BYRONENERGY LIMITED

Quarterly Report for the Period Ended 31 December 2023

Summary

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- Byron generated quarterly net sales revenue for the December 2023 quarter of approximately US$11.8 million (90% oil and 10% natural gas), up approximately 40% on the September 2023 quarter of US$8.4 million due to higher production of oil and gas and higher realised gas prices partly offset by lower realised oil prices;

- Byron's share of oil and gas production (net sales volume) for the December 2023 quarter was 141,443 barrels of oil and 387,574 mmbtu of gas compared to the previous quarter of 99,566 barrels of oil and 237,934 mmbtu of gas. Oil and gas production for the December 2023 quarter was higher due to increased production from the SM58 G Platform due to commencement of production from SM58 G4 and G6BP1 wells during the December quarter;

- Realised net prices of US$ 75.54 per barrel of oil and US$ 2.63 per mmbtu of natural gas net to Byron after quality adjustments, oil and gas transportation charges and royalties were achieved during the December quarter (September 2023 quarter: net realised prices of US$ 77.44 per barrel of oil and US$ 2.42 per mmbtu of natural gas);

Name:	**Byron Energy Limited**
ASX code:	**BYE**
Shares on issue at 31 Dec 2023:	**1,081.4 million**
Quoted shares:	**1,081.4 million**
Options on issue (unquoted):	**2.0 million**
Cash at Bank 31 Dec 2023:	**US$6.6 million**
Borrowings 31 Dec 2023:	**US$3.4 million**
Revenue prepayment 31 Dec 2023:	**US$19.0 million**
Market Capitalisation at 31 Dec 2023:	**A$108 million (@A$0.10 per share)**

- During the December 2023 quarter, Byron made a second draw of US$ 9.0 million under the US$ 22.0 million Oil Prepayment Facility with an oil supermajor, taking the total drawdown to US$ 19.0 million;

- SM58 G4 and G6BP1 wells commenced production during the December quarter following successful completion of the two wells; and

- Byron was the high bidder on SM60 and SM70 at the Gulf of Mexico OCS Lease Sale 261 held in New Orleans, Louisiana on 20 December 2023.

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

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Corporate

Issued Capital

As at 31 December 2023, Byron's issued capital comprised:-

Securities	Total issued	Quoted	Unquoted
Shares (ASX:BYE)	1,081,395,102*	1,081,395,102*	Nil
Options (expiring on 31 December 2024 with an exercise price of A$0.16)	2,000,000	Nil	2,000,000

*Includes 40,840,000 shares subject to voluntary escrow. These shares are already quoted on the ASX and have the same rights as all other ordinary shares issued by Byron, except they are placed in trading lock. The shares in voluntary escrow are held by executive directors, staff and contractors of the Company

Borrowings and oil revenue prepayment

As at 31 December 2023, Byron's outstanding loans comprised: -

Lender	US$ M	A$ M	31 Dec 2023 US$ equivalent (@A$1=US$0.6840)	30 Sept 2023 US$ equivalent (@A$1=US$0.6458)
Directors	2.00	1.75	3.20	3.13
Shareholder	-	0.35	0.24	0.23
Total	**2.00**	**2.10**	**3.44***	**3.36***

*as at 31December 2023, Byron also had US$ 0.9 million in insurance premium financing outstanding.

Directors' and Shareholder Loans

Byron's outstanding loans of approximately US$ 3.44 million as of 31 December 2023, from entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young, all directors of the Company, and a longstanding shareholder. These loans are due to be repaid by 31 December 2025.

Oil Revenue Prepayment

In August 2023, the Company's oil purchaser provided access to further funding of US$ 22.0 million (Oil Prepayment Facility) primarily to fund the SM58 development drilling & completion program.

An initial draw of US$ 10 million was taken in September 2023 and a second draw of US$ 9 million was made in December 2023, taking the total draw as at 31 December 2023 to US$ 19.0 million of the US$ 22.0 million available under the agreement.

For further information on the Oil Prepayment Facility refer to the Company's ASX release of 15 September 2023 and 15 December 2023.

Oil price hedging

Under the Oil Prepayment Facility, referred to above, Byron is required to hedge approximately 450 bopd of working interest (WI) oil production. It should be noted that these hedging requirements are expressed in WI barrels under the Oil Prepayment Facility as the counterparty contracts to buy all Byron controlled barrels comprising those barrels sold on behalf of the royalty owners (Federal government) as well as Byron. For clarity, the First and Second draw hedge requirements, if expressed in Byron's Net revenue Interest (NRI), for purposes such as determining a share of net production or resultant net revenue, is approximately 374 net bo using an average NRI of 83%.

Under the Oil Prepayment Facility, Byron also has the option to place additional financial or derivative hedging with the counterparty. Consequently, Byron's realised prices for oil may at any time be a combination of hedged and unhedged volumes. The Company's current oil hedging position comprises three transactions under the Forward

Corporate (cont.)

Sale Agreement (FSA), which specifies a price per physical barrel in advance for each delivery period during the term of the contract.

The hedging counterparty 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.

As of 31 December 2023, Byron's hedged oil production is as follows: -

Period	Daily Hedged WI Volume (bopd)	Period Hedged WI Volume (bbl)	Daily Hedged NRI Volume (bopd)	Period Hedged NRI Volume (bbl)**	NYMEX WTI Fixed Base Price Crude Oil*
FSA Hedge 1 Jan 2024-31 August 2025 (entered during September 2023 quarter)	250	152,250	208	126,672	US$74.49
FSA Hedge 2 1 Jan 2024- 31 August 2025 (entered during the September 2023 quarter)	225	137,025	187	113,883	US$74.56
FSA Hedge 1 Jan 2024-30 June 2024 (entered during the December 2023 quarter)	200	36,400	166	30,212	US$72.25

*West Texas Intermediate (WTI) fixed base price is then adjusted for NYMEX Roll, LLS/WTI price differentials, Transportation (estimated at -US$5.69/barrel +-0.20) to arrive at a realised price; the fixed price per barrel under the FSA qualifies for purposes of royalty calculations.

**The actual NRI volume will depend on weighted average production from SM58 G and SM71 F platforms.

During the December 2023 quarter, Byron realised a small profit on a put option (300 bopd on a NRI basis for the December quarter).

Cashflow

Byron generated receipts from customers of approximately US$ 9.9 million during the December 2023 quarter, compared to US$ 8.7 million for the September 2023 quarter. After deducting payments for production (lease operating expenses) net receipts from production were US$ 7.9 million for the quarter, an increase of US$ 1.2 million from the previous quarter. After deducting payments for development of US$ 25.3 and other operating activities of US$ 1.8 million and adding the drawdown of US$ 9.0 million in oil revenue prepayments, the net cash outflow from operating activities was US$ 10.2 million. Byron ended the December 2023 quarter with a cash balance of US$ 6.6 million, a reduction of US$ 10.3 million over the 30 September 2023 balance.

Consolidated statement of cash flows (US$ million)	Dec 23 quarter	Sept 23 quarter
Cashflow from operating activities		
Receipts from customers	9.9	8.7
Payments for production	-2.0	-2.0
Net receipts from production	**7.9**	**6.7**
Payment for development	-25.3	-2.0
Payments for other operating activities (net)	**-1.8**	**-1.8**
Oil revenue pre-payment / (repayment)	**9.0**	**10.0**
Net cash from / (used in) operating activities	**-10.2**	**12.9**

Corporate (cont.)

Consolidated statement of cash flows (US$ million)	Sep 23 quarter	Jun 23 quarter
Cash flows from investing activities		
Exploration and evaluation	-0.1	-0.2
Net cash from / (used in) investing activities	**-0.1**	**-0.2**
Cash flows from financing activities		
Net cash from / (used in) financing activities	-	-
Net increase / (decrease) in cash and cash equivalents for the period	**-10.3**	**12.7**
Cash and cash equivalents at end of quarter	**6.6**	**16.9**

For further details on the December 2023 quarter cashflows refer to Appendix 5B.

Oil and Gas Production/Sales

Byron's share of oil and gas production and sales for the December 2023 quarter and financial year to date is summarised in the table below.

Production (sales)	Dec 2023 quarter	Sept 2023 quarter	Year to date 31 Dec 2023 (6 months)	Year to date 31 Dec 2022 (6 months)
Net production (Byron share (NRI basis) SM71				
Oil (bbls)	30,767	27,739	58,505	139,023
Gas (mmbtu)	25,668	31,896	57,563	121,671
Net production (Byron share (NRI basis) SM58				
Oil (bbls)	108,715	68,374	177,089	181,033
Gas (mmbtu)	361,795	205,763	567,558	830,045
Net production (Byron share (NRI basis) SM58 E1 well				
Oil (bbls)	1,961	3,453	5,415	9,820
Gas (mmbtu)	111	276	387	1,564
Total Net production (NRI basis)				
Oil (bbls)	**141,443**	**99,566**	**241,009**	**329,876**
Gas (mmbtu)	**387,574**	**237,934**	**625,508**	**953,280**

Aggregate oil and gas production and sales, net to Byron, were 141,443 bbls of oil and 387,574 mmbtu of gas for the December 2023 quarter compared to 99,566 bbls of oil and 237,934 mmbtu of gas for the September 2023 quarter. Oil and gas production and sales for the December 2023 quarter were above the September quarter due

BYRONENERGY LIMITED

Oil and Gas Production/Sales (cont.)

to higher SM58 oil and gas production, mainly as a result of G4 and G6 BP01 wells coming on stream, partly offset by lower SM71 production, mainly due to F3 well decline and gas generator downtime.

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

Sale revenue (accrual basis) US$ million	Dec 2023 quarter	Sept 2023 quarter	Year to date 31 Dec 2023	Year to date 31 Dec 2022
Net sales revenue (Byron share on NRI basis)	11.8	8.4	20.2	33.4

Net sales revenue for the December 2023 quarter was approximately US$ 11.8 million (90% oil and 10% natural gas) after quality adjustments, oil transportation charges and royalties, up approximately 40% compared to US$ 8.4 million for the prior quarter with the increase mainly due to higher oil and gas production and higher realised gas prices partly offset by lower realised oil prices.

For the December 2023 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$ 75.54 per bbl (US$ 81.23 excluding transportation) compared to US$ 77.44 per bbl and US$ 83.15 per bbl respectively for the September 2023 quarter.

Oil prices decreased over the quarter with the West Texas Intermediate oil price starting the December quarter at US$ 90.77 per bbl and ending the quarter at US$ 71.89 having traded in the range of US$68.27/bbl to US$90.77/bbl.

Oil market sentiment turned somewhat bearish during the December 2023 quarter as non-OPEC+ supply strength coincided with slowing global oil demand growth. The extension of OPEC+ output cuts through 1Q24 did little to prop up oil prices.

Byron realised an average gas price after transportation deductions of approximately US$ 2.63 per mmbtu for the December 2023 quarter (US$ 2.99 excluding transportation) compared to US$ 2.42 per mmbtu and US$ 2.79 per mmbtu respectively for the September 2023 quarter.

U.S. natural gas prices closed the December 2023 quarter at US$ 2.51 approximately 14% below the September 2023 close of US$ 2.93, based on robust production and a warmer start to the winter heating season that cut space-heating demand.

Project Updates

Salt Dome Projects

South Marsh Island 73 Salt Dome

The South Marsh Island 73 (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. Majority of the field production has come from depths less than 7,500 feet in high quality sandstone reservoirs.

Oil and Gas Production/Sales (cont.)

(a) South Marsh Island 71

Byron owns the South Marsh Island block 71 (SM71) a lease in the 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.

As of 31 December 2023, the SM71 F facility has produced approximately 4.8 million barrels of oil (Mmbo) (gross) since initial production began. The facility has also produced approximately 5.6 billion cubic feet of gas (Bcfg) (gross).

Total December 2023 quarter gross sales volumes for all wells on the SM71 F Platform totalled 75,631 barrels of oil and 63,163 mmbtu of gas (September 2023 quarter, 68,079 barrels and 78,432 mmbtu). Higher oil production from SM71 F Platform for the December quarter was mainly due to higher uptime during the December quarter.

Water cut from the SM71 F3 well continued to increase (averaged approximately 89% water cut for the December quarter compared to approximately 80% for the September 2023 quarter. The up-dip SM71 F1 well continues to produce water free and the rate will continue to be managed to optimize the D5 Sand reservoir's oil production.

The F2 and F4 wells produce intermittently from the J1 Sand.

See page 8 for further comments on SM71 well performance.

(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.

Byron also holds an interest in the SM69 E2 well under the Joint Exploration Agreement (JEA) with W&T Offshore, Inc. (W&T Offshore). As previously reported, Byron's 100% Working Interest (WI) and 80.33% Net Revenue Interest (NRI) in the SM69 E2 well reduced to 70% WI with an unburdened 58.33% NRI, effective 1 January 2023, after WT Offshore exercised its option to convert its overriding royalty interest into a working interest in the E2 well.

Water depth in the area is approximately 132 feet.

As of 31 December 2023, the SM58 G facility has produced approximately 9.0 Bcfg and 0.98 million barrels of oil and condensate (gross) on a cumulative basis from seven wells (G1, G2, G3, G4, G5, G6 and E2).

SM58 G Wells on Production:

The SM58 G1 well produces from the Upper O Sand and after producing 56.5-degree gravity condensate since inception of production, the G1 is now producing 36-degree dark oil.

The SM58 G2ST produces from the O Sand producing oil, gas and with associated formation water.

The SM58 G3 and G5 currently produce from the J Sand and L2 Sand respectively. The Company plans to mobilise coiled tubing to the platform in late January to wash the fill out the G5 well and attempt to slide the sleeve to achieve a zone change.

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Oil and Gas Production/Sales (cont)

SM58 G4, drilled as an attic well to K4 Sand oil production, commenced production in late October 2023 at over 600 bopd (gross) of 35.50 API oil and 540 mcfgpd (gross). Production averaged 547 bopd (gross) and 493 mcfgpd with water production of 88 bwpd for the period since commencement of production and ending on 31 December 2023.

SM58 G6 BP1, drilled as an attic well to N2 Sand oil production, commenced production in mid November 2023. Initial production was gas with 58.0 API condensate with the condensate changing to dark 47.0 API oil soon after production started. Production averaged 321 bopd (gross) and 3.4 mcfgpd without any water production for the period from commencement of production and ending on 31 December 2023, at the same original choke size of 22/64ths.

See page 8 for an update on SM58 G well performance and current work program.

SM69 E2 Well:

The SM69 E2 well produces from the K4/B65 Sand. During the December 2023 quarter, the SM69 E2 well production has remained relatively steady with no water production. The E2 well produced at an average gross daily rate of 580 bopd and 0.210 MMcfgpd (597 bopd and 0.323 Mmcfgpd during the September2023 quarter). Byron continues to manage the well production rates to achieve optimal oil and gas recovery.

Production of oil, gas and any other liquids from the E2, located on SM69 E platform, flows to the Byron operated SM58 G platform where separation occurs before oil and gas are sent to sales pipelines. Under the JEA, Byron will continue to process the production at SM58 G Facility on behalf of the joint interest under a forthcoming Production Handling Agreement with the non-operating partner paying Byron for the processing and transportation of production.

Total quarterly gross sales volumes for all wells, including E2, on the SM58 G Platform, totalled 145,053 barrels of oil and 440,037 mmbtu of gas for the December 2023 quarter (September 2023 quarter 98,426 barrels of oil and 256,685 mmbtu of gas). Higher production was due to a commencement of oil and gas production from G4 and G6BP1 wells, partly offset by a combination of drilling rig downtime (completion of G4 and G6 wells) and compressor downtime.

See page 8 for an update on SM69 E2 well performance and current work program.

(c) South Marsh Island SM58 E1 well, SM69 E Platform

Byron holds a non-operated 53% WI (44.167% NRI) in the South Marsh Island 69 E platform with two active producing wells, the SM58 E1 and E2 wells. 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 December 2023 quarterly net sales volumes for the SM58 E1 well totalled 1,961 barrels of oil and 111 mmbtu of gas (September 2023 quarter 3,453 barrels of oil and 276 mmbtu of gas).

W&T Offshore, Inc is the designated operator of this well and portion of the block to facilitate the surface operatorship of the jointly owned SM58 E1 well which surfaces from the SM69 E platform located in the NE corner of the SM69 block.

(d) SM58 G and SM71 F Well Performance Update and Upcoming Work Program

As of December 31, 2023, Byron's net daily production, from all of the producing wells, stood at 1,626 bopd and 4,372 mcfpd or 2,355 boepd. At the end of the December quarter, Byron's daily production was down from levels

Project Updates (cont)

reported on 28 November 2023 for a variety of factors. Beginning in December, a combination of cold weather creating freezing problems of production equipment, downhole and topside paraffin build-ups, compressor capacity and downtime (also related to cold weather), other topside production equipment problems and well performance have resulted in lower daily production than seen in the early part of the quarter. Some of these issues have carried over to January 2024 and work is underway to address these problems.

(i) SM58 G

The SM 58 G platform has now produced a total of approximately 9 bcf and 1 mmbo since production began in September of 2020. Nearly all the gas and roughly half the oil have come from wells drilled off the SM58 G platform with the remaining oil coming from the SM69 E2 which is operated by Byron and produced through the SM58 G platform. The status of key wells at the end of December follows.

SM58 G1 BP01 (G1) - The G1 well was producing 253 bopd and 1,153 mcfpd from the O Sand at the end of December, down from rates 340 bopd reported on 28 November 2023. This decrease is entirely due to paraffin build ups in topside flowlines and the shallow portion of the production tubing. These build ups were cleared in mid-January and the well has returned to prior rates of around 340 bopd of 38.50 API oil. The change to oil has prompted Byron to permit the SM58 G9 as an outboard structural test of the O Sand to further delineate the oil leg in the O Sand. The G9 well will be drilled as part of the next drilling program at SM58 G platform.

SM58 G4 (G4) - At the end of December, the G4 well was producing 417 bopd and 550 mcfpd from the K4 Sand. Oil rates were down from 600 bopd reported on 28 November 2023. In addition, the G4 is now producing 251 barrels of water per day (bwpd). The source of the water production is uncertain. However, the G4 has continued to produce at consistent rates of total fluids per day without any changes to the 25/64th" choke. The water could be from any of three sources; the K4 formation itself, the 1964 Shell A8 750' north of the G4 and has records of failed abandonment plugs being set across the K4 Sand or the 1966 Shell A24 which has no K4 Sand but does have wet sand stringers on strike with the G4 and about 1,100 feet west. In January, Byron ran bottom hole pressure and temperature gauges in the G4 to gain insight into the water incursion. Once bottom hole pressures are analysed, the G4 will be flowed at different rates to observe how the water changes to choke changes. That work will determine how to best produce the K4 reserves in the G4.

SM58 G6 BP01 (G6) - The G6 well was producing at rates of 288 bopd and 2,561 mcfpd from the N2 sand, down from rates of 350 bopd as reported on 28 November 2023. As evidenced by the G6 change from gas to 43.10 API oil production shortly after start-up, the N2 Sand intersection is just updip from the N2 Sand gas/oil contact. Because the gas flows preferentially to oil it will take time for the N2 Sand gas cap to become fully saturated with oil and for the G4 completion to achieve full pressure support from the downdip aquifer, the well has experienced a drop in flowing tubing pressure. The G6 is in compression but due to limits on gas quantities in the compressor, the current rates are expected to remain in this range for the near future.

SM69 E2 (E2) - At the end of December 2023, the E2 well was producing at rates of 475 bopd and 257 mcfpd down from rates of 600 bopd reported on 28 November 2023. The decrease at the end of December is attributable solely to equipment issues on the outside operated SM69 E platform. While Byron operates the E2 well, another company operates the SM69 E platform and is responsible for maintenance of associated equipment. The crane on the SM69 E platform went out of service in late December 2023, due to an engine failure in late December. With no crane, chemicals used for treatment of paraffin were unable to be lifted onto the platform and the E2 well rate has declined slowly because of the buildup of paraffin. The operator of the platform has advised that the crane will be back in service in late January and Byron expects the E2 to return to full production levels of approximately 600 bopd once the paraffin is cleared and chemical treatments can resume.

Project Updates (cont)

(ii) SM71 F

Cold temperatures and issues with compressor capacity combined to reduce platform uptime to lower-than-normal levels. Individual well performance was largely unaffected, but the reduced operating time resulted in lower total production toward the end of December.

(iii) Upcoming Work Program

In January, Byron mobilised slickline equipment and personnel to the SM58 G platform to undertake a comprehensive work program of paraffin cutting and bottom hole pressure measurements in all wells. The SM58 G5 well is being prepared for the upcoming zone change from the L2 sand to N2 Sand. The G5 zone change is expected to begin in early February when weather permits and will utilise a liftboat and coil tubing.

OCS Lease Sale 261 Results

Byron Energy Inc, a wholly owned subsidiary of the Company, was the high bidder on the South Marsh Island 60 lease (SM60) and the South Marsh Island 70 lease (SM70) at the Gulf of Mexico, Outer Continental Shelf (OCS) Lease Sale 261 held in New Orleans, Louisiana on Wednesday, 20 December 2023. An apparent high bid is subject to OCS bid adequacy review and under Bureau of Ocean Energy Management (BOEM) rules may be rejected if deemed inadequate. The BOEM review process can take up to 90 days.

The Company bid a total of US$ 310,985 in bonus bids on the two blocks comprising:

Block	Gross Bonus Amount ($US)	Working Interest (WI)	Net Revenue Interest (NRI)
SM60	$128,750	100.00%	81.25%
SM70	$182,235	100.00%	81.25%

Byron previously held the leases over SM60 and SM70 but relinquished each lease in the June quarter of 2023, in recognition of near-term lease expiry, economic considerations, and rig availability making drilling unlikely. However, recent geophysical and geological information has re-confirmed the prospectivity of each block and Byron decided to reacquire the leases.

Properties

As of 31 December 2023, Byron's portfolio of properties, all in the shallow waters of the Gulf of Mexico, USA comprised: -

Properties	Operator	Interest WI/NRI* (%)	Lease Expiry Date	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	April 2028	21.98
South Marsh Island Block 61	Byron	100.00/87.50	September 2027	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	70.00/58.33***	Production	1.3
South Marsh Island Block 66	Byron	100.00/87.50	December 2025	20.23
Grand Isle 63	Byron	100.00/81.25	April 2028	20.23
Grand Isle 72	Byron	100.00/81.25	April 2028	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.*

**** Effective 1 January 2023 Byron's 100% WI and 80.33% NRI in the SM69 E2 well reduced to 70% WI with an unburdened 58.33% NRI, after WT Offshore exercised its option to convert its overriding royalty interest into a 30% working interest in the E2 well which achieved payout in December 2022.*

The table above excludes SM60 and the SM70 leases as these leases had not been awarded as of 31 December 2023. Byron was the high bidder at the Gulf of Mexico, Outer Continental Shelf (OCS) Lease Sale 261 held in New Orleans, Louisiana on Wednesday, 20 December 2023. A high bid is subject to OCS bid adequacy review and under BOEM rules may be rejected if deemed inadequate. The BOEM review process can take up to 90 days.

Glossary

1P = Proved Reserves
2P = Proved and Probable Reserves
3P = Proved, Probable and Possible Reserves
Bbl = barrels
bcf = billion cubic feet
Bcfg = billion cubic feet gas
Bo = barrel of oil
Bopd = barrels of oil per day
Bcpd = barrels of condensate per day
Bw = barrels of water
Bwpd = barrels of water 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
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 1.10 btu's currently for SM71 / SM58 production; the heat content of SM71 / SM58 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	31 December 2023

	Consolidated statement of cash flows	**Current quarter US$'000**	**Year to date (6 months) US$'000**
1.	**Cash flows from operating activities**		
1.1	Receipts from customers	9,943	18,628
1.2	Payments for		
	(a) exploration & evaluation	(44)	(81)
	(b) development	(25,324)	(27,274)
	(c) production	(2,046)	(4,045)
	(d) staff costs	(906)	(1,846)
	(e) administration and corporate costs	(410)	(1,433)
1.3	Dividends received (see note 3)	-	-
1.4	Interest received	14	20
1.5	Interest and other costs of finance paid	(308)	(425)
1.6	Income taxes paid	-	-
1.7	Government grants and tax incentives	-	-
1.8	Other (provide details if material)	-	-
	- Cash Contributions (refunds) from (to) JV partners	-	235
	- Oil price hedge cash settlements	(99)	(99)
	- Oil revenue prepayments (net)	9,000	19,000
1.9	**Net cash from / (used in) operating activities**	**(10,180)**	**2,680**

2.	**Cash flows from investing activities**		
2.1	Payments to acquire or for:		
	(a) entities		
	(b) tenements	(62)	(62)
	(c) property, plant and equipment		
	(d) exploration & evaluation	(50)	(272)

Consolidated statement of cash flows		Current quarter US$'000	Year to date (6 months) US$'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**	**(112)**	**(334)**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)		
3.2	Proceeds from issue of convertible debt securities		
3.3	Proceeds from exercise of options / interest free loan repayments		
3.4	Transaction costs related to issues of equity securities or convertible debt securities		
3.5	Proceeds from borrowings		
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)		
3.10	**Net cash from / (used in) financing activities**	**-**	**-**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	16,860	4,224
4.2	Net cash from / (used in) operating activities (item 1.9 above)	(10,180)	2,680
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(112)	(334)

Consolidated statement of cash flows		Current quarter US$'000	Year to date (6 months) US$'000
4.4	Net cash from / (used in) financing activities (item 3.10 above)	-	-
4.5	Effect of movement in exchange rates on cash held	(3)	(5)
4.6	**Cash and cash equivalents at end of period**	**6,565**	**6,565**

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	6,565	16,860
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)**	**6,565**	**16.860**

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	492
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$ 258k and A$ 191k, 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 $'000**
7.1a	Loan facilities (unsecured and repayable by 31 December 2025, bearing 12% interest p.a.)	US$ 2,000 & A$ 2,100	US$ 2,000 & A$ 2,100
7.1b	Loan facilities (secured)	-	-
7.2	Credit standby arrangements	-	-
7.3	Other (please specify) Oil revenue prepayment facility (secured)*	US$ 22,000	US$ 19,000
7.4	**Total financing facilities**	US$ 24,000 & A$ 2,100	US$ 21,000 & A$ 2,100

7.5	**Unused financing facilities available at quarter end***	US$3,000

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.

**Oil prepayment revenue fee is US$1.27 a barrel of oil and US$1.04 a barrel of oil for first draw of US$ 10 million and the second draw of US$ 9 million respectively. Repayments don't begin for 6 months and repayments are made in equal instalments from the Company's oil revenue over 18 months commencing in March 2024 with the final repayment made in August 2025.*

8.	***Estimated cash available for future operating activities***	**US$'000**
8.1	Net cash from / (used in) operating activities (item 1.9)	(10,180)
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	(112)
8.3	**Total relevant outgoings (item 8.1 + item 8.2)**	**(10,292)**
8.4	Cash and cash equivalents at quarter end (item 4.6)	6,565
8.5	Unused finance facilities available at quarter end (item 7.5)	3,000
8.6	**Total available funding (item 8.4 + item 8.5)**	**9,565**
8.7	**Estimated quarters of funding available (item 8.6 divided by item 8.3)**	**0.93**

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:
Receipts from customers in the next quarter while subject to production levels and oil and gas prices are expected to be substantial. Payments for development expenditure will be substantially less in the next quarter than the previous 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 received a prepayment of US$19.0 million in September and December 2023 quarters from the buyer of crude oil and hedging counterparty under the oil forward sale agreement. The Company has also obtained extended terms of trade with certain key contractors and industry service suppliers.

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 expected 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: 25 January 2024

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.