22 March 2023

The biggest player in the Beetaloo

30-day average initial production flow (IP-30) from Amungee horizontal well 2 (A2H) expected in 2Q 2023.

- Up to 24 stages over 1,200m to be stimulated at A2H.
- Gas flow testing post well clean up expected in mid to late April with IP-30 before the end of the 2Q 2023.
- Helmerich & Payne (H&P) rig that has the capability to drill 4,000m horizontal wells has departed the US enroute to the Beetaloo to partner with TBN.

TBN has a stated prospective 2U resource (net to TBN) of 147 Tcf and a 2C contingent resource of ~1.5 Tcf in the Beetaloo Basin in Northern Australia.

We forecast that TBN has funding available to meet its current forecast work program until the middle of CY 2023.

By the end of CY2023 we expect TBN in a position to sanction a 100 mm scfd pilot development.

TBN is looking to develop the resource so as to target the Australian and export liquified natural gas (LNG) markets. Beetaloo gas is forecast to be well-positioned to supply gas when LNG projects in northern Australia / Gladstone are forecast to require backfilling.

Investment Thesis

Now the biggest player in the Beetaloo: TBN has restated its proposed commercialisation program to supply gas from the Beetaloo Basin to the Australian east coast and global liquified natural gas (LNG) markets in a 2025-2030 timeframe.

The first goal is to prove up 0.7 trillion cubic feet (Tcf) of net 2P gas reserves and sanction a 100 tera joule (TJ) per day (gross) Amungee pilot development by the end of CY 2023.

By the end of CY 2025 TBN want to be producing 100 TJ/day from the pilot development and are targeting ~5.0 Tcf of net 2P gas reserves sourced from TBN's interest in the binding gas supply agreement (GSA) with Origin Energy (ORG) and a proposed 2.2 million tonne per annum (Mtpa) LNG tolling agreement or development opportunity.

Longer term TBN want to be producing 1 billion cubic feet per day (Bcfd) (~390 peta joules (PJ) per annum) to backfill existing LNG plants or new greenfield plants by 2028-2030.

Valuation

We derive a June 2023 valuation for TBN of $0.54 per share based on a $0.50/(2P+2C) (GJ) resource multiple.

Risks

The key risks in our view that the company share price faces includes project funding, identification of economic reserves, development and production costs, product pricing, reserve life and production decline rates.

Equities Research Australia
Energy

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Tamboran Resources (TBN) is a gas exploration company that aims to prove up new 2P reserves and develop gas production out of the Beetaloo Basin in the Northern Territory in order to supply the Australian domestic market and Asian LNG market.
http://www.tamboran.com/

Valuation	**A$0.54** *(Prev A$0.58)*
Current price	**A$0.21**
Market cap	**A$297m**
Net Cash December 2022	**A$61m**

Upcoming Catalysts / Next News

Period	
2Q 2023	Flow testing results from Amungee 2H
2H 2023	Drill, stimulate and flow test up to three wells in acquired acreage.

Share Price ($A)

Source: FactSet

Report prepared by MST Access, a registered business name of MST Financial services ABN 617 475 180 AFSL 500 557

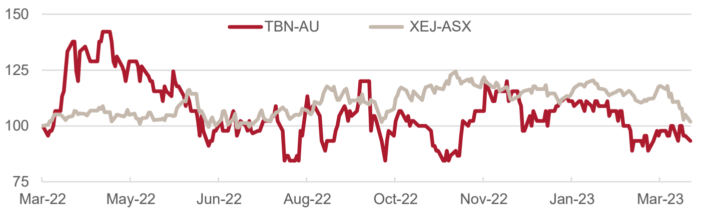
Tamboran Resources Financial Data

Tamboran Resources	TBN-AU

Year end 30 June

MARKET DATA			
Price	**$**		**0.21**
52 week high / low	A$	0.32	0.19
Valuation	**A$**		**0.54**
Market capitalisation	A$m		297.4
Shares on issue (basic)	**m**		**1416.0**
Options	m		62.2
Shares on issue (diluted)	**m**		**1478.2**

12 month relative performance versus S&P/ASX 200 Energy Index



INVESTMENT FUNDAMENTALS		FY21	FY22	FY23E	FY24E
EPS reported	¢	(19.2)	(1.5)	(1.8)	(2.6)
EPS underlying	**¢**	**(19.2)**	**(1.5)**	**(1.8)**	**(2.6)**
P/E reported	**x**	**(1.8)**	**(14.4)**	**(11.6)**	**(8.0)**
P/E underlying	**x**	**(1.8)**	**(14.4)**	**(11.6)**	**(8.0)**
Dividend	**¢**	**0.0**	**0.0**	**0.0**	**0.0**
Payout ratio	%	0.0%	0.0%	0.0%	0.0%
Yield (Y/E/ spot)	**%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
Net Tangible Assets	$m	104.4	128.6	227.5	295.7
Net Tangible Assets per share	¢	16.0	17.2	16.1	17.5
Free cash flow	$m	(21.8)	(67.2)	(151.8)	(106.2)
Free cash flow yield	%	(50.3)	(43.1)	(59.8)	(32.5)
Price to Free cash flow	x	(2.0)	(2.3)	(1.7)	(3.1)
Year end shares	**m**	**653**	**747**	**1,416**	**1,691**
Average shares on issue	m	124	708	1,209	1,554
Year end / Spot share price	$	0.35	0.22	0.21	0.21
Market cap (Y/E / Spot)	$m	229	164	297	355
Net debt /(cash)	**$m**	**(63)**	**(27)**	**(6)**	**(7)**
Enterprise value	**$m**	**165**	**138**	**291**	**348**
EV/EBITDAX	**x**	**n/m**	**n/m**	**n/m**	**n/m**
Gearing (net debt / EBITDAX)	**x**	**n/m**	**n/m**	**n/m**	**n/m**

Licenses	TBN Ownership	Partners
EP 76	38.75%	Sheffield 38.75%, Falcon Oil 22.5%
EP 98	38.75%	Sheffield 38.75%, Falcon Oil 22.5%
EP 117	38.75%	Sheffield 38.75%, Falcon Oil 22.5%
EP 136	100.0%	
EP 161	25.0%	Santos 75%
EP 143	100.0%	
EP(A) 197	100.0%	

RESERVES & RESOURCES			
Prospective Gas Reources net to TBN (Tcf)	**Low (1U)**	**Best (2U)**	**High (3U)**
Lower Kyalla	0	0	1
Mid Velkerri C	20	36	75
Mid Velkerri B	52	86	176
Mid Velkerri A	13	26	60
Total (Tcf)	**86**	**148**	**312**
Contingent 2C Gas Reources net to TBN (Bcf)	**Low (1C)**	**Best (2C)**	**High (3C)**
Lower Kyalla	0	0	0
Mid Velkerri C	133	590	1,342
Mid Velkerri B	202	897	2,039
Mid Velkerri A	0	0	0
Total (Bcf)	**335**	**1,488**	**3,381**
Total (PJ)	**355**	**1,577**	**3,584**

Spot Valuation				
2C plus 2P (PJ)	1,577	1,577	1,577	1,577
Resource multiple A$ / (2P+2C) (GJ)	**0.25**	**0.50**	**0.75**	**1.00**
Reserve Value (A$m)	391	788	1,183	1,577
Net cash (MSTe June 2023) (A$m)	6	6	6	6
Equity valuation (A$m)	**397**	**794**	**1,189**	**1,583**
Share value per diluted share (A$)	**0.27**	**0.54**	**0.80**	**1.07**

PROFIT AND LOSS		FY21	FY22	FY23E	FY24E
Sales	**$m**	**0.0**	**0.0**	**0.0**	**0.0**
Other income	$m	2.5	0.6	7.5	0.0
Operating costs	$m	(18.1)	(10.8)	(28.7)	(39.9)
EBITDAX	**$m**	**(15.6)**	**(10.2)**	**(21.2)**	**(39.9)**
Exploration & evaluation expensed	$m	0.0	0.0	0.0	0.0
EBITDA	$m	**(15.6)**	**(10.2)**	**(21.2)**	**(39.9)**
Depreciation & Amortisation	$m	(0.4)	(0.6)	(0.7)	(0.8)
EBIT	**$m**	**(16.0)**	**(10.7)**	**(21.9)**	**(40.7)**
Net interest	$m	(7.8)	(0.1)	0.0	0.0
Pretax Profit	$m	**(23.8)**	**(10.8)**	**(21.8)**	**(40.7)**
Tax expense	$m	0.0	0.0	0.0	0.0
NPAT	**$m**	**(23.8)**	**(10.8)**	**(21.8)**	**(40.7)**

BALANCE SHEET		FY21	FY22	FY23E	FY24E
Cash	$m	63.1	26.8	5.9	7.1
Receivables	$m	0.4	2.9	2.9	2.9
Other	$m	0.0	1.0	1.0	1.0
Current assets	$m	**63.6**	**30.7**	**9.8**	**11.0**
Exploration & Evaluation	$m	46.6	85.0	187.4	285.4
Oil and Gas assets	$m	0.7	16.4	34.1	3.3
Right of use assets	$m	1.4	1.0	0.7	0.5
Other	$m	0.3	1.0	1.0	1.0
Non current assets	$m	**49.0**	**103.4**	**223.2**	**290.2**
Total Assets	**$m**	**112.6**	**134.1**	**233.0**	**301.3**
Accounts Payable	$m	5.7	3.9	4.0	4.2
Borrowings	$m	0.0	0.0	0.0	0.0
Other	$m	1.3	0.8	0.7	0.7
Current liabilities	$m	**7.0**	**4.6**	**4.8**	**5.0**
Borrowings	$m	0.0	0.0	0.0	0.0
Provisions	$m	1.1	0.7	0.5	0.4
Other	$m	**0.1**	**0.2**	**0.2**	**0.2**
Non current liabilities	$m	**1.2**	**0.9**	**0.7**	**0.6**
Total Liabilities	**$m**	**8.2**	**5.5**	**5.5**	**5.5**
Equity	$m	183.9	217.4	357.9	467.9
Retained earnings	$m	(88.1)	(98.9)	(120.8)	(161.4)
Reserves / Other	$m	8.6	10.1	(9.6)	(10.7)
Total equity	**$m**	**104.4**	**128.6**	**227.5**	**295.7**

CASH FLOW		FY21	FY22	FY23E	FY24E
EBITDAX	$m	**(15.6)**	**(10.2)**	**(21.2)**	**(39.9)**
Working Capital / Other	$m	2.5	(2.3)	7.5	1.8
Net interest	$m	(0.1)	(0.0)	(0.0)	0.0
Tax paid	$m	0.0	0.0	0.0	0.0
Operating cash flow	**$m**	**(8.6)**	**(11.1)**	**(19.6)**	**(38.1)**
Exploration & development	$m	(13.2)	(54.9)	(93.4)	(68.0)
Acquisitions	$m	0.0	(1.2)	(27.4)	0.0
Divestments	$m	0.0	0.0	0.0	0.0
Other	$m	0.0	(0.0)	(11.4)	0.0
Investing cash flow	**$m**	**(13.2)**	**(56.1)**	**(132.2)**	**(68.0)**
Change in Equity	$m	83.0	35.0	140.4	110.0
Increase / (Decrease) in borrowings	$m	0.0	0.0	0.0	0.0
Dividend	$m	0.0	0.0	0.0	0.0
Transaction costs / Other	$m	(3.7)	(3.8)	(9.4)	(2.6)
Financing cash flow	**$m**	**79.3**	**31.1**	**131.1**	**107.4**
FX	$m	0.0	(0.2)	(0.2)	0.0
Change in Cash	$m	57.5	(36.3)	(20.9)	1.3
Cash year end	**$m**	**63.1**	**26.8**	**5.9**	**7.1**

Source. Company data. MST Access.

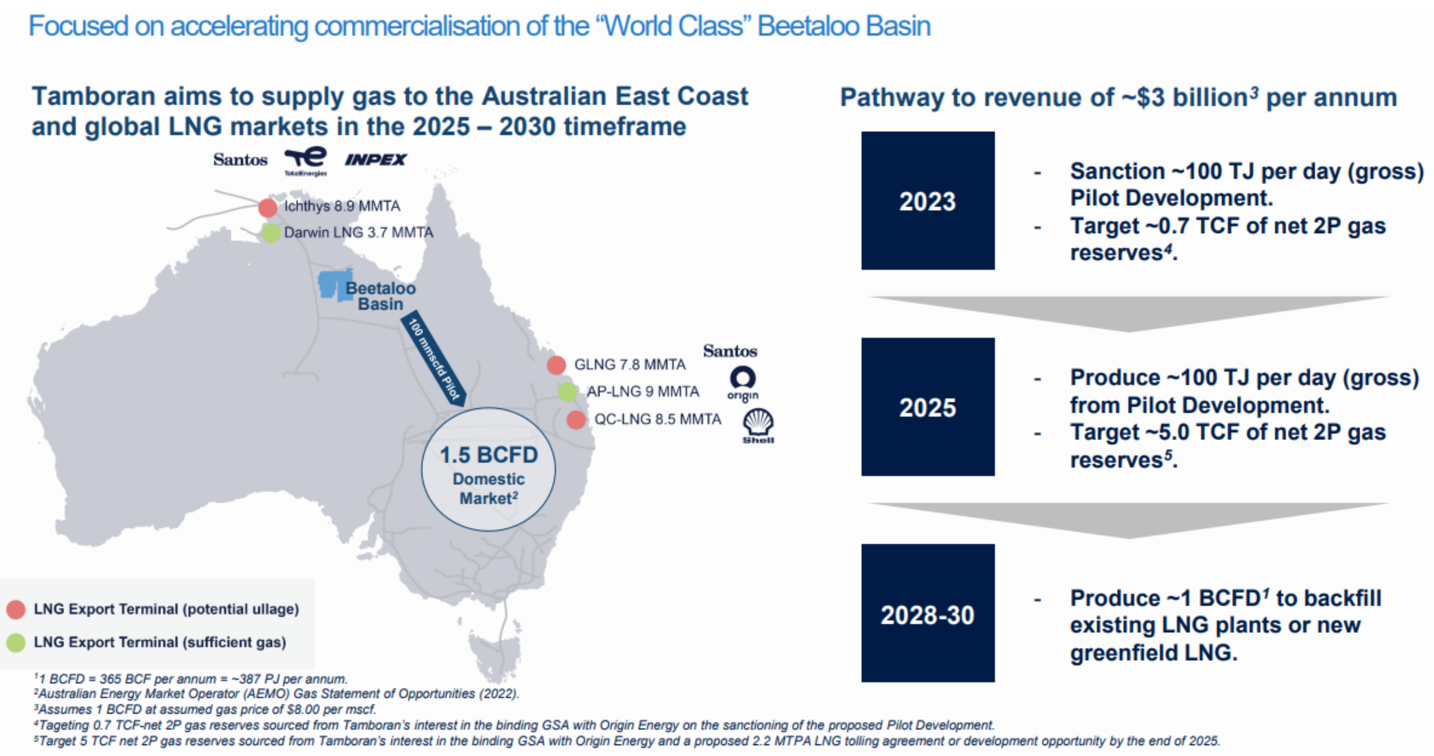
Tamboran Resources Investment Thesis

TBN has a stated prospective 2U resource (net to TBN) of 147 Tcf and a 2C contingent resource of ~1.5 Tcf in the Beetaloo Basin in Northern Australia. TBN is looking to develop the assets so as to target the undersupplied Australian LNG export markets and domestic gas markets.

We forecast that TBN has funding available to meet its current forecast work program until the middle of CY 2023. At that stage it will need to seek new funding via equity, debt (reserve backed lending), pre-paid gas sales or asset sell downs and or farm outs. Our financial forecasts (Figure 1) assume equity is issued in CY2023 to progress the program.

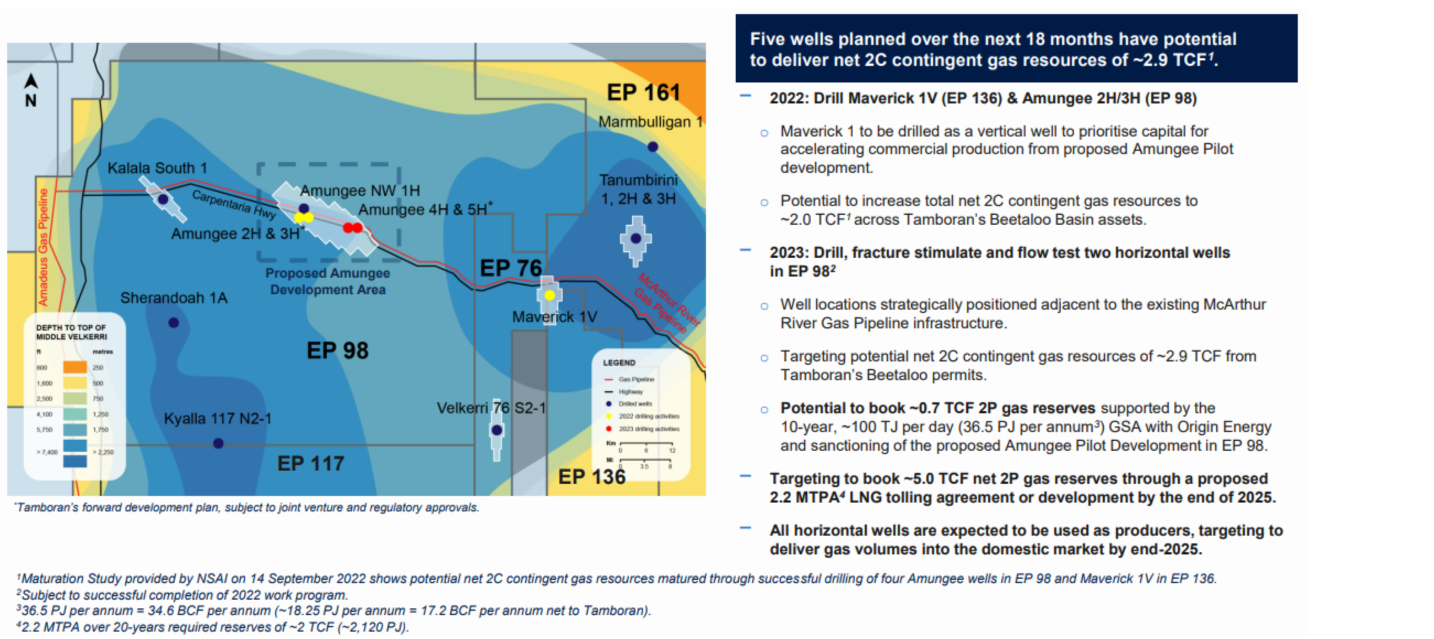
Valuation: We have a spot valuation of $0.54 per share for TBN (Figure 15).

Figure 1: Target is to become a 1 Bcfd producer to backfill existing and new LNG plants



Source: Company

Figure 2: Pathway to ~5.0 Tcf of net 2P gas reserves by the end of 2025 with first production in 2025



Source: Company

September 2022 transformational acquisition

TBN recently entered into a number of transactions that has materially lifted its prospective and contingent resource base.

Key points to note are:

- TBN and Bryan Sheffield agreed to jointly (50% each) acquire Origin Energy's (ORG) 77.5 % interest in three Beetaloo Basin permits (EP 98, 117 and 76) through a joint venture (JV) for an upfront cash consideration of $60 m plus
- a future production revenue royalty of 5.5% to ORG on those permits.
- Falcon Oil and Gas (FO) hold the remaining 22.5% in the permits.

Post the acquisition, TBN has:

- become the largest acreage holder in the Beetaloo Basin with ~1.9 million net prospective acres (up 445% from 0.35 million acres
- increased its net 2C contingent gas resources 270% to ~1.5 Tcf from 0.4 Tcf, and
- increased its net 2U prospective gas resources 370% to ~147 Tcf from 31 Tcf.
- The JV entered into a binding 10-year Gas Sales Agreement (GSA) for up to 36.5 PJ per annum (100 TJ/day) (18.3 PJ per annum net to Tamboran) with ORG who will have the option to acquire at least an additional 200 TJ per day for 10-years from the JV interest in the permits. We speculate that the contract will be oil linked. If we assumed a 10% slope against a Brent oil price benchmark, at current prices and exchange rates (Brent spot US$73/bbl and AUDUSD of 0.67), the potential gas contract price would be currently ~A$11/GJ at Ballera.
- TBN has committed to solely fund the remaining ORG Stage 3 farm-in commitments that were contracted with Falcon Oil and Gas (FO), which includes the drilling of two horizontal wells, at an estimated cost of $80 m, and back costs to the effective date of 1 July 2022.
- Equity capital of ~140m at $0.21 per share has been raised via institutional and private placements and a share purchase plan to fund the various transactions and program requirements.
- Helmerich and Payne (H&P), the largest onshore driller in the United States, invested $22 m in the placement. TBN has finalised a drilling contract with H&P for a super-spec FlexRig® (Rig 469) for a two-year term. The rig will mobilise into Australia for the TBN's 2023 proposed drilling campaign and has recently departed the United States and is enroute to the Beetaloo.
- As part of the strategic alliance, H&P will have the right of first refusal until 2033 to provide TBN all subsequent rigs required to accelerate TBN's 1 billion cubic feet per day (Bcfd) development plan at market rates.
- Once imported into Australia, H&P's super-spec FlexRig®, with more than 2,000 horsepower and one-million-pound hook load will be one of Australia's most powerful onshore drilling rigs. Capable of drilling more than 4,000 metre horizontal sections within the Mid-Velkerri "B Shale", the rig is expected to support a material reduction in cost per unit of recoverable gas.
- TBN has granted a 2.3% overriding royalty interest (ORRI) covering TBN's EP 136 (100%), EP 161 (25%), EP 98, EP 117 and EP143 (the ORG assets) (38.75%), EP 143 (100%) and EP 197 (100%) to Sheffield interests for a cash consideration of $22 m.

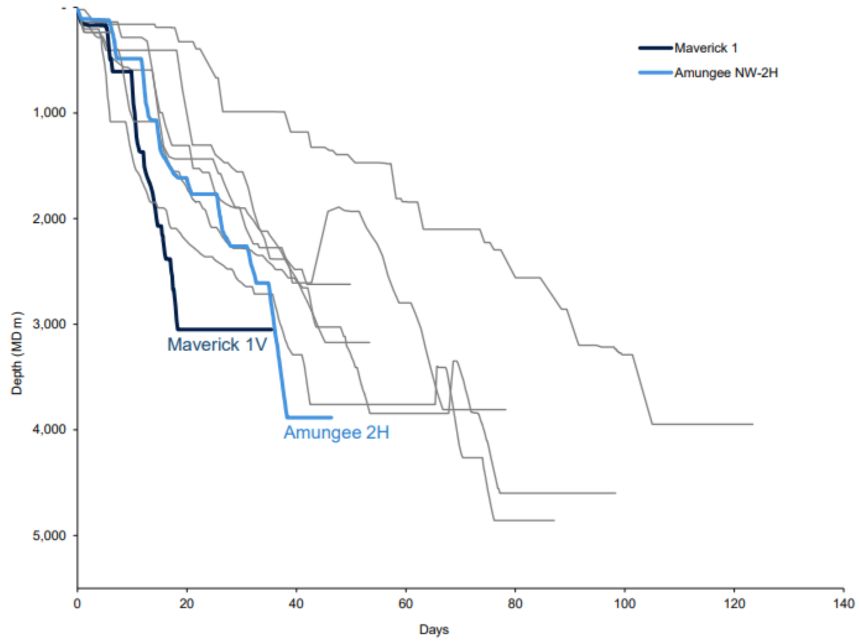
Forward work plan

Following the acquisition, TBN moved its attention away from EP 136 and is now focussing on EP 98. This follows a decision to prioritise the acceleration of booking 2P reserves and first commercial production from the proposed Amungee Pilot Development, which is supported by the recently signed 10-year GSA with Origin.

As a result, Maverick 1H in EP 136 (100% funding by TBN), which was planned to have a 1,000m lateral drilled was changed to be a vertical well (M1V).

This well was completed (Target depth (TD) of 3,050m was reached in 18.3 days) at a total cost of ~$30m (well below the original forecast cost given the speed it was completed and the lack of the proposed fracks (20 fractures at $0.7m per frack saves $14m).

Figure 3: Maverick 1V and Amungee 2H drilling performance – Fastest vertical and horizontal wells in Beetaloo to date1



- Tamboran has been able to leverage learnings from drilling of Tanumbirini 2H and 3H by funding only 25% of costs (Santos 75% and operator).
- Maverick 1V was Tamboran's first operated well in the Beetaloo.
- Vertical section drilled to 3,050-metres in only 18.3 days.
- Application of latest generation US drilling technology, including specialised Drilling Bit design.
- Amungee 2H drilled to Total Depth in 38 days, faster than nearby wells drilled below 2,500-metres.
- Plans to incorporate further learnings into Tamboran's 2023 drilling program to further reduce drilling time and cost.

[1]For a true vertical section greater than 2,500-metres.

Source: Company

The forward plan for M1V is now to acquire wireline logs and then to suspend the well and assess the potential to use data from the two Amungee wells to optimise a future 3,000 m horizontal section in the Maverick well, using the H&P super-spec FlexRig®, which is planned to be mobilised into Australia for the Company's 2023 proposed development drilling campaign.

The first of the two planned wells required under the farm-in commitments with FO, Amungee 2 Horizontal (A2H) was spudded on 10 November 2022 and was successfully drilled to a TD of 3,883m with a 1,275m horizontal section within the primary target of the Mid-Velkerri "B" Shale (Figure 4).

The A2H well is currently being stimulated by hydraulic fracture stimulation program (up to 24 fracks over 1,200m) with a US style unconventional shale design. The well is designed with 5-½ inch casing that allows for effective placement of proppant into the formation, optimising completion efficiency.

An additional well (previously Amungee 3H) is proposed to be drilled post the completion of A2H. Timing is dependent on where the team decides to locate the well. If it is drilled where ORG originally planned, it will likely be completed by mid-year using the rig that drilled A2H.

If the TBN team decide to relocate the drill site, the well could potentially be drilled by the H&P rig forecast to arrive mid-year and thus well completion would slip into the second half of the calendar year.

Once the two wells have been drilled, the funding of future work will be in line with the ownership levels; i.e. TBN will fund 38.75% going forward. Rather than the 100% required for the inherited FO farm in commitments and the 100% funding required if TBN continued on working in EP 136.

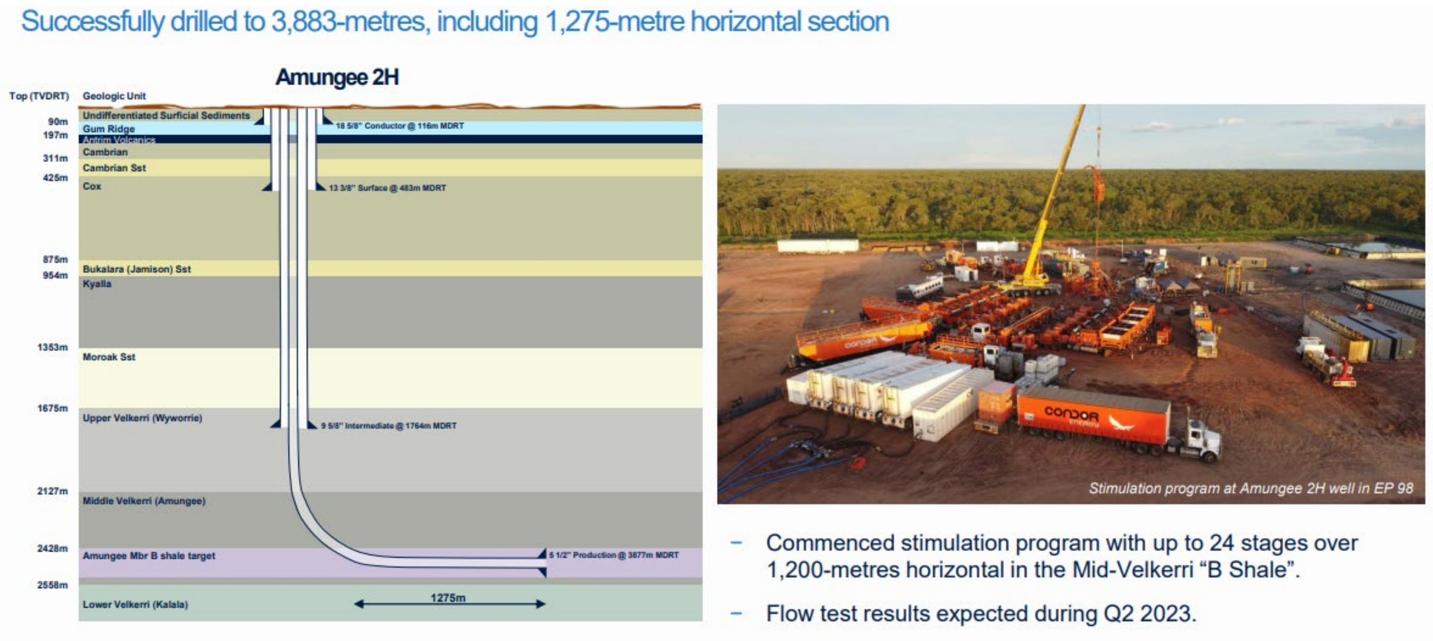
TBN's forward work program envisaged five wells (Figure 2) over the 18 months from September 2022 to March 2024: M1V (completed), A2H (about to start flow testing) and then to drill three additional wells.

The last two well are proposed to have 3,000m laterals with 50m fracture spacing (60 fracks) the well costs are forecast to be circa $50m-$55m per well; so a ~$43m funding cost for TBN for both wells (38.75% of $110m). (Figure 5)

The question then is will FO participate given both wells will cost them ~$25m. If FO choose not to participate TBN could potentially have to fund 50% of the wells, or $55m.

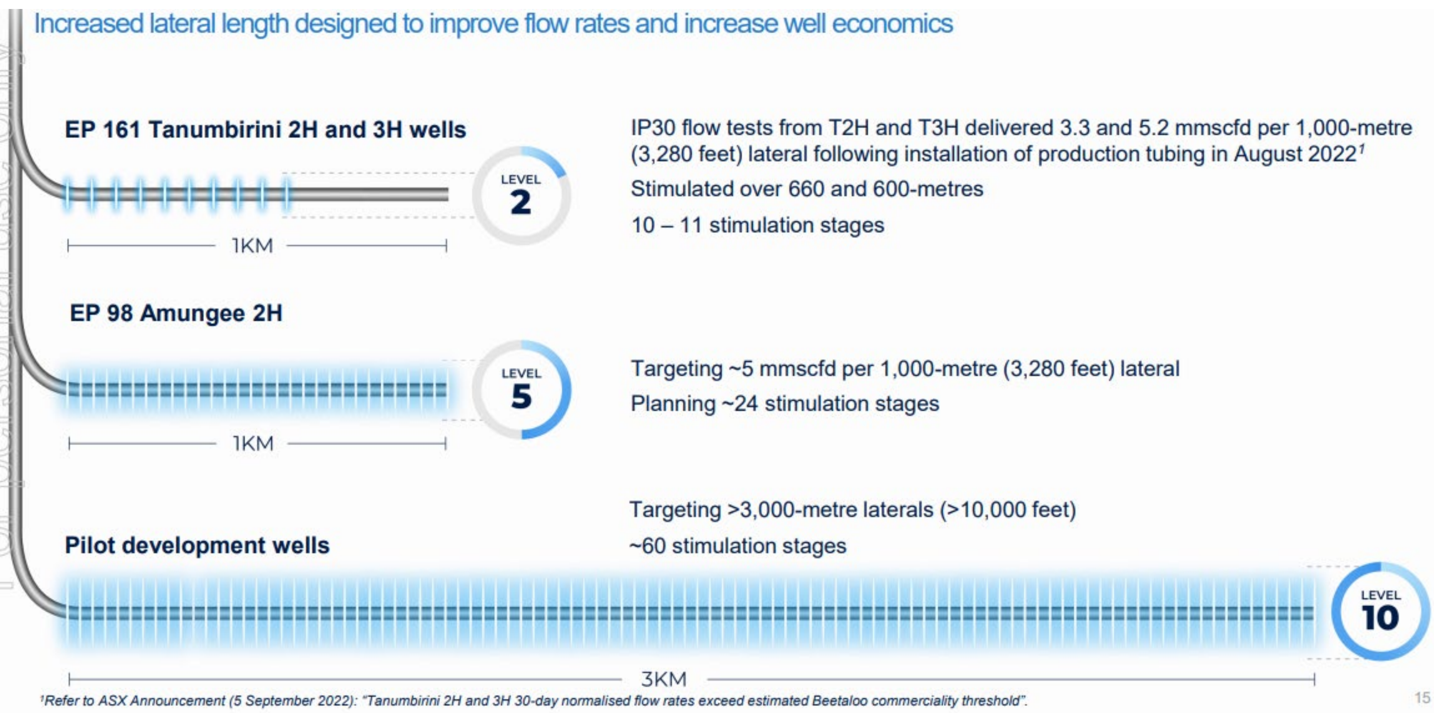
Following the five well program, if successful, it is expected to allow TBN to sanction the proposed Amungee Pilot Development by the end of CY 2023.

Figure 4: EP 98 Amungee 2H



Source: Company

Figure 5: Upcoming wells to be optimised with US style stimulation design



Source: Company

Cash flow forecasts and near-term funding requirements

We table below a simple summary of what we believe are TBN's near term cash flows reflecting the stated plans at the recent equity raise.

Key forecasts and assumptions going down the cash flow statement are:

- Staff and administration costs to step up following the acquisition of the ORG assets reflecting the ORG staff coming on board to TBN.
- As per the FY22 annual report TBN has a $2.4m capital commitment by the end of CY 2022 to maintain its interest in EP 161. Given the land access difficulties encountered with Rallen over the last year and the inability to undertake any activity, the commitments are delayed. Given the materiality (lack of) we have included cash outflows of ~$1m per quarter going forward.
- The completion of M1V in EP 136 in the December quarter was forecast at $19m in the capital raise presentation.

Figure 6: Forecast Tamboran Resources cash flows out to June 2024

FY (A$m)	1Q23	2Q23	3Q23	4Q23	1Q24	2Q24	3Q24	4Q24
FY (A$m)	Sep-22	Dec-22	Mar-23	Jun-23	Sep-23	Dec-23	Mar-24	Jun-24
Receipt from customers								
Operating costs								
Staff costs	(1.2)	(3.2)	(3.2)	(3.3)	(3.5)	(3.6)	(3.8)	(4.0)
Admin and corporate costs	(1.4)	(4.9)	(4.9)	(5.1)	(5.4)	(5.6)	(5.9)	(6.2)
Receipt from government grants		3.8	3.7					
Net interest	(0.0)	0.0						
Net Operating Cash Flow	**(2.6)**	**(4.2)**	**(4.3)**	**(8.4)**	**(8.8)**	**(9.3)**	**(9.8)**	**(10.2)**
Net proceeds / (payment) for PPE	(8.8)	(9.5)			30.0			
TBN's share of EP161 costs (25%)		(1.0)	(1.0)	(1.0)	(1.0)	(1.0)		
TBN's share of EP136 costs (100%)	(9.3)	(5.5)	(2.5)	(2.5)	(2.5)	(2.5)		
TBN's share of EP98 / 117 / 76 costs (38.75%)	(7.3)	(21.3)	(18.7)		(21.5)	(21.5)	(21.5)	(21.5)
Evaluation / Other			(2.5)	(2.5)	(2.5)	(2.5)		
Royalty reduction				(11.4)				
Acquisitions	(10.3)	(17.1)						
Divestments								
Net Investing Cash Flow	**(35.7)**	**(54.4)**	**(24.7)**	**(17.4)**	**2.5**	**(27.5)**	**(21.5)**	**(21.5)**
Equity raised	39.2	101.2			55.0		55.0	
Debt & Equity raise costs	(0.9)	(8.1)			(2.2)			
Lease liabilty / Other	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Financing Cash Flow	**38.2**	**93.1**	**(0.1)**	**(0.1)**	**52.7**	**(0.1)**	**54.9**	**(0.1)**
Movement in cash	**(0.2)**	**34.5**	**(29.1)**	**(25.9)**	**46.4**	**(36.9)**	**23.6**	**(31.8)**
Opening Cash	26.8	26.7	60.9	31.8	5.9	52.2	15.3	39.0
FX impacts	0.1	(0.2)						
Closing Cash	**26.7**	**60.9**	**31.8**	**5.9**	**52.2**	**15.3**	**39.0**	**7.1**

Source: Company. MST Access.

- TBN is committed to fund 100% ($80m) of the next two wells (previously A2H and A3H) as part of the remaining ORG Stage 3 farm-in commitments that were contracted with FO. We have assumed the fracturing and flow testing of the well costs ~$19m in the March 2023 quarter (likely to run into the June quarter).
- The remaining Amungee wells we assume total ~$83m. $40m for A3H (100% funded by TBN) and $43m for A4H and A5H (TBN's share 38.75% of two wells at $55m per well). We have assumed the wells are completed by the end of the March 2024 quarter and expenditure is spread evenly over the four quarters including the June 2023 quarter. NB: If FO is unable to fund its 22.5% share of the $110m well program, TBN and Sheffield may be up for $55m each versus the $43m we have assumed.
- We assume a front-end engineering and design (FEED) study is completed over CY2023 for the Amungee Pilot Development at a cost of $10m (spread evenly over the year).

- We have assumed TBN exercises its rights to reduce the overriding royalty interests (ORRI’s) payable to Bayless (reduction from 4% to 2% at a cost US$7m) and Petrohunter's (reduction from 2% to 1% at a cost of US$1m) due to be paid by 1 July 2023. The forecast cost of A$11.4m potentially could be funded with scrip but we have assumed it is cash expensed at this stage.
- TBN acquired three drill rigs in early CY 2022. Given the new relationship with H&P, these rigs will now not be required and we forecast will sold for ~$30m (timing unknown but we have assumed in the September 2023 quarter).

Thus. based on our forecasts by June 2023 TBN will have cash available of ~$6m and will require new funding by the end of the September 2023 quarter.

Amungee Pilot Development

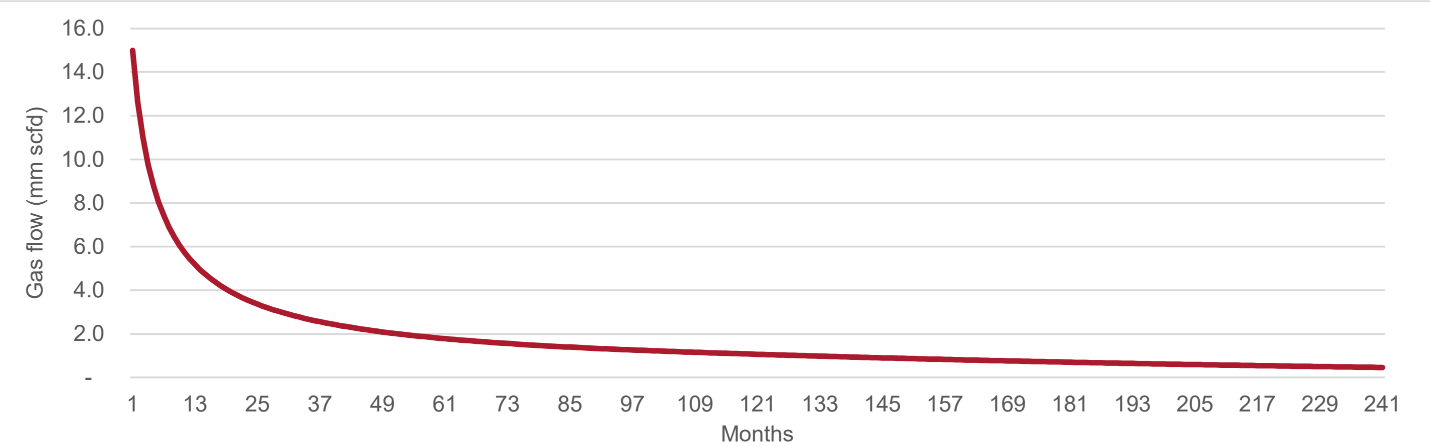
We reference our June 2022 note where we detailed potential production profiles so as to forecast a model for the proposed pilot program for EP136. On the same basis we have recast our numbers reflecting the new ownership structure and royalty regimes for the Amungee Pilot Development.

Production and well forecasts

Key factors used are:

- Initial flow rates of 15 mm scfd based on 5.0 mm scfd per 1,000 m laterals with 3,000 m laterals to be drilled.
- Initial decline rates of 90 %.
- Minimum decline rate of 8 %.
- Hyperbolic coefficient (b factor) of 1.3.
- As can be see below well production is forecast to by ~2/3rds over the first 12 months and drops from 15 mmscfd to ~2.0 mmscfd over the first five years. (Model available on request).

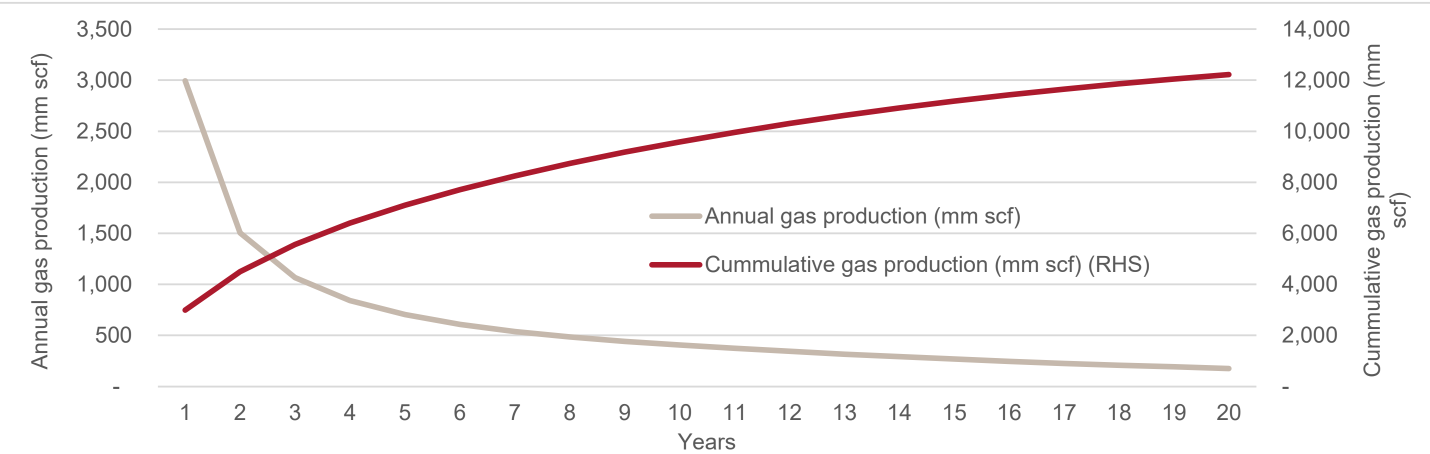
Figure 7: Forecast well production profile



Source: Company. MST Access.

Total gas production, or estimated ultimate recovery (EUR), over 20 years is estimated at ~12 Bcf (our model duration) with ~14 Bcf produced over a 40-year time frame.

Figure 8: Forecast well annual production profile



Source: Company. MST Access.

As a result of our calculated well performance, we forecast that ~13 wells will be required in the first year of the development (assuming ~ 2 wells every 2 months) followed by 7 wells in Year 2, followed by 5 in Year 3, then ~4 wells per annum for a few years and then ~ 3 wells per annum on an ongoing basis. This would allow TBN to produce ~110 mm scfd of well head gas which would result in ~100 mm scfd of sales gas to be sent to market. Clearly as the production decline flattens and the number of wells lifts, the number of new wells per annum required falls.

Figure 9: First ten-year forecast production profile and well capex required

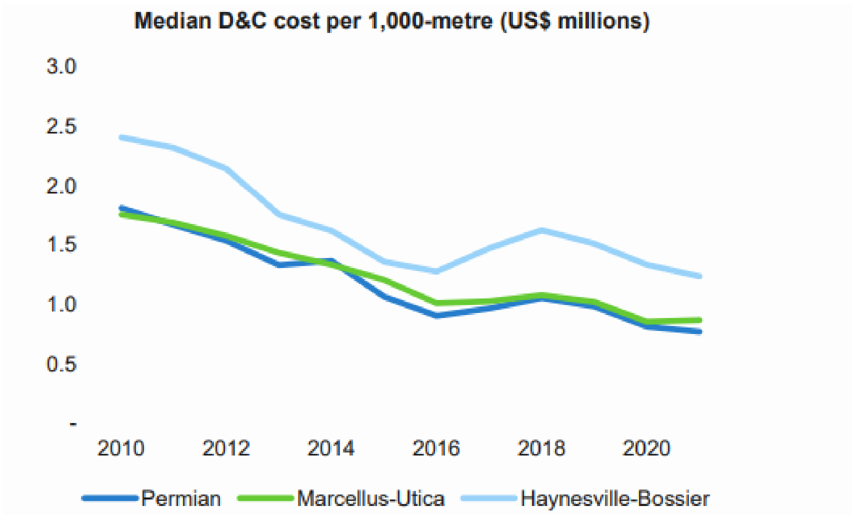
Year	1	2	3	4	5	6	7	8	9	10
Gas produced (Bcf)	25.5	40.0	40.6	39.7	39.8	40.2	40.6	40.0	40.0	40.3
Implied gas produced (mm scfd)	70	110	111	109	109	110	111	109	109	110
Gas produced (PJ)	26.9	42.2	42.9	41.9	42.0	42.4	42.8	42.2	42.2	42.5
Percentage CO_2	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
CO_2 (Bcf)	0.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
CO2 (t)	41,836	65,613	66,636	65,051	65,224	65,839	66,500	65,520	65,518	66,085
Other gas shrinkage to net gas sold	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Other gas shrinkage to net gas sold	1.3	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Sales gas sold (Bcf)	23.5	36.8	37.4	36.5	36.6	36.9	37.3	36.8	36.8	37.1
Implied sales gas (mm scfd)	**64**	**101**	**102**	**100**	**100**	**101**	**102**	**101**	**101**	**102**
Sales gas sold (PJ)	24.8	38.8	39.4	38.5	38.6	39.0	39.4	38.8	38.8	39.1
Well capex (A$m)										
Number wells drilled	13	7	5	4	4	4	4	3	3	3
Cummulative wells drilled	13	20	25	29	33	37	41	44	48	51
Capex per well	33	30	28	25	23	20	21	21	22	22
Average well cost	34	31	29	26	24	21	20	21	21	22
Well capex (A$m)	**425**	**225**	**147**	**110**	**100**	**83**	**75**	**68**	**70**	**72**

Source: Company. MST Access.

On this basis, in the first three years of the pilot program, ~25 wells will need to be drilled which will clearly require a meaningful level of new capital. By this stage however, TBN will have booked a 2P reserve from which it will be able to secure reserve backed lending (RBL) to fund the project. Additionally, it may choose to farm out an additional stake to lower its holding and to reduce TBN's equity requirements.

We have assumed TBN become more efficient with its well drilling and average well costs fall from A$34m to $20m per well over the first six years as per the management teams experience in the United States shale basins.

Figure 10: Cost reduction in capex (drilling, completion and facilities equipment) have fallen 50% since 2010



Source: Company, Rystad Energy

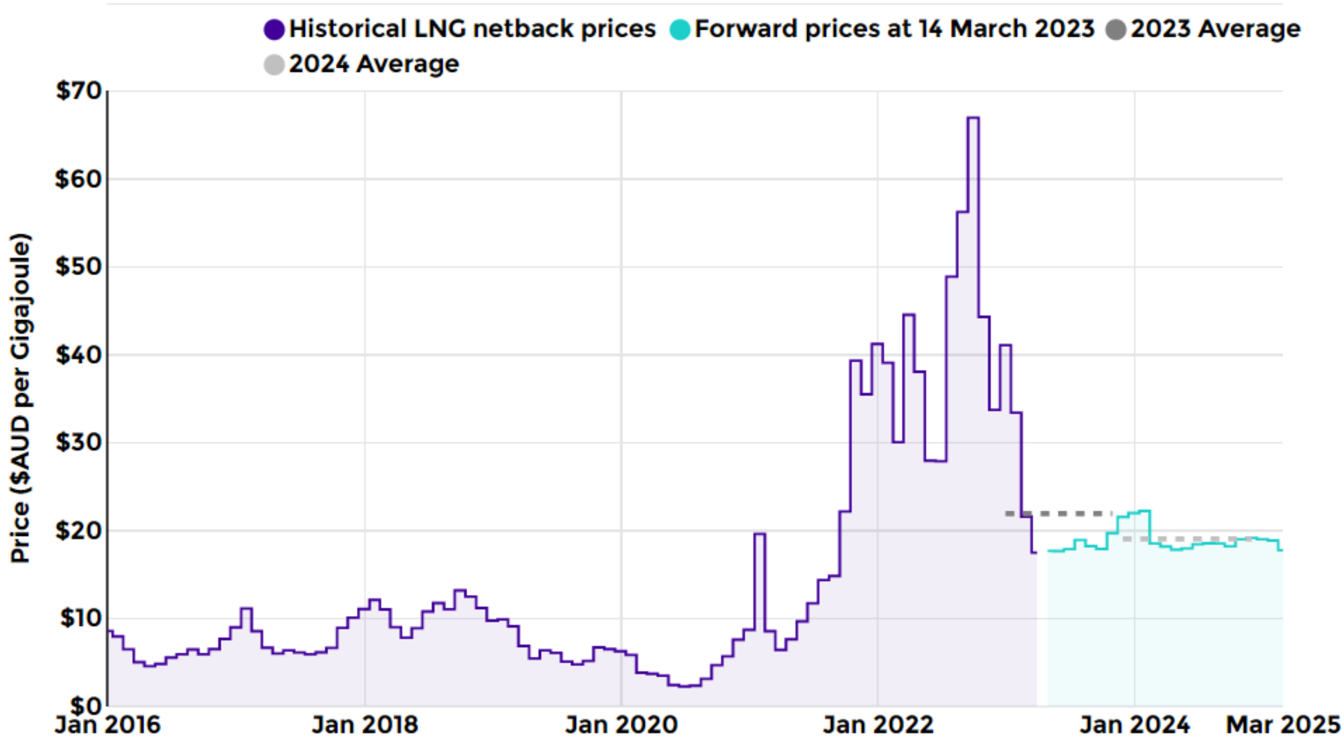
We also note, if initial gas flows are higher than 5.0 mm scfd, the number of wells required to meet a 100 mm scfd pilot program would be lower; e.g. If initial flows are 7.5 mm scfd the number of wells to be drilled in the first three years would drop from ~25 wells to ~17 wells, a capex saving of $266m.

Forecast financials

With a production profile and a forecast capex program we have generated the forecast cash flows for the program. See Appendix 5 for the TBN key target assumptions for the pilot program and transport costs to market.

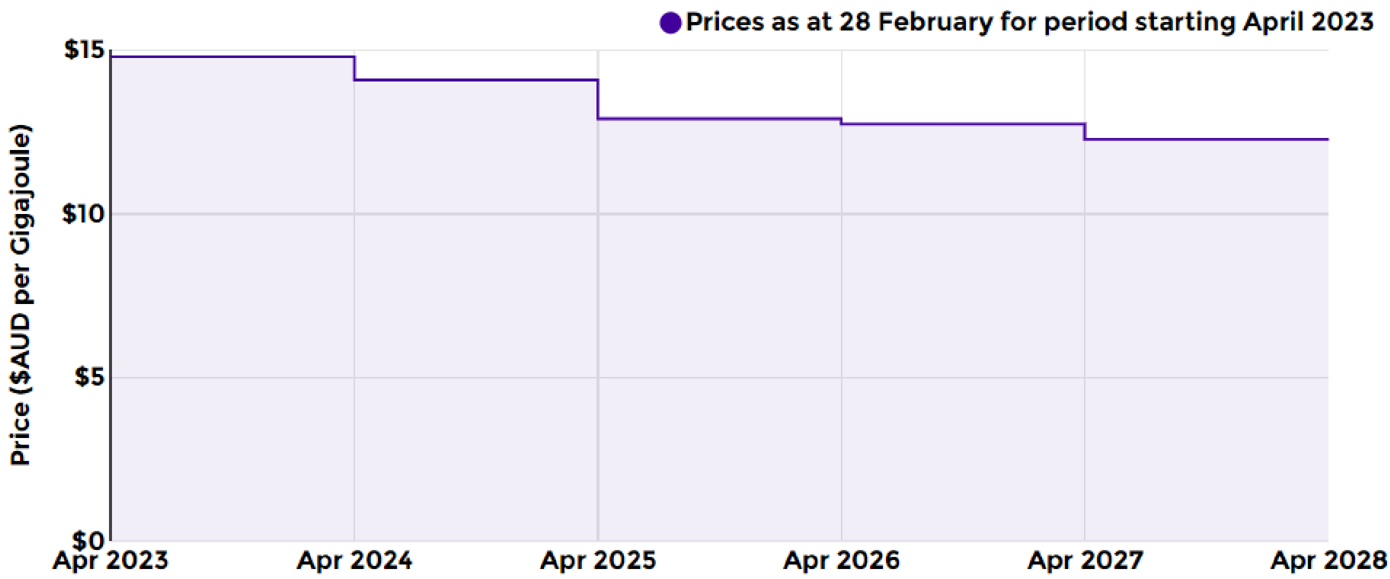
Key to the project economics is gas price received. For modelling we have assumed a starting sales gas price of A$10/GJ. We do not believe this is unduly optimistic given where current liquified natural gas (LNG) netback prices are currently pricing (16 March 2023) as estimated by the Australian Competition & Consumer Commission (ACCC) and potentially could be conservative.

Figure 11: Historical and forward LNG netback price at Wallumbilla (A$/GJ)



Source: ACCC, 16 March 2023.

Figure 12: Forward LNG netback price at Wallumbilla (A$/GJ)



Source: ACCC, 16 March 2023.

We table below our forecast base case pilot program forecasts assuming a $4.30 transportation haulage tariff. That is what we see as the worst-case transport option and cost to get to market.

Figure 13: Forecast cash flows for Pilot program (10 years of a 20-year pilot program)

Year	1	2	3	4	5	6	7	8	9	10
Gas produced (Bcf)	25.5	40.0	40.6	39.7	39.8	40.2	40.6	40.0	40.0	40.3
Implied gas produced (mm scfd)	70	110	111	109	109	110	111	109	109	110
Gas produced (PJ)	26.9	42.2	42.9	41.9	42.0	42.4	42.8	42.2	42.2	42.5
Percentage CO_2	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
CO_2 (Bcf)	0.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
CO2 (t)	41,836	65,613	66,636	65,051	65,224	65,839	66,500	65,520	65,518	66,085
Other gas shrinkage to net gas sold	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Other gas shrinkage to net gas sold	1.3	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Sales gas sold (Bcf)	23.5	36.8	37.4	36.5	36.6	36.9	37.3	36.8	36.8	37.1
Implied sales gas (mm scfd)	**64**	**101**	**102**	**100**	**100**	**101**	**102**	**101**	**101**	**102**
Sales gas sold (PJ)	24.8	38.8	39.4	38.5	38.6	39.0	39.4	38.8	38.8	39.1
Inflation	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Gas price (A$/GJ)	10.00	10.25	10.51	10.77	11.04	11.31	11.60	11.89	12.18	12.49
Sales revenue	**248**	**398**	**414**	**415**	**426**	**441**	**457**	**461**	**473**	**489**
Fixed operating costs	(15)	(15)	(16)	(16)	(17)	(17)	(17)	(18)	(18)	(19)
Variable operating costs ($/GJ)	0.50	0.51	0.53	0.54	0.55	0.57	0.58	0.59	0.61	0.62
Variable operating costs	(13)	(22)	(23)	(23)	(23)	(24)	(25)	(25)	(26)	(27)
Operating costs	(28)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)
Gross operating cash flow	**219**	**361**	**376**	**376**	**386**	**400**	**414**	**418**	**429**	**443**
Private Royalties	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%
Private Royalties	(17)	(28)	(29)	(29)	(30)	(31)	(32)	(33)	(33)	(35)
State royalties	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
State royalties	(22)	(36)	(38)	(38)	(39)	(40)	(41)	(42)	(43)	(44)
Carbon tax ($/ t CO_2)	30	31	32	32	33	34	35	36	37	37
Carbon tax	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Transport cost (A$/GJ)	4.30	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37
Transport costs	(106)	(171)	(178)	(178)	(183)	(190)	(196)	(198)	(203)	(210)
Pre tax operational cash flow	**72**	**124**	**129**	**129**	**132**	**137**	**142**	**143**	**147**	**152**
Well capex (A$m)										
Number wells drilled	13	7	5	4	4	4	4	3	3	3
Cummulative wells drilled	13	20	25	29	33	37	41	44	48	51
Average well cost	34	31	29	26	24	21	20	21	21	22
Well capex (A$m)	**425**	**225**	**147**	**110**	**100**	**83**	**75**	**68**	**70**	**72**
Pre tax free cash flow	**(353)**	**(101)**	**(18)**	**18**	**33**	**54**	**67**	**75**	**77**	**80**
20 year ungeared pre tax IRR	**9.8%**									

Source: Company. MST Access.

MST key assumptions are:

- 20-year project life.
- Gas price and cost inflation of 2.5% per annum.
- Fixed operating costs of $15 m per annum inflating at 2.5%.
- Variable operating costs of $0.50/GJ produced inflating at 2.5%.
- Private royalties assumed for EP98 are 2.3% to Sheffield and 5.5% to Origin Energy.
- State royalties at 10% of gross value.
- We assume produced gas contains 3% of carbon dioxide and an additional 5% of gas shrinkage occurs through plant use flaring etc. Carbon tax of $30/tonne CO2 produced.

- Transport costs for pilot program of ~$4.30/GJ comprising $1.59/GJ for the Northern Gas Pipeline (NGP), $1.15/GJ for the Carpentaria Gas Pipeline (CGP) and $1.54/GJ for the South-West Queensland Pipeline (SWQP).
- We assume additional compression will be required to get gas to Wallumbilla for the SWQP, otherwise the tariff is $1.32/GJ]. See Appendix 4.
- We assume the cost of constructing a 100 mm scfd pipeline from the production areas to the NGP is funded by Jemena and is incorporated in our forecast operating costs. NB: TBN alternatively could pipe across to the Amadeus Gas Pipeline through an expanded MacArthur River Pipeline (See Appendix 4), so capex would be lower but for the life of the pilot program haulage tariffs would be slightly higher.
- Amortisation of well capital expenditure in line with gas production.

Based on our assumptions the pilot program will earn a pre-tax internal rate of return (IRR) of ~10 %. We note if we lift the forecast gas price received to $15/GJ, our base case ungeared IRR lifts from ~10 % to 58 %.

If we then assume the same assumptions as our base pilot program but assume gas transportation costs lower to $0.50/GJ to $1.00/GJ through a new Jemena pipeline to Darwin, the IRR lifts to ~53% to 46 %.

If we assume gas prices of $15/GJ and a $1.00/GJ transportation price to Darwin, the IRR lifts to ~over 100%.

Valuation demonstrates material share price upside potential

Capital structure

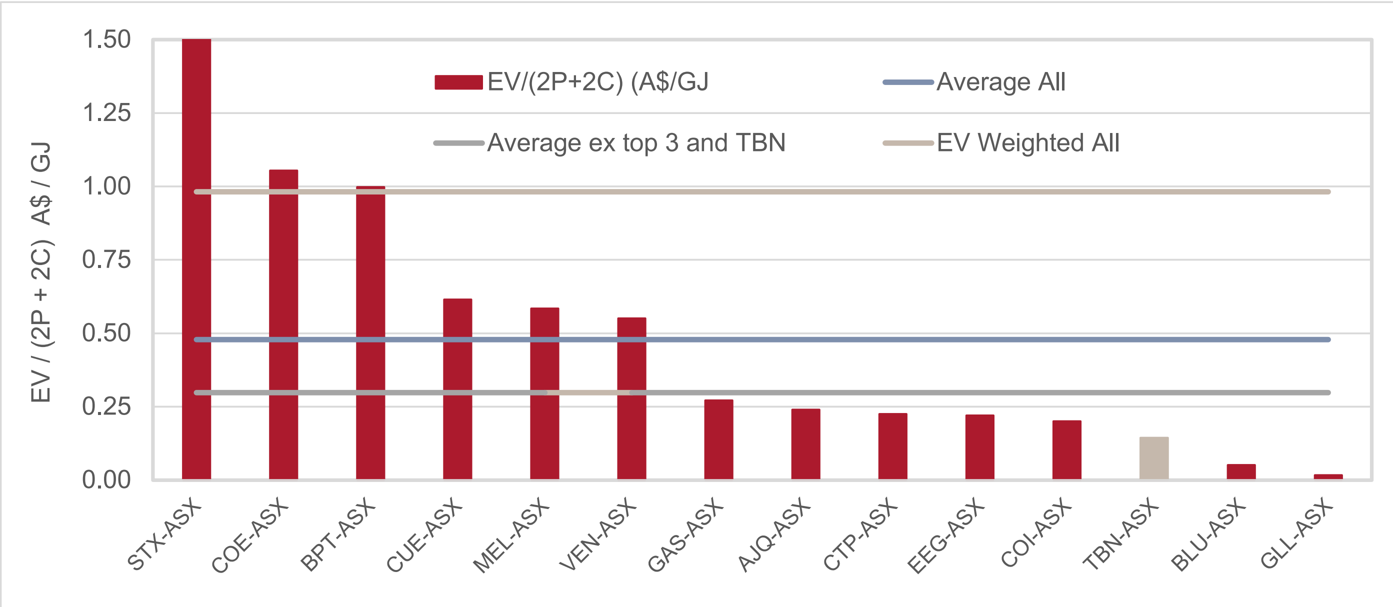
TBN currently has 1,416m shares on issue. There are an additional 62.2m options and performance shares that we forecast will issue resulting in a fully diluted share count of 1,478.2m shares on issue.

Spot valuation

We derive a spot valuation for TBN of $0.54 (previously $0.58) per share based on a $0.50 / (2P+2C) (GJ) resource multiple.

See table below for the oil and gas comparable companies EV multiples listed in Australia. The average multiple is ~$0.50/GJ.

Figure 14: Peer comparisons on a 2P+2C basis (A$/GJ) – Average ~$0.50/GJ



Source: FactSet. MST Access.

We then value TBN's net 1,577PJ at $0.50/GJ, in line with the average A$/GJ of 2P reserve plus 2C resource for similar listed Australian exploration and production companies (Figure 14) and add our forecast 30 June 2023 net cash position to get a spot equity value for TBN.

We then divide by the forecast diluted shares on issue.

Figure 15: Spot Valuation (MSTe 30 June 2023 cash levels) based on different EV/(2P + 2C) multiples ($/GJ))

Spot Valuation					Currently trading at
2C plus 2P (Bcf)	1,488	1,488	1,488	1,488	1,488
2C plus 2P (PJ)	1,577	1,577	1,577	1,577	1,577
Resource multiple A$ / (2P+2C) (GJ)	**0.25**	**0.50**	**0.75**	**1.00**	**0.18**
Reserve Value (A$m)	391	788	1,183	1,577	291
Net cash (MSTe June 2023) (A$m)	6	6	6	6	6
Equity valuation (A$m)	**397**	**794**	**1,189**	**1,583**	**297**
Share value per diluted share (A$)	**0.27**	**0.54**	**0.80**	**1.07**	**0.21**

Source: Company. MST Access.

Risks

The company and share price face a range of risks, including:

- extent and quality of the resource vs. expectations,
- financial risks such as funding,
- plant construction and commissioning costs,
- securing routes to markets,
- reserve life,
- production decline rates,
- competition from LNG imports to Eastern Australia and other domestic gas discoveries impacting final gas pricing,
- listed company risks such as significant shareholder selling,
- Company-specific risks such as management issues,
- relationships with business partners,
- environmental and operational risks,
- regulatory risks, and
- macroeconomic risk.

Appendix 1 - Resources and Reserves

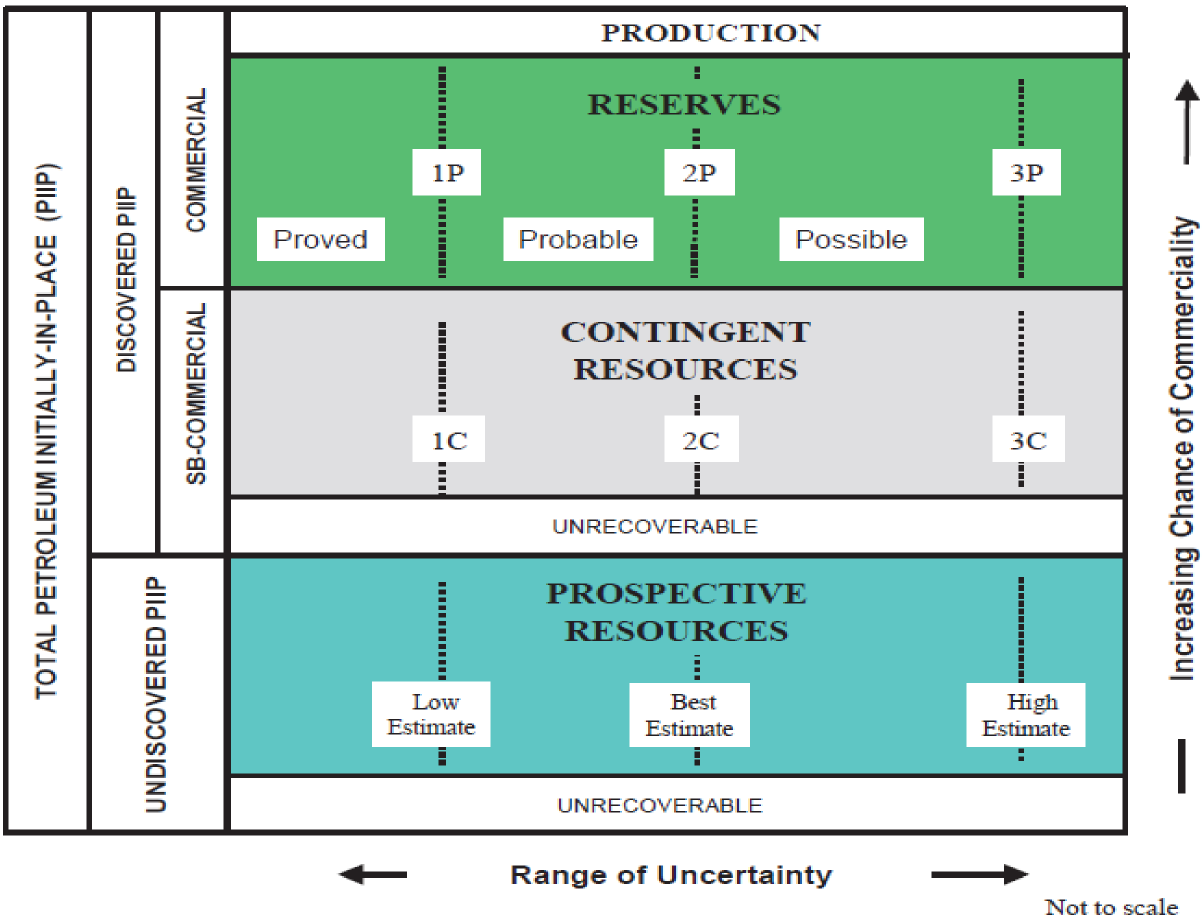
We note below the three categories into which estimated quantities of potentially recoverable petroleum can be placed: Prospective Resources, Contingent Resources and Reserves. Within each category, three estimates are designated to describe the range, with greater certainty at the low end and less certainty at the high end.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but where the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. The categories within Reserves, in order of decreasing certainty, are Proved, Probable and Possible.

Figure 16: Resources and Reserves Classification



Source: PRMS Resources Classification.

TBN Resources and Reserves

Figure 17: Tamboran Resources and Reserves (excludes condensate)

EP136 (100%)			
Prospective Gas Reources net to TBN (Tcf)			
	Low (1U)	**Best (2U)**	**High (3U)**
Lower Kyalla		0.2	
Mid Velkerri C		6.1	
Mid Velkerri B		9.7	
Mid Velkerri A		3.0	
Total (Tcf)	**11.1**	**19.1**	**40.0**

EP136 (100%)			
Contingent 2C Gas Reources net to TBN (Bcf)			
	Low (1C)	**Best (2C)**	**High (3C)**
Lower Kyalla			
Mid Velkerri C			
Mid Velkerri B			
Mid Velkerri A			
Total (Bcf)	**0**	**0**	**0**

EP161 (25%)			
Prospective Gas Reources net to TBN (Tcf)			
	Low (1U)	**Best (2U)**	**High (3U)**
Lower Kyalla		0.2	
Mid Velkerri C		3.5	
Mid Velkerri B		6.5	
Mid Velkerri A		2.1	
Total (Tcf)	**7.1**	**12.4**	**26.5**

EP161 (25%)			
Contingent 2C Gas Reources net to TBN (Bcf)			
	Low (1C)	**Best (2C)**	**High (3C)**
Lower Kyalla		0	
Mid Velkerri C		159	
Mid Velkerri B		245	
Mid Velkerri A		0	
Total (Bcf)	**83**	**404**	**941**

EP98, EP117 & EP76 (38.75%)			
Prospective Gas Reources net to TBN (Tcf)			
	Low (1U)	**Best (2U)**	**High (3U)**
Lower Kyalla			
Mid Velkerri C		26.0	
Mid Velkerri B		69.9	
Mid Velkerri A		20.4	
Total (Tcf)	**67.4**	**116.4**	**245.5**

EP98, EP117 & EP76 (38.75%)			
Contingent 2C Gas Reources net to TBN (Bcf)			
	Low (1C)	**Best (2C)**	**High (3C)**
Lower Kyalla			
Mid Velkerri C		431	
Mid Velkerri B		652	
Mid Velkerri A			
Total (Bcf)	**252**	**1083**	**2440**

EP143 (100%)
Prospective Gas Reources net to TBN (Tcf)
Total (Tcf)

EP143 (100%)
Contingent 2C Gas Reources net to TBN (Bcf)
Total (Bcf)

EP197 (100%)
Prospective Gas Reources net to TBN (Tcf)
Total (Tcf)

EP197 (100%)
Contingent 2C Gas Reources net to TBN (Bcf)
Total (Bcf)

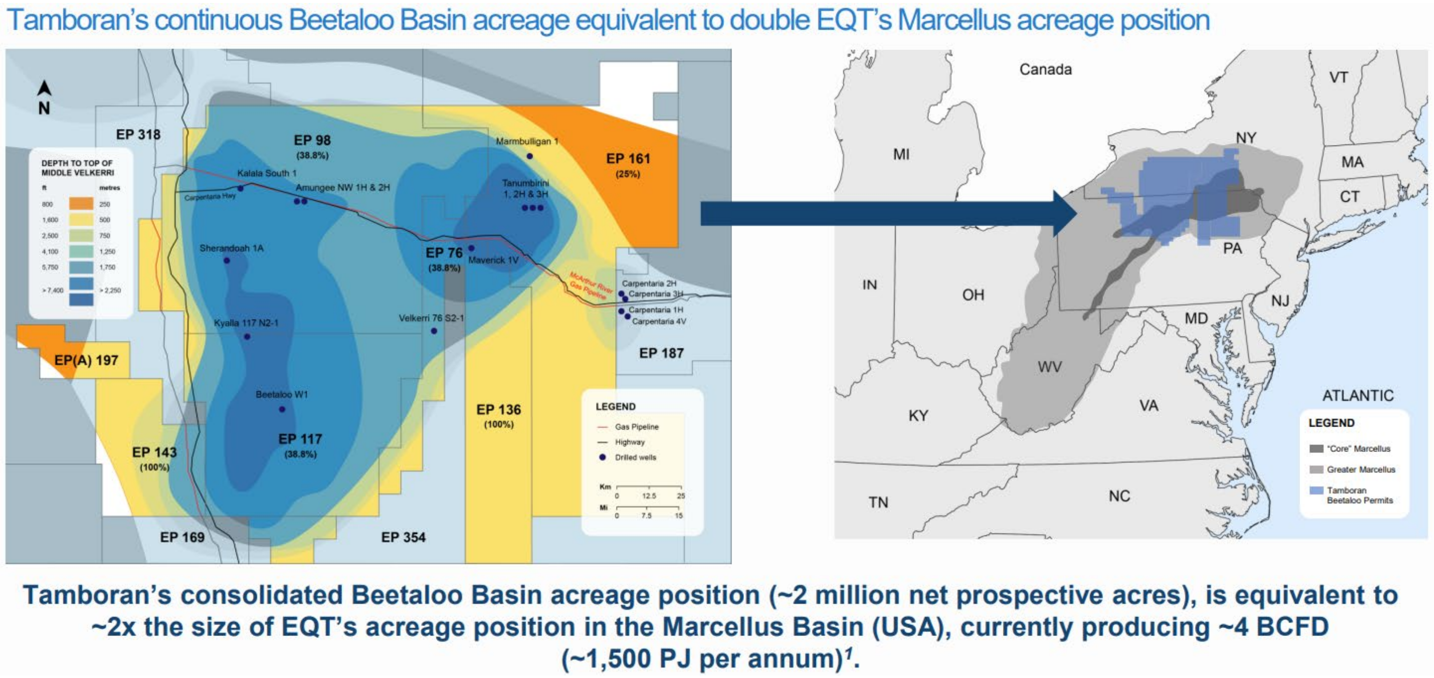
Total			
Prospective Gas Reources net to TBN (Tcf)			
	Low (1U)	**Best (2U)**	**High (3U)**
Lower Kyalla	0.2	0.5	1.5
Mid Velkerri C	20.5	35.6	75.2
Mid Velkerri B	51.8	86.1	175.7
Mid Velkerri A	13.2	25.6	59.7
Total (Tcf)	**85.6**	**147.8**	**312.0**

Total			
Contingent 2C Gas Reources net to TBN (Bcf)			
	Low (1C)	**Best (2C)**	**High (3C)**
Lower Kyalla	0	0	0
Mid Velkerri C	133	590	1342
Mid Velkerri B	202	897	2039
Mid Velkerri A	0	0	0
Total (Bcf)	**335**	**1488**	**3381**

Source: Company.

Appendix 2 - Tamboran Resources Licenses

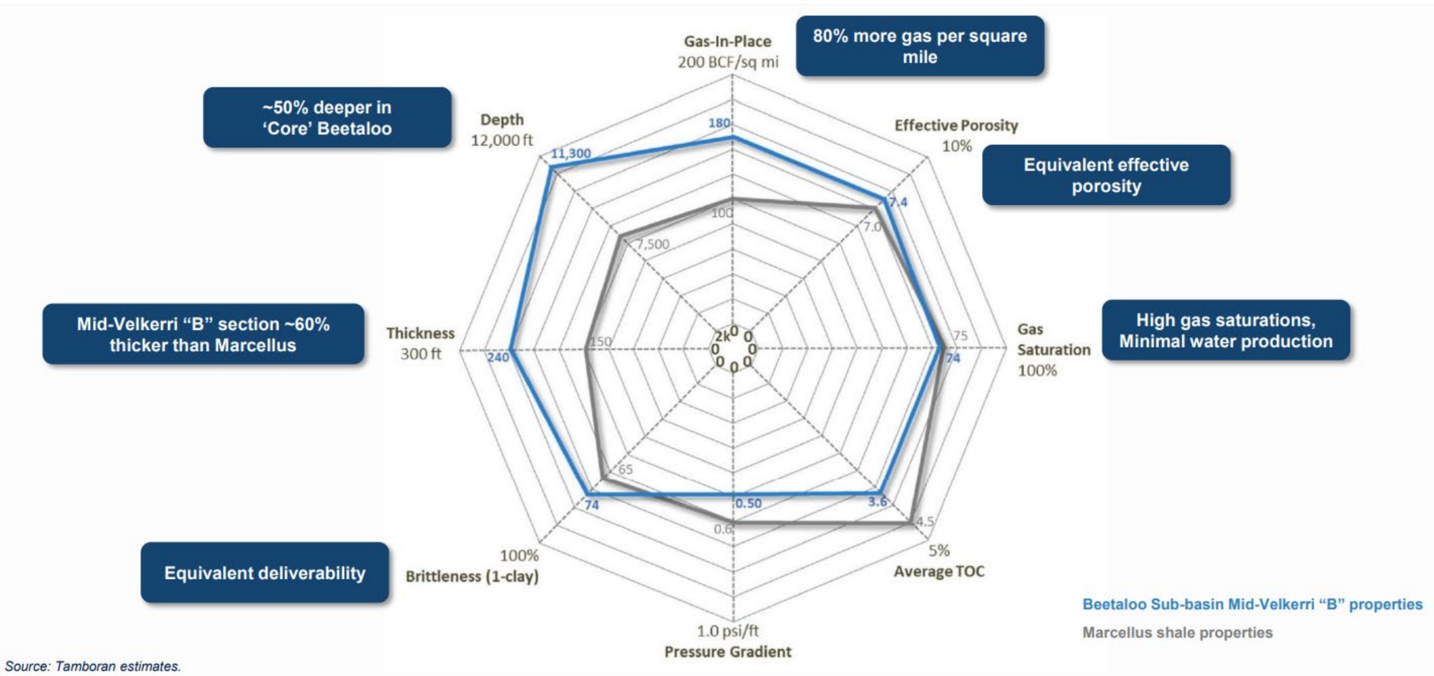
Figure 18: Tamboran Resources License Location



Source: Company.

Appendix 3 - Mid-Velkerri "B" compared to Marcellus shale

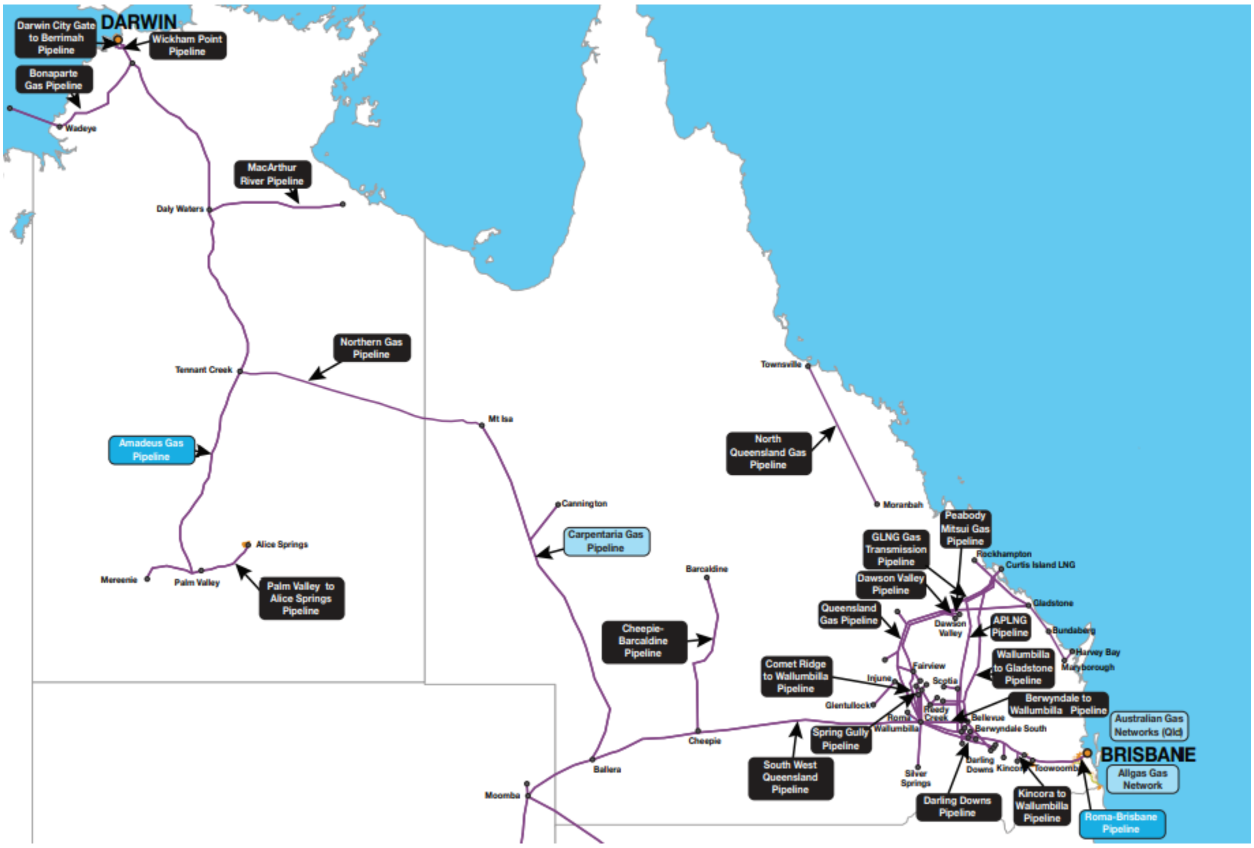
Figure 19: High productivity potential with original gas in place equivalent to three stacked Marcellus shale play



Source: Company.

Appendix 4 - East Coast Australia Pipelines

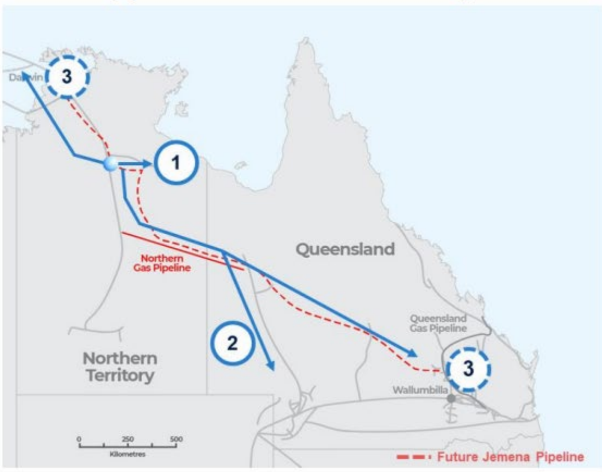
Figure 20: TBN will need access to Northern Gas, Carpentaria Gas and South-West Queensland pipelines



Source: Company.

Figure 21: TBN targeted full cycle cost to get gas from EP136 to Australian East Coast and or Darwin

Illustrative pipeline to commercialise Beetaloo gas



Cost Breakdown (US$ per mcf)	① 2023-2024 Local NT	② 2025 SE existing infra	③ 2028+ Domestic & LNG backfill Wallumbilla	Ichthys / Darwin LNG
Upstream Cost[1] US$ per mcf	~$3.10	~$2.00	~$1.40 or less	
Northern Territory via McArthur River Pipeline	~$0.30			
East Coast Existing infrastructure		~$2.70		
Ichthys / Darwin LNG via new Jemena pipeline (~1 BCFD)				~$0.30
Wallumbilla via new Jemena pipeline (~1,000 BCFD)			~$1.40	
Total Sales (US$/mcf)	~$3.40	~$4.70	~$2.70	~$1.70
LNG Plant Liquefaction			~$2.50	~$2.50
LNG Shipping Australia to Japan			~$0.60	~$0.50
Total Delivered LNG (US$ per mcf)			~$5.80	~$4.70

[1]Upstream costs include operating costs (fixed and variable) of ~A$1.00 per GJ and drilling capital expenditure (refer to slide 32).

Source: Company.

Methodology & Disclosures

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