AUSTRALIS OIL & GAS

5 February 2021

Reserve and Resource Update Year end 2020

Australis Oil & Gas
ABN: 34 609 262 937

ASX: ATS

Australis is an upstream oil and gas company seeking to provide shareholders value and growth through the strategic development of its quality onshore oil and gas assets in the United States of America.

The Company's acreage within the core of the oil producing TMS contains 3.7 million bbls of producing reserves providing free cash flow and over 170 million bbls of mid case 2P + 2C recoverable oil.

The Company was formed by the founders and key executives of Aurora Oil & Gas Limited, a team with a demonstrated track record of creating and realising shareholder value.

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Australis Oil and Gas Limited ("Australis" or "Company") is pleased to provide its YE2020 reserve and resource update as independently assessed by Ryder Scott Company L.P. ("Ryder Scott") with an effective date of 31 December 2020[1].

There have been no material changes to the existing or future well production performance assumptions by Ryder Scott since the YE2019 estimates and all future locations in each reserve category were considered economic.

Due to the significant acreage position that Australis holds in the TMS, the reserves allocated under the ASX reporting regulations is always limited by the development schedule adopted by a company the size of Australis, i.e. a reduction in the proposed development program will reduce the associated reserves, assuming no other changes.

As a reflection of prevailing market conditions, the YE2020 reserve estimate assumes a conservative development schedule compared to previous years. Only 58 gross (40 WI) wells are assumed to be drilled within the maximum permitted 5-year development window (YE2019 – 180 gross / 154 WI wells). This reduced assumed development program has generated commensurate reductions in the reserve estimates and consequential increases in the contingent resources.

The Company holds approximately 107,500 net acres in the TMS Core, which has been used to generate the following:

- **Net oil reserve estimates:** (variance vs YE2019[2]) based on a limited development area assessed for reserves of only ~10% of the Company's acreage in the TMS Core:
    - PDP – 3.7 MMbbls (+3%)
    - 1P – 10.4 MMbbls (-79%)
    - 2P – 21.0 MMbbls (-66%)
    - 3P – 27.5 MMbbls (-70%)
- **Net contingent oil resource estimates:** (variance vs YE2019[2]) based on the remaining undeveloped acreage in the TMS Core:
    - 1C – 20.8 MMbbls (+332%)
    - 2C – 149.4 MMbbls (+15%)
    - 3C – 270.7 MMbbls (+15%)
- PDP volumes have increased despite over 411 Mbbls of net production (post royalties) during the year.
- The NPV(10) of the PDP volumes at an assumed flat oil price of US$47.02/bbl is US$47.2 million.

Australis Managing Director and CEO Ian Lusted, said

"Whilst a more conservative development program assumed for the Ryder Scott report has led to a reallocation of reserves to contingent resources, all future well locations considered are economic and key production performance parameters haven't materially changed since 2019. Although there is a reduction in the allocation of reserves, based on the limited 5-year development plan, the oil hasn't gone anywhere and the fundamentals of the TMS continue to be robust as shown by the increase in PDP reserves in a lower price environment and no material changes to the future development well Type Curves."

Australis 2020 year end reserve and resource estimates

At the effective date of the report, 31 December 2020, Australis held the rights to 107,500 net acres within the TMS Core area. The existing 38 operated wells and 17 non-operated wells developed approximately 9,000 net acres of this position and at the effective date Australis retains a Proved Developed Producing ("PDP") reserve of 3.7 million bbls after royalties from these wells.

Each year, for the purposes of estimating undeveloped reserves, a development schedule is generated which has to be appropriate and reasonable for Australis to execute. This development plan is prepared in consultation with Ryder Scott and takes into consideration market conditions and Australis's operational capacity, including financing and historical drilling activity. The plan must also conform to the various ASX and SPE-PRMS requirements, the key points of which are:

- the development plan is executed over a 5-year period from the effective date; and
- proved well locations must be drilled within 5 years of the date they were <u>first</u> certified as a reserve in previous reports.

The development plan in the YE2019 Reserve Report consisted of 180 gross wells to be drilled, while the YE2020 Reserve Report development plan is considerably reduced to 58 gross wells. The schedule and breakdown in each reserve category is summarised in Table 1 below.

Period	Rig Count		Development Well Count							
			Proved (PUD)		Probable		Possible		Total	
	YE19	YE20	YE19	YE20	YE19	YE20	YE19	YE20	YE19	YE20
Year 1	2	0	7	0	0	0	4	0	11	0
Year 2	3	1	31	8	0	0	1	0	32	8
Year 3	4	1	44	5	2	3	1	2	47	10
Year 4	4	2	18	7	6	12	26	1	50	20
Year 5	4	2	11	9	4	6	25	5	40	20
Total			**111**	**29**	**12**	**21**	**57**	**8**	**180**	**58**

Table 1: Comparison of rig and gross well count each year of the 2019 and 2020 reserve development plans.

The YE2020 development schedule assumes no drilling in 2021, with activities commencing in January 2022 with a single rig and then a second rig added at the beginning of 2024.

Table 1 above provides the total (gross) wells drilled. Australis has a working interest in each which dictates the reserves the Company can take credit for during the wells production life. On a WI well count for the proved reserve category, Australis had 104 WI proved undeveloped wells in the YE2019 development plan, but only 16 WI proved undeveloped wells in the YE2020 development plan. The ratio reduction of WI well count is the same as the reduction in PUD reserves between the two reports.

There has been no change to the fundamentals of the TMS undeveloped wells and Ryder Scott has made no material changes to their assumptions on future undeveloped well production performance.

This and previous year end reserve development schedules only ever assume development of a modest portion of the total acreage position that Australis holds. Based on our existing leasehold position, allowing for the acreage associated with the existing producing wells, Australis estimates a total of approximately 400 future net wells will develop the entire reserve and resource position. The total YE2020 development schedule corresponds to only 40 future net wells, or only 10% of the developable TMS Core acreage.

The remaining undeveloped acreage that has not been considered for reserves (approximately 90% of our undeveloped TMS Core acreage) transitions into the contingent resource categories.

Ryder Scott assessed all future locations they evaluated for development to be commercial and they allocated the following oil reserves and resources to the Australis TMS position in the YE2020 report.

Reserve Category	Australis Reserves[1]		Net Oil YE2020 vs YE2019[2]
	Gross Oil (Mbbls)	Net Oil (Mbbls)	
Proved Developed Producing (PDP)	5,383	3,656	+3%
Proved Undeveloped (PUD)	15,128	6,722	-85%
Proved (1P)	**20,511**	**10,377**	**-79%**
Probable Developed Producing	695	486	-26%
Probable Undeveloped	15,462	10,157	-21%
Probable Total	16,157	10,644	-22%
Proved + Probable (2P)	**36,668**	**21,021**	**-66%**
Possible Developed Producing	821	574	-18%
Possible Undeveloped	10,650	5,868	-80%
Possible Total	11,472	6,441	-80%
Proved + Probable + Possible (3P)	**48,139**	**27,462**	**-71%**

Table 2: Comparison of reserve estimates for YE2020 and YE2019.

The YE2020 PDP net reserve estimate[1] of 3.66 MMbbls is reconciled to the YE2019 report below in Table 5. Although Australis has produced 410,700 bbls (post royalties) and no new wells were brought on to production during 2020, the allocated net PDP Reserves has increased by 109,000 bbls which, as the reconciliation below in Table 5 shows, is primarily due to reduced operating costs, increasing their economic life. The NPV(10) of the net PDP reserves volume is US$47.25 million, which is a decrease of 25% from the YE2019 value, predominantly due to the lower oil price assumption for the YE2020 report of US$47.02/bbl (vs. YE2019 assumed price of US$60.27/bbl).

Contingent Resource Category	Oil (Mbbls)[1]	Oil YE2020 vs YE2019[2]
Low Estimate (1C)	20,789	+332%
Best Estimate (2C)	149,420	+15%
High Estimate (3C)	270,673	+15%

Table 3: Comparison of contingent resource estimates for YE2020 and YE2019.

Assumptions

Key assumptions used by Ryder Scott to generate the YE2020 estimates are as follows:

- Reserves and contingent resources estimates are based on the deterministic estimation method.
- The oil price used for all reserves analysis in this report is a flat realised $47.02/bbl, which is based on the average achieved price by Australis during the month prior to the effective date of the report, it is US$13.25/bbl (22%) less than the realised price assumed in the YE2019 estimates.
- Operating costs for developed producing wells are based on actuals incurred between December 2019 and November 2020 but omits May 2020 costs as Australis voluntarily curtailed production which affected the operating costs for this month. Operating costs for future wells are based on the same data and are management's conservative estimates of likely costs going forward.
- The existing PDP estimates are based on production from 38 operated and 17 non-operated wells (37.5 net wells).
- Proposed future well locations are allocated a reserve category based on proximity to existing wells and production.
- The five-year development plan used for this reserve report is detailed in Table 1 and assumes a one rig program starting in January 2022 and a second rig added in January 2024. A total of 58 gross well locations. The development plan assumes eight wells per standard development unit and approximately 250 acre spacing.
- Anticipated D, C & T well costs range from US$9.5 to US$10.9 million depending on well length and timing. The estimated long-term cost of a 7,500 ft drilled lateral is on average US$9.5 million which is based on recent contract updates.
- The development plan assumes an initial estimate of 45 days to drill new wells in year 2, which then reduces to 37 days from the start of year 3 of the development schedule.
- Type curves were derived from historical production data. Proved, probable and possible type curves were generated by Ryder Scott and used for future wells within the development plan. Table 4 provides the type curve EUR's for each reserve class and provides a comparison to YE2019

Reserve category	Type Curve EUR	
	YE2019[2] (Mbbls)	YE2020[1] (Mbbls)
Proved	527	520
Probable	611	604
Possible	709	700

Table 4: Comparison of Reserve Type Curve EURs for YE2020 and YE2019.

- Type curves were scaled to planned future well horizontal length.
- Average royalty payable on future well locations allocated a reserve in this report is 19.2%.
- Contingent resources are estimated for areas not included in the reserve development area. The 1C contingent resources are limited to any development unit (usually 1920 gross acres) that contains an existing TMS well which would have been considered as reserves had the development plan included such locations within the five-year development window. The 2C and 3C considered all the remaining undeveloped net acreage within the core area but used different estimates of in-place volumes and recovery factors.
- No gas sales are assumed as all gas is consumed on the lease, therefore neither gas nor gas liquids have been included in the reserves estimates.

PDP reconciliation

Table 5 below provides a reconciliation of net PDP reserves between 31 December 2019 and 31 December 2020.

Description	Net Oil (Mbbl)
PDP Reserve (31/12/19)[2]	**3,547**
2019 Net Production	(411)
Technical Adjustment	(26)
2019 Production Variance	(71)
Lower oil price	(63)
Lower operating cost	692
Changes to ownership	(16)
Other	4
PDP Reserve (31/12/20)[1]	**3,656**

Table 5: Reconciliation of PDP reserves between YE2019 and YE2020.

Contributors to the upwards adjustments shown in the above table are discussed below.

- The lower operating costs achieved in 2020 were the single biggest contributor to the PDP increases observed at YE2020. These have been generated through reductions in workover frequency and both fixed and variable operating costs. Overall a reduction of 13% was achieved on a per bbl basis and this extends economic cut off, thereby adding reserve volumes.

- The operating cost improvements were offset by the reduction in assumed oil price to $47.02/bbl, which influences PDP volumes by shortening economic cut off.
- The reconciliation includes an adjustment for variance in planned 2019 production volumes, which were primarily due to the voluntary curtailment that took place in Q2 2020.
- There were then non-material adjustments for well performance and changes in ownership (wells reaching various payout thresholds with associated reversionary interest).

It is testimony to both the change in operating costs and maintenance of well performance that despite producing nearly 12% of our YE2019 PDP reserves, the YE2020 figure was actually 3% higher, ie effectively a 15% improvement in these figures.

TMS Contingent Resource reconciliation

Table 6 below summarises the change in contingent resource estimated on 31 December 2019 and 31 December 2020.

Description	Net Contingent Resource 31 Dec 2019[2] (MMbbl)	Net Contingent Resource 31 Dec 2020[1] (MMbbl)
Low Contingent Resource (1C)	6.3	20.8
Most Likely Contingent Resource (2C)	129.5	149.4
High Contingent Resource (3C)	234.8	270.7

Table 6: Comparison of contingent resources for YE2019 and YE2020.

The following key factors contributed to the changes in contingent resource.

- All subsurface assumptions on in place volumes and recovery factors remained identical for both the YE2019 and the YE2020 resource estimates.
- A significantly reduced 5-year development program left more acreage in each contingent resource category which was the only contributor to the increases in estimated volumes.
- The decision by Australis during 2020 to cease discretionary expenditure, led to a reduction in the total land position from 115,000 to 107,500 net acres and this contributed to the contingent resources being commensurately reduced.

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This ASX announcement was authorised for release by the Australis Disclosure Committee.

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GLOSSARY

Unit	Measure	Unit	Measure
B	Prefix – Billions	bbl	Barrel of oil
MM	Prefix – Millions	boe	Barrel of Oil equivalent (1bbl = 6 mscf)
M	Prefix – Thousands	scf	Standard cubic foot of gas
/d	Suffix – per day	Bcf	Billion cubic feet of gas

Unit	Measure
Gross	The total well count or 100% volume produced from a well or in a reserve category
WI	Company beneficial interest before royalties or burdens
Net or NRI	Company beneficial interest after royalties or burdens
C	Contingent Resources (1C/2C/3C equivalent to low/most likely/high)
NPV(10)	Net Present Value (@ discount rate)
EUR	Estimated Ultimate Recovery (oil and gas) of a well
WTI	West Texas Intermediate oil benchmark price
LLS	Louisiana Light Sweet oil benchmark price
D, C & T	Drill, Complete, Tie – in and artificial lift
2D/3D	2 and 3 dimensional seismic surveys
Opex	Operating Expenditure
HBP	Held by production – within a formed unit a producing well meets all lease obligations within that unit. Primary term remains valid whilst well is on production.
LOE	Lease Operating Expense
TMS Core	The Australis designated productive core area of the TMS delineated by production history
Type Curve	The estimated ultimate recovery (EUR) and associated production profile for a future development well location

Notes

1. Estimates from the independent Ryder Scott report, effective 31 December 2020 and dated 29 January 2021. The report was prepared in accordance with the definitions and disclosure guidelines contained in the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management (SPE-PRMS) as revised in June 2018. Ryder Scott generated their independent reserve and contingent resource estimates using deterministic methods.
2. Contingent Resources and Reserves estimated with an effective date 31 December 2019 are taken from the independent Ryder Scott report dated 31 January 2020 and announced on 11 February 2020 and titled 'Reserve and Resource Update Year End 2019'.

Competent Persons Statement

The reserves and contingent resource estimates provided in this announcement pertaining to the Tuscaloosa Marine Shale is based on, and fairly represents, information and supporting documentation, prepared by, or under the supervision of, Raymond Yee, P.E., who is an employee of Ryder Scott Company, L.P. an independent professional petroleum engineering firm. Mr Yee is a Professional Engineer in the State of Texas (Registration No. 81182). The reserve and resource information pertaining to the Tuscaloosa Marine Shale in this announcement has been issued with the prior written consent of Mr Yee in the form and context in which it appears.

Forward Looking Statements

This document may include forward looking statements. Forward looking statements include, but are not necessarily limited to, statements concerning Australis' planned development program and other statements that are not historic facts. When used in this document, the words such as "could", "plan", "estimate", "expect", "intend", "may", "potential", "should" and similar expressions are forward looking statements. Although Australis believes its expectations reflected in these statements are reasonable, such statements involve risks and uncertainties, and no assurance can be given that actual results will be consistent with these forward-looking statements.