand section;

- SM58 G2 well was sidetracked to Byron's SM58 Brown Trout prospect; SM58 G2 ST well reached a final, total depth of 7,720 MD/7,035 TVD feet on 4 October 2020 (USCDT) and 280 gross feet of hydrocarbon bearing section was logged with LWD gamma ray/resistivity tools, no water contact was observed within the interval with 7 inch casing run and completion operations are finished as of the date of this report; and

- Byron released it 30 June 2020 reserves and resources report on 10 September 2020, with 2P reserves of 17.5 Mmbbl of oil and 105.3 Bcf of gas, net to Byron.

Name:	Byron Energy Limited
ASX code:	BYE
Shares on issue at 30 Sep 2020:	1,040.3 million
Quoted shares:	1,040.3 million
Options on issue (unquoted):	41.1 million
Cash at Bank 30 Sep 2020:	US$11.5 million
Borrowings 30 Sep 2020:	US$22.0 million
Market Capitalisation at 30 Sep 2020:	A$172 million (@A$0.165 per share)

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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ABN 88 113 436 141

Corporate

Equity Raising

At a shareholder meeting on 9 July 2020 the shareholders approved the issue of approximately 16.7 million ordinary shares to interests associated with directors at A$0.13 per share, raising an additional A$2.2 million. This was part of the placement of shares by the Company announced on 19 May 2020.

Issued Capital

As at 30 September 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

Borrowings

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 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 2021. For further details of the Promissory Note refer to the Company's ASX release dated 4 December 2019.

Byron's outstanding loans of approximately US$3.5 million 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.

As at 30 September 2020, Byron's outstanding loans comprised:-

Lender	US$ M	A$ M	US$ Equivalent (@A$1=US$0.7108)
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 30 September 2020, Byron also had US$ 0.89 million in insurance premium financing outstanding

COVID-19

On 30 March 2020, Byron provided an update on the impact of COVID-19 on the Company operations. Consistent with that update, Byron has not experienced any material interruptions from COVID-19 to the Byron operated SM71 and SM58 platforms, in the Gulf of Mexico. Byron's Lafayette, Louisiana based team and the Australian based team continue working as advised by the respective governments.

Corporate (cont.)

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, 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 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.

Byron's hedged oil production as at 30 September 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*
Oct-Dec 2020 (Put options)	400	36,800	US39.00**	unhedged	unhedged	To be determined
Oct-Dec 2020 (Forward sale agreement)	670	61,640	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.

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

BYRONENERGY LIMITED

Oil and Gas Production/Sales

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

Production (sales)	Sep 2020 quarter	Jun 2020 quarter	YTD 30 Sep 2020	YTD 30 Sep 2019
Net production (Byron share (NRI basis) SM71				
Oil (bbls)	91,761	81,249	91,761	107,301
Gas (mmbtu)	163,398	396,541	163,398	135,840
Net production (Byron share (NRI basis) SM58				
Oil (bbls)	4,953	-	4,953	-
Gas (mmbtu)	365,290	-	365,290	-
Net production (Byron share (NRI basis) SM58 E1 well				
Oil (bbls)	2,567	3,739	2,567	4,338
Gas (mmbtu)	872	1,208	872	1,077
Total Net production (NRI basis)				
Oil (bbls)	99,281	84,988	99,281	111,639
Gas (mmbtu)	529,560	397,749	529,560	136,917

Oil and gas production and sales, net to Byron, were 99,281 bbls of oil and 529,560 mmbtu of gas for the September 2020 quarter compared to 84,988 bbls of oil and 397,749 mmbtu of gas for the June 2020 quarter.

The September quarter production of oil and gas was boosted by commencement of production from the SM58 G Platform in early September 2020, SM71 F1 well coming back on production after being shut-in in March 2020 during a period of depressed oil prices but adversely affected by two separate shut ins during the September quarter, due to Hurricane Sally and Hurricane Laura.

Net Sales Revenue (accrual basis) US$ million	Sep 2020 quarter	Jun 2020 quarter	YTD 30 Sep 2020	YTD 30 Sep 2019
Net sales revenue (Byron share on NRI basis)	5.1	3.8	5.1	6.7

During the September 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$ 41.51 per bbl (US$ 46.03 excluding transportation) compared to US$ 36.20 per bbl and US$ 40.71 per bbl respectively for the June 2020 quarter.

Byron realised an average gas price after transportation deductions of approximately US$ 1.49 per mmbtu during the September quarter (US$ 1.85 excluding transportation) compared to US$ 1.28 per mmbtu and US$ 1.64 per mmbtu respectively for the June 2020 quarter.

Oil and gas production/sales (cont.)

Net sales revenue for the September quarter 2020 was US$5.1 million compared to US$3.8 million for the June 2020 quarter. Net sales revenue was boosted by oil and gas sales from the SM58 G1 well (on production for part of September only), higher production from SM71 and higher realised oil and gas prices during the September 2020 quarter.

Project Updates

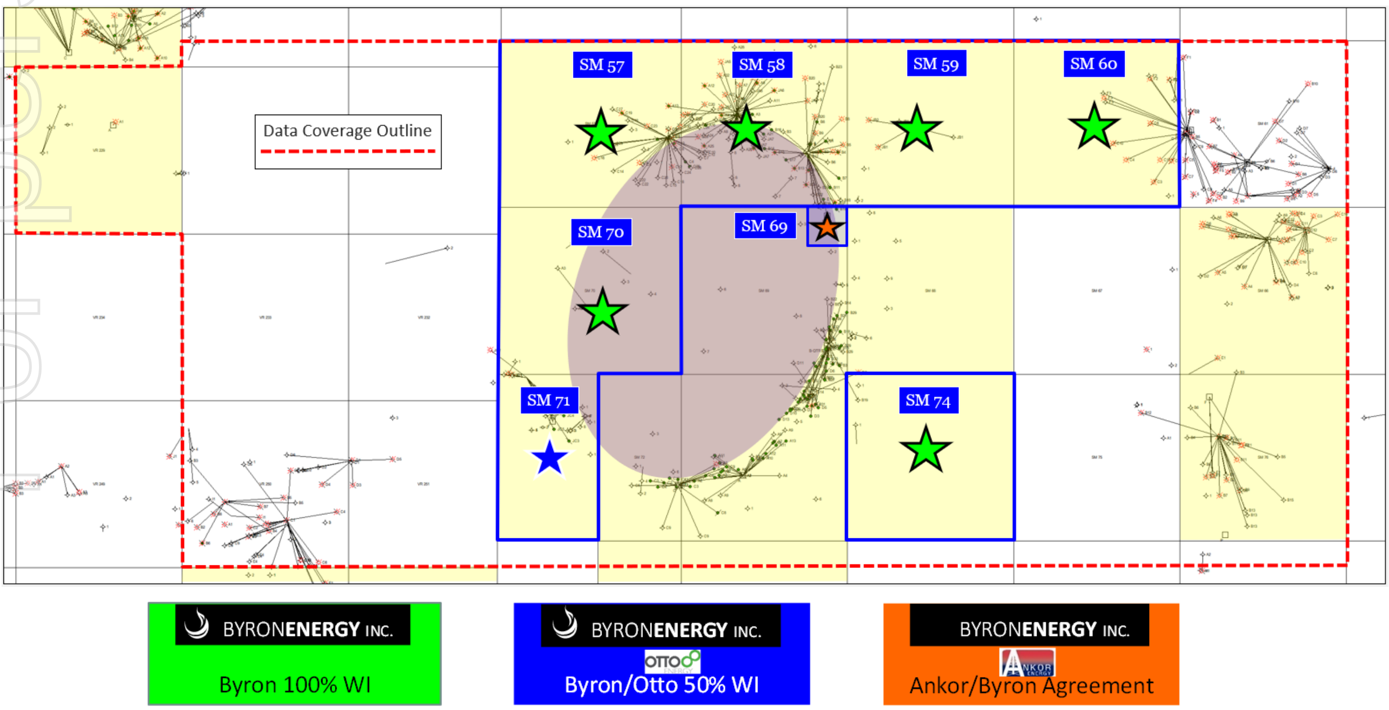
Salt Dome Projects

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 ("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 6 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



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Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

(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.

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 in mid-March 2020.

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

As of 30 September 2020, the SM71 F facility has produced over 2.6 million barrels of oil (gross) since initial production began. The facility has also produced approximately 3.7 billion cubic feet of gas (gross).

As of 30 September 2020, the SM71 platform gross production rate was approximately 2,765 barrels of oil per day and 1.75 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 was shut in. The F4 well is currently expected to be on production again in November 2020 at which time it will be assessed for future potential.

(b) SM58 G Production Platform and Exploration/Development Drilling

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 9-12 months compared to a new build facility.

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.

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

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 the 8-inch diameter 39,000-foot (12 km) gas sales line and tie-in operations were completed in mid-August 2020.

On Wednesday, 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 of 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 maximize production rate and recovery. The completion job was conducted without any operational issues and was completed about 5 days ahead of schedule.

Gas and oil production from the SM58 G platform was initiated on the afternoon of 7 September 2020 (USCDT) when the SM58 G1 well was opened to sales. Initial test rates from the Upper O Sand were 19.4 million cubic feet of gas per day, 375 barrels of oil per day, no formation water and a flowing tubing pressure of 1375 psi. The flowing tubing pressure matched pre-production nodal models for the gas and condensate rates from the tests. Production from the SM58 G1 well during the first twenty days of October averaged approximately 18.3 mmcfd and 272 barrels of oil on a gross basis with no water and little decline in flowing tubing pressure.

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 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 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.

SM58 G2ST reached final total depth 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"). 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.

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

LWD gamma ray and resistivity tools indicated 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 indicated two, or possibly three, distinct sand lobes. The thickness and presence of multiple lobes of sand was in line with pre-drill expectations and the Company made the decision to run production casing.

Operations to complete the O Sand in the South Marsh Island 58 G2 Sidetrack ("SM58 G2ST") are now finished and construction crews have begun to tie the well into the SM58 G Platform's production equipment. Once the well is tied in, it will be brought into production. Due to delays caused by Hurricane Zeta and pipeline shut-ins, the well is not expected to begin producing until the week commencing 2 November 2020.

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.

The EOD drilling rig has been released over the winter months and drilling operations are expected to re-start in early March 2021. This should avoid the worst weather months in the Gulf and ensure that the Company can fund the drilling program through internally generated cash flow from sales of oil and gas.

(c) 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.

(d) 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.

Byron currently expects to drill the SM69 E2 well in the first half of 2021 and, if successful, 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.

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BYRONENERGY LIMITED

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

(e) 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.

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.

(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").

To minimize the risk associated with the potential change in the regulatory environment post the 2020 election in the USA, Byron has accelerated the permitting for the remaining seven wells at SM58/57, two wells at SM60, and four wells at SM70.

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 the September 2018 quarter, 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.

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

Project Updates (cont)

Main Pass 306 (cont)

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 September 2020 quarter, the Company expects to shortly start scoping an RTM seismic imaging project over the MP306 field.

Non-Salt Dome Projects (Byron Operated)

Grand Isle Block 95

During the September 2020 quarter the Company relinquished Grand Isle Block 95, as announced on 1 September 2020.

Reserves and Resources

The Company's reserves and resources estimate as at 30 June 2020 was released on 10 September 2020 with 2P reserves of 17.5 Mmbbl of oil and 105.3 Bcf of gas, net to Byron.

Refer to the Company's ASX release of 10 September 2020 for additional information on reserves and resources as at 30 June 2020, compiled by Collarini Associates.

Properties

As at 30 September 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 (Km²)
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 74***	Byron	100.00/81.25	June 2022	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*
**** Metgasco Limited has a residual right to a 30% WI which has not yet been assigned*

Glossary

1P = Proved Reserves
2P = Proved and Probable Reserves
3P = Proved, Probable and Possible Reserves
Bbl = barrels
bcf = billion cubic feet
Bopd = barrels of oil per day
btu = British Thermal Units
mcfg = thousand cubic of gas
mcfgpd = thousand 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.

1 mcfg equals approximately 1.09 btu's for SM 71 production; the heat content of SM 71 gas may vary over time.

Appendix 5B

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

Name of entity

Byron Energy Limited

ABN	*Quarter ended ("current quarter")*
88 113 436 141	30 September 2020

	Consolidated statement of cash flows		Current quarter US$'000	Year to date (3.months) US$'000
1.	**Cash flows from operating activities**			
1.1	Receipts from customers		4,281	4,281
1.2	Payments for			
	(a)	exploration & evaluation	(34)	(34)
	(b)	development	(11,478)	(11,478)
	(c)	production	(1,077)	(1,077)
	(d)	staff costs	(642)	(642)
	(e)	administration and corporate costs	(494)	(494)
1.3	Dividends received (see note 3)		-	-
1.4	Interest received		1	1
1.5	Interest and other costs of finance paid		(744)	(744)
1.6	Income taxes paid		-	-
1.7	Government grants and tax incentives		-	-
1.8	Other (provide details if material)		-	-
	- Cash Contributions from JV partners		169	169
1.9	**Net cash from / (used in) operating activities**		**(10,018)**	**(10,018)**

2.	**Cash flows from investing activities**			
2.1	Payments to acquire or for:			
	(a)	entities		
	(b)	tenements		
	(c)	property, plant and equipment		
	(d)	exploration & evaluation	(151)	(151)
	(e)	investments		
	(f)	other non-current assets		

Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (3.months) US$'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**	**(151)**	**(151)**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)	1,533	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)	(36)
3.5	Proceeds from borrowings	3,500	3,500
3.6	Repayment of borrowings		
3.7	Transaction costs related to loans and borrowings		
3.8	Dividends paid		
3.9	Other (provide details if material)	(4)	(4)
3.10	**Net cash from / (used in) financing activities**	**4,993**	**4,993**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	16,645	16,645
4.2	Net cash from / (used in) operating activities (item 1.9 above)	(10,018)	(10,018)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(151)	(151)
4.4	Net cash from / (used in) financing activities (item 3.10 above)	4,993	4,993

Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (3.months) US$'000**
4.5	Effect of movement in exchange rates on cash held	58	58
4.6	**Cash and cash equivalents at end of period**	**11,527**	**11,527**

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	11,527	16,645
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)**	**11,527**	**16,645**

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	424
6.2	Aggregate amount of payments to related parties and their associates included in item 2	-

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.

*Payments to directors comprise: (i) Non-executive directors' fees of A$ 40k, (ii) Executive directors' salaries and service fees of US$ 207k and A$ 151k, and (iii) quarterly interest payments of US$ 48k and A$ 44k to certain directors on the loan facilities listed in 7.1a.

7.	***Financing facilities*** *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.*	**Total facility amount at quarter end $'000**	**Amount drawn at quarter end $'000**
7.1a	Directors' / Shareholders' Loan facilities (unsecured and repayable by 31 March 2022, bearing interest at 10% p.a.)	US$ 2,000 & A$ 2,100	US$ 2,000 & A$ 2,100
7.1b	Crimson Midstream Loan facilities (secured over the SM71 & SM58 assets on a 3 year fixed term, bearing interest at 15% p.a with no loan repayments until 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)	(10,018)
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	(151)
8.3	**Total relevant outgoings (item 8.1 + item 8.2)**	**(10,169)**
8.4	Cash and cash equivalents at quarter end (item 4.6)	11,527
8.5	Unused finance facilities available at quarter end (item 7.5)	-
8.6	**Total available funding (item 8.4 + item 8.5)**	**11,527**
8.7	**Estimated quarters of funding available (item 8.6 divided by item 8.3)**	**1.1**

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.

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: Net operating cash flows are expected to improve substantially over the coming quarters. Receipts from customers are expected to increase as production from SM58 ramps up with SM58 G Platform having commenced production on 7 September 2020 from SM58 G1 well, as announced to the ASX on 9 September 2020. In addition, the SM58 G2ST well is expected to start production in early November 2020. Payments for development expenditure will taper off substantially given the completion of SM58 production facilities and pipelines in September quarter. In addition, as announced on 5 October 2020, upon completion of operations on SM58 G2ST well Byron will release the drilling rig during the winter months and renew drilling operations in early March 2021, in order to avoid the worst weather months in the Gulf and ensure that the Company can fund the drilling program though cash flow generated through sales of oil and gas production.

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: As stated in 8.8.1 above, net operating cash flows are expected to improve substantially over the coming quarters. In addition, the Company has secured improved credit terms from two key service providers which allows for delay of settlement in respect to SM58 pipeline installation costs and part of the SM58 drilling and completion costs until cashflow from production has built up during the December 2020 and March 2021 quarters.

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 8.8.1 and 8.8.2 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: 30 October 2020..

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.