For Immediate Release ASX Announcement

4 November 2021

Company Presentation Material

Please find attached to this document a copy of the presentation that will be presented by Australis Oil & Gas Limited today at Euroz Hartleys Energy Snapshot Conference.

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

For further information, please contact either:

Ian Lusted
Managing Director
Australis Oil & Gas Limited
+61 8 9220 8700

Graham Dowland
Finance Director
Australis Oil & Gas Limited
+61 8 9220 8700

ASX: ATS

Euroz Hartleys
Energy Snapshot Conference

4 November 2021

AUSTRALIS OIL & GAS

Important Notice and Disclaimer

This presentation has been prepared by Australis Oil & Gas Limited ABN 34 609 262 937 (ASX: ATS) (**Australis**).

Summary of information: This presentation contains general and background information about Australis' activities current as at the date of the presentation and should not be considered to be comprehensive or to comprise all the information that an investor should consider when making an investment decision. The information is provided in summary form, has not been independently verified, and should not be considered to be comprehensive or complete. The information in this presentation remains subject to change without notice. Australis is not responsible for providing updated information and assumes no responsibility to do so.

Not financial product advice: This presentation is not financial product, investment advice or a recommendation to acquire Australis securities and has been prepared without taking into account the objectives, financial situation or needs of individuals. Before making an investment decision prospective investors should consider the appropriateness of the information having regard to their own objectives, financial situation and needs, and seek legal, taxation and financial advice appropriate to their jurisdiction and circumstances. Australis is not licensed to provide financial product advice in respect of its securities or any other financial products. Australis assumes that the recipient is capable of making its own independent assessment, without reliance on this document, of the information and any potential investment and will conduct its own investigation.

Disclaimer: Australis and its related bodies corporate and each of their respective directors, agents, officers, employees and advisers expressly disclaim, to the maximum extent permitted by law, all liabilities (however caused, including negligence) in respect of, make no representations regarding, and take no responsibility for, any part of this presentation and make no representation or warranty as to the currency, accuracy, reliability or completeness of any information, statements, opinions, conclusions or representations contained in this presentation. In particular, this presentation does not constitute, and shall not be relied upon as, a promise, representation, warranty or guarantee as to the past, present or the future performance of Australis.

Future performance: This presentation contains certain forward-looking statements and opinion. Generally, words such as "anticipates", "expects", "intends", "plans", "believes", "seeks", "estimates", "potential" and similar expressions are intended to identify forward-looking statements. The forward-looking statements, opinion and estimates provided in this presentation are based on assumptions and contingencies which are subject to change without notice, as are statements about market and industry trends, which are based on interpretations of current market conditions. Forward-looking statements, including projections, forecasts and estimates, are provided as a general guide only and should not be relied on as an indication or guarantee of future performance and involve known and unknown risks, uncertainties and other factors, many of which are outside the control of Australis. Past performance is not necessarily a guide to future performance and no representation or warranty is made as to the likelihood of achievement or reasonableness of any forward-looking statements or other forecast.

Not an offer: This presentation is for information purposes only. This presentation is not, and should not be considered as, an offer or an invitation to acquire securities in Australis or any other financial products and neither this document nor any of its contents will form the basis of any contract or commitment

Monetary values: Unless otherwise stated, all dollar values are in United States Dollars (US$). The information in this presentation remains subject to change without notice.

TMS Core – Opportunity Summary

1 **Unique Strategic Opportunity**

- ✓ Proven productivity
- ✓ Large position
- ✓ Strong base-case well economics with significant upside
- ✓ Infrastructure, commodity pricing, field rules, supportive regulator and local authorities make play attractive
- ✓ Access to all historical data and records
- ✓ **Entry cost similar to an exploration play!**

2 **Substantial Oil Asset with Ability for Growth**

- ✓ Effective control over the TMS Core - ~400 future net well locations
- ✓ No federal leases
- ✓ 33 operated wells producing >1,250 bbls/day
- ✓ Large resource of 170 MMbbls oil[1]
- ✓ **Path to significant growth via leasing, downspacing and additional prospective formations**

3 **Multiple TMS-specific Value Drivers**

- ✓ Recent productivity **over 1,000 bbls/d IP30.**
- ✓ Liquids rich - 95% oil and sold at LLS-based premium to WTI
- ✓ Abundant infrastructure and multiple marketing options
- ✓ Low average royalty rates @ 20%
- ✓ **3rd Party activity underway in the field**

4 **Strong Well Economics with Upside**

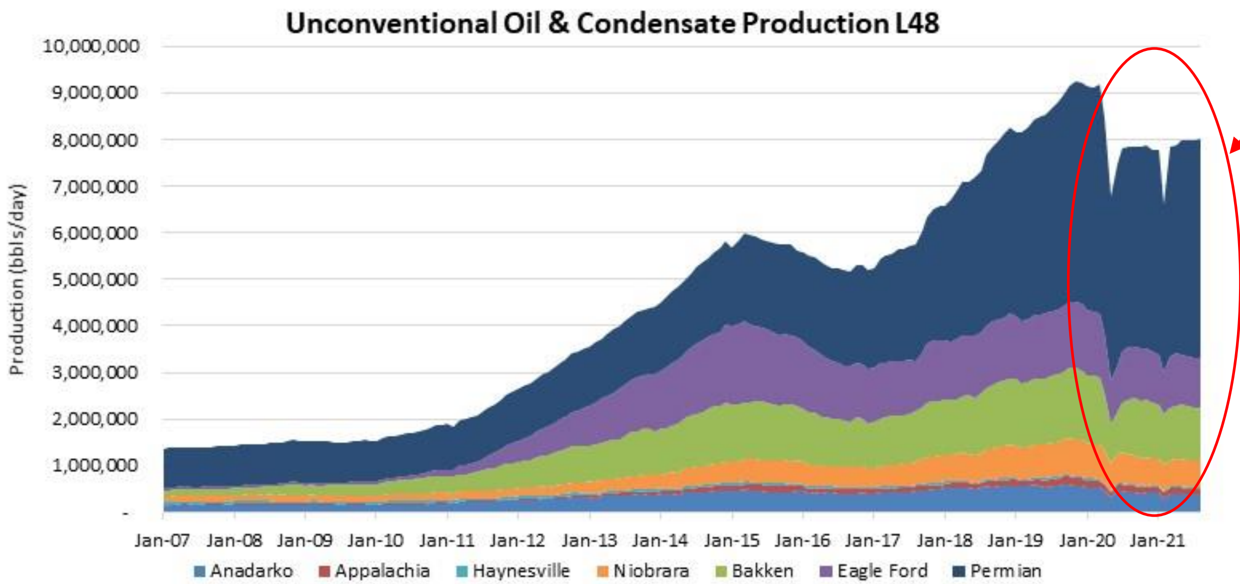
- ✓ Single well NPV(10) of \$8.3m and IRR of 57% (WTI \$65/bbl & \$9.0m well cost[A]) using average historical well performance
- ✓ Further productivity and cost improvements very achievable
- ✓ **Modest additional cost reductions and price improvement lead to an NPV(10) of \$13.3m and IRR of 113% (WTI \$80/bbl & \$8.0m well cost[B])**

AUSTRALIS OIL & GAS

A: Well cost includes drilling, completion, facilities & artificial lift in Full Field Development mode
B: See Slide 11 for more detail

Evolution of the US Shale Industry

US unconventional oil production growth has steadied as unconventional industry matures



Oil Production declining in key US shale fields other than the Permian which is driving gentle overall growth

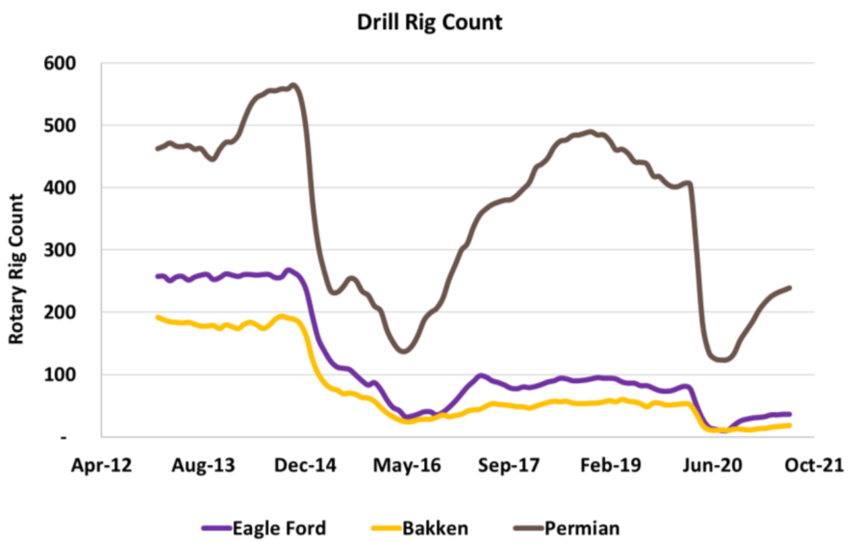
- US oil production grew rapidly to over 14 million bbls per day and shale alone became the 4th largest contributor to oil production in the world.
- The Permian, Eagle Ford and Bakken generated over 86% of shale production in the last few months:
- Eagle Ford and Bakken are now mature – were already plateauing by early 2020 – have not recovered from COVID – both approx. 25% down
- In 2019 the Permian was 41% of shale production; the end of 2021 - 60%
- Permian is the sole source of US growth but heavily consolidated by large producers in last 18 months

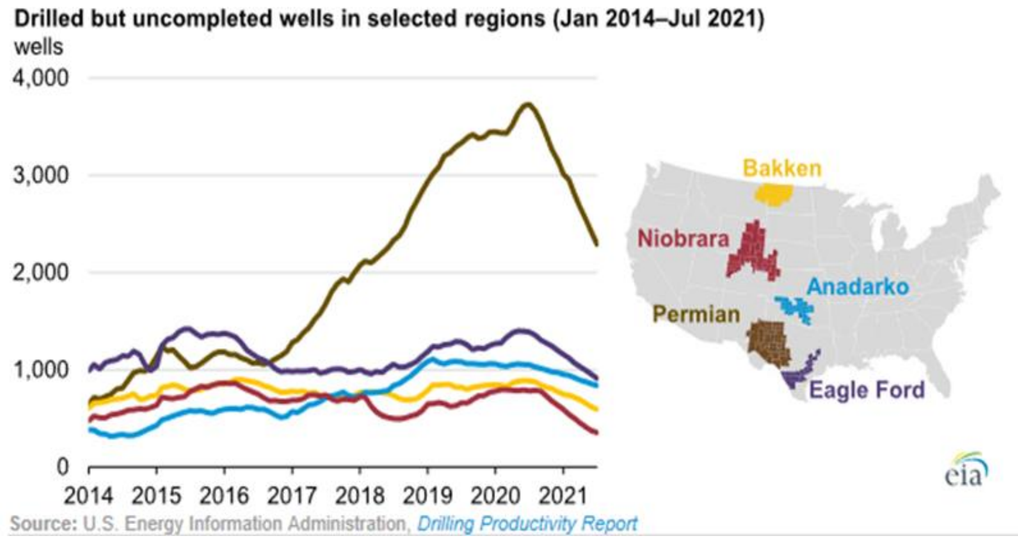
AUSTRALIS OIL & GAS

Source: EIA Drilling Productivity Report September 2021

US shale industry recent drivers and Australis strategy

US unconventional growth has steadied as unconventional industry matures





- Rig count remains low (from YE19: 40% down in Permian, 55% in Eagle Ford and 66% in Bakken).
- Companies have been consuming Drilled Uncompleted wells (DUCs)
- DUCs are finite – Operators will be forced to spend more to drill with limited inventory in mature plays
- Industry will be forced to look outside familiar areas as remaining growth area is tightly held.

The TMS is one of the last quality oil weighted plays that has been appraised but not developed

AUSTRALIS OIL & GAS

Source: EIA Drilling Productivity Report September 2021

TMS Core – Path to Development & Partnering

1 Execution De-risked

- ✓ **Reduction in execution risk through the application of technology and accumulated knowledge**
- ✓ Data from over $1B in capex in TMS including:
  - Over 6-year production history
  - Considerable technical data
  - ATS team direct experience in executing wells consistently in the play
- ✓ Historic and recent drilling operations analysed, identified key remaining risks and solutions
- ✓ Established best practice for future drilling

2 Significant development flexibility

- ✓ Operated position provides optionality on timing and control over capital profile
  - Long lease life
  - 38,100 acres HBP (38% of total)
- ✓ Mississippi is a favourable jurisdiction for O&G operators with supportive regulator

3 Productivity Upside

- ✓ Results to date achieved using older hybrid frac design - largely superseded
- ✓ Longer laterals will improve productivity and economics, already 2 wells > 9,000 ft
- ✓ Australis has identified the studies necessary to confirm such improvements

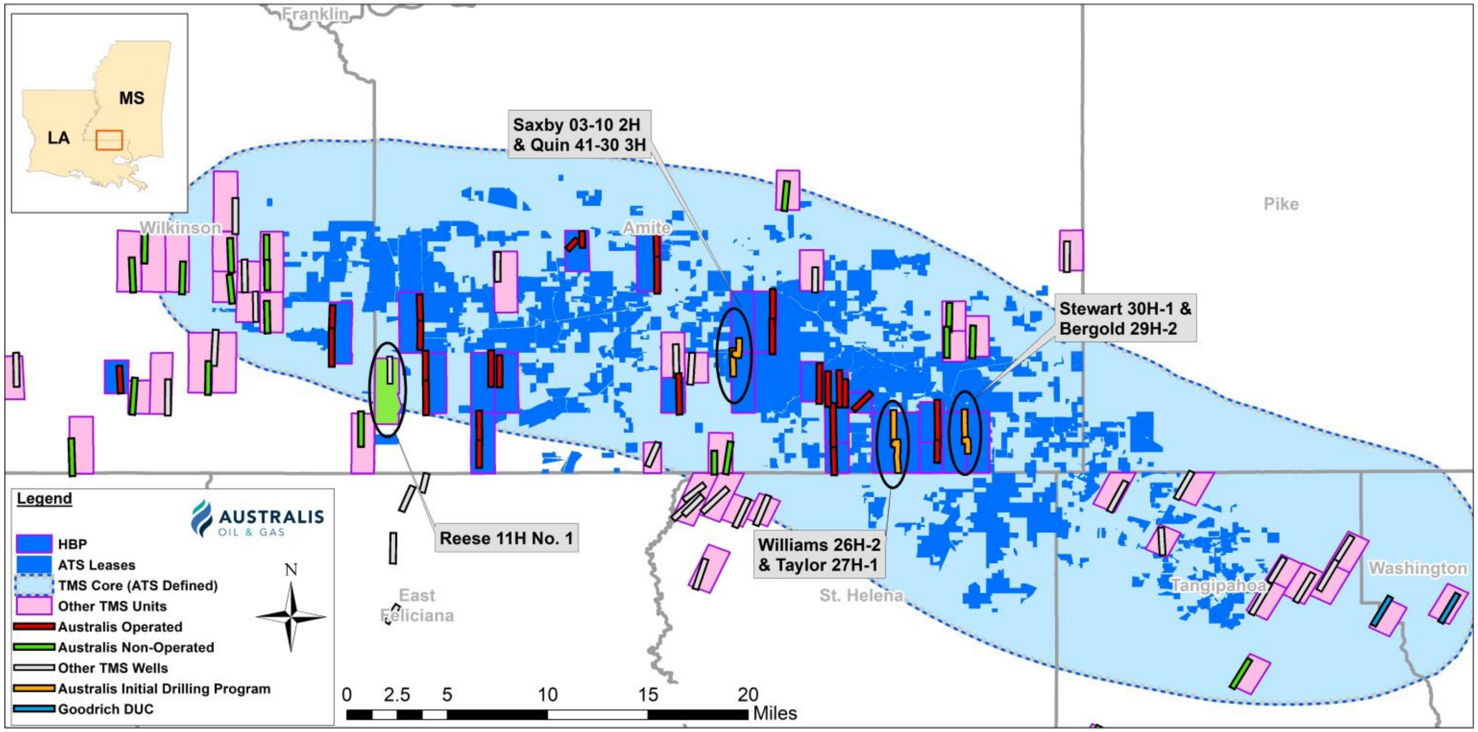
4 Additional target horizons

- ✓ Austin Chalk rights across majority of acreage
- ✓ EagleTusc potential observed and preliminarily mapped across acreage

AUSTRALIS OIL & GAS

Tuscaloosa Marine Shale

Production history of 91 horizontal industry wells drilled from 2010 to 2019 have delineated the TMS Core



- Largest land holder with ~100,000 contiguous net acres – corresponds to ~ 400 net new well locations
- Largest production operator with 33 producing wells
- Largest TMS producer ~ 1,250 bopd, with low operating costs and reduced overheads
- 170 million bbls[1] net to Australis
- Ability to scale up
- Third party activity in the area – State Line Exploration permitted last year – site now active

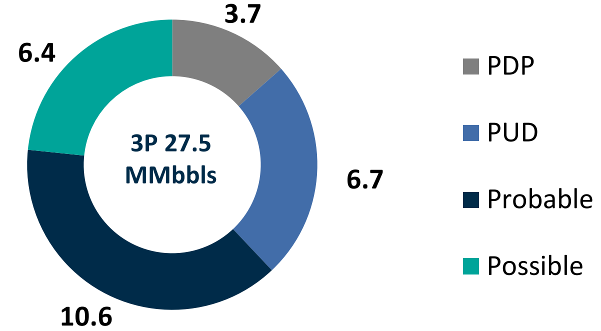
AUSTRALIS OIL & GAS

Significant Oil Reserve and Resource in TMS Core

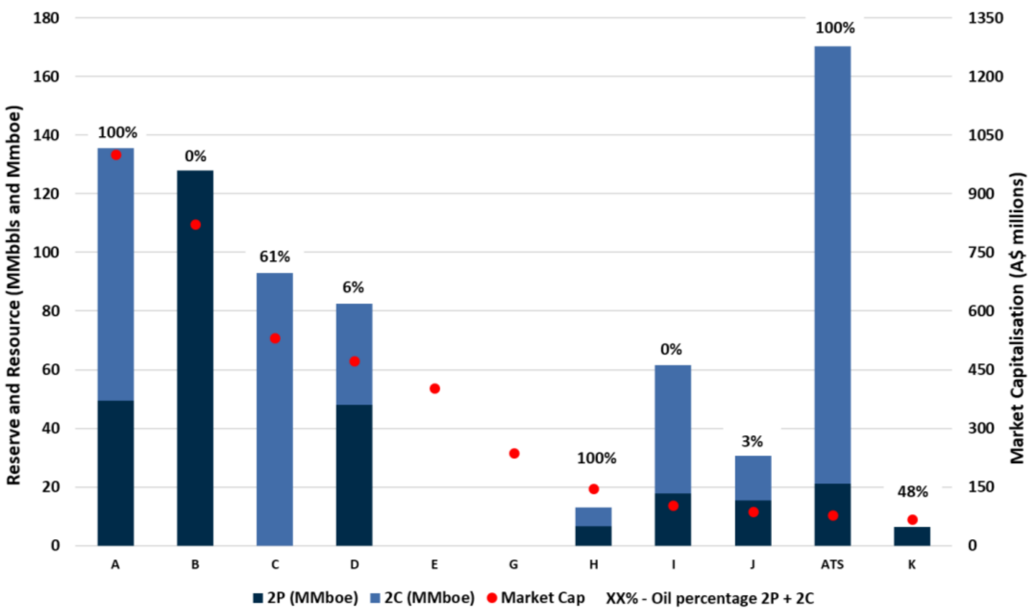
Significant scale - ~400 net well locations on existing acreage based on 250 acre well spacing

- Net recoverable oil independently assessed as at 31 December 2020[1] is based on 107,500 net acres in TMS Core
- Based on a **very modest development plan** - no wells drilled in 2021 and only 58 gross (40 WI) wells drilled in 5-year period
- Remaining acreage considered contingent on a qualifying development plan
- The mid case estimated recoverable volume from all 107,500 net acres is ~170 MMbbl[1]
- Chart here shows a comparison of this position to ASX peers
- **Opportunity to grow reserves and resource base** with additional leasing and further field development in improving price environment
  - Each addition of 10,000 net acres provides ~38 more future well locations and ~17mm bbls of recoverable oil

Australis TMS Reserves[1] (only 10,400 net acres (~10%) assessed for development)



Australis Peer Group comparison - 2P, 2C, % Oil and Market Cap[2,3]



Peer Group: 88 Energy, Carnarvon Petroleum, Central Petroleum, Comet Ridge, Cooper Energy, Helios Energy, Horizon Oil, Karoon Energy, Otto Energy and Senex Energy

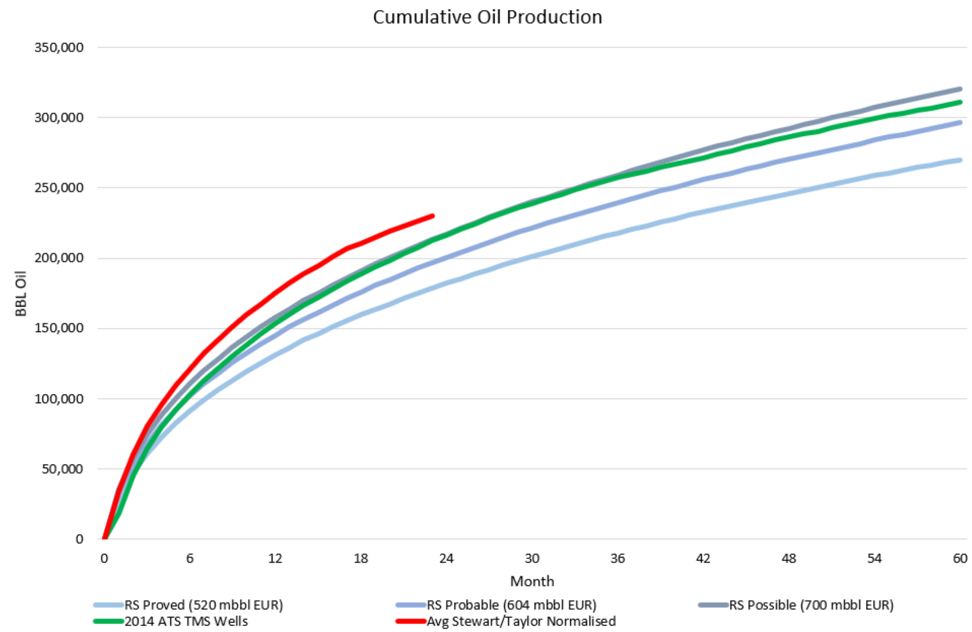
AUSTRALIS OIL & GAS

Strong Single Well Economics in TMS Core

- **Tier 1 oil well productivity in the TMS Core**
  - Ryder Scott generate three Type Curves for reserve categories.
  - Historical performance of 2014 ATS TMS wells between mi and high Ryder Scott Type Curves.
  - Australis TMS wells drilled in 2019 performing at or above 2014 ATS TMS wells, with IP30 > 1,000 bbls/d for full lengt laterals
- **TMS production is liquids rich at premium pricing**
  - >95% oil with 39-41 degree API
  - Achieves LLS-based premium over WTI (average: ~$3.48/bbl past 3 years)
- **Competitive Opex for oil wells**
  - Low transport costs due to proximity to existing infrastructure and multiple nearby refining markets
  - Access to and capacity for water, SWD, roads and power
- **Low well royalty rate** (~20% average)

TMS Netbacks	CY 2020	CY 2019
Average Realised Sales Price (*excl. hedging*)	$42.39/bbl	$62.03/bbl
Average Field Netback (NRI)	**$24.01/bbl**	**$40.93/bbl**

Comparison of Ryder Scott estimates to historical well performance

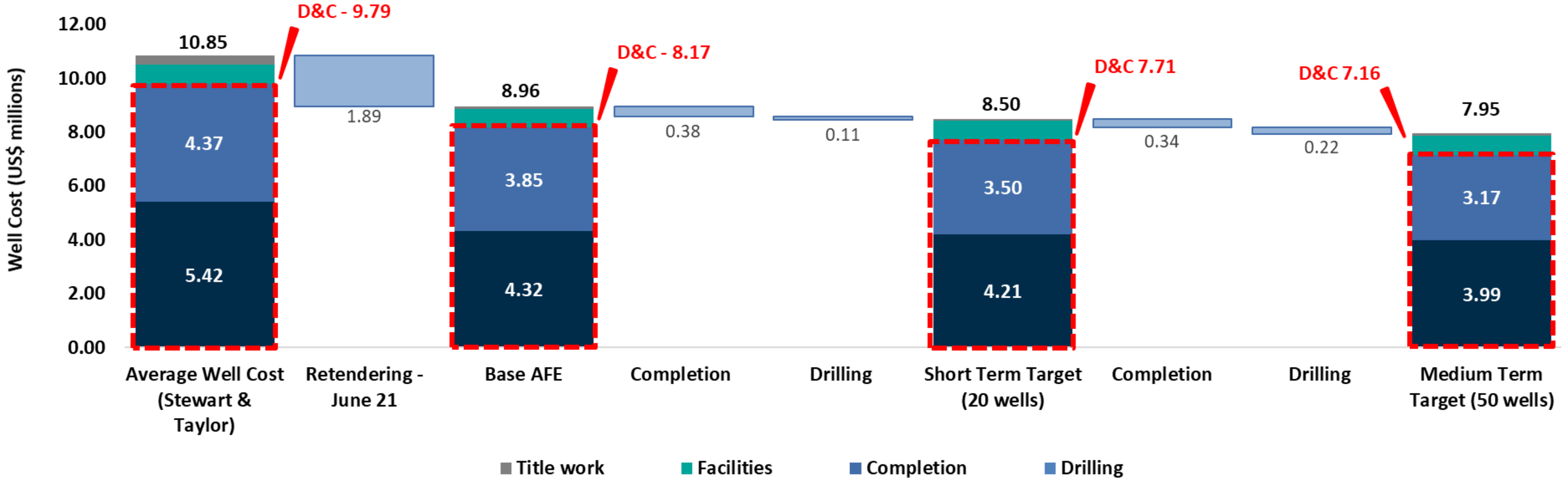


EUR (30 Years) – based on average historical performance[3]		
Gas	0.16	Bcf
Oil/Condensate	610	Mbbl
NGLs	20	Mbbl
EUR/well	**656**	**Mboe**

AUSTRALIS OIL & GAS

Clear path to substantial reduction in well costs

Reduced well costs from execution efficiencies and refinement will drive further improvements in economics



Starting point of $10.85M - Average well cost for 2018 Australis-drilled Stewart and Taylor Wells

Current Base case AFE $9.0m - target for average of first 10 wells (7,500 ft lateral, 7,200 ft completed length)

Short term target AFE $8.5m - by well 20 in development program[4]

Medium term target AFE $8.0m – by well 50 in development program[4]

Longer Term? Anticipated well cost for a 10,000ft lateral (post well 50) - $9.38 million[4]

AUSTRALIS OIL & GAS

Note These cost estimates are based on a Full Field Development mode (FFD), ie each unit and pad is sequentially fully drilled out
Surface facilities cost not changed in each scenario, will improve under FFD scenario
Total cost estimates include cost of unit title work – split between 8 wells in unit

Future single well economics - sensitivities

Impact of reduced well costs and variable oil price in FFD mode (assumes no improvements to historical well production performance)

	Base AFE	Short term target	Medium term target	Medium term target
	Av wells 1 - 10	Well #20	Well #50	Well #50
	BT NPV10 $million			
WTI $/bbl	Well Costs $million (7,500 ft)			10,000 ft
	$9.0	$8.5	$8.0	$9.4
$50	$4.04	$4.47	$4.69	$8.15
$55	$5.46	$5.91	$6.12	$10.06
$60	$6.89	$7.33	$7.54	$11.97
$65	$8.32	$8.76	$8.98	$13.87
$70	$9.76	$10.19	$10.41	$15.79
$75	$11.19	$11.63	$11.83	$17.70
$80	$12.63	$13.06	$13.26	$19.60
$85	$14.04	$14.47	$14.69	$21.50

	Base AFE	Short term target	Medium term target	Medium term target
	Av wells 1 - 10	Well #20	Well #50	Well #50
	BT IRR			
WTI $/bbl	Well Costs $million (7,500 ft)			10,000 ft
	$9.0	$8.5	$8.0	$9.4
$50	29%	33%	35%	53%
$55	37%	42%	45%	67%
$60	47%	53%	56%	83%
$65	57%	64%	68%	101%
$70	68%	77%	82%	120%
$75	81%	91%	97%	142%
$80	94%	107%	113%	166%
$85	109%	123%	131%	192%

	BT NPV0 $million			
WTI $/bbl	Well Costs $million (7,500 ft)			10,000 ft
	$9.0	$8.5	$8.0	$9.4
$50	$10.40	$10.84	$11.06	$17.19
$55	$12.68	$13.13	$13.34	$20.23
$60	$14.96	$15.41	$15.62	$23.29
$65	$17.24	$17.68	$17.91	$26.33
$70	$19.53	$19.97	$20.19	$29.39
$75	$21.81	$22.27	$22.47	$32.44
$80	$24.11	$24.56	$24.76	$35.48
$85	$26.38	$26.82	$27.05	$38.52

	Payout from IP (months)			
WTI $/bbl	Well Costs $million (7,500 ft)			10,000 ft
	$9.0	$8.5	$8.0	$9.4
$50	29	26	25	17
$55	23	21	20	14
$60	19	17	16	12
$65	16	14	14	10
$70	14	12	12	9
$75	12	11	10	8
$80	11	10	9	7
$85	9	8	8	6

Base case economics

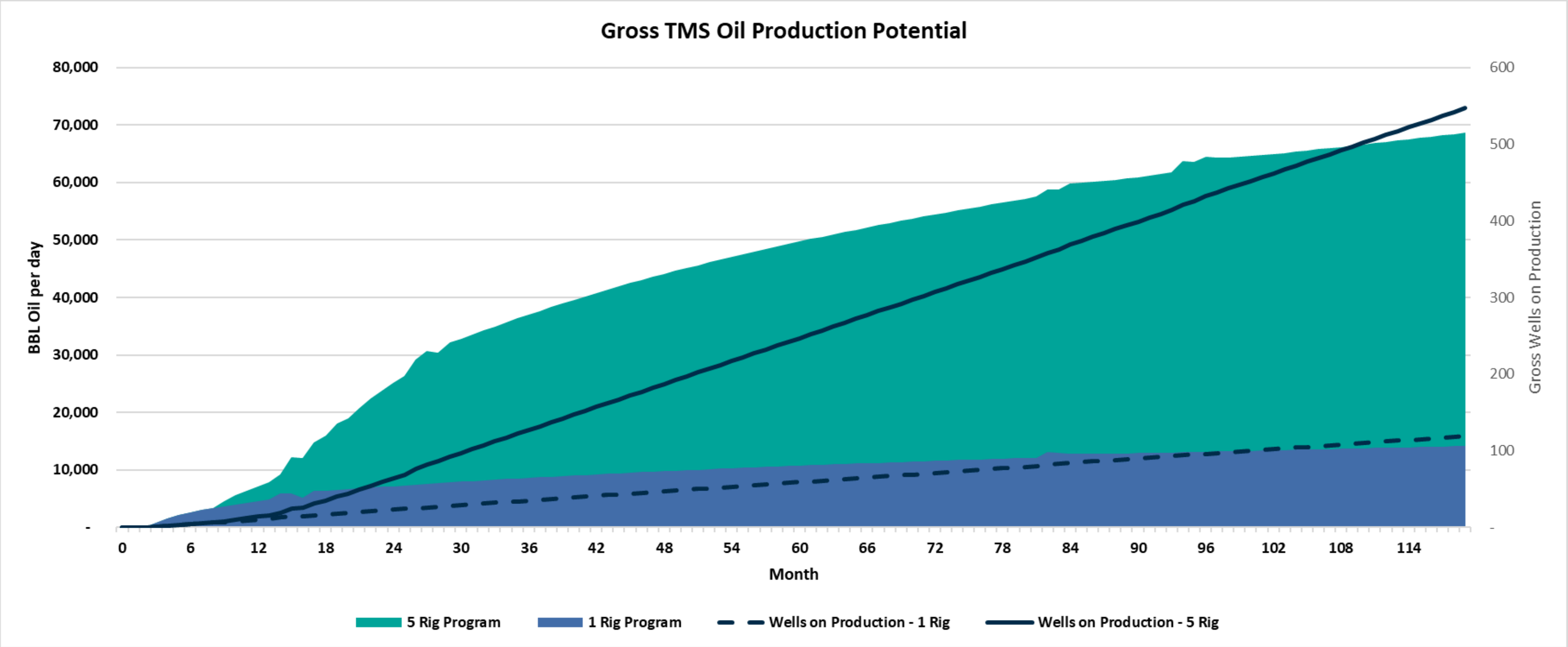
Upside case economics

AUSTRALIS OIL & GAS

Note See slide 15 for other assumptions used for single well economic evaluations

Example Development Scenarios

Field production growth[5] will be dramatic with even modest development cases



- Chart shows field production with a single rig program (blue) and a 5 rig program (green), the latter ramping up the rig count to 5 over 18 months.
- At the end of a 10 year period field production peaks at **68.5 Mbopd** (green) and 14.1 Mbopd (blue)
- Assumes average production profile of 2014 ATS TMS wells

AUSTRALIS OIL & GAS

Note – existing PDP is not shown on this chart

Summary

Experienced team and sound strategy will ultimately drive shareholder returns.

TMS Asset Quality

- Not guess work!
  Comparable productivity to best areas in the USA. Long production history from over 90 wells
- Product stream 95% oil and a light sweet crude demands a premium to WTI
- Strong base case well economics, with all other plays having shown substantial improvement during development

Strategic Advantages of TMS

- Large resource of oil
- Proximity to infrastructure
- Known well spacing with >6 year production history
- Supportive legislative environment with no federal leases
- Modest and flexible capital requirements
- Potential for acreage growth

Shale Industry Transformation

The broader shale industry is facing a structural transformation due to the following:

- Diminishing Tier 1 inventory locations
- Limited opportunity for exploration or new field developments
- Remaining growth play, Permian, tightly held

Value Creation

Having managed and protected the asset during the turmoil of 2020, Australis is seeking a partner or partners to bring capital to re-rate the TMS asset valuation through development of the reserve and resource base.

Appendix

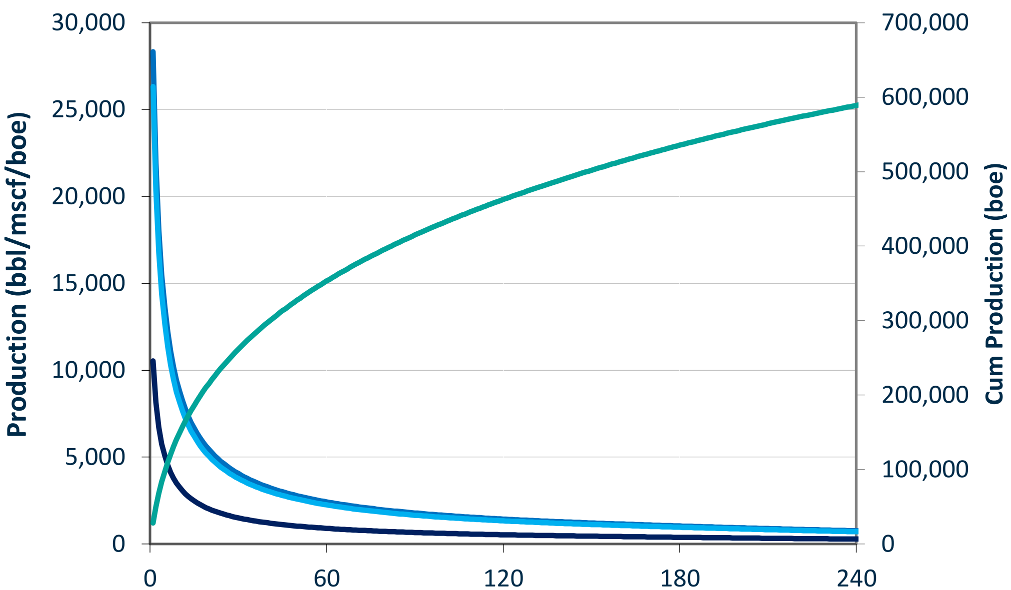
Conservative Base Case Economics

Assumes completed lateral length of 7,200 ft only, production and opex assumptions are based on history and the capex costs are current estimates (slide 8)

Base Case Assumptions*

EUR (30 Years)		
Gas	0.16	Bcf
Oil/Condensate	610	Mbbl
NGLs	20	Mbbl
EUR/well	**656**	**Mboe**
Well Cost	**US$**	
Drilling	$3.9	million
Completion	$4.3	million
Tie in & Title work	$0.8	million
Total Well Cost	**$9.0**	**million**
Operating Expenditure	**US$**	
Fixed Opex	$8,935	/well/month
Variable Opex[A]	$1.07	per bbl fl
Variable Opex	$1.93	Per bbl
Other Assumptions		
NRI	80%	
Realised Net Differential[B]	$2.00	$ per bbl
Abandonment cost	1.0%	of well cost
Escalation	2.0%	

Production Forecast



Oil Price - WTI US$/bbl	Cashflow US$ million	Pre-tax NPV10 US$ million	IRR %	Payback Months
$55	$12.7	$5.5	37%	23
$65	$17.2	$8.3	57%	16
$75	$21.8	$11.2	81%	12

AUSTRALIS OIL & GAS

A. Includes water disposal
B. Australis sells its oil at LLS benchmark, which trades at a premium to WTI. Realised differential represents LLS premium less local differential.
** Economics based on 20 year cash flows from first production*

Footnotes

1. All estimates and risk factors taken from Ryder Scott, report prepared as at 31 December 2020 and generated for the Australis concessions to SPE standards. See ASX announcement released on 5 February 2021 titled “Reserves and Resources Update Year End 2020”. Australis is not aware of any new information or data that materially affects the information included in the referenced announcement and all the material assumptions and technical parameters underpinning the estimates in the original announcement continue to apply and have not materially changed. Ryder Scott generated their independent reserve and contingent resource estimates using a deterministic method which is based on a qualitative assessment of relative uncertainty using consistent interpretation guidelines. The independent engineers using a deterministic incremental (risk based) approach estimate the quantities at each level of uncertainty discretely and separately.
2. Based on public data including reserve announcements and annual reports from ASX Peer Companies. Market Capitalisations as at 1/11/2021
3. Oil equivalent volumes are expressed in thousands of barrels of oil equivalent (Mboe), determined using the ratio of 6 Mscf of gas to 1 bbl of oil
4. Key assumptions used to generate improved well cost estimates are
   - Short term target: removal of additional logging, de-bundling of chemicals from frac contract, re-source sand based on continuous program, 10% improvement in drilling speed/efficiency and a 5% improvement in other drilling related phases.
   - Medium term target: improved frac pump uptime, utilisation of improved frac fluid design, removal of acid pad, reduces mob costs and switch from CT drillouts.
   - Longer term 10,000 ft laterals, costs based on time to drill additional lateral length using medium term target assumptions and production/EUR is pro-rata to horizontal well length.
5. Production scenario modelling makes the following key assumptions:
   - Chart shows total field production for new wells only (no existing PDP)
   - Both scenarios commence rig activity in month 0
   - 5 rig scenario adds 2nd rig at end month 6, 3rd and 4th rigs at end month 12 and 5th rig at end month 18
   - Single well productivity based on average of 2014 ATS TMS wells
   - Well drilling duration assumed to be 30 days and 3 months between spud and first production.

AUSTRALIS OIL & GAS

Glossary

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

Abbreviation	Description
TMS	Tuscaloosa Marine Shale
TMS Core	The Australis designated productive core area of the TMS delineated by production history
WI	Working Interest
C	Contingent Resources – 1C/2C/3C – low/most likely/high
NRI	Net Revenue Interest (after royalty)
Net	Working Interest after deduction of Royalty Interests
NPV (10)	Net Present Value (discount rate), before income tax
HBP	Held by Production (lease obligations met)
EUR	Estimated Ultimate Recovery per well
WTI	West Texas Intermediate Oil Benchmark Price
LLS	Louisiana Light Sweet Oil Benchmark Price
Opex	Operating Costs
Capex	Capital Costs
PDP	Proved Developed Producing
PUD	Proved Undeveloped Producing
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
D, C & T	Drilling, Completion, Tie In and Artificial Lift
G&A	General & Administrative
KMP	Key Management Personnel
Royalty Interest or Royalty	Interest in a leasehold area providing the holder with the right to receive a share of production associated with the leasehold area
Field Netback	Oil and gas sales net of royalties, production and state taxes, inventory movements, field based production expenses, hedging gains or losses but excludes depletion and depreciation.
EBITDA	Net loss / profit for the period before income tax expense or benefit, finance costs, depreciation, depletion, amortisation and impairment provision
Net Acres	Working Interest before deduction of Royalty Interests
IP24	The peak oil production rate over 24 hours of production
IDP	Initial drilling program of 6 wells in the TMS by Australis commencing late 2018
IP30	The average oil production rate over the first 30 days of production
IRR	Internal Rate of Return
FFD	Full field development mode – ie each unit and surface pad is fully drilled out