BYRONENERGY LIMITED

Quarterly Report for the Period Ended 30 June 2020

Summary

Name:	**Byron Energy Limited**
ASX code:	**BYE**
Shares on issue at 30 Jun 2020:	**1,023.5 million**
Quoted shares:	**1,023.5 million**
Options on issue (unquoted):	**41.1 million**
Cash at Bank 30 Jun 2020:	**US$16.6 million**
Borrowings 30 Jun 2020:	**US$18.4 million**
Market Capitalisation at 30 Jun 2020:	**A$143 million (@A$0.14 per share)**

- Byron's share of oil and gas production (net sales volume) for the June 2020 quarter, from SM71 and SM58 E1 well, was 84,988 barrels of oil and 397,749 mmbtu of gas;

- Net revenue recorded for the June 2020 quarter, from SM71 and SM58, was approximately US$3.7 million (net to Byron after quality adjustments, transportation charges and royalties) with realised net prices of US$36.20 per barrel of oil and US$1.28 per mmbtu of natural gas during the period;

- No material adverse impact on production or construction due to COVID-19 outbreak during the June quarter;

- After curtailing oil production on 31 March 2020 to more closely align with previously hedged volumes, Byron announced on 7 May 2020 that it had increased production back to original levels;

- Additional production volumes were hedged in June 2020, for the remainder of the 2020 calendar year, in the form of oil price put options, covering 400 bopd with a strike price of US$39 per barrel on the WTI base price;

- During the June quarter Byron raised approximately A$27.6 million in equity, before costs, through a placement (A$13.8 million) and an SPP (A$13.8 million), allowing Byron to accelerate development drilling at SM58 and SM69;

- Byron secured an additional US$3.5 million in finance facilities from Crimson Midstream; and

- Load out of the SM58 G Platform and jacket begun on 9 June 2020 and was completed in early July 2020. Completion operations on SM58 G1 well, drilled and logged in September 2019, commenced on 18 July 2020 utilising the Enterprise Offshore Drilling 264 jack-up rig.

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

Corporate

Equity Raising

During the June quarter Byron raised approximately A$27.6 million in equity before costs through a placement (106.3 million shares @A$0.13/share raising A$13.8 million) and a SPP (106.3 million shares @A$0.13/share raising A$13.8 million). 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 June 2020, Byron's issued capital comprised:-

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

Borrowings

As previously reported, in the December quarter 2019 Byron signed a binding Secured Promissory Note ("Promissory Note") with Crimson Midstream Operating, LLC ("Crimson Midstream"), a portfolio company of The Carlyle Group, to borrow an initial amount of US$15.0 million. The first tranche of US$10.0 million under Promissory Note facility was drawn by the Byron group in December 2019. The second tranche of US$5.0 million under the Promissory Note was drawn in January 2020. 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 on the same terms and conditions as the existing US$15 million facility, with the option of up to $1 million of that to be provided in the form of equipment or vendor services applied to SM58 G platform and pipeline(s) installation. The additional promissory note has not been issued yet.

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, with the first-year being interest-only. 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$3.4 million from entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young, directors of the Company, and another long standing shareholder were extended by one year to 31 March 2022, with all other conditions remaining the same.

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

Lender	US$ M	A$ M	US$ Equivalent (@A$1=US$0.6863)
Directors	2.00	1.75	3.20
Shareholders	-	0.35	0.24
Crimson Midstream	15.00	-	15.00
Total	**17.00**	**2.10**	**18.44**

* as at 30 June 2020, Byron also had US$1.49 million in insurance premium financing outstanding

Corporate (cont.)

COVID-19

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

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, which specifies a price per barrel in advance for each delivery period during the term of the contract, and a financial hedge in the form of a put option which provides the buyer of the 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 both the forward sale agreement and the put options, one of the global oil industry's "supermajors", is also the purchaser of Byron's oil production under a mutually agreed long term purchase arrangement, which provides Byron with a stable, aligned counterparty.

In December 2019, Byron entered into an oil hedging program on 670 bopd, approximately 50% of the Company's net SM71 proved producing forecast production. This was implemented at a preferred customer rate, using a fixed-price forward sale agreement (the "Forward Sale Agreement").

In response to the dislocation in the global and local crude oil markets and the unprecedented volatility in prices, Byron further enhanced and protected its fixed West Texas Intermediate Calendar Month Average ("WTI CMA") Base Price hedge position, under the Forward Sale Agreement, by placing the following hedges on two previously floating components of the pricing mechanism:

(i) a fixed price hedge on the Louisiana Light Sweet/WTI ("**LLS/WTI**") differential for May 1 through December 31, 2020 on 670 bopd @ minus US$2.78 per barrel, and

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

In June 2020 Byron added an additional 400 bopd hedge for the remainder of 2020 in the form of put options ("Put Options") with a strike price of US$39 per barrel on the WTI base price.

Under the Forward Sale Agreement and Put Options, as at 30 June 2020 the Company had hedged approximately 1,070 barrels of oil per day, or 75%, of Byron's forecasted volume, from existing wells hedged for the remainder of 2020.

Byron's hedged oil production as at 30 June 2020 is as follows:-

Corporate (cont.)

Hedging (Cont.)

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
Jul-Dec 2020 (Put options)	400	73,600	US39.00**	unhedged -US$0.27 (estimated on futures curve)	unhedged US$1.40 (estimated on futures curve)	Estimated floor of Not Less Than **US$40.13**
Jul-Dec 2020 (Forward sale agreement)	670	122,897	US$54.78	-US$1.80 (fixed)	-US$2.78 (fixed)	**US$50.20**
Jan-Dec 2021 (Forward Sale Agreement)	450	164,250	US$52.86	unhedged	Unhedged	To be determined
Jan-Dec 2022 (Forward Sale Agreement)	400	146,000	US$52.70	unhedged	unhedged	To be determined

*WTI CMA base price is adjusted for NYMEX Roll, LLS/WTI price differentials, Transportation (estimated at -US$4.70/barrel +-0.20) to arrive at a realised price.
** Minimum WTI CMA base price prior to NYMEX Roll Adjust and/or LLS/WTI Differential

The table above applies to hedged production only. Unhedged production is subject to these same price components but based on their published monthly index values.

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

Project Updates

Salt Dome Projects

1. South Marsh Island 73 Salt Dome

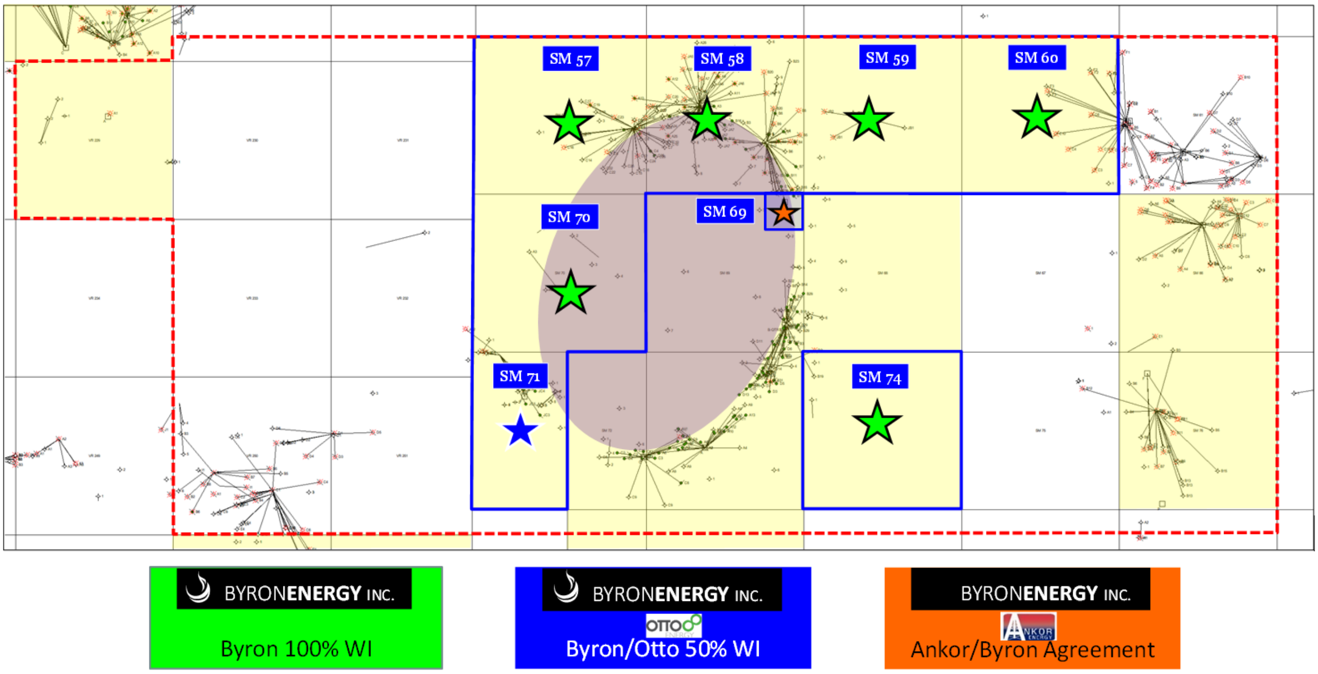
The SM73 field encompasses nine OCS lease blocks (81 square miles) which overlie a large piercement salt dome. The salt dome is responsible for providing the trapping mechanism for production in all portions of the SM73 field. The SM73 field is productive from discrete hydrocarbon-bearing sandstone reservoirs 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.

Salt Dome Projects (cont)

South Marsh Island 73 Salt Dome (cont)

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



(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") 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.

(i) SM 71 Production

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

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

Salt Dome Projects (cont)

South Marsh Island 73 Salt Dome (cont)

(ii) Production at 30 June 2020

As of 30 June 2020, the SM71 platform the gross production rate was approximately 2,870 barrels of oil per day and 4.6 million cubic feet of gas per day and no water from the F1 and F3 wells. F2 and F4 wells were each producing small amounts of water.

(iii) SM 71 Production Statistics

Byron's share of SM 71 production for the quarter ended 30 June 2020 is shown in the table below.

SM71 Production (sales)	June 2020 quarter	March 2020 quarter	YTD 30 June 2020	YTD 30 June 2019
Gross production				
Oil (bbls)	197,755	206,656	923,027	1,116,375
Gas (mmbtu)	550,871	372,593	1,532,750	2,213,706
Byron share of Gross Production (WI Basis)				
Oil (bbls)	99,999	103,346	462,653	558,188
Gas (mmbtu)	488,051	288,920	1,081,614	1,106,853
Net production (Byron share (NRI Basis))				
Oil (bbls)	81,249	83,968	375,906	453,527
Gas (mmbtu)	396,541	234,748	878,811	899,318

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

During June 2020 quarter, gross oil production averaged 2,173 barrels of oil per day ("bopd").

SM71 Sale revenue (accrual basis) US$ million	June 2020 quarter	March 2020 quarter	YTD 30 June 2020	YTD 30 June 2019
Net sales revenue (Byron share on NRI basis)	3.7	4.4	20.6	31.0

For the quarter ended 30 June 2020, Byron's share of net revenue was approximately US$ 3.7 million compared to US$ 4.4 million in the March 2020 quarter, due to lower average realised oil and gas prices and lower oil production, as a result of Byron's decision to shut in the SM71 F1 well and reduce production from the F3 well to 1,850 bopd, effective 31 March 2020, to maximise long term value by linking production to volume commitments under the Company's forward sale agreement, during a period of depressed prices.

Salt Dome Projects (cont)

South Marsh Island 73 Salt Dome (cont)

During the June 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$ 36.99 per bbl (US$ 41.50 excluding transportation) compared to US$ 47.57 per bbl and US$ 52.08 per bbl respectively for the March 2020 quarter.

Byron realised an average gas price after transportation deductions of approximately US$ 1.28 per mmbtu during the June quarter (US$ 1.64 excluding transportation) compared to US$ 1.50 per mmbtu and US$ 1.88 per mmbtu respectively for the March 2020 quarter.

Gas was not processed for NGLs as direct gas sales delivered higher proceeds due to supressed NGL commodity pricing during the quarter.

(iv) SM 71 F4 Well

The SM71 F4 well was turned over to production in mid-March 2020 and the D5 Upper Sand has now produced a total of 0.6 billion cubic feet of gas, 1,875 barrels of condensate and 1,025 barrels of 41 degree API oil for a total of 2,900 barrels of condensate and oil. Throughout the June quarter, the F4 has continued to decline in reservoir pressure indicating a very weak water drive for the D5 Upper Sand reservoir. The well is currently being produced through the platform compressor and of 30 June 2020, the F4 well was producing approximately 2.8 million cubic feet of gas and 53 barrels of oil, accompanied by 2 barrels of water (gross basis) per day. On 27 July 2020, the F4 was producing 2.1million cubic of gas and 77 barrels of 37.8 API oil and 6 barrels of water (gross basis) at a flowing tubing pressure of 215 psi. Byron's internal mapping and volumetrics indicates a potential gas cap of between 0.5 and 1.0 Bcf. Ultimately, the oil recovery from the D5 Upper Sand will depend on the strength of the reservoir water drive mechanism, but that support appears to be weak.

As previously reported, Otto declined to participate in the SM71 F4 well. After re-evaluating the SM71 F4 well for geological and drilling risks versus potential rewards, Byron decided to drill the F4 well on a 100% basis.

The SM71 Offshore Operating Agreement provides for participation in proposed operations by fewer than all parties, including the right for the non-participating party to revert to their working interest after the participating party has recouped, out of 100% of production, an amount of six hundred percent (600%) of all costs associated with drilling and completion, as outlined in Byron's ASX release of 2 October 2019.

(v) SM 71 F5 Well

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

Byron reported the well results on 23 March 2020 (refer to Byron's ASX release dated 23 March 2020 for details). At the end of drilling operations on the F5, the open hole portion of the F5 was temporarily abandoned for use as a future side-track. Because of uncertainty related to the potential impact of the COVID-19 on operations, Byron and Otto elected to defer a sidetrack operation at this time. The SM71 F5 wellbore was temporarily abandoned in a manner that allows it to be efficiently sidetracked in the future when the uncertainty relating to the COVID-19 epidemic has dissipated and also at a time where oil prices are higher.

(b) South Marsh Island 58

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

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Salt Dome Projects (cont)

South Marsh Island 73 Salt Dome (cont)

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

SM58 G Production Platform and Development Drilling

Byron's final Development Operations Coordination Document ("DOCD") was approved on 4 June 2020. The DOCD allows 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.

Pipeline operations began in early July 2020. Completion operations utilising the Enterprise Offshore Drilling ("EOD") 264 jack-up drilling rig commenced on 18 July 2020 after the EOD 264 was jacked up to working height over the platform well bay and the process of tying back the SM58 G1 well, drilled and logged in September 2019, began.

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 drilling of the G2 well will follow immediately after completion of the G1 well. The bottom-hole location of the G2 is near the G1 well and the well will be drilled to an approximate measured depth of 11,600 feet (MD) (10,575 feet true vertical depth (TVD)). The primary goal of the G2 is to redrill and evaluate the Lower O Sand section.

The timing of additional new wells from the SM58 G Platform, beyond G2, to test the Upper and Lower O Sands defined in Byron's Steelhead Prospect and the Upper O Sand in the Brown Trout Prospect, is dependent on results of the G2 well and oil price outlook at the time.

When completed and installed, the SM58 G platform will be 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.

SM58 Production Statistics

Byron's share of production for the quarter ended 30 June 2020 is shown in the table below. Byron acquired the SM 58 lease effective 1st January 2019.

Salt Dome Projects (cont)

South Marsh Island 73 Salt Dome (cont)

SM58 Production (sales)	June 2020 quarter	March 2020 quarter	YTD 30 June 2020	YTD 30 June 2019
Gross production				
Oil (bbls)	8,465	11,415	40,294	19,683
Gas (mmbtu)	2,736	2,368	9,610	10,756
Byron share of Gross Production (53% WI)				
Oil (bbls)	4,486	6,050	21,356	10,497
Gas (mmbtu)	1,450	1,255	5,093	5,736
Net production (Byron share 44.167% (after royalty))				
Oil (bbls)	3,739	5,042	17,797	8,693
Gas (mmbtu)	1,208	1,046	4,244	4,751

Sale revenue (accrual basis) US$ million	June 2020 quarter	March 2020 quarter	YTD 30 June 2020	YTD 30 June 2019
Net sales revenue (Byron share 44.167% NRI)	0.1	0.2	0.8	0.5

(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 development 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.

If the SM58 G2 well is successful Byron will be positioned to drill SM69 E2 well soon after under the JEA.

Salt Dome Projects (cont)

South Marsh Island 73 Salt Dome (cont)

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

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

(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") at the Gulf of Mexico OCS Lease Sale 250 held on 21 March 2018 in New Orleans, Louisiana.

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

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, reflecting the recently reduced Federal Government Royalty of 12.5% versus pre-2017 rate of 18.75%.

EI62/63/76/77 were designated as the 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. Final deliverables were received during the June quarter 2019. Analysis of the reprocessed data is continuing.

Salt Dome Projects (cont)

3. Main Pass 293, 305 & 306

Byron currently holds a 100% WI and an 87.50% NRI in Main Pass 293, 305 & 306 ("MP 306 Field") acquired at the Gulf of Mexico, Outer Continental Shelf ("OCS") Lease Sale 251 ("Lease Sale 251") held in New Orleans, Louisiana on 15 August 2018.

The three leases comprise the MP306 field as formerly designated by the Bureau of Ocean Energy Management ("BOEM"). The MP 306 Field was discovered in 1969 and lies in approximately 200 feet of water. Total produced hydrocarbons from the field are 96 million barrels of oil and 107 bcf of gas from 172 of the 249 total wells drilled. The field ceased production in late 2009 and the last well drilled on any of these blocks was in 2004. The production was from a number of sands ranging from a depth of 4,000 to 9,000 feet.

The structural complexity of the salt dome combined with the stratigraphic variation of the trapping sands and possible deeper stratigraphic targets makes this salt dome an ideal candidate for RTM seismic imaging, similar to Byron's operated SM71 salt dome project.

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

Non-Salt Dome Projects (Byron Operated)

1. Grand Isle Block 95

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

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

No material activity was undertaken on GI 95 during June 2020 quarter.

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Properties

As at 30 June 2020, Byron's portfolio of properties, all in the shallow waters of the Gulf of Mexico, and coastal marshlands of Louisiana, USA comprised:-

Properties	Operator	Interest WI/NRI* (%)	Lease Expiry Date	Area (Km^2)
South Marsh Island Block 71	Byron	50.00/40.625	Production	12.16
South Marsh Island Block 57	Byron	100.00/81.25	June 2022	21.98
South Marsh Island Block 59	Byron	100.00/81.25	June 2022	20.23
South Marsh Island Block 60	Byron	100.00/87.50	June 2024	20.23
South Marsh Island Block 58 (Excl. E1 well)	Byron	100.00/83.33**	Production	20.23
South Marsh Island Block 58 (E1 well in S ½ of SE ¼ of SE ¼ and associated production infrastructure in NE ¼ of NE ¼ of SM69)	Ankor	53.00/44.167		
South Marsh Island Block 69 (NE ¼ of NE ¼)	Byron	100.00/77.33-80.33	Production	1.3
South Marsh Island Block 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
Grand Isle Block 95	Byron	100.00/87.50	September 2022	18.37

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

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

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

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
Mmbo = 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 currently 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 June 2020

	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	3,897	22,753
1.2	Payments for		
	(a) exploration & evaluation (if expensed)*	(78)	(8,455)
	(b) development	(20,483)	(34,698)
	(c) production	(882)	(3,364)
	(d) staff costs	(638)	(2,407)
	(e) administration and corporate costs	(327)	(1,999)
1.3	Dividends received (see note 3)		
1.4	Interest received	1	12
1.5	Interest and other costs of finance paid	(658)	(1,765)
1.6	Income taxes paid		
1.7	Government grants and tax incentives		
1.8	Other (provide details if material)		
	- Oil price hedging premium	(339)	(339)
	- Refundable Security Deposits	-	150
	- Cash contributions from farminees / JV partners	412	5,009
1.9	**Net cash from / (used in) operating activities**	**(19,095)**	**(25,103)**

2.	**Cash flows from investing activities**		
2.1	Payments to acquire:		
	(a) entities		
	(b) tenements		
	(c) property, plant and equipment		
	(d) exploration & evaluation (if capitalised)*	(883)	(15,810)
	(e) investments		

Consolidated statement of cash flows		Current quarter US$'000	Year to date (12 months) US$'000
	(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**	**(883)**	**(15,810)**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)	18,574	36,269
3.2	Proceeds from issue of convertible debt securities		
3.3	Proceeds from exercise of options	-	1,742
3.4	Transaction costs related to issues of equity securities or convertible debt securities	(463)	(1,506)
3.5	Proceeds from borrowings	-	17,990
3.6	Repayment of borrowings	-	(3,691)
3.7	Transaction costs related to loans and borrowings		
3.8	Dividends paid		
3.9	Other (provide details if material)	(9)	(39)
3.10	**Net cash from / (used in) financing activities**	**18,102**	**50,765**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	18,170	6,783
4.2	Net cash from / (used in) operating activities (item 1.9 above)	(19,095)	(25,103)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(883)	(15,810)
4.4	Net cash from / (used in) financing activities (item 3.10 above)	18,102	50,765
4.5	Effect of movement in exchange rates on cash held	351	10
4.6	**Cash and cash equivalents at end of period**	**16,645**	**16,645**

**adjusted for new ASX reporting format requirements.*

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	16,645	18,170
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)**	**16,645**	**18,170**

6.	***Payments to related parties of the entity and their associates***	**Current quarter $A'000**
6.1	Aggregate amount of payments to related parties and their associates included in item 1	334
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

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 $'000**
7.1a	Loan facilities 1. (unsecured and repayable by 31 March 2021, bearing 10% interest p.a.)	US$ 2,000 & A$ 2,100	US$ 2,000 & A$ 2,100
8.1b	Loan facilities (secured over the SM71 & SM58 assets on a 3 year fixed term, bearing 15% interest p.a with no loan repayments until 2nd year of loan term.)	US$ 18,500	US$ 15,000
7.2	Credit standby arrangements	-	-
7.3	Other (please specify)	-	-
7.4	**Total financing facilities**	US$ 20,500 & A$ 2,100	US$ 17,000 & A$ 2,100

7.5	**Unused financing facilities available at quarter end***	US$3,500

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.

*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 on the same terms and conditions as the existing US$15 million facility.

8.	***Estimated cash available for future operating activities***	**US$'000**
8.1	Net cash from / (used in) operating activities (Item 1.9)	(19,095)
8.2	Capitalised exploration & evaluation (Item 2.1(d))	(883)
8.3	Total relevant outgoings (Item 8.1 + Item 8.2)	**(19,978)**
8.4	Cash and cash equivalents at quarter end (Item 4.6)	16,645
8.5	Unused finance facilities available at quarter end (Item 7.5)	3,500
8.6	Total available funding (Item 8.4 + Item 8.5)	**20,145**
8.7	**Estimated quarters of funding available (Item 8.6 divided by Item 8.3)**	**1.0**

8.8 If Item 8.7 is less than 2 quarters, please provide answers to the following questions:

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: Future development expenditure will be materially lower, as the SM58 platform has been completed and successfully installed, as announced to the ASX 6 July 2020

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, future development expenditure will be materially lower, as the SM58 platform has been completed and successfully installed. In addition, (i) a further A$ 2.2 million in equity was raised, as approved the EGM on 9 July 2020. In addition, (ii) US$3.5 million in additional finance facilities, finalised in the June 2020 quarter, is expected to be drawn down in the September 2020 quarter, and (iii) significant oil and gas production is planned to commence from SM58 in September 2020.

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

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

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: 29 July 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.