



Amplitude Energy investor presentation

May 2026



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This document contains forward looking statements. These statements are subject to risks associated with the oil and gas industry. Amplitude Energy believes the expectations reflected in these statements are reasonable. A range of variables or changes in underlying assumptions may affect these statements and may cause actual results to differ. These variables or changes include but are not limited to price, demand, currency, geotechnical factors, drilling and production results, development progress, operating results, engineering estimates, reserve estimates, environmental risks, physical risks, regulatory developments, cost estimates, relevant regulatory approvals (State and Commonwealth) and timing delays beyond the reasonable control of Amplitude Energy.

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The ECSP is also subject to project and corporate risks associated with the oil and gas industry. Amplitude Energy believes the expectations reflected in the ECSP are reasonable. However, a range of variables or changes in underlying assumptions may affect these statements and may cause actual results to differ. These variables or changes include but are not limited to price, demand, currency, geotechnical factors, drilling and production results, development progress, operating results, engineering estimates, reserve estimates, environmental risks, physical risks, regulatory developments, cost estimates, relevant regulatory approvals (State and Commonwealth) and timing delays beyond the reasonable control of Amplitude Energy. See further Risk Management section (pages 59-62) of Amplitude Energy's FY25 Annual Report.

The following are non-IFRS measures: EBITDAX (earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment); EBITDA (earnings before interest, tax, depreciation, depletion and impairment); EBIT (earnings before interest and tax); underlying profit; and free cashflow (operating cash flows less investing cash flows net of acquisitions and disposals and major growth capex less lease liability payments). Amplitude Energy presents these measures to provide an understanding of Amplitude Energy's performance. They are not audited but are from financial statements reviewed by Amplitude Energy's auditor. Underlying profit excludes the impacts of asset acquisitions and disposals, impairments, hedging, and items that fluctuate between periods.

Numbers in this report have been rounded. As a result, some figures may differ insignificantly due to rounding and totals reported may differ insignificantly from arithmetic addition of the rounded numbers.

References to "\$mm" mean millions of Australian dollars, unless stated otherwise. Conversions of US dollar denominated figures into Australian dollars has been made where applicable.

The estimates of petroleum reserves, prospective and contingent resources contained in this presentation are at 30 June 2025. Amplitude Energy prepares its petroleum reserves, prospective and contingent resources estimates in accordance with the 2018 Petroleum Resources Management System (PRMS) sponsored by the Society of Petroleum Engineers (SPE). The reserves and resources information in this presentation is based on, and fairly represents, information and supporting documentation prepared by, or under the supervision of James Clark, who is a full time employee of Amplitude Energy and is a member of the SPE. He meets the requirements of a QPRRE, is qualified in accordance with ASX Listing Rule 5.41 and has consented to the inclusion of this information in the form and context in which it appears. The conversion factor of 1 PJ = 0.163417 MMboe has been used to convert from sales gas (PJ) to oil equivalent (MMboe). Condensate and crude oil are converted at 1bbl = 1 boe. The conversion factor 1 MMbbls = 6.11932 PJe has been used to convert Oil (MMbbls) and condensate (MMbbls) to gas equivalent (PJe)

For Prospective Resources the estimated quantities of petroleum that may be potentially recovered by the application of future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration, appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.

Approved and authorised for release by Jane Norman, Managing Director and CEO, Amplitude Energy Limited, Level 11, 55 Currie Street, Adelaide 5000.

Key Contacts

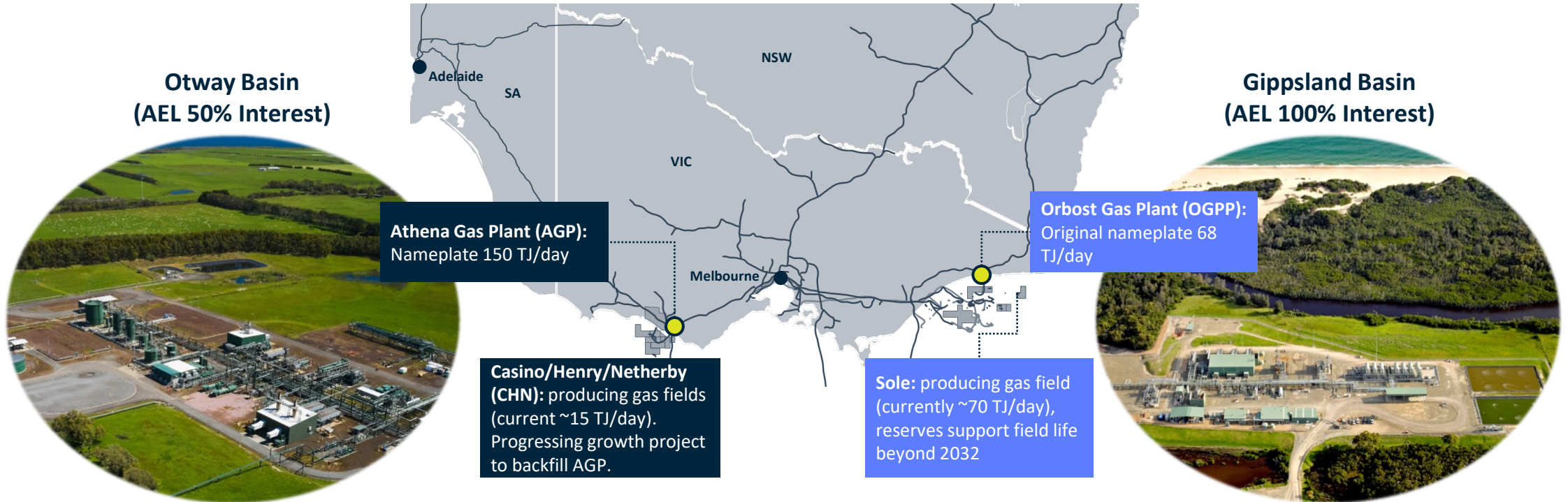
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Australian domestic gas producer with strong base and growth upside

Amplitude Energy is a growing, pure-play exposure to Australia's tight east coast domestic gas market



HY FY26 strong existing business

- Revenue +6%¹ to >\$140m
- u-EBITDAX +9%¹ to >\$100m
- Adj. cash from operations +6%¹ to >\$85m

Near-term growth

Pursuing projects intended to grow group production by around 50%+ by end 2028²

Strategic infrastructure position

Allows future growth through equity gas resources or third-party tolling

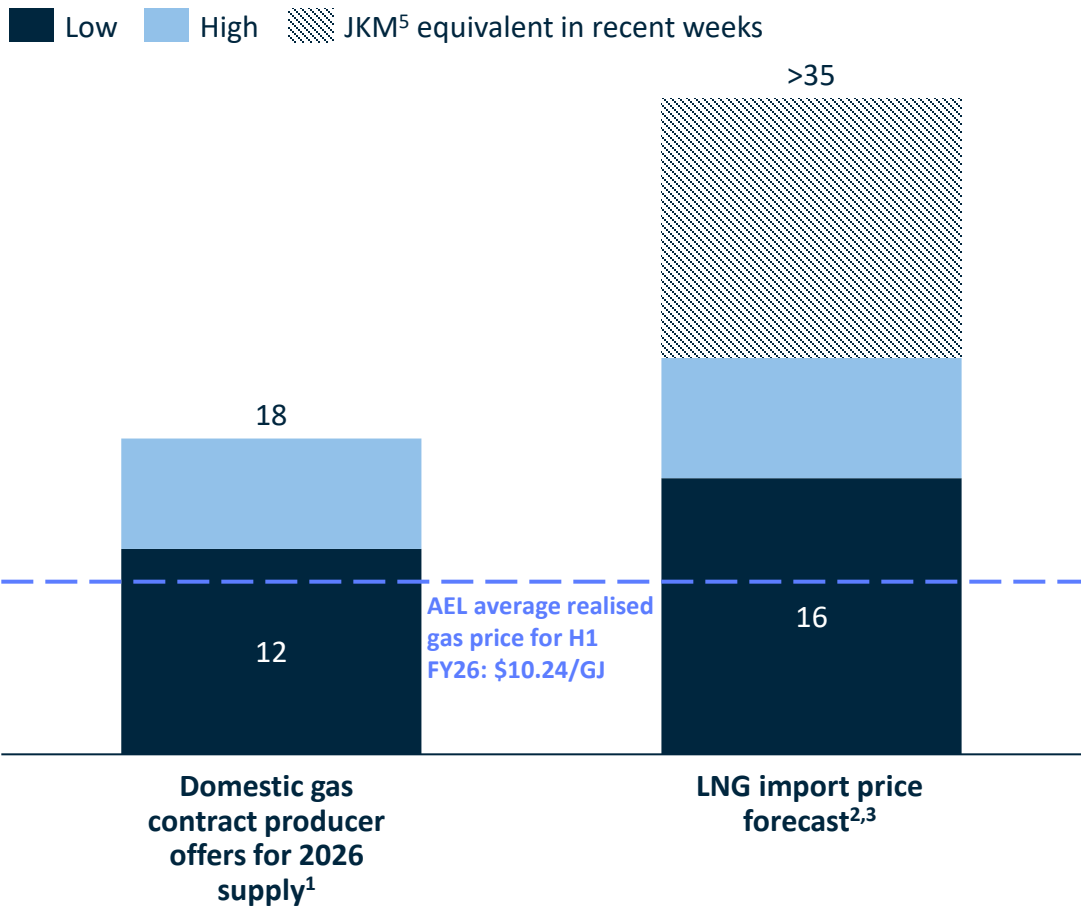


¹ Comparisons are to H1 FY25 figures. u-EBITDAX = Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment. In H1 FY26, the Company is no longer adjusting for the NOGA levy in its underlying results due to it being a recurring expense. Adj. cash from operations = Operating cash flow excluding restoration spend and other non-recurring and non-underlying items. | ² Illustrative, based on group production of 75.5 TJ/day in H1 FY26. Targeted production through the AGP post ECSP is indicative and subject to a number of variables including exploration success, Final Investment Decision, field resources, resource composition and field pressures.

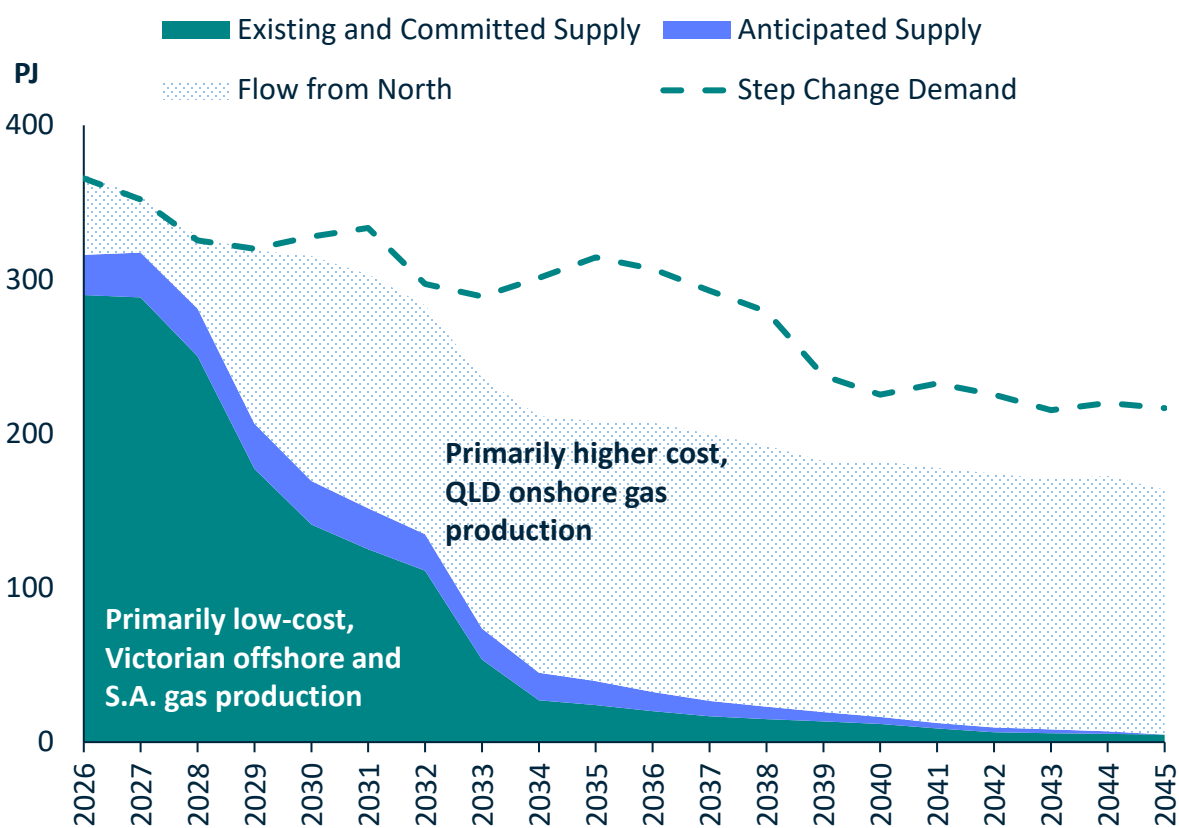
Higher domestic gas prices likely without substantial new local supply

Domestic gas is the cheapest and lowest emissions option to meet local demand

Australian Southern States contracted gas prices, A\$/GJ



Australian Southern States supply and demand balance⁴, PJ

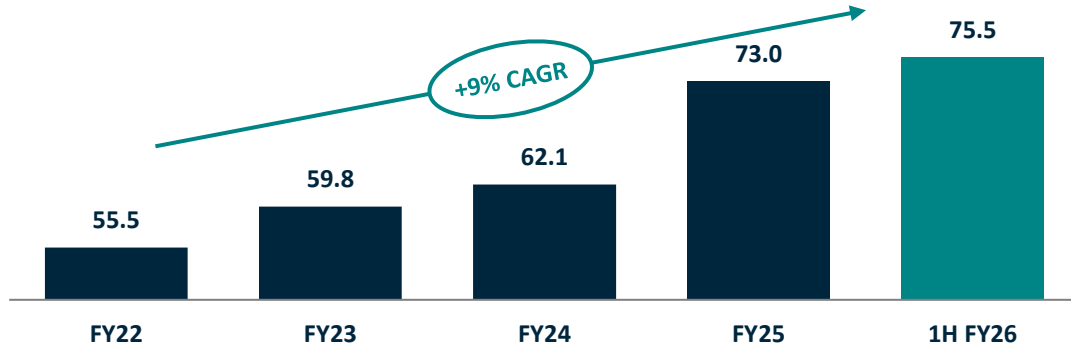


¹ ACCC Gas Inquiry Report, December 2025, Page 28, Chart 2.8 | ² EnergyQuest, East Coast Gas Outlook 2024, column indicates the “low” and “high” estimates for LNG imports from Port Kembla Energy Terminal into Sydney in 2026 | ³ Platts, LNG Japan / Korea DES Spot Cargo converted from US\$/MMBtu to equivalent A\$/GJ. | ⁴ AEMO, 2026 Gas Statement of Opportunities. | ⁵ Japan/Korea Marker (Asian benchmark reference price for LNG spot sales)

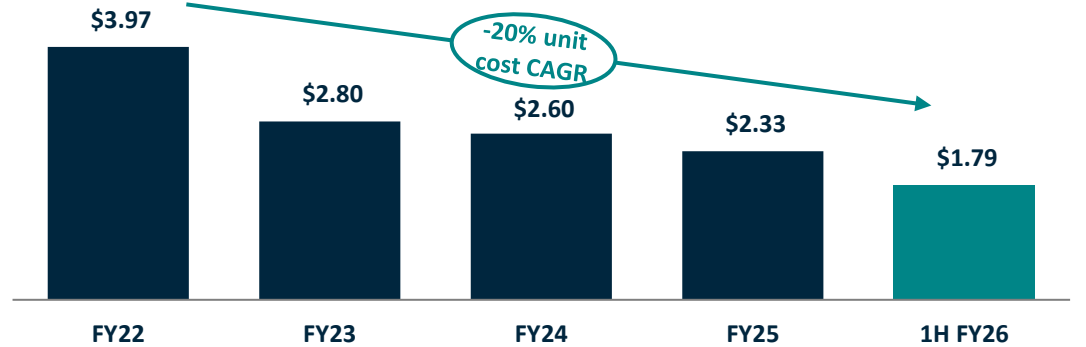
Proven performance and cash generation, with further upside ahead

Increased production and operational leverage has generated substantial margin expansion

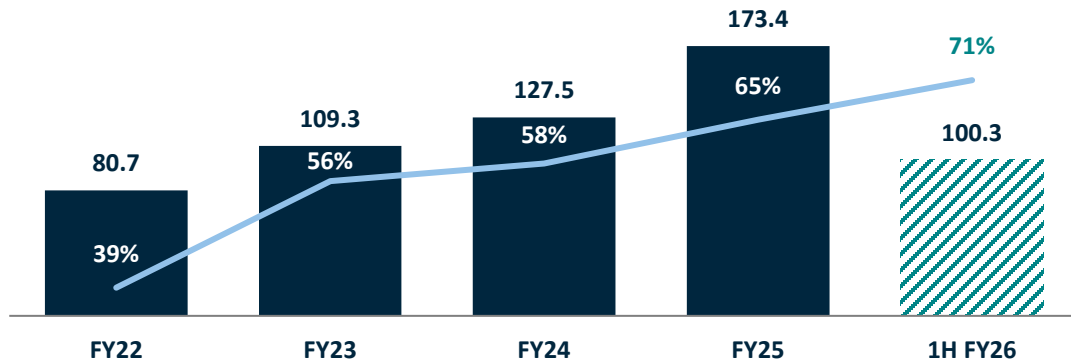
Production, TJe/day



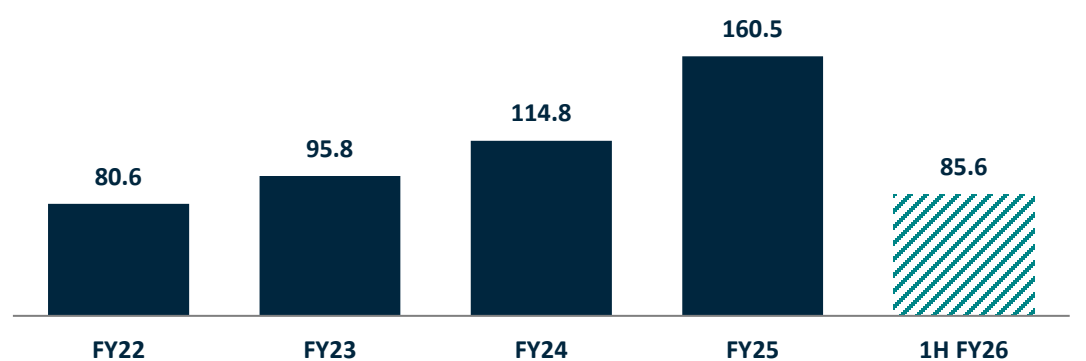
Production expenses¹, \$ per GJ produced



Underlying EBITDAX², \$mm \ margin, %



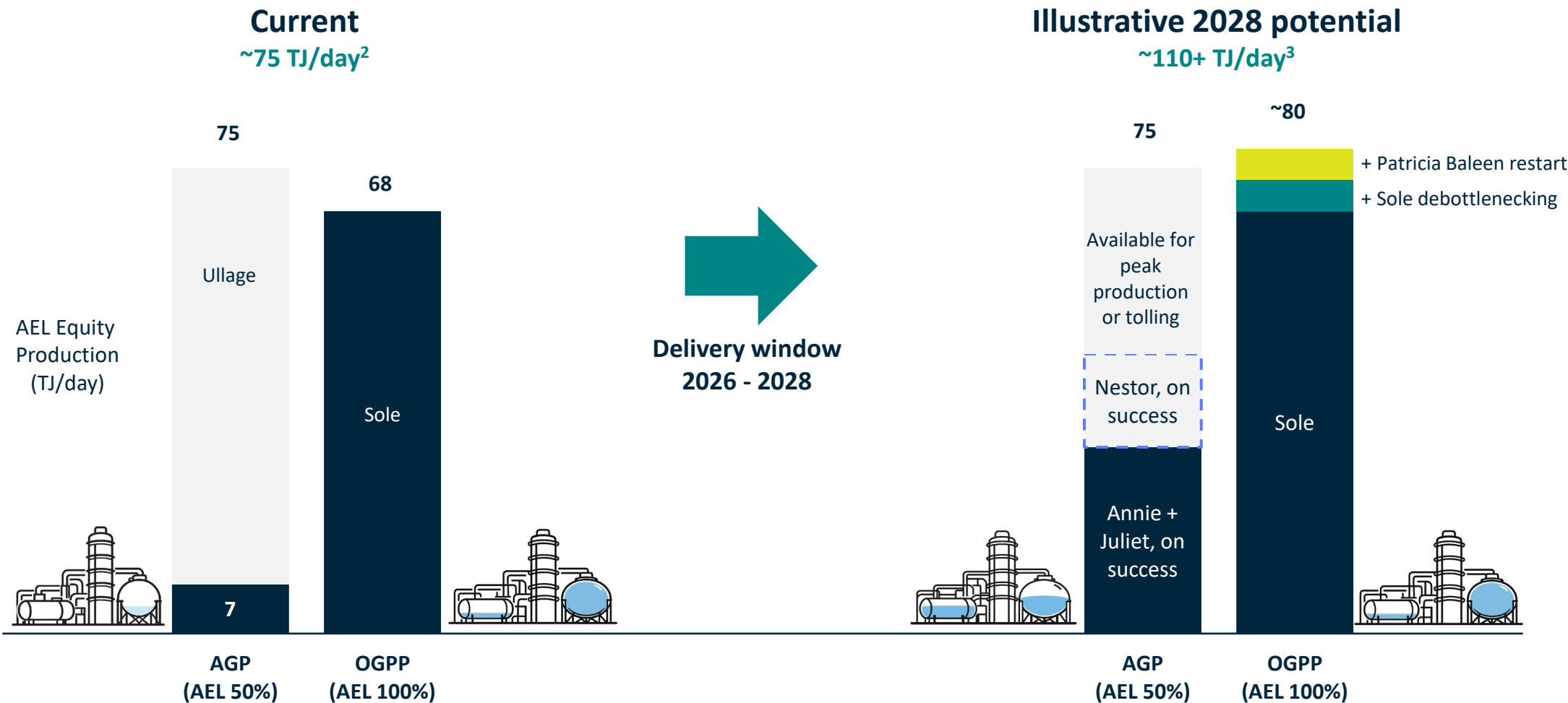
Adjusted cash from operations, \$mm³



¹ Production expenses comprise labour, materials, overheads, insurance, license costs, JV management and carbon offset costs, but excludes third-party product purchases, transport and trading costs, royalties, pipeline general visual inspection (GVI) costs and non-cash depreciation and amortisation | ² Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment. In H1 FY26, the Company is no longer adjusting for the NOGA levy in its underlying results due to it being a recurring expense. | ³ Operating cashflows excluding restoration spend and other non-recurring and non-underlying items

Transformative near-term brownfield growth

Backfilling existing infrastructure can deliver growth in equity production of around 50%+ by 2028¹

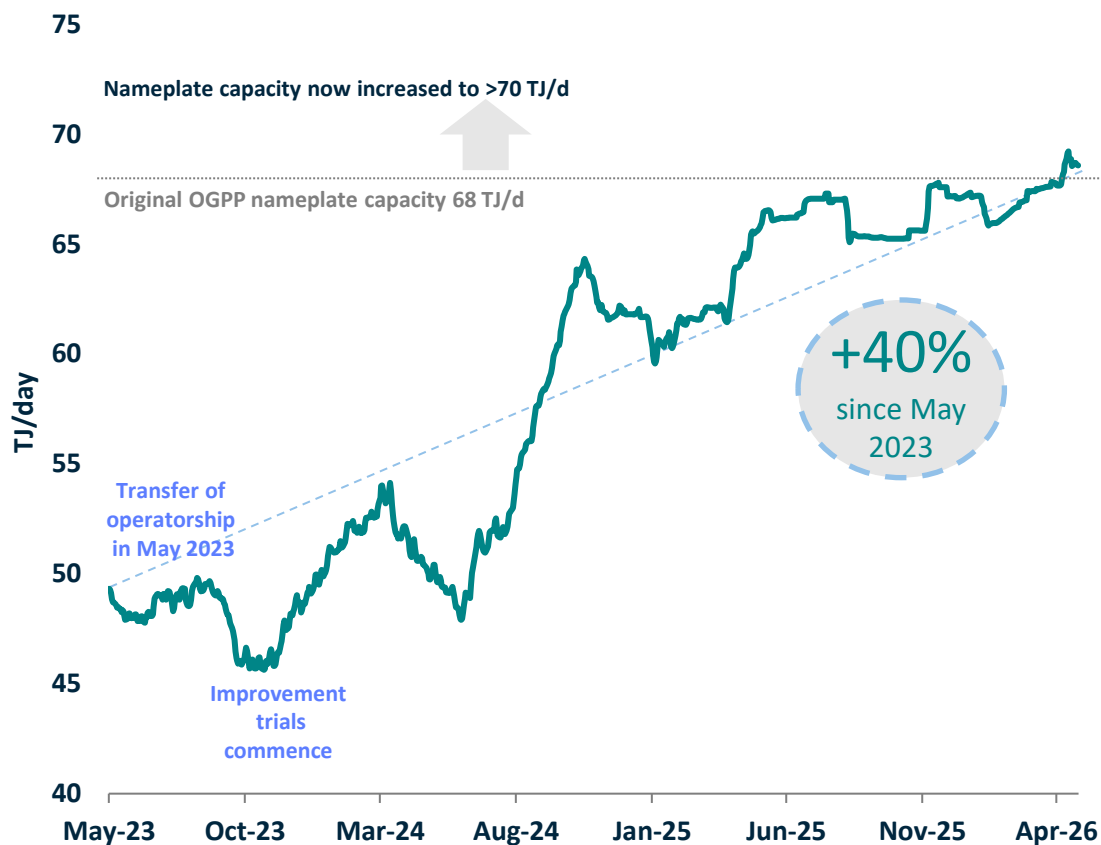


¹ Illustrative, increase by end 2028 is relative to group production of 75.5 TJ/day in H1 FY26. Targeted production through the AGP post ECSP is indicative and subject to a number of variables including exploration success, Final Investment Decision, field resources, resource composition and field pressures. | ² Q3 FY26 | ³ Post ECSP production, first gas expected in 2028.

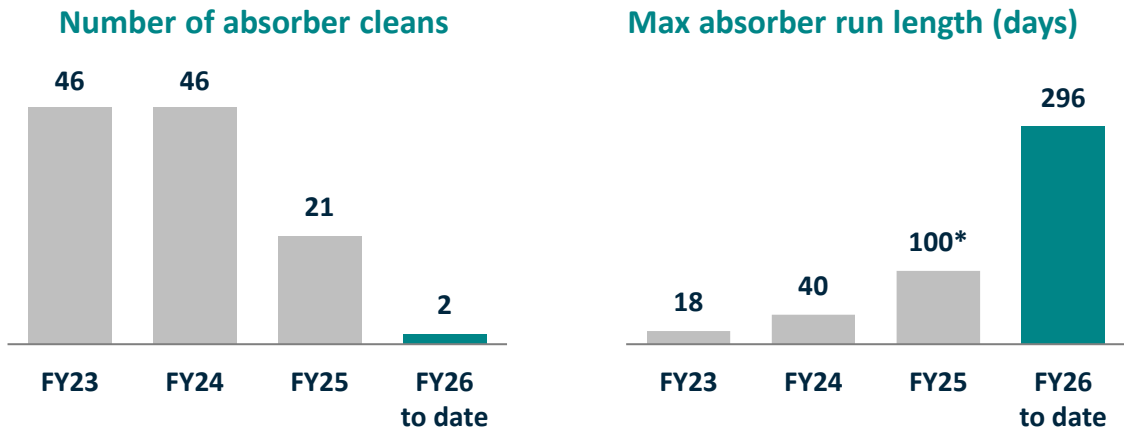
Orbost production continues to increase

New production records set at Orbost Gas Processing Plant (OGPP), with potential for further increases from debottlenecking

OGPP average processing rate, 90-day average¹, TJ/day



Select OGPP operational KPIs



- OGPP sulphur removal system no longer a constraint on production
- Focus now on debottlenecking the inlet pipeline and further plant reliability improvements
 - Record daily production rate of ~72 TJ recently achieved in April
- Sole reservoir performance remains strong; reserves reviews will be undertaken to assess further upside

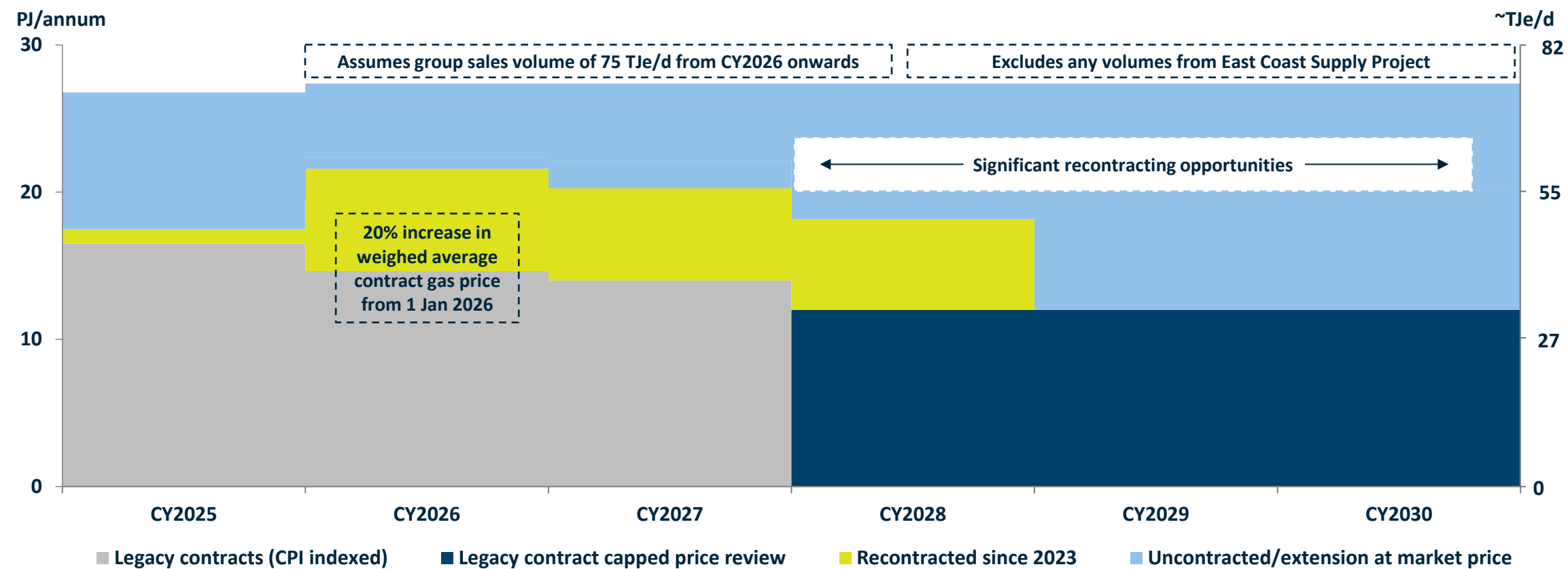


¹Excludes days where planned maintenance shutdowns were undertaken
*As at end of FY25

Exposure to higher gas contract prices

Legacy Sole gas contracts are rolling off, providing Amplitude Energy with the opportunity to recontract gas into higher term prices

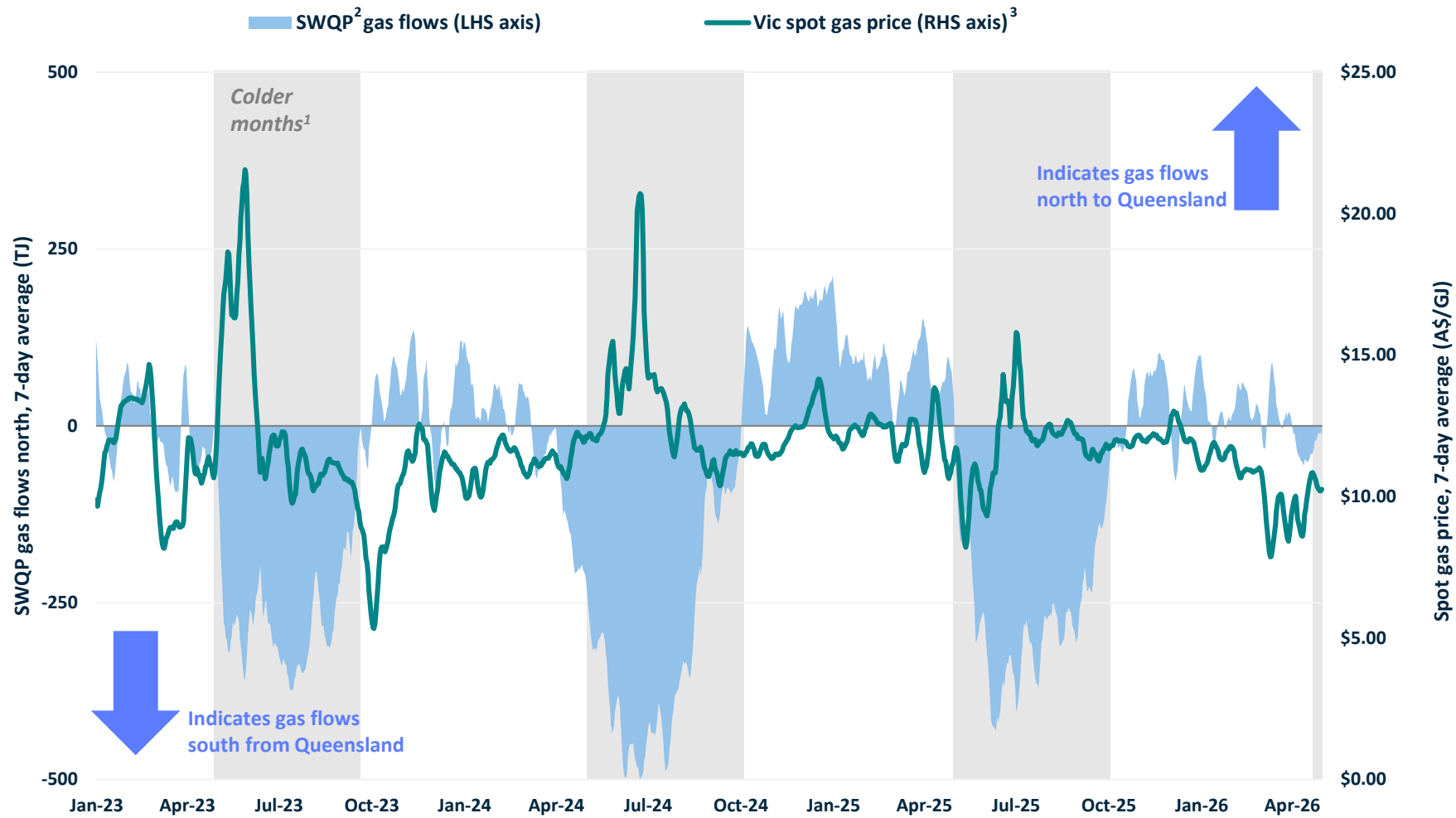
Gas contract stack, existing reserves only¹



¹ Net to Amplitude Energy's equity share, the annual contract quantity volumes shown are indicative only and assume group sales volume of 75 TJe/day from 1 January 2026 (actual group sales volume of 73.4 TJe/d shown for CY2025). This forward-looking statement is subject to the qualifications on page 2 of this presentation. There can be no guarantee that these production levels will be achieved. The annual contract quantity volumes shown are for illustrative purposes only and do not constitute production guidance. Existing reserves are on a 2P basis.

Strong Victorian winter demand typically drives up spot gas prices

Demand driven price spikes in colder months pulls gas into southern markets from Queensland



- **Demand** can no longer solely be met from southern production during peak winter months
- **Supply** from Queensland onshore production is required to meet demand during these periods
- Typical to see **upwards spot gas price** response in southern markets during colder months



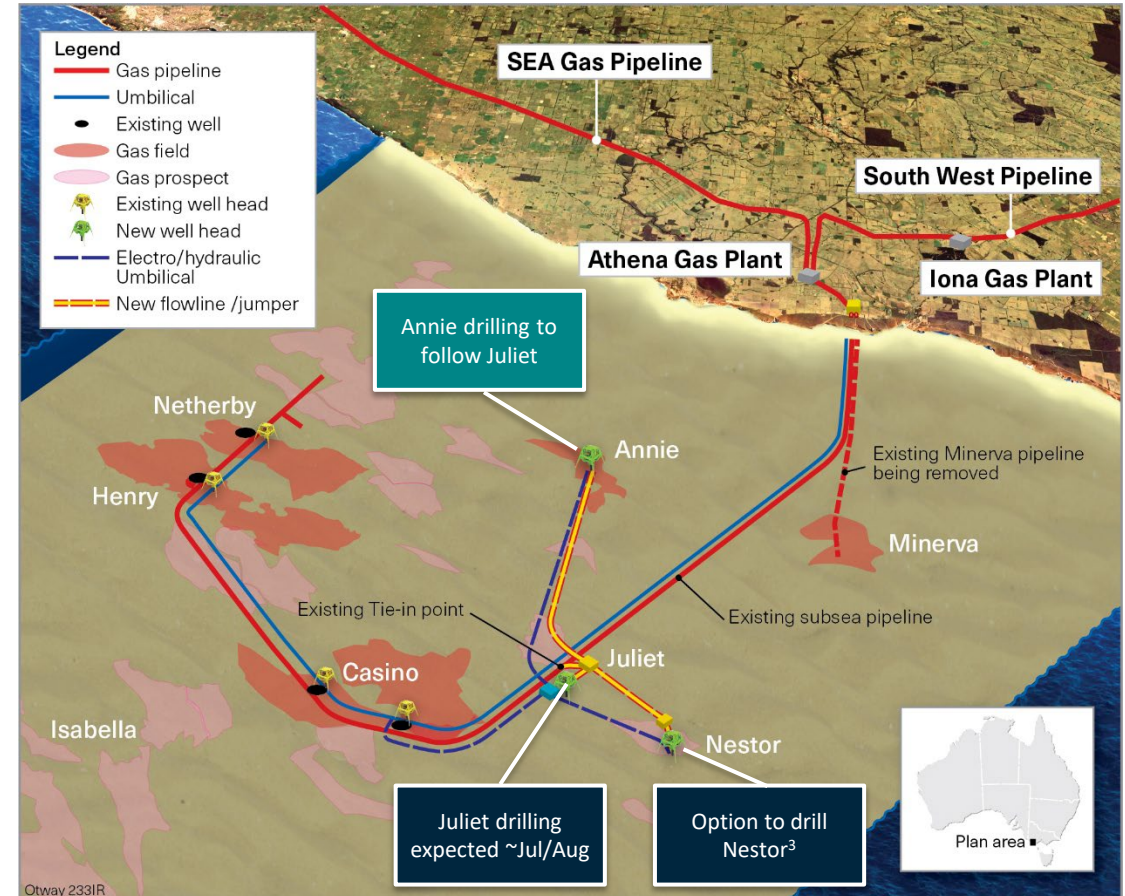
¹May – September | ²Gas flows in South West Queensland Pipeline. Negative indicates flows south. Source: AEMO | ³ DWGM, 6am interval. Source: AEMO

ECSP on track for first gas in 2028

Focused on new supply from the Offshore Otway Basin through existing infrastructure

- ✓ Backed by **Annie discovery**, 65 PJ gross 2C¹; production license expected imminently
- ✓ Upsized by testing the highly-prospective **Juliet** target around July/August, and potentially **Nestor** later in 2026, to improve project economics
- ✓ Supported by **foundation contracts** for ECSP supply with major gas customers
- ✓ Project is **fully funded**, with strong JV alignment
- ✓ **Derisked capital exposure** with vast majority of capex locked-in, or at known rates, and project engineering complete
- ✓ Returns expected to **comfortably exceed** internal investment hurdle rates²

ECSP activity and infrastructure overview



¹ Amplitude Energy net interest is 50% (32.3 PJ 2C). The Low (P90), Mid (P50), Mean and High (P10) Annie resource estimates, and net share of each, were first announced to ASX on 24 February 2020 and the latest resource estimates are included in Otway Basin contingent resources figures as disclosed in Amplitude Energy's ASX release 'Reserves and Contingent Resources at 30 June 2023' on 25 August 2023. | ² Based on AEL internal mid-case assumptions. | ³ Nestor well is subject to joint venture board approvals

FY26 business priorities being delivered



Progress the ECSP on schedule and budget



Development FEED complete

First well complete, project on schedule and budget

Positive gas contracting outcomes



Maximise asset utilisation



OGPP production capacity increased to >70 TJ/day

AGP reliability loss of <1%

Patricia Baleen restart progressed



Increase average realised gas prices



20% step up in contracted gas prices from Jan 2026

Pursuing various gas marketing and trading initiatives to further increase average realised prices



Reduce production costs, streamline systems & processes



OGPP production costs reduced well below \$2/GJ

Further organisational improvement initiatives underway



APPENDIX A

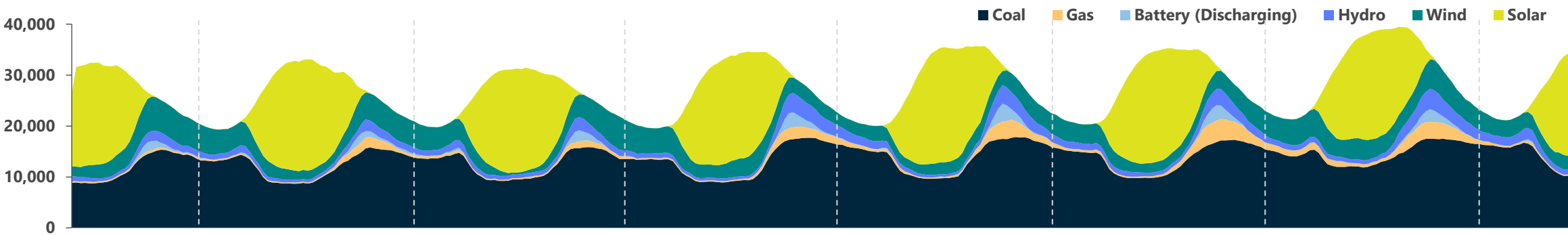
Additional materials



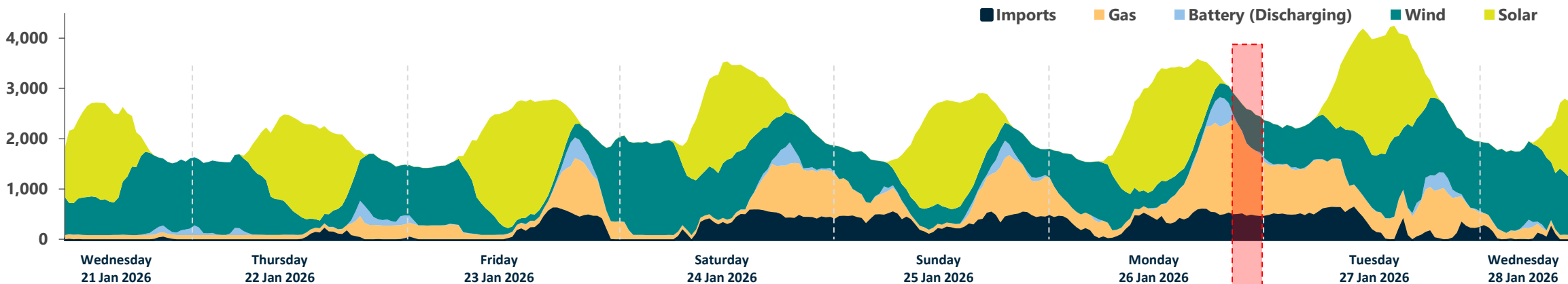
Increasing role of gas in the electricity market

Gas is already proving its critical role in firming the national electricity grid; its role will become more important as coal retires.

NEM electricity supply¹ by type (average ~45% renewables in CY2025), MW



South Australian electricity supply¹ by type (average ~70% renewables in CY2025), MW



Between 8pm-midnight on Australia Day, gas (50-60%+) and Victorian imports (15-20%) supplied >70% of South Australia's electricity

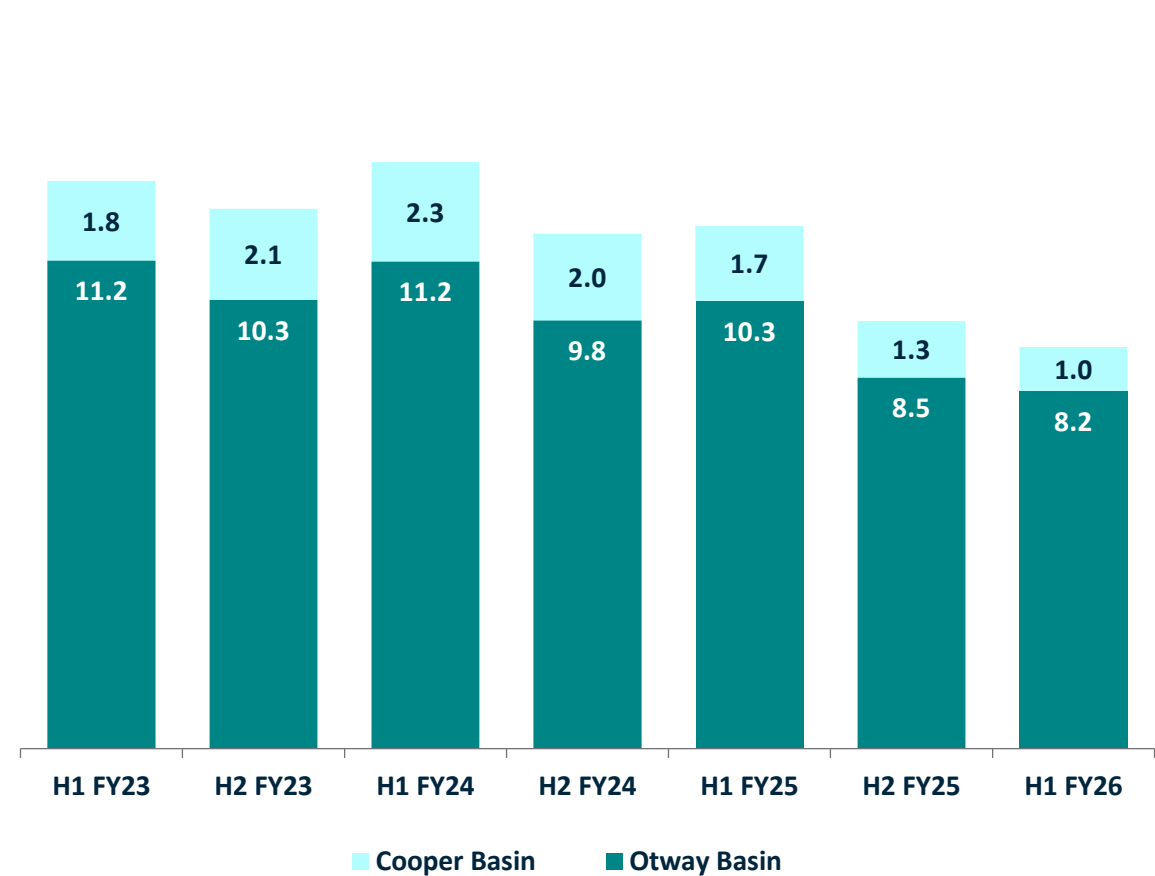


Data sourced from www.opennem.org.au. Excludes exports | ¹ Refers to reported electricity supply in the National Electricity Market (NEM), incorporating all Australian states and territories excluding Western Australia and the Northern Territory

Otway & Cooper Basins

Development work expected to result in production recovering in H2 from H1 FY26

Otway & Cooper Basin production, TJe/d¹



- Otway Basin \ Athena Gas Plant (AGP)
 - Excellent AGP reliability performance over 1H FY26
 - Natural decline as expected with 3-well CHN² well-cycling pattern
 - Casino-4 well brought back into production in H2 FY26, improving CHN well-cycling and reducing the near-term natural decline rate
 - FEED complete on AGP re-lifing for East Coast Supply Project
- Cooper Basin
 - Production recovering post easing of floods (+21% QoQ in Q2 FY26)
 - Successful 3-well development campaign undertaken at Callawonga, with first production in H2 FY26
 - Assessing prospect portfolio ahead of next phase of development

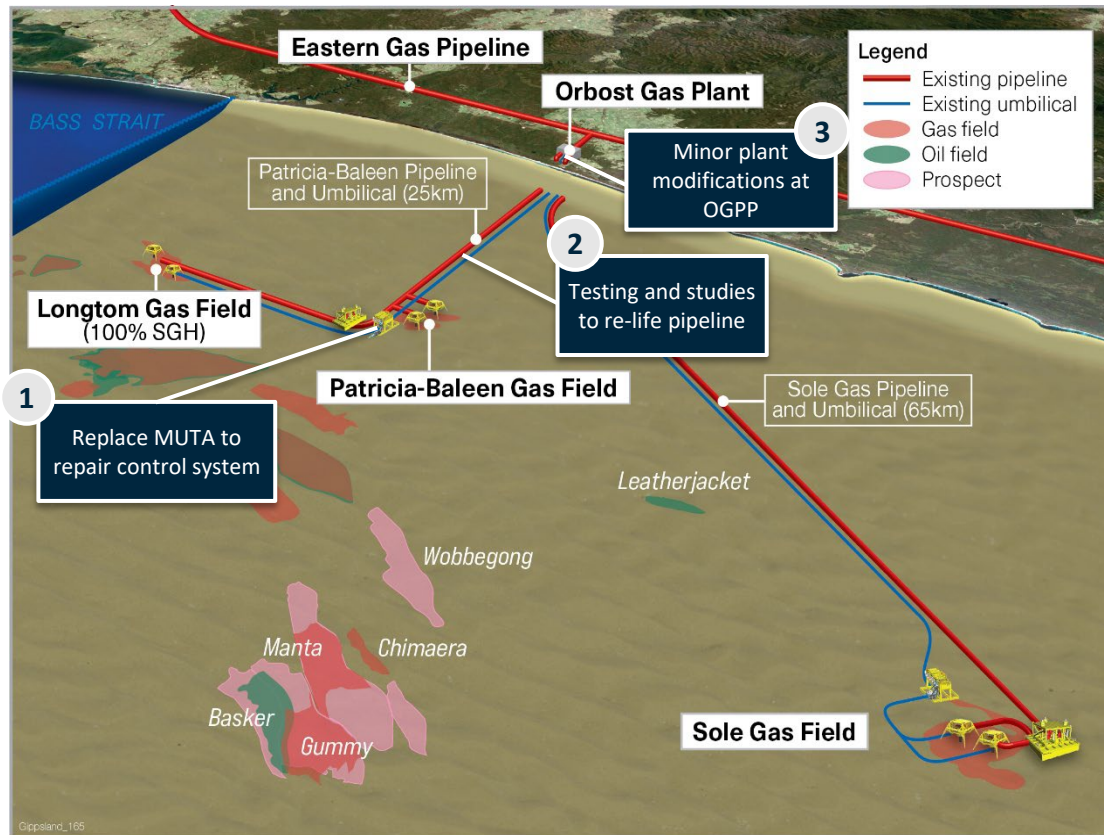


¹ All figures shown net to Amplitude Energy. | ² Casino, Henry and Netherby fields in the offshore Otway Basin

Progressing Patricia Baleen restart in Gippsland Basin

The Patricia Baleen restart project is a unique low-cost opportunity to unlock supply flexibility for the east coast market while adding value to Amplitude Energy's existing portfolio

Gippsland Basin infrastructure overview



Low-risk brownfield infrastructure repair project

Patricia Baleen overview	- Wholly owned gas field located 25km south of OGPP with all infrastructure in place - Brownfield resource with a successful history of production - Supports Gippsland supply hub for east coast market demand - Restart expected to maximise value from existing portfolio
Investment highlights	- Multi use potential – future production, third party processing or gas storage - Production restart targets ~3-10 TJ/day through OGPP¹ - High returns project driven by low-cost restart potential - Leverages existing tie-in to OGPP - Maximises asset utilisation through existing infrastructure - Extends Sole/OGPP life prior to subsequent backfill projects
Storage potential	Unlocks flexibility to maximise returns from gas price volatility
Pathway forward	- SELECT phase reservoir, plant integration and pipeline re-life studies well progressed with FEED targeted in FY26 - Production lease application submitted to NOPTA in December 2025 - Agreement with SGH to participate in the SELECT phase to assess Longtom gas processing options



¹ Indicative rate range tested as part of the ongoing Select Phase studies. To be confirmed during FEED studies.

APPENDIX B

Further Financial Information



FY26 guidance: production guidance increased

Higher gas production is driving cost efficiencies, greater cash generation and earnings, ahead of ECSP

FY26 production: Increased to 73 – 77 TJe/d

- Upgrade driven by higher OGPP production rates to date and confidence in those increases being sustained
 - Top end of guidance now assumes moderate production increases through debottlenecking
 - Range reflects different production scenarios for remainder of FY26

	Rate (TJe/day)	Total (PJe, FY26)
Previous	69 – 74	25.2 – 27.0
New	73 – 77	26.6 – 28.1

FY26 expense guidance **unchanged**

- Production expenses guidance of \$54 – 60mm¹
- Other cash expenses & costs of sales guidance of \$24 – 28mm^{1,2}
- Costs of general visual inspections (GVI) of Sole and Patricia Baleen pipelines excluded from guidance
 - GVI currently tracking below \$16m budget

FY26 capex guidance **unchanged**

- Capex guidance remains \$125 – 150mm³
 - Reflects Amplitude's 50% share of expected FY26 ECSP expenditure and ~\$28m cost carry by O.G. Energy



¹ Excludes pipeline GVI expenses | ² Excludes selling & transport costs associated with accessing Sydney spot gas market. | ³ Excludes decommissioning costs.

Record H1 production & financial metrics

Higher production growth and gas price realisations driving earnings and cash generation

<i>\$mm unless indicated</i>	H1 FY25	H1 FY26	Change
Production, TJe/d	73.5	75.5	▲ 3%
Sales revenue	133.7	141.5	▲ 6%
Average realised gas price (\$/GJ)	9.69	10.24	▲ 6%
Production expenses ¹	28.9	24.9	▼ (14)%
u-EBITDAX ²	92.2	100.3	▲ 9%
Underlying profit/(loss) after tax ²	7.8	25.7	▲ 229%
Operating cash flow	45.4	76.0	▲ 67%
Adjusted cash from operations ³	81.5	85.6	▲ 5%
Capital expenditure incurred	23.9	11.1	▼ (54)%
Restoration payments	32.9	10.0	▼ (70)%
	31 Dec 24	31 Dec 25	
Cash and cash equivalents	51.0	81.3	▲ 59%
Drawn debt	305.2	115.2	▼ (62)%
(Net debt)/cash	(254.2)	(33.9)	▼ (87)%

- **Record production** due to strong OGPP performance
 - Tracking above guidance, prior to recent capacity increase
- **Record revenue** due to higher sales volumes and higher realised gas prices
- **Reduced production expenses, run-rate below guidance**
 - Significantly reduced sulphur management costs at OGPP
 - Unit costs ▼ 16% to \$1.79/GJe (H1 FY25: \$2.14/GJe)
 - Higher CHN offshore maintenance costs expected in H2 FY26
- **Record u-EBITDAX** due to margin expansion and operational leverage
- **Record adjusted cash from operations²**
- Low capex spend, largely associated with ECSP long-leads
 - Expected to increase in H2 FY26 due to drilling campaign
- Restoration payments significantly lower, and mainly reflect the now-complete Minerva wells decommissioning programme
- **Low net debt position** ahead of ECSP investment phase



¹ Production expenses comprise labour, materials, overheads, insurance, license costs, JV management and carbon offset costs, but excludes third-party product purchases, transport and trading costs, royalties, pipeline general visual inspection (GVI) costs and non-cash depreciation and amortisation | ² In H1 FY26, the Company is no longer adjusting for the NOGA levy in its underlying results due to it being a recurring expense. As a result of this, the H1 FY25 comparatives have been re-stated, resulting in a decrease of \$1.0 million on a pre-tax basis and \$0.7 million on a post-tax basis | ³ Excluding restoration spend and other non-recurring and non-underlying items

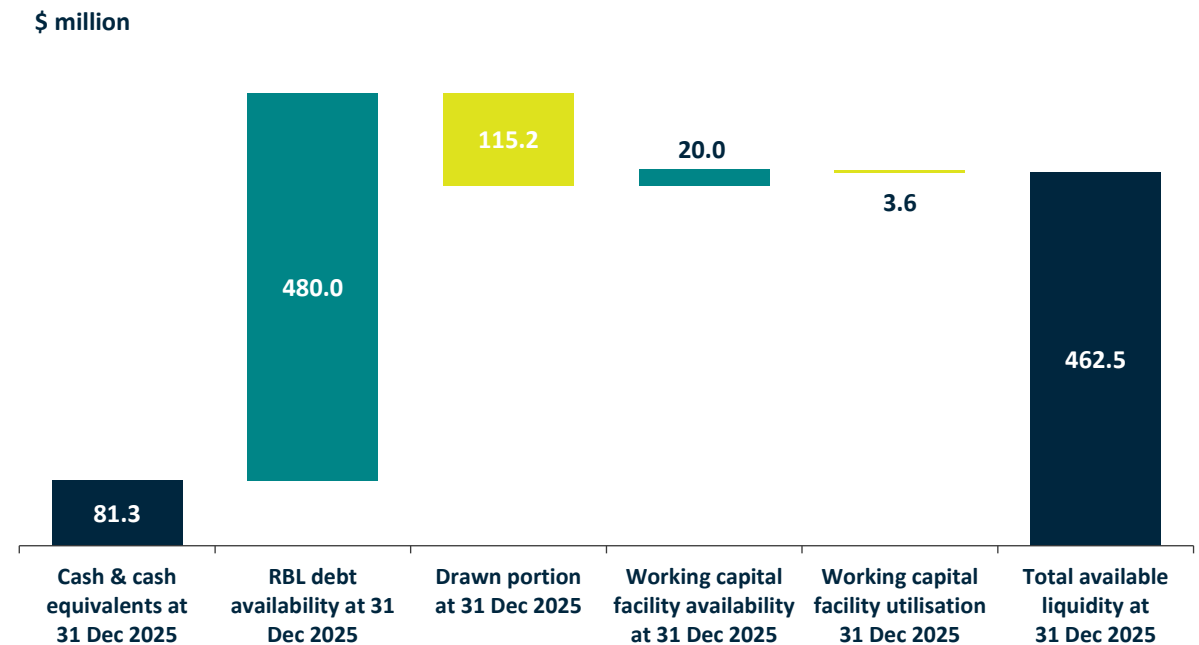
Significant capacity within debt facilities

Reserve-based loan (RBL) provides financing flexibility and liquidity as the company enters its next leg of growth

Bank facilities overview

- Senior, secured RBL
 - Facility limit of \$480mm, fully available at present
 - September 2029 maturity
 - Supportive group of eight domestic and international banks
 - Interest rate on drawn portion BBSY + 3.25%
- Intention to maximise future debt availability by optimising RBL parameters
 - Includes potentially incorporating Offshore Otway discoveries in the ECSP into the RBL borrowing base
- RBL currently drawn to \$115m, with cash on balance sheet of \$81m (net debt \$34m)
- \$20m working capital facility

Liquidity overview as at 31 December 2025



Otway exploration opportunities

High quality, low risk prospects in amplitude-supported play

Otway Basin, Top Waarre Formation Prospective Resource Summary¹

Prospect	Permit	AEL equity (%)	Low (P90)		Best (P50)		Mean		High (P10)		Pg ⁴
			Gross ²	Net ³	Gross ²	Net ³	Gross ²	Net ³	Gross ²	Net ³	
Isabella	VIC/L24	50	56.0	28.0	124.1	62.1	148.6	74.3	276.4	138.2	70%
Heera	VIC/L24	50	35.2	17.6	75.1	37.6	86.1	43.1	153.1	76.6	63%
Pecten East	VIC/L33	50	48.6	24.3	72.9	36.5	76.3	38.2	109.2	54.6	73%
Nestor	VIC/P76	50	38.9	19.5	60.9	30.5	64.2	32.1	94.3	47.2	81%
Juliet	VIC/L24	50	30.1	15.1	46.4	23.2	48.8	24.4	71.0	35.5	84%
Total (Bcf)⁵			208.8	104.5	379.4	189.9	424.0	212.1	704.0	352.1	

Note: Effective date: 30 June 2025, unless otherwise specified. AEL is not aware of any new information or data that materially affects the information included in the prior market announcement, and all material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed. The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both a risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially recoverable hydrocarbons.



¹ Prepared in accordance with SPE-PRMS. Reserves and resources information has been prepared by, or under the supervision of, a Qualified Petroleum Reserves and Resources Evaluator (as identified in the Important Notice) and is included with the evaluator's consent. Units: gas volumes in Bcf or PJ. Conversion: 1PJ = 0.163417 MMboe (as disclosed in the important notice). The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and net share of each prospect, were announced to ASX on 9 February 2022. Prospective resource estimates were prepared using the probabilistic method. | ² Gross Prospective Resource is 100% of the unrisks volume estimated to be recoverable from any prospect. The estimated quantities of petroleum that may be potentially recovered by the application of future development project(s) relate to undiscovered accumulations | ³ Net Prospective Resource is the unrisks volume estimated to be recoverable from any discovery attributable to the Amplitude Energy joint venture interest. Prospective resources are reported net of contractual royalties and of volumes lifted on behalf of royalty owners. | ⁴ Pg is chance (or probability) of encountering a measurable volume of mobile hydrocarbons | ⁵ Total is the arithmetic summation of prospective resource estimates. The total may not reflect arithmetic addition due to rounding. Note: The aggregate low estimate may be a very conservative estimate and the aggregate high estimate may be a very optimistic estimate due to the portfolio effects of arithmetic summation