BYRONENERGY LIMITED

Quarterly Report for the Period Ended 30 June 2021

Summary

- Byron's share of oil and gas production (net sales volume) for the June 2021 quarter was 109,680 barrels of oil and 1,022,700 mmbtu of gas compared to the March 2021 quarter of 132,621 barrels of oil and 1,309,513 mmbtu of gas;

- Net revenue recorded for the June 2021 quarter, was approximately US$9.7 million (net to Byron after quality adjustments, transportation charges and royalties) with realised net prices of US$59.26 per barrel of oil and US$2.82 per mmbtu of natural gas for the June 2021 quarter (March 2021 quarter: net revenue approximately US$11.8 million with realised net prices of US$ 53.71 per barrel of oil and US$ 3.22 per mmbtu of natural gas);

- Byron has executed a contract with Enterprise Offshore Drilling ("EOD") and the EOD 351 rig is due to commence drilling the SM69 E2 well in August 2021; and

Name:	**Byron Energy Limited**
ASX code:	**BYE**
Shares on issue at 30 June 2021:	**1,040.3 million**
Quoted shares:	**1,040.3 million**
Options on issue (unquoted):	**41.1 million**
Cash at Bank 30 June 2021:	**US$4.1 million**
Borrowings 30 June 2021:	**US$18.7 million**
Market Capitalisation at 30 June 2021:	**A$104 million (@A$0.10 per share)**

- On 18 June 2021, Byron announced that its refinancing initiative through Seaport Global securities had come to an end as it was unable to reach agreement on acceptable terms with the potential lender due to significant disagreement with the proposed ongoing hedging strategies.

Corporate

Issued Capital

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

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

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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 (cont.)

Borrowings

As at 30 June 2021, Byron's outstanding loans comprised:-

Lender	US$ M	A$ M	June 30 2021 US$ equivalent (@A$1=US$0.7518)	March 31 2021 US$ equivalent (@A$1=US$0.7602
Directors	2.00	1.75	3.32	3.33
Shareholder	-	0.35	0.26	0.27
Crimson Midstream	15.10	-	15.10	16.75
Total	17.10	2.10	18.68*	20.35

*as at 30 June 2021, Byron also had US$ 1.5 million in insurance premium financing outstanding

Crescent (formerly Crimson) Midstream

As of 30 June 2021, the outstanding principal balance of the Crescent Promissory Note has been reduced to US$ 15.1 million from US$ 16.75 million as of 31 March 2021. The balance of the Crescent Promissory Note is repayable over the period 1 July 2021 to 30 November 2022.

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 30 June 2021, from entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young, all directors of the Company, and a longstanding shareholder are due to be repaid on 31 March 2022.

Cashflow

Byron generated approximately US$ 1.0 million in net cash inflow during the June 2021 quarter resulting in a cash balance as at 30 June 2021 of US$ 4.1 million, compared to US$ 3.1 million as at 31 March 2021, as shown in the table below. During the June quarter Byron commenced repayment of oil revenue prepayments received in the March 2021 quarter. Byron paid the final invoices in relation to the SM58 development, in line with agreed credit terms, for expenditure incurred in the December 2020 quarter.

Consolidated statement of cash flows (US$ million)	Jun quarter	Mar quarter	Change
Cashflow from operating activities			
Receipts from customers	9.9	10.6	-0.7
Payments for production	-1.7	-1.7	0.0
Net receipts from production	8.2	8.9	-0.7
Payments for development	-1.4	-7.3	5.9
Other cash outflow from operating activities	-1.9	-1.9	0.0
Oil Revenue Pre-payment	**-1.8**	**3.5**	**-5.3**
Net cash from / (used in) operating activities	**3.1**	**3.2**	**-0.1**

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Corporate (cont.)

Cashflow (cont)

Cash flows from investing activities			
Net cash from / (used in) investing activities	**-0.4**	**-0.2**	**-0.2**
Cash flows from financing activities			
Net cash from / (used in) financing activities	**-1.7**	**-1.4**	**-0.3**
Net increase / (decrease) in cash and cash equivalents for the period	**1.0**	**1.6**	**-0.6**
Cash and cash equivalents at end of quarter	**4.1**	**3.1**	

Notes

- During the March 2021 quarter, Byron received an oil revenue prepayment of US$ 3.5 million from the hedging counterparty under the existing forward sale agreement referred to below. The repayment of US$ 3.5 million commenced in May 2021. During the June quarter 2021 Byron repaid US$ 1.75 million with US$ 1.75 million outstanding as of 30 June 2021; and
- For further details on June quarter cashflows refer to Appendix 5B

Oil Price Hedging

Byron's realised prices for oil are a combination of hedged and unhedged volumes. As at 30 June 2021, the Company's oil hedging position is governed by: -

- a forward physical sale agreement ("Forward Sale Agreement"), which specifies a price per barrel in advance for each delivery period during the term of the contract; and
- financially settled swaps ("Swaps") which guarantee the price that Byron will receive for the hedged barrels under the Swaps.

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

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*
Jul-Dec 2021 (Forward Sale Agreement)	450	82,800	US$52.86	unhedged	unhedged	To be determined
July-Dec 2021 (Swaps)	200	36,800	US$60.78 (monthly average)	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.

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Corporate (cont.)

Oil price hedging (cont)

For additional information on the Company's oil price hedging activities, refer to ASX releases dated 22 April 2020, 18 June 2020 and 8 March 2021.

Debt refinancing initiative through Seaport Global

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

In further announcements on: -

- 31 March 2021, Byron reported that it was reviewing several term sheets received from interested lenders, with assistance from Seaport; and
- 18 June 2021, Byron announced that it was unable to reach agreement on acceptable terms with the potential lender on the proposed ongoing hedging strategies and terminated negotiations.

Consequently, this refinancing initiative came to an end on 18 June 2021.

Oil and Gas Production/Sales

Byron's share of oil and gas production and sales for the June 2021 quarter and financial year to date is summarised in the table below.

Production (sales)	Jun 2021 quarter	Mar 2021 quarter	Year ending 30 Jun 2021	Year ending 30 Jun 2020
Net production (Byron share (NRI basis) SM71				
Oil (bbls)	91,189	92,277	364,748	375,906
Gas (mmbtu)	86,084	77,940	398,834	878,811
Net production (Byron share (NRI basis) SM58				
Oil (bbls)	11,095	34,507	71,558	0-
Gas (mmbtu)	935,733	1,231,137	4,202,475	0-
Net production (Byron share (NRI basis) SM58 E1 well				
Oil (bbls)	7,397	5,838	16,791	17,797
Gas (mmbtu)	883	437	2,588	4,244
Total Net production (NRI basis)				
Oil (bbls)	109,680	132,621	453,098	393,703
Gas (mmbtu)	1,022,700	1,309,513	4,603,897	883,055

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Oil and Gas Production/Sales (cont)

Aggregate oil and gas production and sales, net to Byron, was 109,680 bbls of oil and 1,022,700 mmbtu of gas for the June 2021 quarter compared to 132,621 bbls of oil and 1,309,513 mmbtu of gas for the March 2021 quarter.

The quarterly and financial year to date net sales revenue is summarised below.

Sale revenue (accrual basis) US$ million	Jun 2021 quarter	Mar 2021 quarter	YTD 30 Jun 2021	YTD 30 Jun 2020
Net sales revenue (Byron share on NRI basis)	9.7	11.8	35.8	21.4

Net sales revenue for the June 2021 quarter was US$ 9.7 million compared to US$ 11.8 million for the March 2021 quarter. Net sales revenue was lower during the June 2021 quarter due to lower oil and gas production as well as lower gas prices partly offset by higher realised oil prices.

For the June 2021 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$ 59.26 per bbl (US$ 63.83 excluding transportation) compared to US$ 53.71 per bbl and US$ 58.28 per bbl respectively for the March 2021 quarter.

Byron realised an average gas price after transportation deductions of approximately US$ 2.82 per mmbtu for the June 2021 quarter (US$ 3.17 excluding transportation) compared to US$ 3.22 per mmbtu and US$ 3.56 per mmbtu respectively for the March 2021 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 a 50% working interest.

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Project Updates (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 until it was shut 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.

As of 30 June 2021, the SM71 F facility has produced approximately 3.4 million barrels of oil ("Mmbo") (gross) since initial production began. The facility has also produced approximately 4.3 billion cubic feet of gas ("Bcfg") (gross). The SM71 lease ranks number 3 of all Gulf of Mexico currently active oil producing leases on the US Gulf of Mexico shelf with the SM71 F3 and F1 ranked as the number 1 and number 2 active oil producing wells. The D5 Sand completions in the SM71 F1 and F3 wells have total gross oil production of over 3.2 Mmbo.

Total June 2021 quarter gross sales volumes for all wells on the SM71 F Platform totalled approximately 224,465 barrels of oil and 211,900 Mmbtu with only minor amounts of water produced by the SM71 F2. The F1 an F3 continue to produce water-free from the D5 Sand.

Based on a 91 day quarter, gross oil and gas production at SM71 for the June quarter 2021 equated to daily rates of approximately 2,467 barrels of oil and 2,329 Mmbtu of gas (2,523, barrels of oil and 2,132 Mmbtu of gas for the March 2021 quarter).

As at 26 July 2021 (US CST) daily production rates, on a gross basis, were approximately 2,417 barrels of oil and 2.1 Mmcfgpd.

Overall the SM71 F Platform production continues to perform in line with the current forecasts of the Byron's third-party reserve engineers, Collarini Associates ("Collarini") having exceeded all previous proved forecasts since inception.

(b) South Marsh Island 58

Byron holds all the operator's rights, title, and interest in and to the South Marsh Island block 58 ("SM58") lease to a depth of 13,639 feet subsea with 100% WI and 83.33% NRI. Below 13,639 feet subsea, Byron has a 50% WI (41.67% NRI) under a pre-existing exploration agreement. To date, all identified drilling opportunities on the SM58 lease are above 13,639 feet subsea.

Water depth in the area is approximately 132 feet.

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

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Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

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

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

Gas and oil production from the G1 well has continued to follow a natural and predictable pressure decline. As of 26 July, daily production stands at 8.9 Mmcfg, 52 barrels of 56.5 degree oil and no water at an FTP of 1,000 psi. Based on performance to date, the production from O Sand in the G1 appears not to be connected to Byron's Steelhead Prospect and the two areas must be separated by stratigraphic boundaries in the O Sand.

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

The G2 well performance continues to be negatively impacted by mechanical and reservoir issues. The G2 well is currently producing about 110 barrels of total liquid per day with water cuts averaging 70%. Byron will acquire bottom hole pressure data from the G2 well in August. Based on that data, a wireline tubing punch operation may also be performed to move the effective depth of the gas lift system deeper in the well bore. If performance does not improve, the G2 will eventually be recompleted uphole, in the J Sand interval above the current O Sand completion with through tubing completion methods. That type of completion operation can be performed without a drilling rig. The J Sand was assigned reserves of 0.370 Mmbo and 0.370 Bcfg in the G2 well by the Company's third party reserve engineers in the 31 December 2021 half year reserve report. As of 26 July 2021, the G2 is producing 32 bopd, 150 Mmcfgpd, at a FTP of 80 psi.

Total quarterly gross sales volumes for all wells on the SM58 G Platform totalled 1,122,884 Mmbtu of gas and 13,314 barrels of oil. Based on a 91 day quarter, gross oil and gas production at SM58 for the June quarter 2021 equated to daily rates of approximately 12,339 mmbtu of gas and 146 barrels of oil (16,415 mmbtu of gas and 460 barrels of oil for the March 2021 quarter).

As at 26 July 2021 SM58 G platform daily production rates, on a gross basis, were approximately 9.0 Mmcfg and 85 barrels of oil.

Ongoing production issues at SM58 G2ST well, previously reported to ASX, including on 11 May 2021, continued in June 2021. The SM58 G2ST well production is below the forecasts of the Byron's third-party reserve engineers, Collarini and its performance will be taken in to account in the Company's 2021 reserve report due for release in the September 2021 quarter.

(c) South Marsh Island 57/59/60/66/70

Byron holds a 100% WI and an 81.25% NRI in SM57/SM59 and a 100% WI and an 87.5% NRI in SM60/66/70.

Water depth in the area is approximately 125 feet.

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

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Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

(d) South Marsh Island SM58 E1 well, SM 69 E Platform and proposed SM69 E2 well

Byron holds a non-operated 53% WI (44.167% NRI) in the South Marsh Island 69 E platform with one active producing well, the SM58 E1 well. The SM58 E1 was drilled from a surface location in SM69 to a bottom hole location in SM58 in 2011 and was initially completed in the K4 Sand (B65 Sand) which produced a total of 632,000 barrels of oil, 0.19 Bcfg of gas and 836,000 barrels of formation water before the well was recompleted in the K Sand in the March 2021 quarter.

Total quarterly gross sales volumes for the SM58 E1 well totalled 16,747 barrels of oil and 1,998 mmbtu. Production from the SM58 E1 well is in line with the Company's expectations.

Ankor Energy, LLC ("ANKOR") is the designated operator of this portion of the block to facilitate the surface operatorship of the jointly owned SM58 E1 well which surfaces from the SM69 E platform which is located in the NE corner of the SM69 block.

Byron also holds a farm-in right under the Joint Exploration Agreement ("JEA") with ANKOR group which provides for the drilling of a SM 69 E2 exploration well in the NE portion of SM69 to be operated by Byron.

By funding 100% of the SM69 E2 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 (equivalent to 83.33% 8/8ths).

The SM69 E2 wellbore is planned 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 and 4.3 Bcfg from two wellbores completed in zones equivalent to these 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 successful Byron would produce it back to the SM58 G platform through a new flowline laid in July 2020. Hydrocarbons from the E2 well would then be processed and sold through the SM58 G Platform.

Byron has executed a contract with Enterprise Offshore Drilling ("EOD") and the EOD 351 rig is due to commence drilling the SM69 E2 well in August 2021. The rig, having previously worked internationally, is currently being brought up to required US regulations and upgraded before undergoing final inspections. Final US Coast Guard and BSEE inspections are scheduled to occur the week of 26th July after which all drilling systems will be stress tested prior to the rig being mobilised to location. The drilling cost for the SM69 E2 well is estimated at US$5.6 million, including 10% contingency for intangible costs, on dry hole basis. This work and therefore timing, can potentially be impacted or delayed by severe tropical weather.

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

(e) South Marsh Island Area permitting status

Byron has spent considerable time pursuing key regulatory permits in the South Marsh Island Project Area.

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Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

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

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

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

2. Eugene Island blocks 62, 63, 76 and 77

Byron currently holds a 100% WI and an 87.5% NRI in EI62/63/76/77 blocks. Water depth in the area is approximately 20 feet.

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 is underway.

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").

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.

The Company is scoping an RTM seismic imaging project over the MP306 field.

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Properties

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

Properties	Operator	Interest WI/NRI* (%)	Lease Expiry Date	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) 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)	Byron Ankor	100.00/83.33** 53.00/44.167	Production	20.23
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*

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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
Bcpd = barrels of condensate per day
btu = British Thermal Units
FTP = flowing tubing pressure
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
Mmbo = million barrels of oil
NGL = Natural gas Liquids, such as ethane, propane and butane
PSI = pounds per square inch
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 currently for SM71 / SM58 production; the heat content of SM71 / SM58 gas may vary over time.

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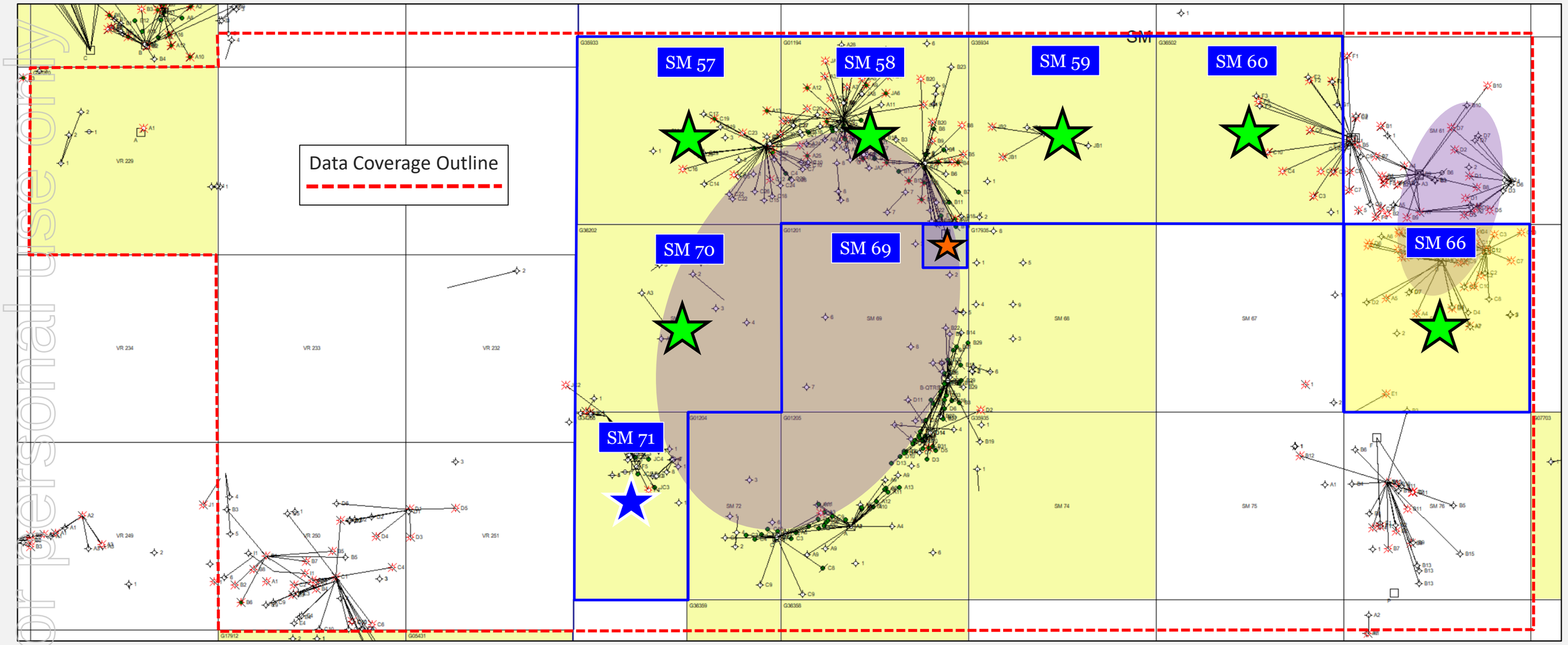
ATTACHMENT 1

Byron Energy GOM South Marsh Island Leases and RTM Data Coverage Area December 2020



BYRONENERGY INC.
Byron 100% WI

BYRONENERGY INC.
Byron/Otto 50% WI

BYRONENERGY INC.
Ankor/Byron Agreement

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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 June 2021

Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (12 months) US$'000**
1.	**Cash flows from operating activities**		
1.1	Receipts from customers	9,903	32,519
1.2	Payments for		
	(a) exploration & evaluation	(82)	(62)
	(b) development	(1,383)	(34,354)
	(c) production	(1,738)	(5,677)
	(d) staff costs	(747)	(2,669)
	(e) administration and corporate costs	(437)	(1,783)
1.3	Dividends received (see note 3)	-	-
1.4	Interest received	-	1
1.5	Interest and other costs of finance paid	(704)	(2,999)
1.6	Income taxes paid	-	-
1.7	Government grants and tax incentives	-	-
1.8	Other (provide details if material)	-	-
	- Oil price cash hedge settlements	17	17
	- Cash Contributions from JV partners	22	195
	- Oil revenue prepay repayments	(1,750)	1,750
1.9	**Net cash from / (used in) operating activities**	**3,101**	**(13,062)**

2.	**Cash flows from investing activities**		
2.1	Payments to acquire or for:		
	(a) entities		
	(b) tenements	-	(178)
	(c) property, plant and equipment		
	(d) exploration & evaluation	(416)	(965)

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Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (12 months) US$'000**
	(e) investments		
	(f) other non-current assets		
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**	**(416)**	**(1,143)**

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	(1,664)	(3,417)
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**	**(1,664)**	**1,576**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	3,127	16,645
4.2	Net cash from / (used in) operating activities (item 1.9 above)	3,101	(13,062)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(416)	(1,143)

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Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (12 months) US$'000**
4.4	Net cash from / (used in) financing activities (item 3.10 above)	(1,664)	1,576
4.5	Effect of movement in exchange rates on cash held	(5)	127
4.6	**Cash and cash equivalents at end of period**	**4,143**	**4,143**

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	4,143	3,127
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)**	**4,143**	**3,127**

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	482
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$ 51, (ii) Executive directors' salaries and service fees of US$ 208k and A$ 202k, and (iii) quarterly interest payments of US$ 48k and A$ 44k to certain directors on the loan facilities listed in 7.1a.

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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 $'000**
7.1a	Loan facilities (unsecured and repayable by 31 March 2022, bearing 10% interest p.a.)	US$ 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 no loan repayments until December 2020.)	US$ 15,100	US$ 15,0100
7.2	Credit standby arrangements	-	-
7.3	Other (please specify)	-	-
7.4	**Total financing facilities**	US$ 17,100 & A$ 2,100	US$ 17,100 & 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)	3,101
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	(416)
8.3	**Total relevant outgoings (item 8.1 + item 8.2)**	**2,685**
8.4	Cash and cash equivalents at quarter end (item 4.6)	4,143
8.5	Unused finance facilities available at quarter end (item 7.5)	-
8.6	**Total available funding (item 8.4 + item 8.5)**	**4,143**
8.7	**Estimated quarters of funding available (item 8.6 divided by item 8.3)**	**N/A**

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:
N/A

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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: N/A	
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: N/A	
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 July 2021.....

Authorised by: 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.

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