

## ANNOUNCEMENT

July 14, 2025

Tamboran Resources Corporation (NYSE: TBN, ASX: TBN)

### SS-2H ST1 delivers Beetaloo Basin record IP60 flow rate of 6.8 MMcf/d

#### Highlights

- The Shenandoah South 2H sidetrack (SS-2H ST1) well achieved a Beetaloo Basin record average 60-day initial production (IP60) flow rate of 6.8 million cubic feet per day (MMcf/d) over a 5,483-foot stimulated horizontal within the Mid Velkerri B Shale.
- The exit rate maintains a steady, low-declining curve at 6.4 MMcf/d with a flowing wellhead pressure of ~720 psi and has exhibited less decline than that of the SS-1H well over the last 30 days of testing.
- The average flow rate of 12.4 MMcf/d over a normalized 10,000-foot horizontal section remains in-line with an average of more than 11,000 wells in the Marcellus Shale dry gas area with production for over a 12-month period.
- The result reinforces Tamboran's view of commercial deliverability from the Beetaloo Basin to the Australian domestic East Coast gas market that typically sells at a premium to Henry Hub.
- Tamboran has commenced the three well 2025 Shenandoah South Pilot Project drilling program with the spudding of the Shenandoah South 4H (SS-4H) well. The wells are being drilled with the Helmerich & Payne (NYSE: HP) super-spec FlexRig® Flex 3 Rig from the SS2 pad in EP 98.

Tamboran Resources Corporation Chief Executive Officer, Joel Riddle, said:

"We are pleased to see the SS-2H ST1 well continues to demonstrate a shallow gas rate decline over the last 30 days, delivering an average IP60 flow rate of 6.8 MMcf/d. This result is a new Beetaloo Basin record and is more than double the previous IP60 record set by the SS-1H well in 2024.

"The normalized rate of 12.4 MMcf/d over a 10,000-foot lateral section aligns with the average of more than 11,000 wells within the Marcellus Shale dry gas area.

"We have now commenced the largest planned drilling program in the Beetaloo Basin to date, with three wells to be drilled back-to-back with a total combined horizontal section of 30,000 feet.

"These three wells are the last remaining wells required to be drilled as part of Tamboran's commitment to deliver 40 MMcf/d to the local market under our gas sales contract with the Northern Territory Government (NTG). With over 90% of electricity in the Northern Territory market supplied from gas fired power generation, our contract with the NTG is expected to play a major role in delivering energy security for all Territorians."

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### Shenandoah South 2H ST1 flow results

The SS-2H ST1 well in Tamboran operated Exploration Permit (EP) 98 achieved average IP60 flow rates of 6.8 MMcf/d following the 35-stage stimulation program across a 5,483 feet (1,671 metres) lateral section in the Mid Velkerri B Shale.

During the 30-day production testing period from day 31 to 60, gas rates declined from 6.6 MMcf/d to 6.4 MMcf/d, with an average 30-day flow rate of 6.4 MMcf/d and a cumulative production of 191 MMcf. Flowing wellhead pressures were drawn down from 906 to 722 psi over the 30-day period.

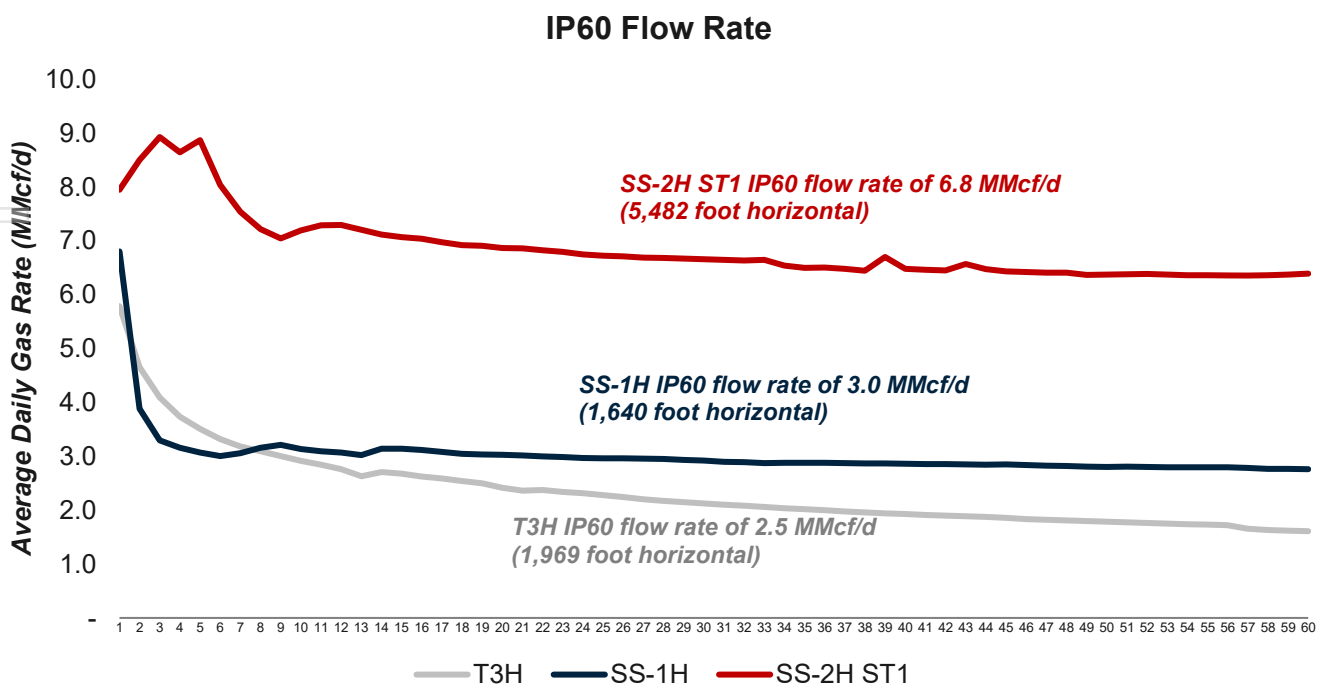
Overall, an IP60 flow rate of 6.8 MMcf/d and cumulative production of 408.2 MMcf was achieved over the entire test period to date. Flowing wellhead pressures were drawn down from 4,565 to 722 psi.

**Table 1: Breakdown of the SS-2H ST1 IP60 flow result**

Rates (MMcf/d)	Actual (5,483 ft)	Normalized (10,000 ft)
Average IP60 flow rate	6.8	12.4
IP60 exit rate	6.4	11.7

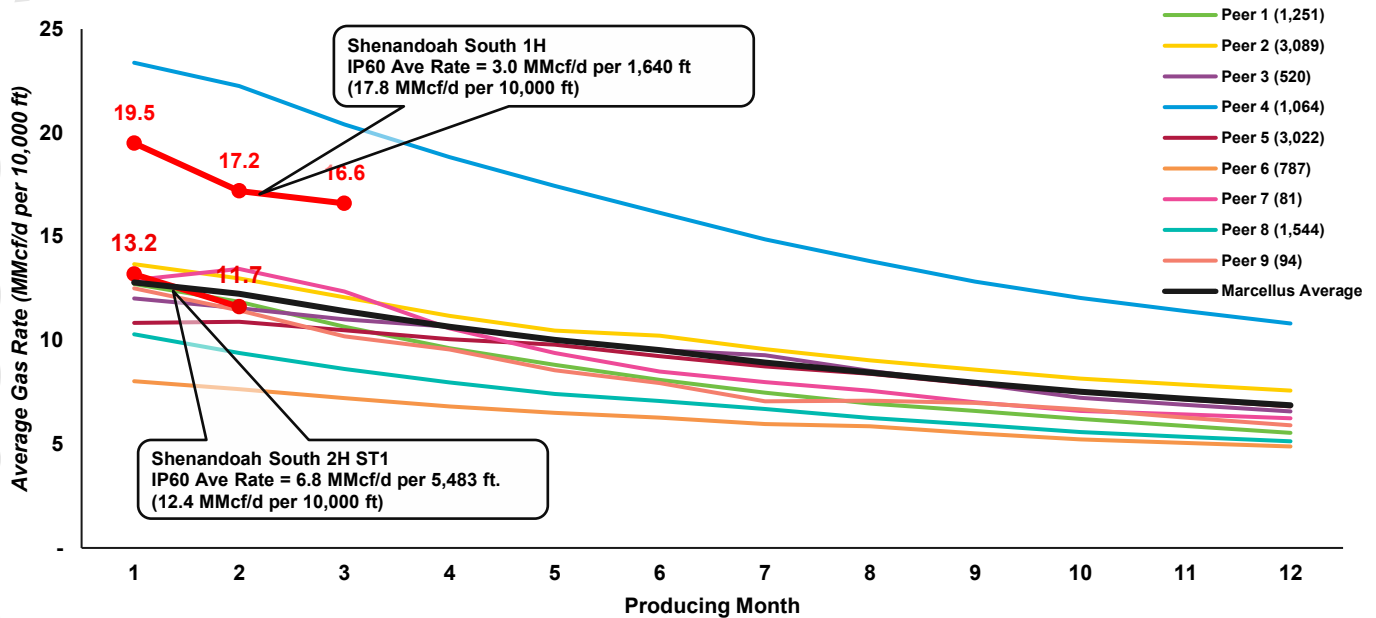
Source: Company data

**Figure 1: SS-2H ST1 IP60 flow rate vs. SS-1H and T3H**



Source: Company data

**Figure 2: Flow tests from Beetaloo Basin wells at Shenandoah South compared to wells drilled in the Marcellus Shale in the dry gas area. SS-2H ST1 aligns with average IP60 rates from more than 11,000 well data set**



Note: SS-1H initial 90-day and SS-2H initial 60-day production plotted against average of wells within the Marcellus shale, grouped by operator, normalized to 10,000 ft lateral length. First month production for Marcellus based on first full calendar month of production; SS-1H and SS-2H ST1 wells commenced testing following a "soaking" period of three weeks and ~60 days respectively. SS-1H average 90-day gas rate of 2.9 MMcfd for 500-metres (~1,640 ft) stimulated lateral length normalized to 10,000 ft, shown in red. SS-2H ST1 average 60-day gas rate of 6.8 MMcfd for 1,671-metres (~5,483 ft) stimulated lateral length normalized to 10,000 ft, shown. Marcellus comparison includes 11,452 wells with minimum 12 months of production from the following operators: Antero Resources, Expand, CNX Resources, Coterra Energy, EQT, HG Energy, Olympus Energy, Range Resources, and Repsol. Marcellus Production Data Source: Enverus Prism Foundations™ Forecast Analytics (Data accessed June 12, 2025).

**This ASX announcement was approved and authorised for release by Joel Riddle, the Chief Executive Officer of Tamboran Resources Corporation.**

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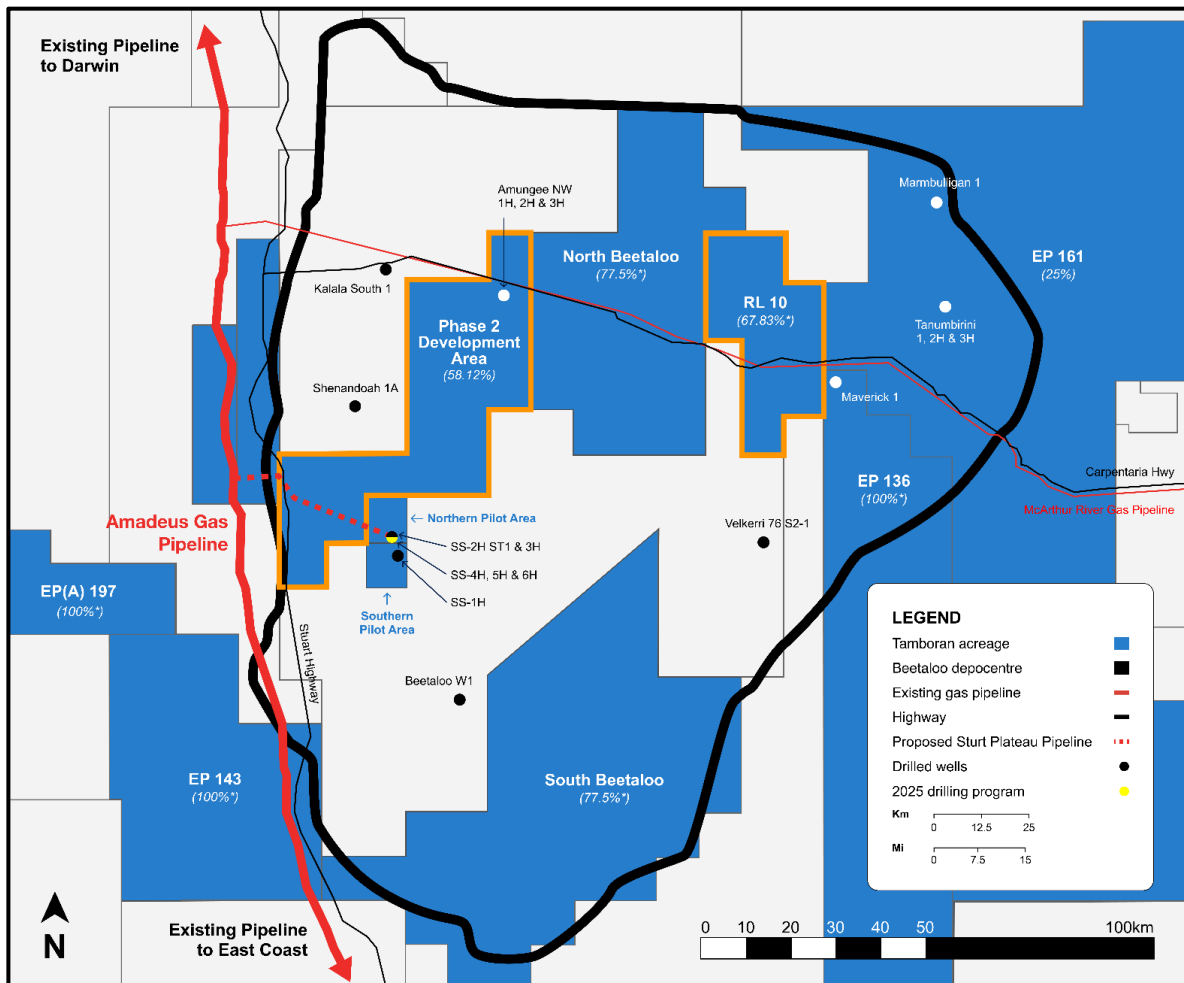
### About Tamboran Resources Corporation

Tamboran Resources Corporation (“Tamboran” or the “Company”), through its subsidiaries, is the largest acreage holder and operator with approximately 1.9 million net prospective acres in the Beetaloo Sub-basin within the Greater McArthur Basin in the Northern Territory of Australia.

Tamboran’s key assets include a 47.5% operating interest over 20,309 acres in the proposed northern Pilot Area, a 38.75% non-operating interest over 20,309 acres in the proposed southern Pilot Area, a 58.13% operating interest in the proposed Phase 2 development area covering 406,693 acres, a 67.83% operated interest over 219,030 acres in a proposed Retention License 10, a 77.5% operating interest across 1,487,418 acres over ex-EPs 76, 98 and 117, a 100% working interest and operatorship in EP 136 and a 25% non-operated working interest in EP 161, which are all located in the Beetaloo Basin.

The Company has also secured ~420 acres (170 hectares) of land at the Middle Arm Sustainable Development Precinct in Darwin, the location of Tamboran’s proposed NTLNG project. Pre-FEED activities are being undertaken by Bechtel Corporation.

**Figure 3: Tamboran’s Beetaloo Basin asset location map**



**Table 2: Disclosures under ASX Listing Rule 5.30 (Shenandoah South 2H ST1)**

**a) The name and type of well.**

Shenandoah South 2H horizontal sidetrack (SS-2H ST1) well.

**b) The location of the well and details of the permit or lease in which the well is located.**

EP 98 of Beetaloo Sub-basin, Northern Territory (future Northern Pilot Area acreage, once checkerboard process and Retention Lease designation is formally completed).

**c) The entities working interest in the well.**

Tamboran holds a 47.5% interest in the well.

**d) If the gross pay thickness is reported for an interval of conventional resources, the net pay thickness.**

Not applicable—this is not a conventional reservoir.

**e) The geological rock type of the formation drilled.**

Organic-rich shale.

**f) The depth of the zones tested.**

Average depth of horizontal 3,017 metres Total Vertical Depth (TVD) (9,899 feet TVD), with 1,671 metres (5,483 ft) of stimulated lateral length.

**g) The types of test(s) undertaken and the duration of the test(s).**

60-day initial production (IP60) gas flow test.

**h) The hydrocarbon phases recovered in the test(s).**

Dry gas - mole %. Methane – 91.7, Ethane – 2.7, Propane – 0.12, Butane & higher <0.05.

**i) Any other recovery, such as, formation water and water, associated with the test(s) and their respective proportions.**

Fracture stimulation fluid is being recovered during testing. The well is currently producing ~70 barrels of water per day with a cumulative 24,923 bbls of water recovered from day 1 of cleanup.

**j) The choke size used, the flow rates and, if measured, the volumes of hydrocarbon phases measured.**

During the 30-day production testing period from day 31 to 60, the choke was opened from 40/64" to 44/64". Gas rates declined from 6.6 MMcf/d to 6.4 MMcf/d, with an average 30-day flow rate of 6.4 MMcf/d and a cumulative production of 191 MMcf. Flowing wellhead pressures were drawn down from 906 to 722 psi. over the 30 day period.

Overall, an IP60 flow rate of 6.8 MMcf/d and 60-day production volume of 408.2 MMcf was achieved over the entire test period to date. Flowing wellhead pressures were drawn down from 4,565 to 722 psi.

**k) If applicable, the number of fracture stimulation stages and the size and nature of fracture stimulation applied.**

35 stage fracture stimulation stages and a toe stage covering over 1,671 metres (5,483 feet) at an average of 40 to 50-metre (131 - 164-foot) interval spacing within the Mid Velkerri B Shale. Average proppant concentrations of 2,706 lbs/ft across the 35 main stages with a total of over 14 million pounds of sand placed.

**l) Any material volumes of non-hydrocarbon gases, such as carbon dioxide, nitrogen, hydrogen sulphide or sulphur.**

Reported as Mol %: CO<sub>2</sub>, – 3.5, N<sub>2</sub> – 1.9, He – 0.1.

**m) Any other information that is material to understanding the reported results.**

The well is planned to be flow tested over a full 90-day period, subject to joint venture approval.

## **Disclaimer**

Tamboran makes no representation, assurance or guarantee as to the accuracy or likelihood of fulfilment of any forward-looking statement or any outcomes expressed or implied in any forward-looking statement. The forward-looking statements in this report reflect expectations held at the date of this document. Except as required by applicable law or the ASX Listing Rules, Tamboran disclaims any obligation or undertaking to publicly update any forward-looking statements, or discussion of future financial prospects, whether as a result of new information or of future events.

The information contained in this announcement does not take into account the investment objectives, financial situation or particular needs of any recipient and is not financial product advice. Before making an investment decision, recipients of this announcement should consider their own needs and situation and, if necessary, seek independent professional advice. To the maximum extent permitted by law, Tamboran and its officers, employees, agents and advisers give no warranty, representation or guarantee as to the accuracy, completeness or reliability of the information contained in this presentation. Further, none of Tamboran nor its officers, employees, agents or advisers accept, to the extent permitted by law, responsibility for any loss, claim, damages, costs or expenses arising out of, or in connection with, the information contained in this announcement.

## **Note on Forward-Looking Statements**

This press release contains “forward-looking” statements related to the Company within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”) and Section 27A of the Securities Act of 1933, as amended. Forward-looking statements reflect the Company’s current expectations and projections about future events at the time, and thus involve uncertainty and risk. The words “believe,” “expect,” “anticipate,” “will,” “could,” “would,” “should,” “may,” “plan,” “estimate,” “intend,” “predict,” “potential,” “continue,” “participate,” “progress,” “conduct” and the negatives of these words and other similar expressions generally identify forward-looking statements.

It is possible that the Company’s future financial performance may differ from expectations due to a variety of factors, including but not limited to: our early stage of development with no material revenue expected until 2026 and our limited operating history; the substantial additional capital required for our business plan, which we may be unable to raise on acceptable terms; our strategy to deliver natural gas to the Australian East Coast and select Asian markets being contingent upon constructing additional pipeline capacity, which may not be secured; the absence of proved reserves and the risk that our drilling may not yield natural gas in commercial quantities or quality; the speculative nature of drilling activities, which involve significant costs and may not result in discoveries or additions to our future production or reserves; the challenges associated with importing U.S. practices and technology to the Northern Territory, which could affect our operations and growth due to limited local experience; the critical need for timely access to appropriate equipment and infrastructure, which may impact our market access and business plan execution; the operational complexities and inherent risks of drilling, completions, workover, and hydraulic fracturing

operations that could adversely affect our business; the volatility of natural gas prices and its potential adverse effect on our financial condition and operations; the risks of construction delays, cost overruns, and negative effects on our financial and operational performance associated with midstream projects; the potential fundamental impact on our business if our assessments of the Beetaloo are materially inaccurate; the concentration of all our assets and operations in the Beetaloo, making us susceptible to region-specific risks; the substantial doubt raised by our recurring operational losses, negative cash flows, and cumulative net losses about our ability to continue as a going concern; complex laws and regulations that could affect our operational costs and feasibility or lead to significant liabilities; community opposition that could result in costly delays and impede our ability to obtain necessary government approvals; exploration and development activities in the Beetaloo that may lead to legal disputes, operational disruptions, and reputational damage due to native title and heritage issues; the requirement to produce natural gas on a Scope 1 net zero basis upon commencement of commercial production, with internal goals for operational net zero, which may increase our production costs; the increased attention to ESG matters and environmental conservation measures that could adversely impact our business operations; risks related to our corporate structure; risks related to our common stock and CDIs; and the other risk factors discussed in this report and the Company's filings with the Securities and Exchange Commission.

It is not possible to foresee or identify all such factors. Any forward-looking statements in this document are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments, and other factors it believes are appropriate in the circumstances. Forward-looking statements are not a guarantee of future performance and actual results or developments may differ materially from expectations. While the Company continually reviews trends and uncertainties affecting the Company's results of operations and financial condition, the Company does not assume any obligation to update or supplement any particular forward-looking statements contained in this document.