Amplitude energy

FY26 half year results

25 February 2026

Disclaimer

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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, 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.

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Executive summary

Compelling market opportunity to grow production through existing infrastructure and maximise returns.

- Record H1 FY26 operational and financial metrics
- FY26 production guidance increased, strong H2 production expected across all three assets
- Further production gains expected from Orbost Gas Processing Plant debottlenecking and potential Sole reservoir upside
- New contracts and CPI indexation driving ~20% increase in contracted gas prices from 1 January 2026, retaining exposure to tight spot markets
- ECSP drilling commenced, active negotiations with potential customers for ECSP foundation contracts, FID expected in coming weeks

#1

H1 FY26 in review

H1 FY26 highlights

Record production and financial metrics

13.9 PJe

GROUP PRODUCTION
NEW RECORD

+3%

75.5 TJe/DAY

$141.5m

SALES REVENUE
NEW RECORD

+6%

$10.24/GJ

AVERAGE REALISED GAS PRICE
NEW RECORD

+6%

$100.3m

UNDERLYING EBITDAX[1]
NEW RECORD

+9%

71% MARGIN

$85.6m

ADJUSTED CASH FROM OPERATIONS[2]
NEW RECORD

+5%

ECSP progress

DRILLING TIME AHEAD OF SCHEDULE, FID ON TRACK

[1] Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment | [2] Operating cashflows excluding restoration spend and other non-recurring and non-underlying items

Health, safety, environment and community performance

Results ahead of industry benchmarks through disciplined operations

Safety

- Excellent safety performance
- Ahead of industry benchmark TRIFR[1]
- No Tier 1 or Tier 2 process safety events
- Over two years without a lost time injury

Environment

- No reportable[2] or notifiable[3] environmental incidents during the period
- Continued workstreams to avoid or minimise direct emissions and offset 100% of residual equity Scope 1 and 2 emissions[4]

Community

- Proactive engagement with stakeholders in the areas where we operate

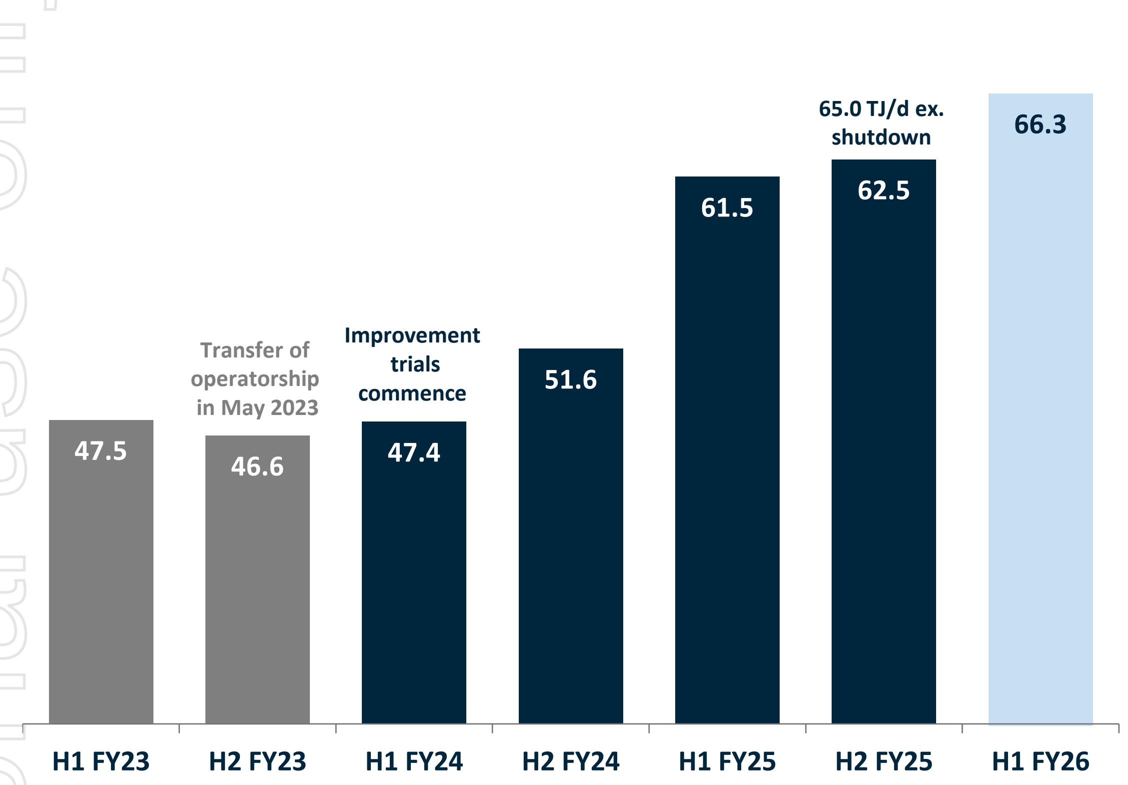
	H1 FY25	H1 FY26
Hours worked	129,058	**145,516**
Recordable injuries	0	**0**
Total recordable injury frequency rate (TRIFR)	3.34	**3.18**
Industry TRIFR[1]	6.15	**4.94**
Reportable environmental incidents	0	**0**

[1] NOPSEMA industry rolling 12-month TRIFR for 31 December 2024 and 31 December 2025 respectively | [2] As defined by Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009 | [3] As defined by the Victorian Environment Protection Act 2017 | [4] Refer to the Amplitude Energy 2025 Sustainability Report for further detail and definitions.

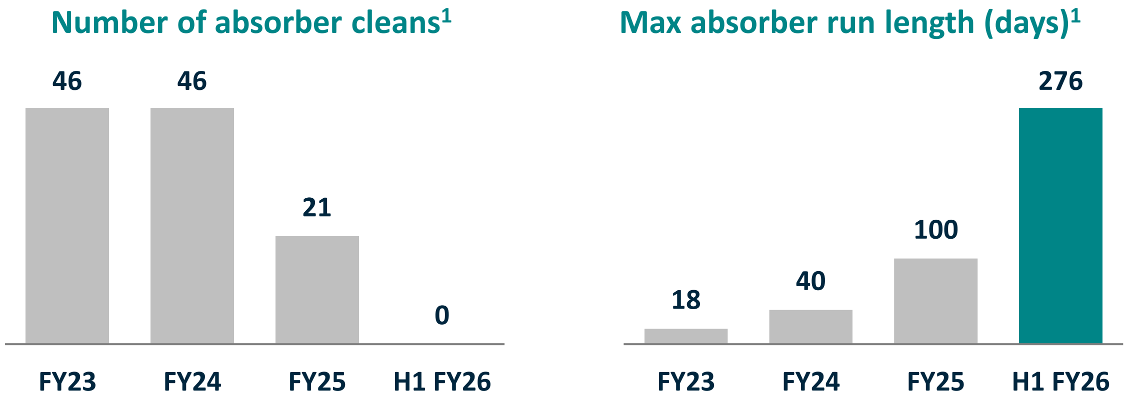
Gippsland Basin production increases further

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

OGPP average processing rate, TJ/d



Select OGPP operational KPIs



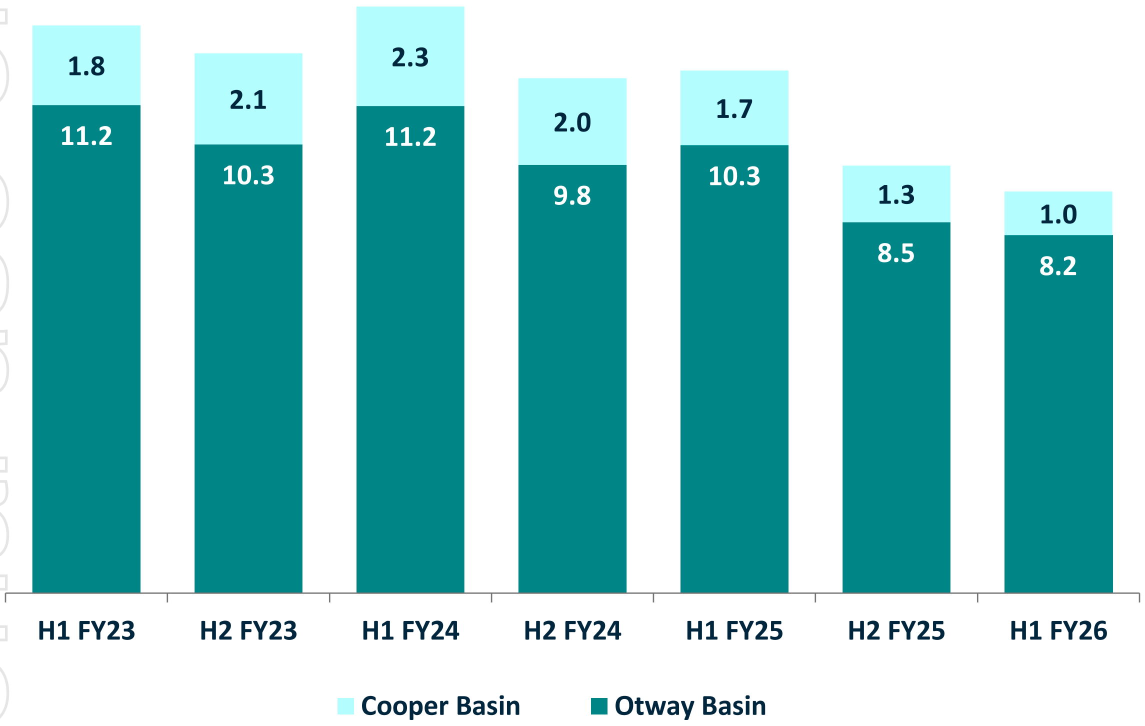
- OGPP sulphur removal system no longer a constraint on production
  - Record absorber unit run-time
  - System redundancy provided by polisher and H_2S scavenger injection
  - Chemical clean-in-place of absorbers recently utilised successfully
- Focus now on debottlenecking the inlet pipeline and further plant reliability improvements
  - Record daily production rate of 71 TJ achieved in January 2026
- Sole reservoir performance remains strong; reserves reviews will be undertaken to assess further upside

[1] As at the end of the relevant period – two absorber cleans have been conducted during H2 FY26 to date

Otway & Cooper Basins

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

Otway & Cooper Basin production, TJe/d[1]



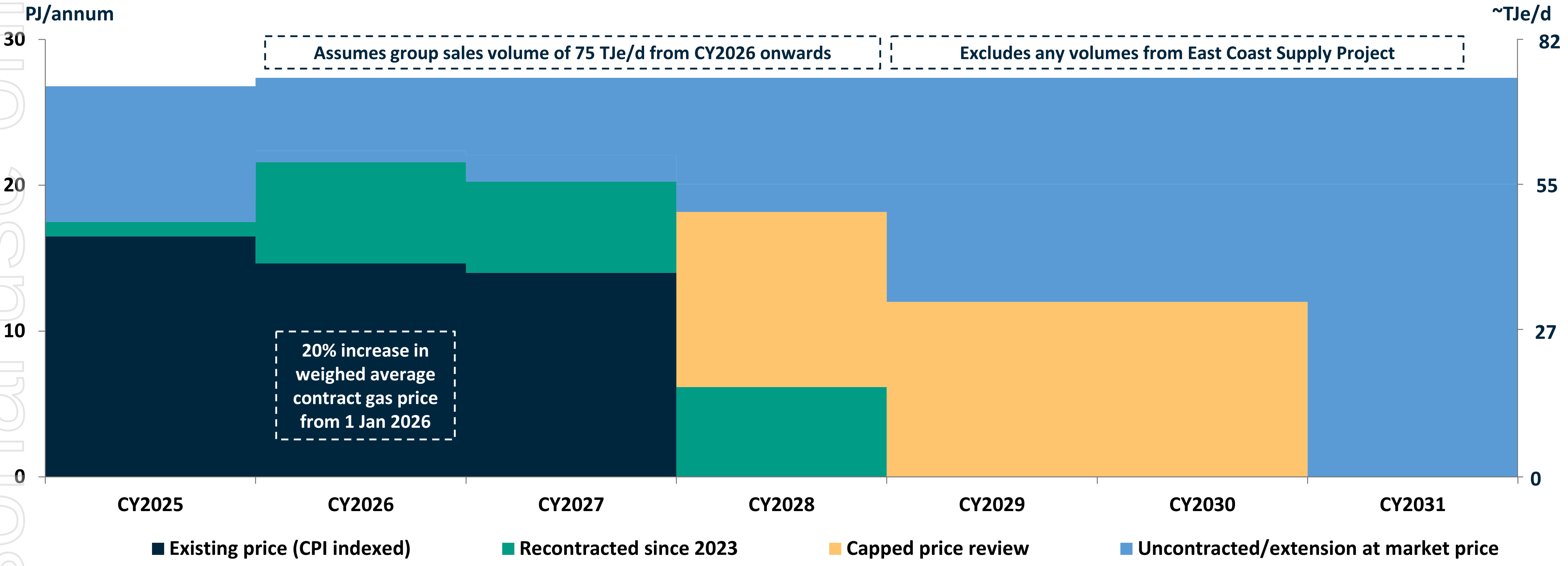
- Otway Basin \ Athena Gas Plant (AGP)
  - — Excellent AGP reliability performance over 1H FY26
  - — Natural decline as expected with current 3-well CHN[2] cycling pattern
  - — Plans underway to bring Casino-4 well back into production and reduce CHN decline
  - — FEED complete on AGP re-lifing for 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 expected 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

Increasing exposure to higher gas prices

Legacy Sole gas contracts are rolling off, providing Amplitude Energy with exposure to much higher contract and spot gas sales

Gas contract stack, existing reserves only[1]

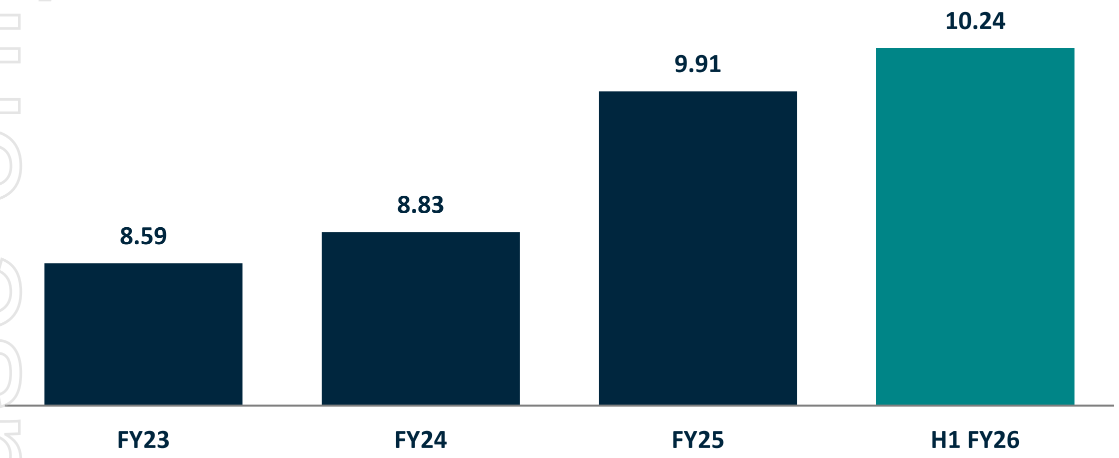


[1] Net to Amplitude Energy's equity share, the annual contract quantity volumes shown are indicative only and assume group sales volume of 75 TJe/day from 1 January 2026 (actual group sales volume of 73.4 TJe/d shown for CY2025). This forward-looking statement is subject to the qualifications on page 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.

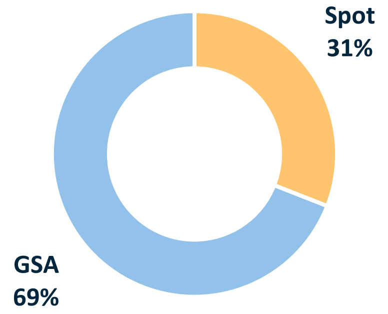
Gas trading & marketing opportunities

Spot sales, new contractual arrangements and other gas market opportunities are allowing Amplitude to generate additional value for its gas sales

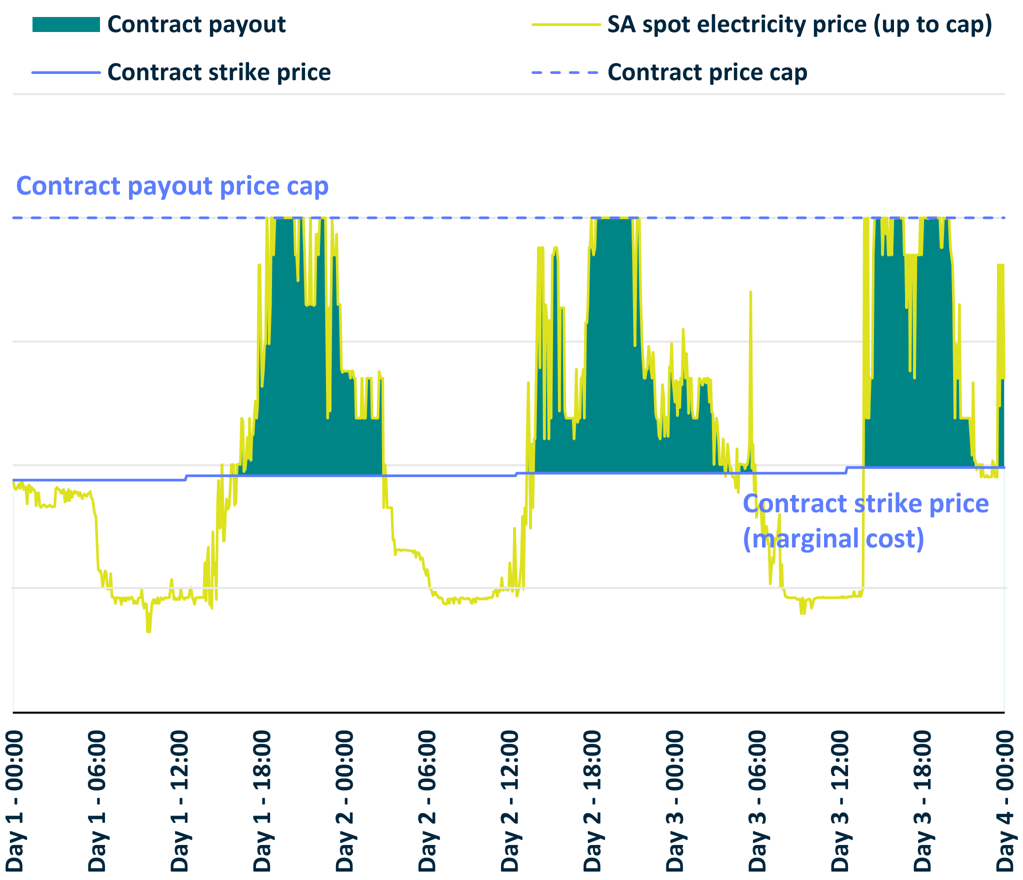
AEL realised gas prices, A$/GJ



H1 FY26 OGPP sales volume mix



Spark spread contractual arrangement (illustrative)

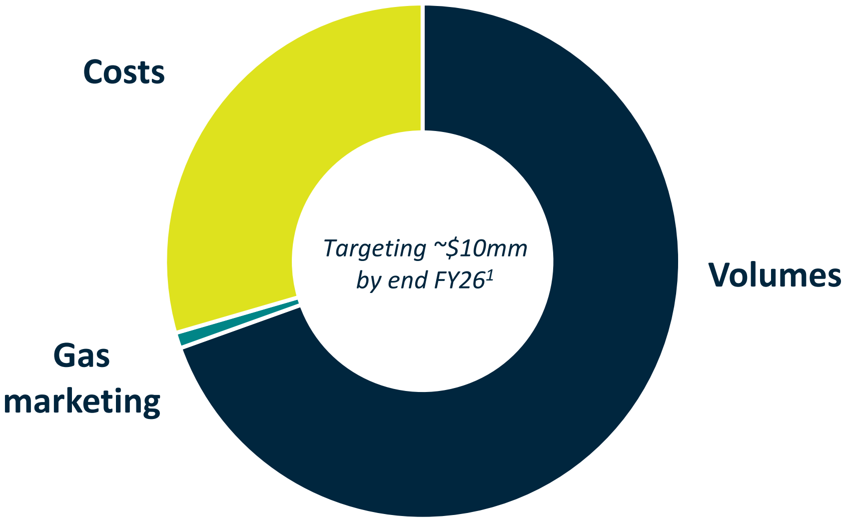


Continuous improvement programme

Targeting around $10mm in annualised cashflow improvements by the end of FY26[1]

H1 FY26 success and full year targets

- ✓ >80 initiatives company-wide, targeting annualised value of around $10 million, forecast to be completed or actioned by the end of FY26
- ✓ Includes corporate efficiency improvements in areas such as finance, supply chain, and maintenance planning and scheduling
- ✓ $1.6 million reduction in G&A in H1 FY26 vs H1 FY25



FY26 targets & focus areas

Targets	▪ Continued emphasis on cost reductions ▪ Maximise production ▪ Grow margins
Volumes	▪ Further increases to OGPP production capacity ▪ Improve reliability performance at OGPP & maintain strong reliability performance at AGP
Costs	▪ Cost reduction opportunity in FY26 includes: – Reduced waste disposal costs – Optimising maintenance spend and night staffing – Insurance premium reductions
Gas marketing	▪ Maximising flexibility to direct spot sales into the highest-price markets on any given day ▪ Shaping spot sale volumes based on market conditions ▪ Additional short & long-term contracting opportunities

[1] Annualised cashflow improvements from initiatives completed or actioned by end FY26. This includes permanent benefits (e.g. operational efficiencies, revenue improvements, etc) and temporal benefits (e.g. accelerated production)

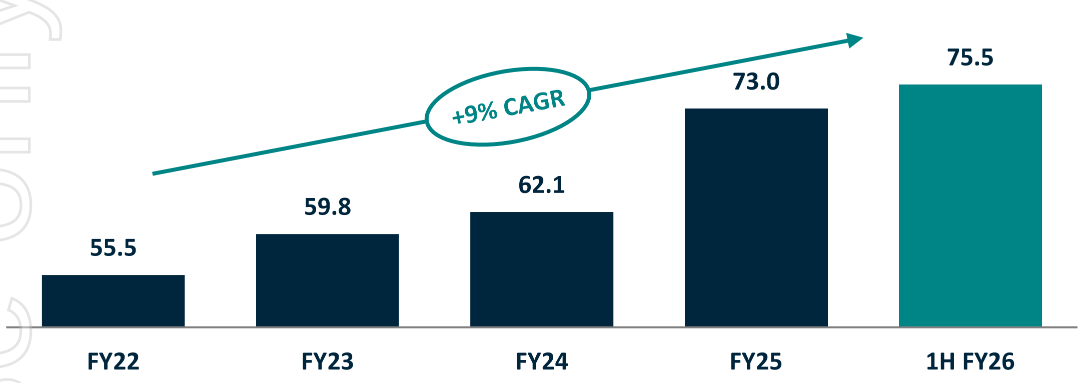
#2

H1 FY26 financial highlights

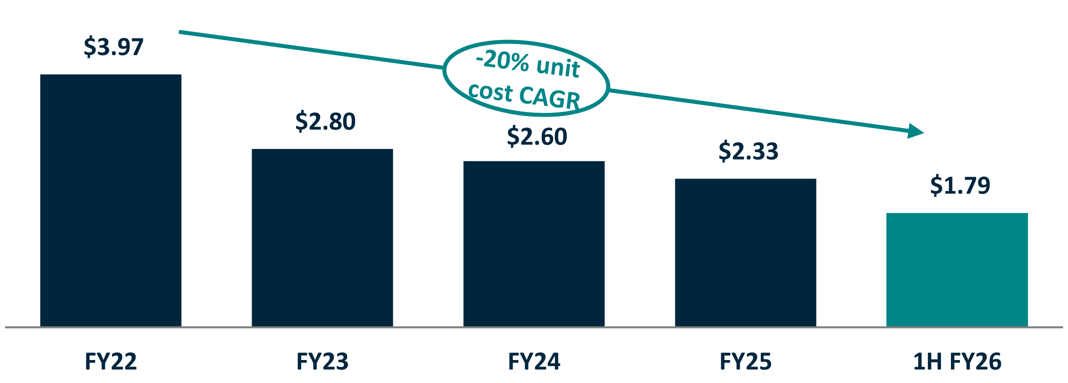
Amplitude Energy has built a track record of performance

Increased production and operational leverage has generated substantial margin expansion

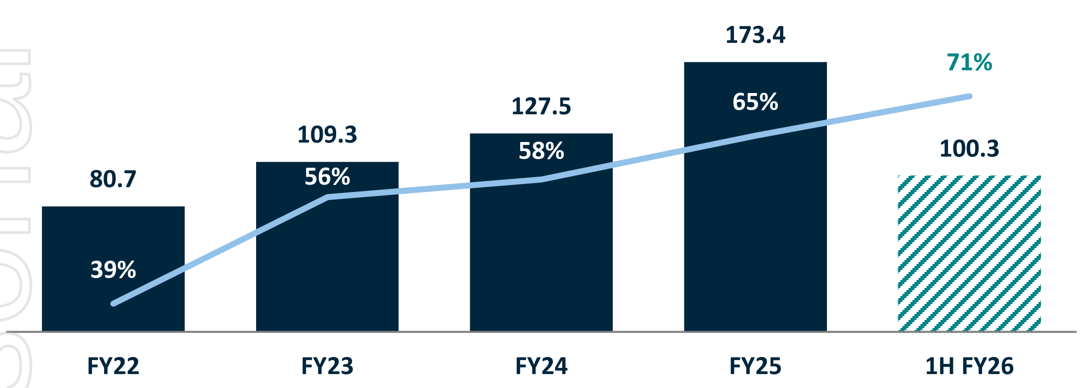
Production, TJe/day



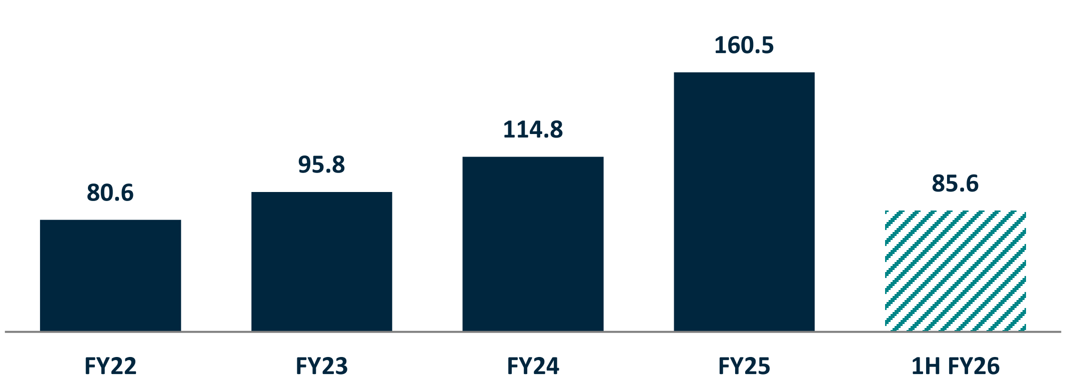
Production expenses[1], $ per GJ produced



Underlying EBITDAX[2], $mm \ margin, %



Adjusted cash from operations, $mm[3]



[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

Record production & financial metrics

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

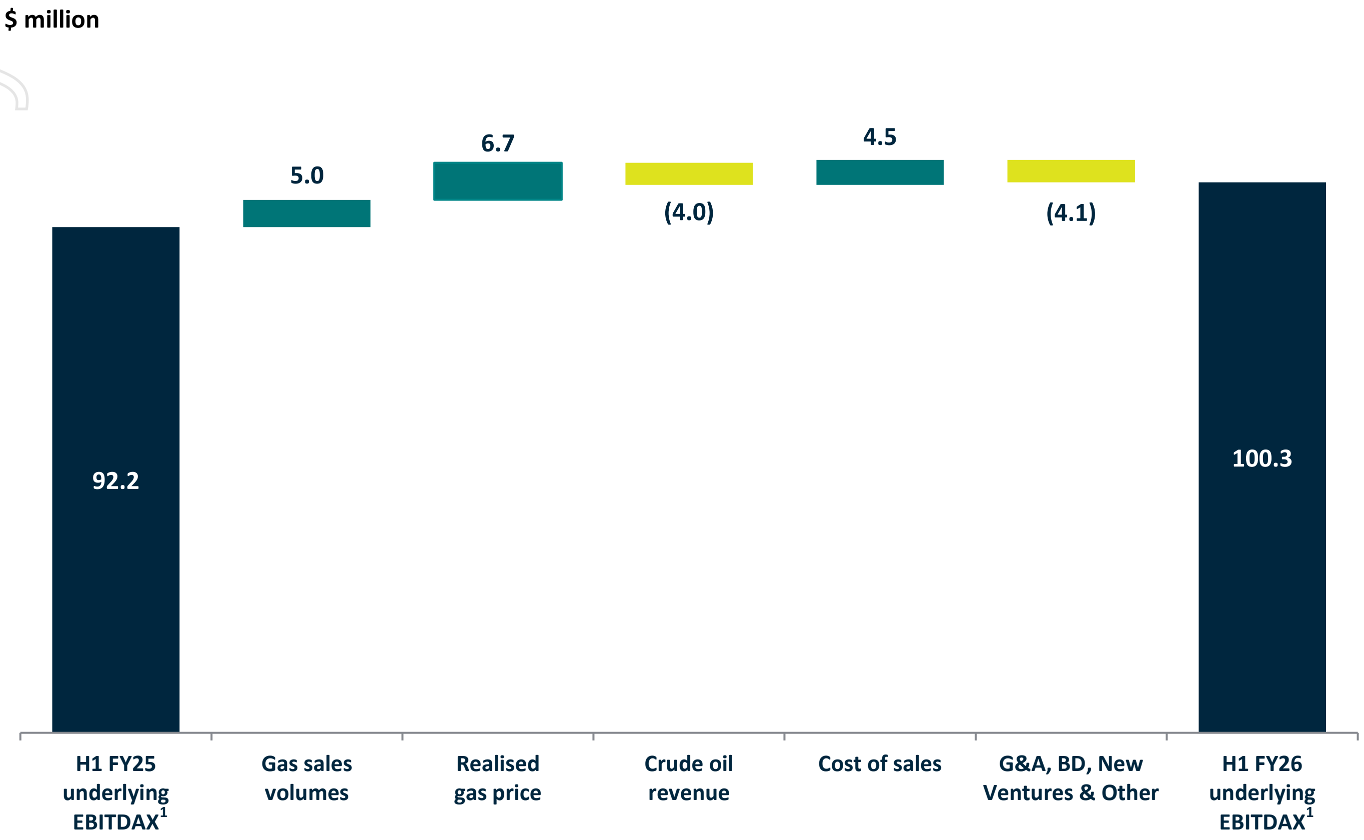
$mm unless indicated	H1 FY25	**H1 FY26**	Change
Production, TJe/d	73.5	**75.5**	▲ 3%
Sales revenue	133.7	**141.5**	▲ 6%
Average realised gas price ($/GJ)	9.69	**10.24**	▲ 6%
Production expenses[1]	28.9	**24.9**	▼ (14)%
u-EBITDAX[2]	92.2	**100.3**	▲ 9%
Underlying profit/(loss) after tax[2]	7.8	**25.7**	▲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 operations[2]**
- 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

Record u-EBITDAX - bridge from H1 FY25 to H1 FY26

Record underlying earnings driven by greater gas sales volume and prices

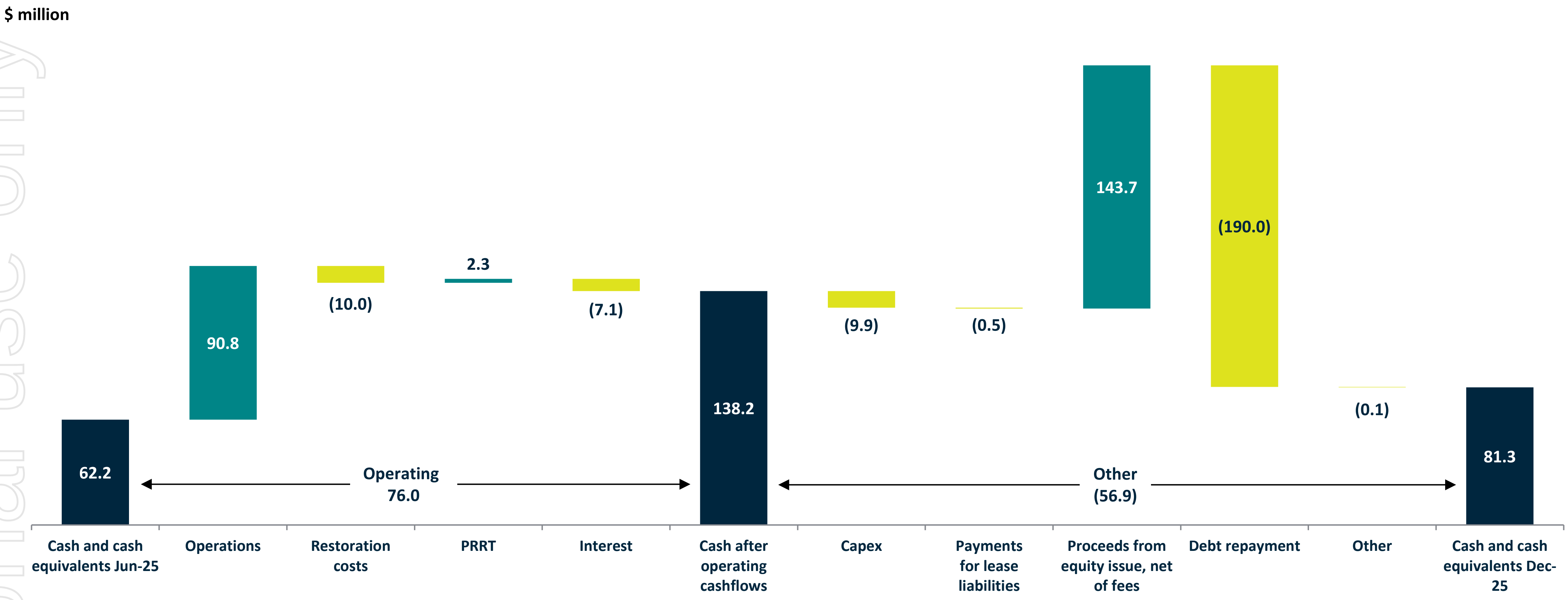


- Increased sales volumes and average realised gas prices, as noted earlier
- Reduced crude oil liftings, impacted by Cooper Basin flooding (expected to recover in H2 FY26)
- Decreased costs of sales largely driven by lower OGPP production costs
- Reduced G&A linked to savings realised from the continuous improvement programme
- Increased other costs in relation to exploration and business development, including to support work associated with ECSP gas contracting
- Result demonstrates strong operating leverage of assets and margin expansion

[1] 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.

Group cash - six monthly bridge from June to December 2025

Strong operating cash flows allowing reduction in net debt



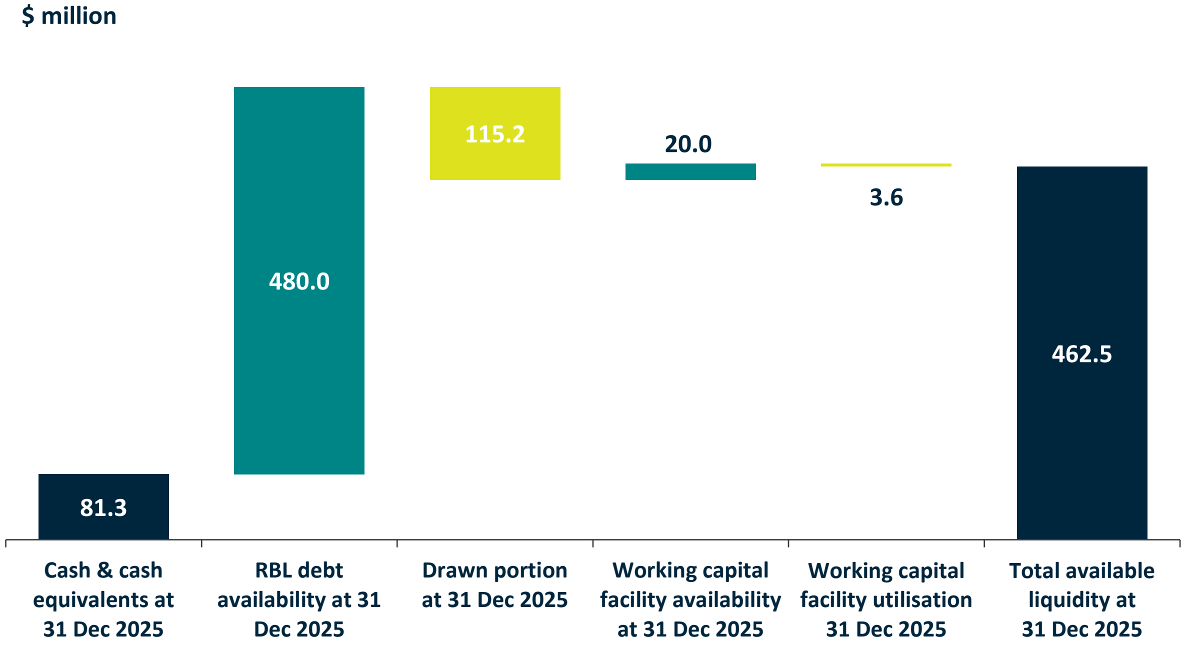
Significant capacity within debt facilities

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



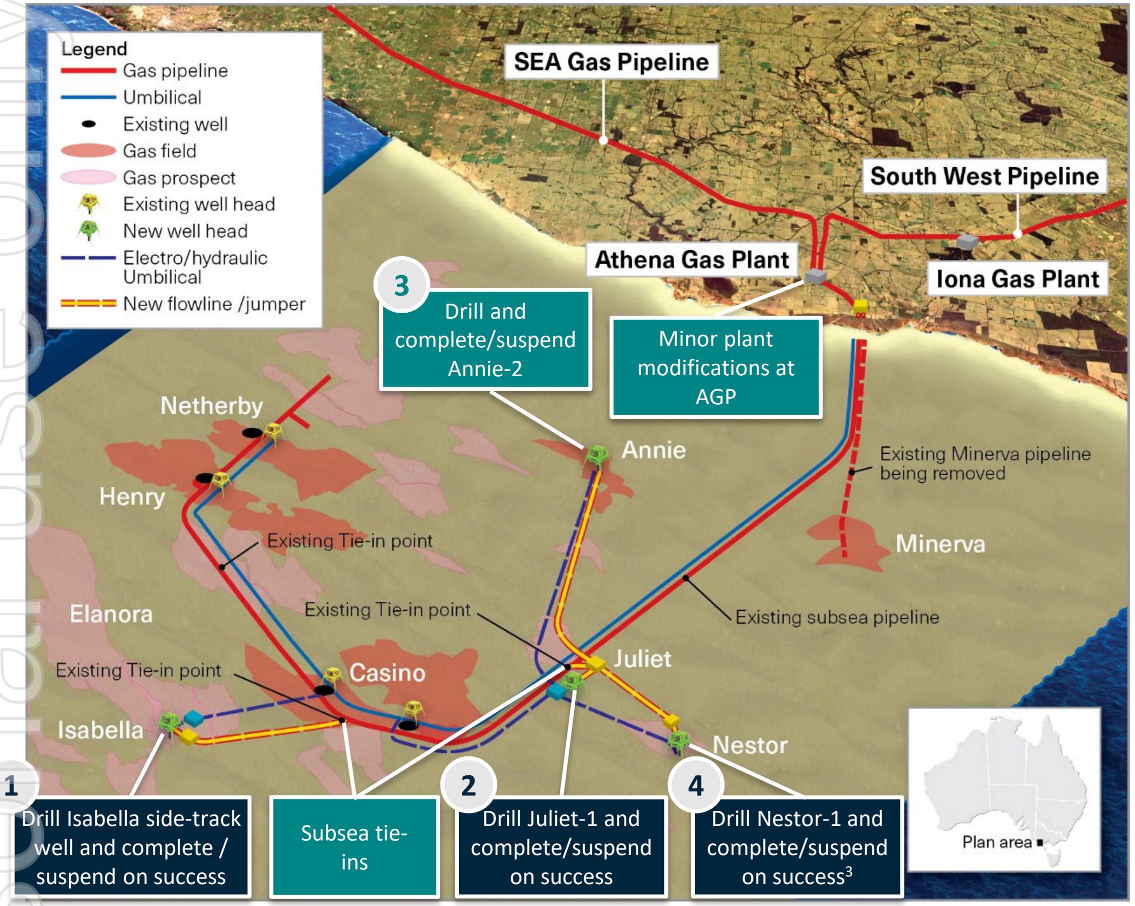
#3

Projects update

ECSP is a brownfield expansion unlocking value of existing infrastructure

Unlocking supply from the Offshore Otway Basin through highly-prospective gas fields and use of existing infrastructure

Offshore Otway Basin infrastructure overview

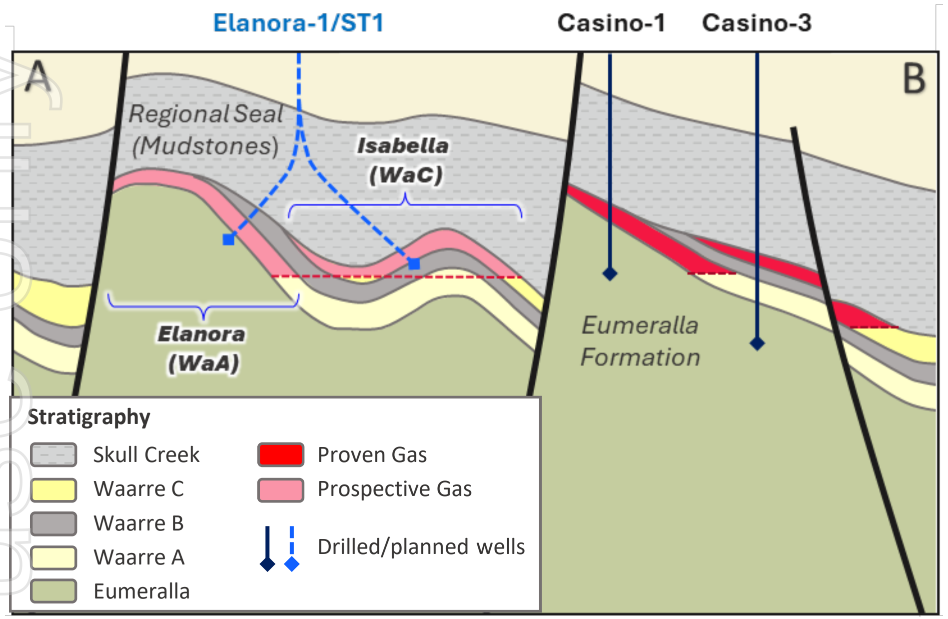


- Taken together ECSP resources would extend the life of the AGP by over a decade on success[1], with first gas targeted in CY2028
- Strong gas customer interest for ECSP supply; active negotiations with multiple counterparties for foundation GSAs
- Takes advantage of existing AGP gas processing capacity of up to 150 TJ/d, allowing for peak supply
- Capital efficient development, allowing completion cost savings following exploration success with a 'one touch' approach
- Returns expected to comfortably exceed internal investment hurdle rates[2]
- One of the largest exploration projects in the east coast domestic gas market this year – enough gas supply for 800,000 households

[1] 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. Exploration, appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons. The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates of ECSP prospects, and net share of each prospect, were announced to ASX on 9 February 2022 and are shown on page 28 of this presentation. The total reflects arithmetic summation of independent probabilistic resource estimates. | [2] Based on AEL internal mid-case assumptions. | [3] Nestor well is subject to joint venture board approvals

Current Otway Basin drilling activity

Currently targeting two separate prospects from one surface location



Isabella Prospective Resource Summary (Bcf)[1]				
	P90	P50	Mean	P10
Gross (100%)	56.0	124.1	**148.6**	276.4
Net (50%)	28.0	62.1	**74.3**	138.2

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.

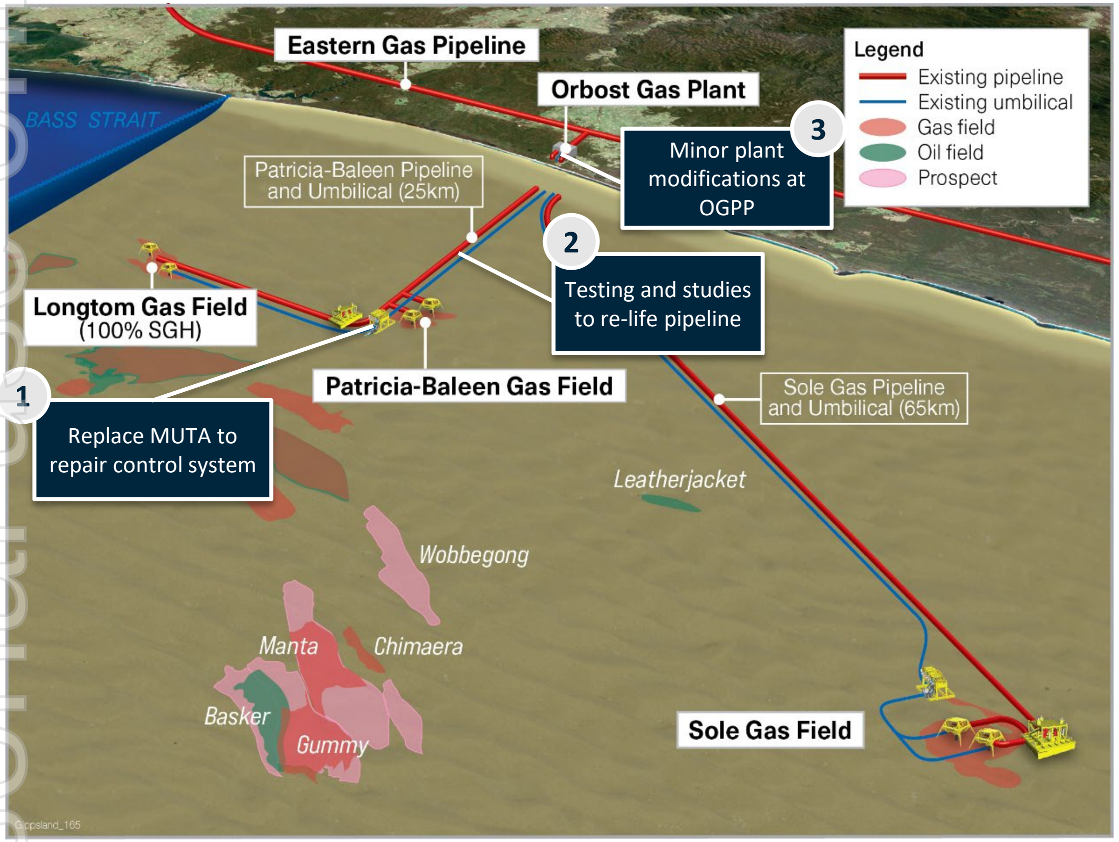
- Twin exploration well to test Waarre Formation targets at Elanora and Isabella prospects from a single surface location
- Isabella sidetrack (ST-1) currently being drilled
  - Waarre C Formation target
  - Intended to be the producing field upon success
  - ~6km from an existing tie-in point in the CHN pipeline
  - Expected timeframe to plug Elanora-1 and drill ST-1 to TD is 14-18 days
- Elanora prospect found to be water-bearing on 10 Feb
  - Spud to total depth completed in ~15 days, ahead of budgeted schedule
  - Encountered thick, moderate-good quality Waarre A reservoir
  - High-quality mudstone top seal
  - Possible gas thief zone being investigated
  - Seismic response analysis to be undertaken over coming months

[1] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and AEL's 50% net share of each prospect, were announced to ASX on 9 February 2022. Net figures are reported according to AEL's economic interest and net of contractual royalties.

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

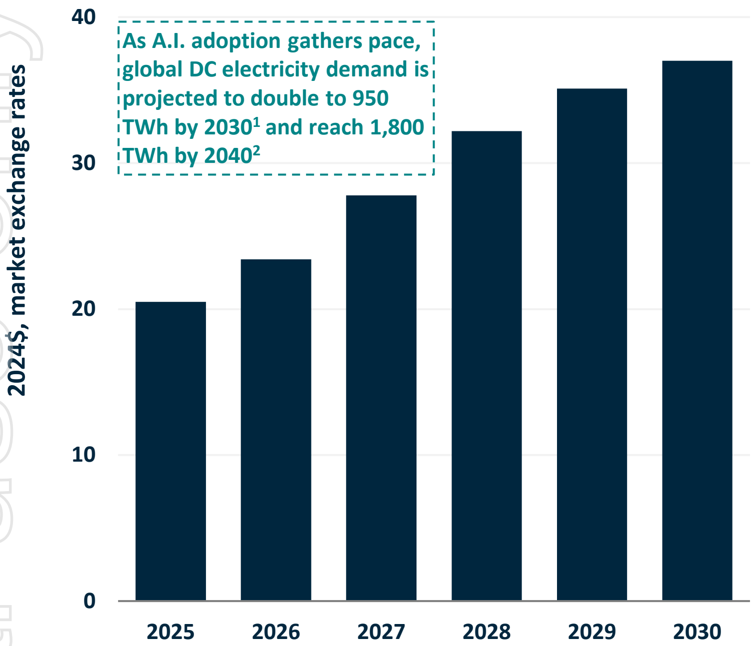
Patricia Baleen overview	▪ Wholly owned gas field located 25km south of OGPP with all infrastructure in place ▪ Brownfield resource with a successful history of production ▪ Supports Gippsland supply hub for east coast market demand ▪ Restart expected to maximise value from existing portfolio
Investment highlights	▪ Multi use potential – future production, third party processing or gas storage – Production restart targets ~3-10 TJ/day through OGPP[1] ▪ 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.

Increased domestic gas supply crucial to Australia's energy future

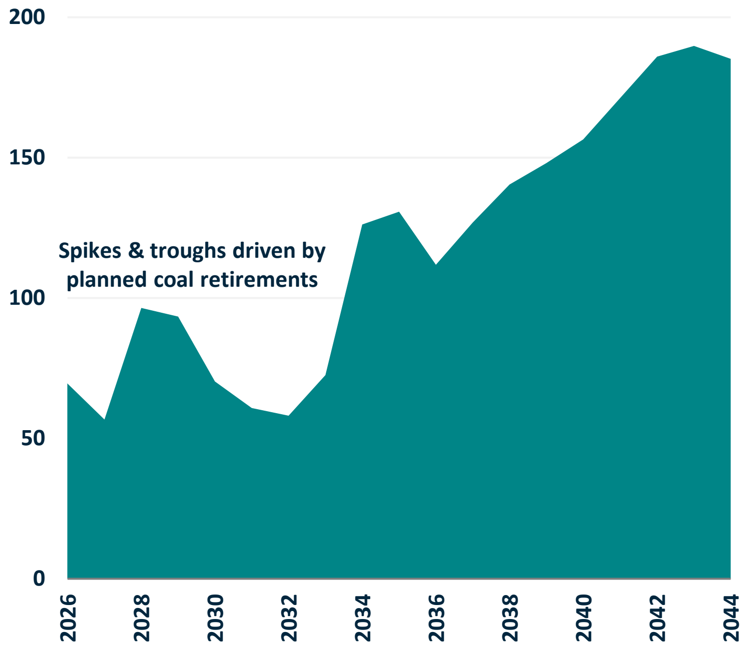
Structural gas demand growth being driven by data centre (DC) roll-outs and coal-to-gas switching, in Australia and worldwide

Forecast power gen. investment for DCs, US$bn[1]



- DC operators are being driven to conventional, dispatchable sources of power like gas[1] due to its availability and reliability

Forecast Australian East Coast GPG[3], PJ/year



- Gas powered generation (GPG) a realistic, scalable source of reliable power growth in Australia
- Coal-to-gas switching in power generation has been an established global trend over decades

Opportunity to address supply challenges

- Gas infrastructure and undeveloped resources already exist in the southeast states to provide low-cost supply to the local market for decades
- Gas Market Review an opportunity to streamline approval process and increase long-term project certainty
- Amplitude is a 100% domestic-only producer, delivering low-cost gas to Australian manufacturers, retailers and power generators
  - Significant investment in ECSP to increase gas supply from the Otway Basin

[1] International Energy Agency, *World Energy Investment 2025, 10th Edition* | [2] Rystad Energy | [3] Gas-fired Powered Generation. Source: AEMO, Gas Statement of Opportunities, Figure 10

#4

H2 FY26 outlook

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 – 60mm[1]
- 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 – 150mm[3]
  - 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.

FY26 business priorities being delivered

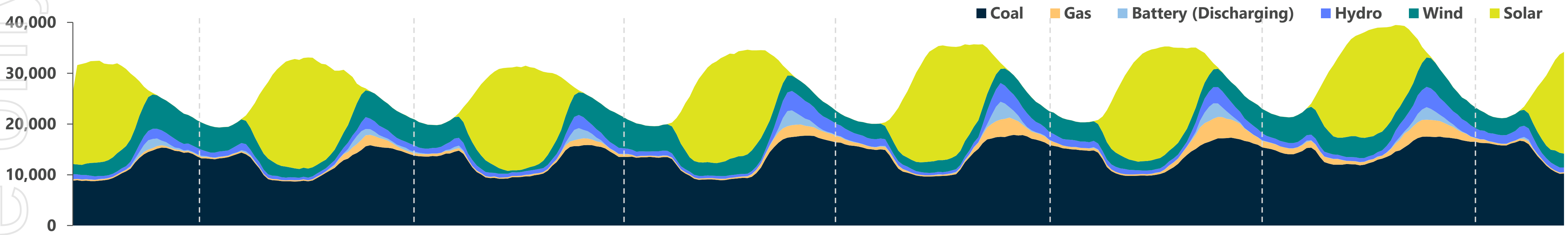
Progress the ECSP on schedule and budget to achieve FID	▪ Development FEED complete ▪ Drilling ahead of budget to date, Isabella underway ▪ Foundation GSA discussions on track
Maximise asset utilisation	▪ OGPP production capacity increased to >70 TJ/day ▪ AGP reliability loss of <1% ▪ Patricia Baleen restart progressed
Increase average realised gas prices	▪ Average realised gas prices +6% on p.c.p. ▪ New contracts commenced, including those with power generation linkages
Reduce production costs, streamline systems & processes	▪ OGPP production costs reduced well below $2/GJ ▪ Further organisational improvement initiatives underway

#4
Appendix

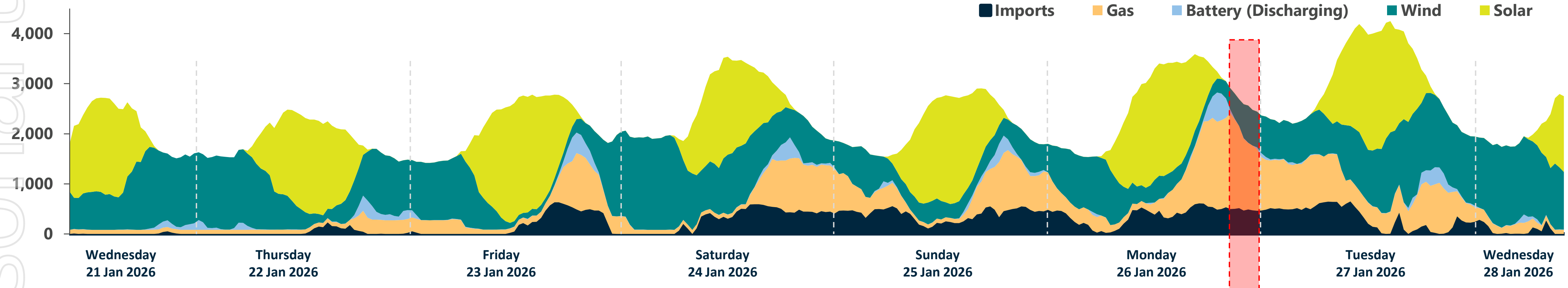
Increasing role of gas in the electricity market

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

NEM electricity supply[1] by type (average ~45% renewables in CY2025), MW



South Australian electricity supply[1] by type (average ~70% renewables in CY2025), MW

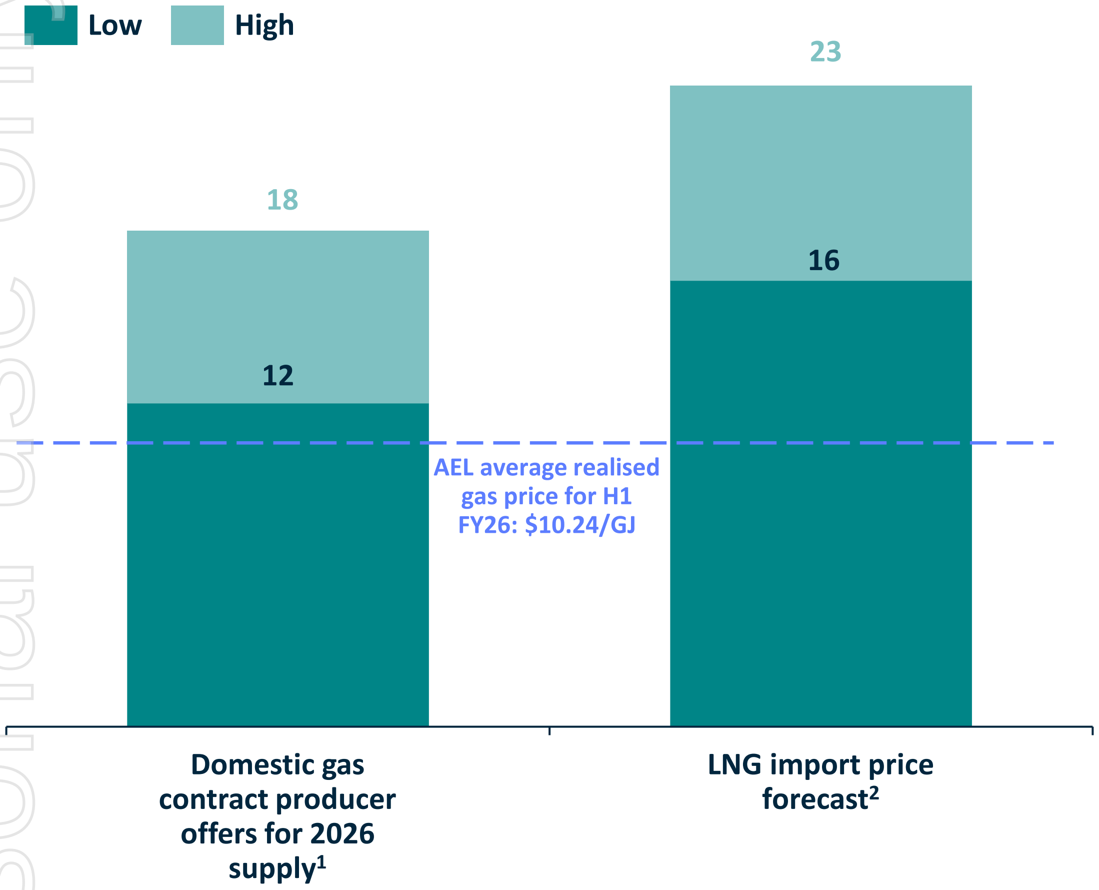


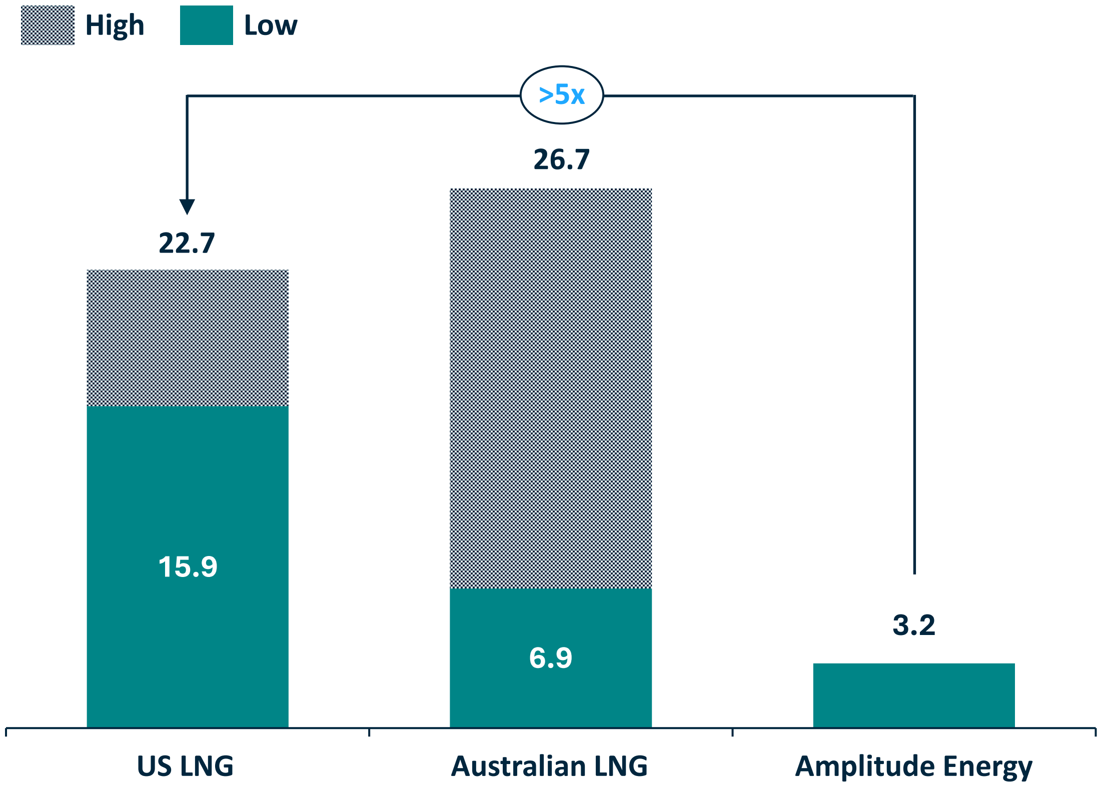
Between 8pm-midnight on Australia Day, gas (50-60%+) and Victorian imports (15-20%) supplied >70% of South Australia's electricity

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

Domestic gas is the cheapest & lowest emissions option

LNG imports to Victoria would be more expensive and ~2-8x more emissions intensive than Amplitude Energy's domestic gas





[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] Greenhouse gas emissions from the liquified natural gas industry in Australia, https://agit.org.au/wp-content/uploads/2023/05/Greenhouse-gas-emissions-from-LNG-CSIRO-final.pdf. LNG ranges exclude shipping and regasification. Regasification typically adds less than 2 $kgCO_2e$/GJ. Amplitude Energy data calculated from FY25 published data for Scope 1 and 2.

Otway exploration opportunities

High quality, low risk prospects in amplitude-supported play

Otway Basin, Top Waarre Formation Prospective Resource Summary[1]

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 unrisked 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 unrisked 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

Notes on calculation of reserves and contingent resources

Amplitude Energy prepares its petroleum Reserves and Contingent Resources in accordance with the definitions and guidelines in the Society of Petroleum Engineers (SPE) 2018 Petroleum Resources Management System (PRMS).

The estimates of petroleum Reserves and Contingent Resources contained in this Reserves statement are as at 30 June 2025. The Company is not aware of any new information or data that materially affects the estimates of reserves and contingent resources, and the material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed.

Unless otherwise stated, all references to Reserves and Contingent Resource quantities in this document are net to Amplitude Energy.

Amplitude Energy has completed its own estimation of Reserves and Contingent Resources for its operated Otway and Gippsland Basin assets. Elsewhere, Reserves and Contingent Resource estimations are based on assessment and independent views of information provided by the permit operators (Beach Energy Limited for PEL 92).

Reference points for Amplitude Energy's petroleum Reserves and Contingent Resources and production are defined points where normal operations cease, and petroleum products are measured under defined conditions prior to custody transfer. Fuel, flare and vent consumed prior to the reference point is excluded.

Petroleum Reserves and Contingent Resources are prepared using deterministic, with support from probabilistic, methods. The Reserves and Contingent Resources estimate methodologies incorporate a range of uncertainty relating to each of the key reservoir input parameters to predict the likely range of outcomes.

Project and field totals are aggregated by arithmetic summation by category. Aggregated 1P and 1C estimates may be conservative and aggregated 3P and 3C estimates may be optimistic due to the effects of arithmetic summation.

Throughout this announcement, totals may not exactly reflect arithmetic addition due to rounding.

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).

Reserves

Under the SPE PRMS 2018, "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 Otway Basin totals comprise the arithmetically aggregated project fields (Casino, Henry and Netherby). The Cooper Basin totals comprise the arithmetically aggregated PEL 92 fields. The Gippsland Basin totals comprise Sole Reserves only.

Contingent Resources

Under the SPE PRMS 2018, "Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies".

The Contingent Resources assessment includes resources in the Gippsland, Otway and Cooper Basins.

Qualified petroleum Reserves and resources evaluator statement

The information contained in this report regarding Amplitude Energy's Reserves and Contingent Resources is based on, and fairly represents, information and supporting documentation reviewed prepared by, or under the supervision of, **Mr James Clark** who is a full-time employee of Amplitude Energy Limited holding the position of Manager, Exploration & Subsurface. Mr Clark holds a Bachelor of Arts (Hons), A Doctorate in Geology, is a member of the American Association of Petroleum Geologists and the Society of Petroleum Engineers, 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.

Reconciliations

$mm	H1 FY25	**H1 FY26**
Underlying net profit / (loss) after tax[1]	**7.8**	**25.7**
Adjusted for:		
Net finance costs	13.8	10.3
Accretion expense	4.9	4.2
Tax expense	8.1	8.7
Depreciation	24.0	16.4
Amortisation	33.5	36.0
Tax impact of adjustments	0.1	(1.0)
Total underlying adjustments after tax	**84.4**	**74.6**
Underlying EBITDAX[1]	**92.2**	**100.3**

$mm	H1 FY25	**H1 FY26**
Statutory net profit / (loss) after tax	**7.6**	**26.2**
Adjusted for:		
Restoration (income)/expense and associated costs	(2.9)	(1.5)
Business restructuring and transformation	3.2	-
Derecognition of deferred income tax asset	-	0.8
Tax impact of adjustments	(0.1)	0.2
Total significant items after tax	**0.2**	**(0.5)**
Underlying net profit / (loss) after tax[1]	**7.8**	**25.7**

[1] 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.

Abbreviations

$	Australian dollars
Amplitude Energy or AEL or Company	Amplitude Energy Limited ABN 93 096 170 295
AGP	Athena Gas Plant
ASX	Australian Securities Exchange
bbl	Barrels
Bcf	Billion cubic feet of gas
boe	Barrel of oil equivalent
CHN	Casino, Henry and Netherby fields
ECSP	East Coast Supply Project
FEED	Front End Engineering Design
G&A	General administration expenses
GJ	Gigajoule
JV	Joint venture
mm	Millions
mmbbl	Million barrels
MMboe	Million barrels of oil equivalent
N/M	Not meaningful
OGPP	Orbost Gas Processing Plant
PEL	Petroleum Exploration Licence
PJ	Petajoules
PJe	Petajoules-equivalent
TJ	Terajoules
TJe/d	Terajoules-equivalent per day
TJ/d	Terajoules per day
u-EBITDAX	Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment