Rottnest Island Investor Conference

18 March 2026

Disclaimer

This document contains summary information about Amplitude Energy and its activities as at the date of this document and should not be considered to be comprehensive or to comprise all the information which a shareholder or potential investor in Amplitude Energy may require in order to determine whether to deal in Amplitude Energy shares. The information is a general summary only and does not purport to be complete. It should be read in conjunction with Amplitude Energy's periodic reports and other continuous disclosure announcements released to the Australian Securities Exchange, which are available at www.asx.com.au.

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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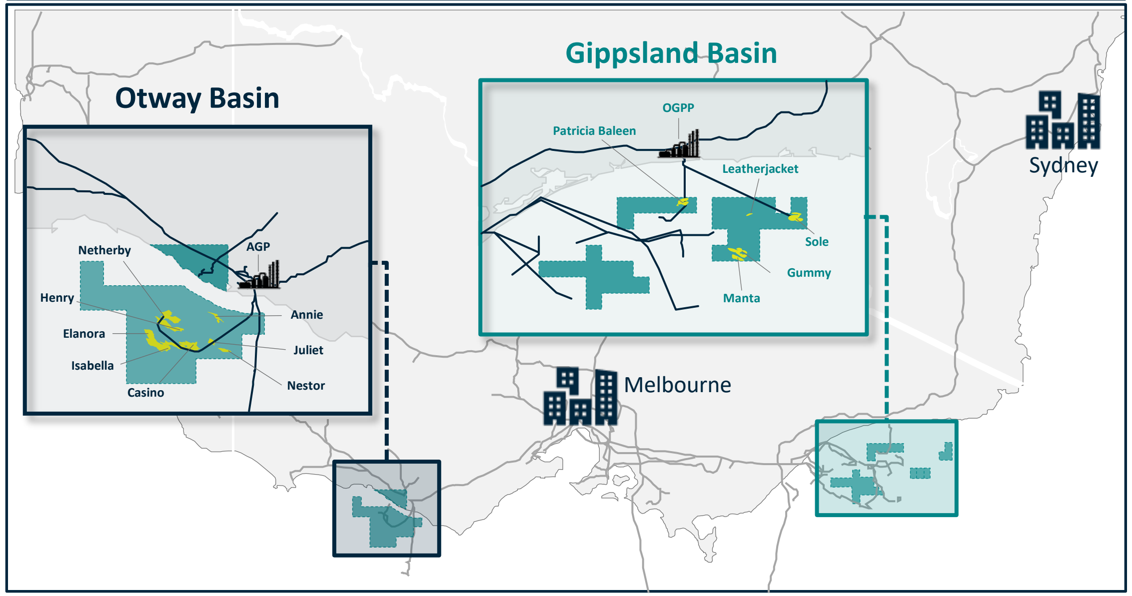
Amplitude Energy overview

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

Integrated operator across Gippsland & Otway Basins



Otway Basin Energy Hub (AEL 50%)	▪ **Athena Gas Plant ("AGP"):** Processing hub for Otway Basin gas, 150TJ/d capacity ▪ **Casino / Henry / Netherby ("CHN"):** producing gas fields ▪ **ECSP[1]:** Low risk exploration & development project targeting 4 new wells
Gippsland Basin Energy Hub (AEL 100%)	▪ **Orbost Gas Processing Plant ("OGPP"):** Processing hub for Gippsland Basin gas; recently increased capacity to >70 TJ/day ▪ **Sole:** producing gas field, 2P Reserves support field life well into 2030s ▪ Multiple exploration opportunities

Amplitude Energy Investment Proposition

- Pure-play exposure to tight east coast domestic gas markets

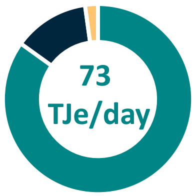
- Strategic infrastructure position, located close to customers

- Strong cash flow generation from producing assets

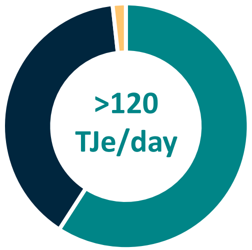
- High value growth and optionality in established basins

- Proven track-record of delivering shareholder value

FY25 group net production



Target group net production post East Coast Supply Project[1]



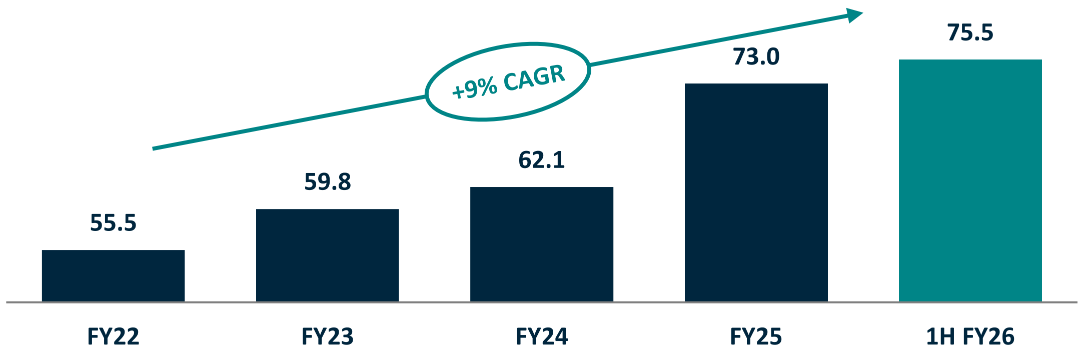
Gippsland Basin | Otway Basin | Cooper Basin

[1] Targeted production post East Coast Supply Project ("ECSP") is indicative and subject to a number of variables, including exploration success, a Final Investment Decision on the development phase of the project, pursuit of the Nestor prospect by the joint venture parties, field resources, resource composition and field pressures.

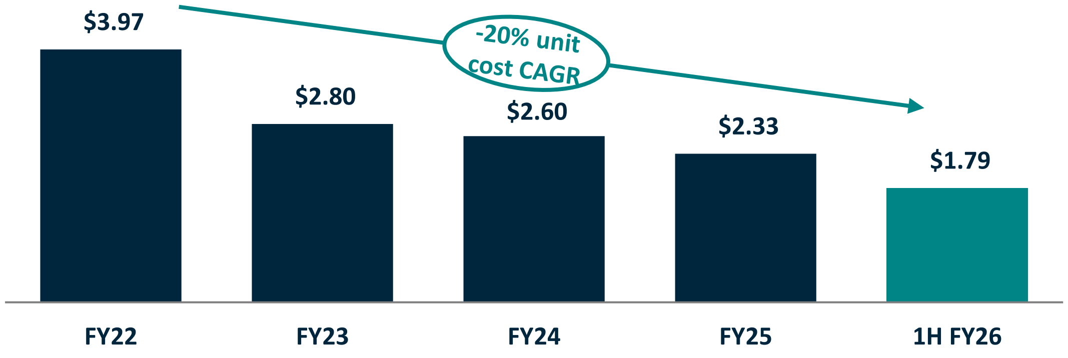
Amplitude Energy has built a track record of performance

Increased production and operational leverage has generated substantial margin expansion

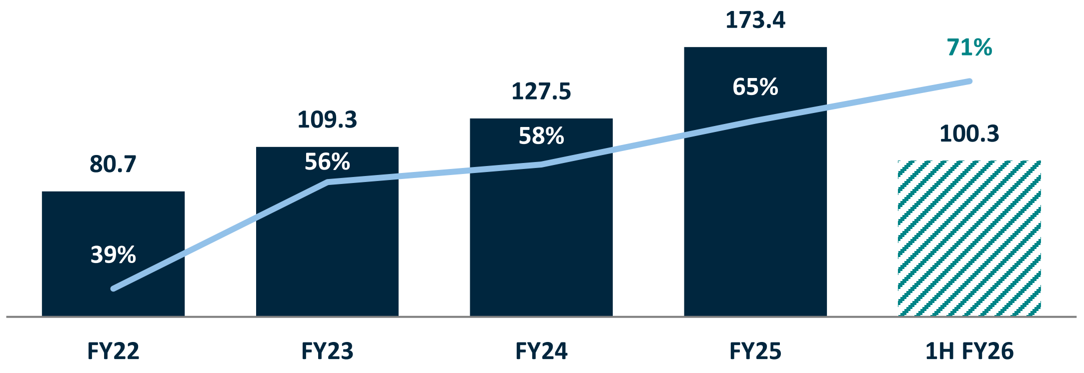
Production, TJe/day



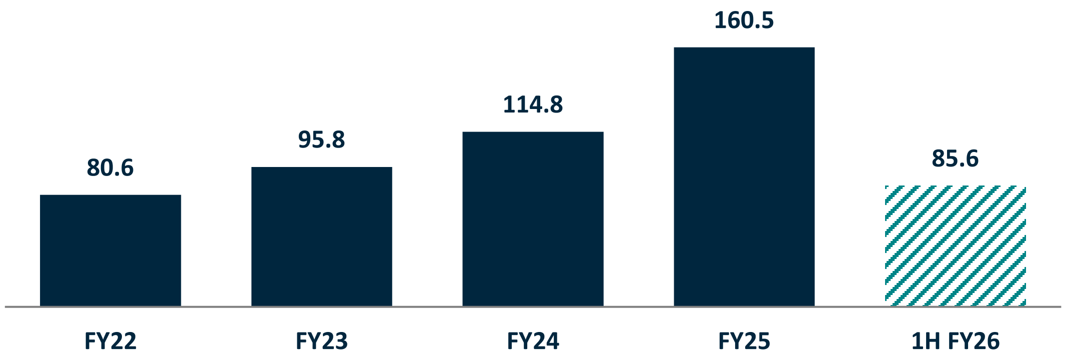
Production expenses[1], $ per GJ produced



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



Adjusted cash from operations, $mm[3]

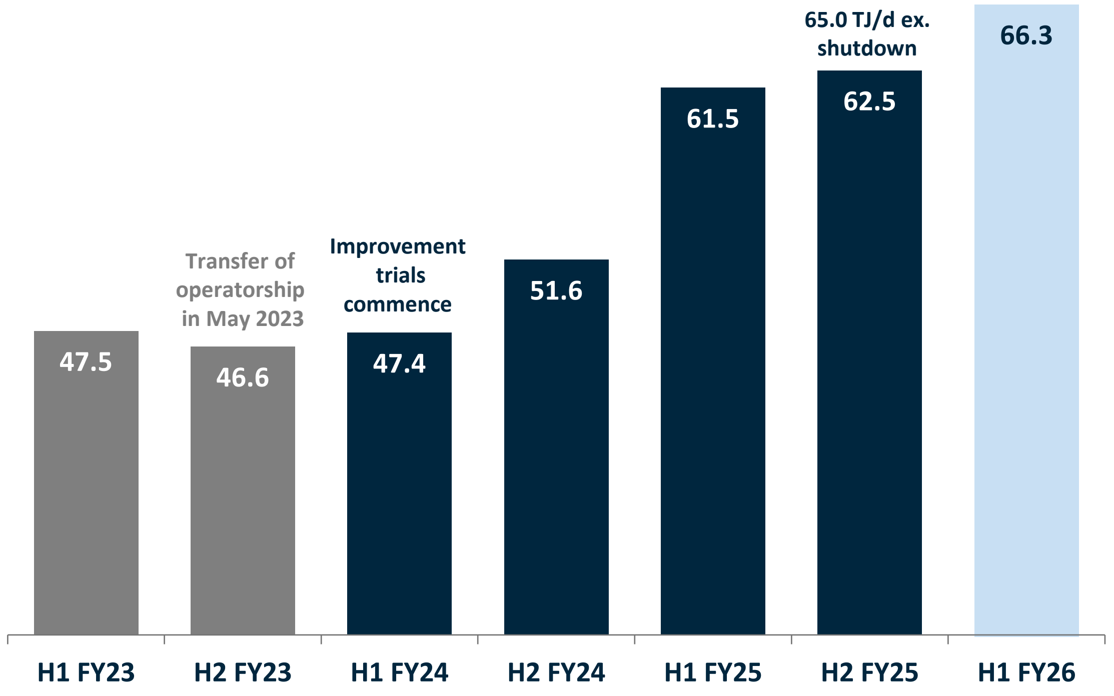


[1] Production expenses comprise labour, materials, overheads, insurance, license costs, JV management and carbon offset costs, but excludes third-party product purchases, transport and trading costs, royalties, pipeline general visual inspection (GVI) costs and non-cash depreciation and amortisation | [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

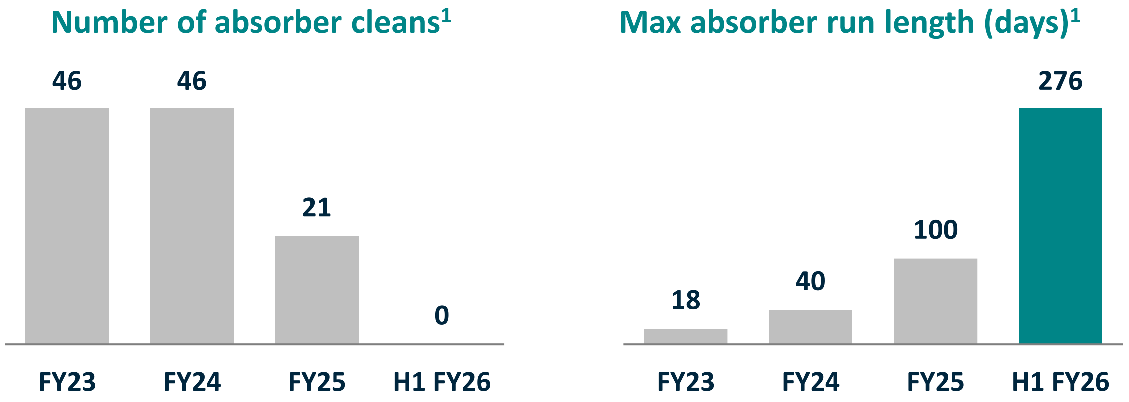
Further growth of Gippsland Basin production

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



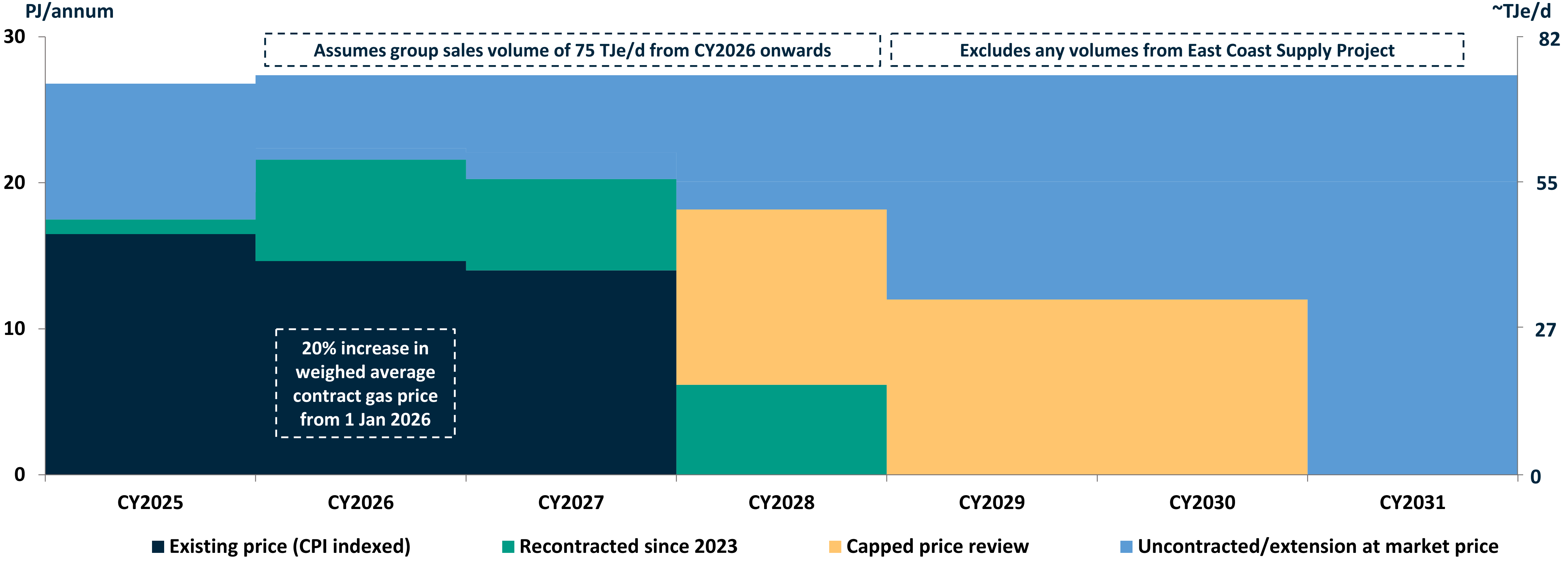
- OGPP sulphur removal system no longer a constraint on production
  - Record absorber unit run-time
  - System redundancy provided by polisher and H_2S scavenger injection
  - Chemical clean-in-place of absorbers recently utilised successfully
- Focus now on debottlenecking the inlet pipeline and further 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

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]

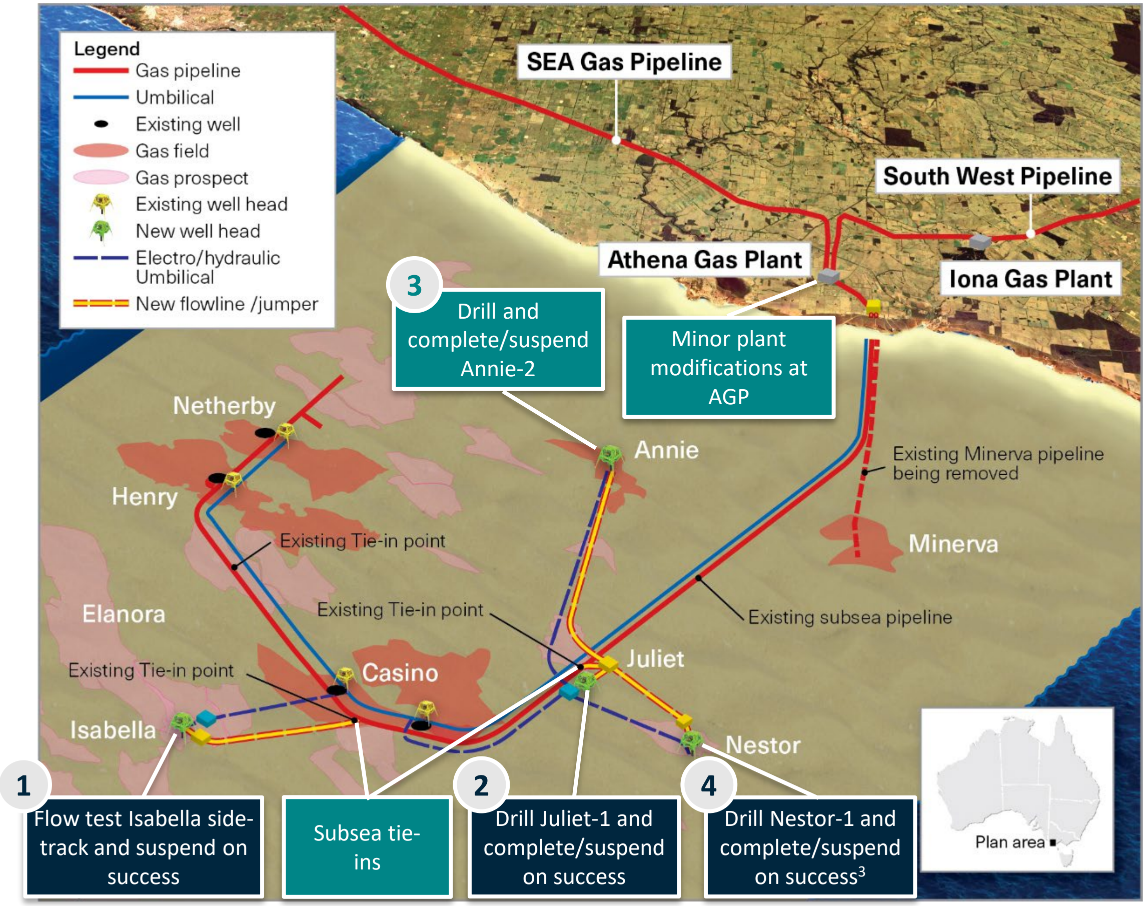


[1] Net to Amplitude Energy's equity share, the annual contract quantity volumes shown are indicative only and assume group sales volume of 75 TJe/day from 1 January 2026 (actual group sales volume of 73.4 TJe/d shown for CY2025). This forward-looking statement is subject to the qualifications on page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

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

ECSP activity and infrastructure overview

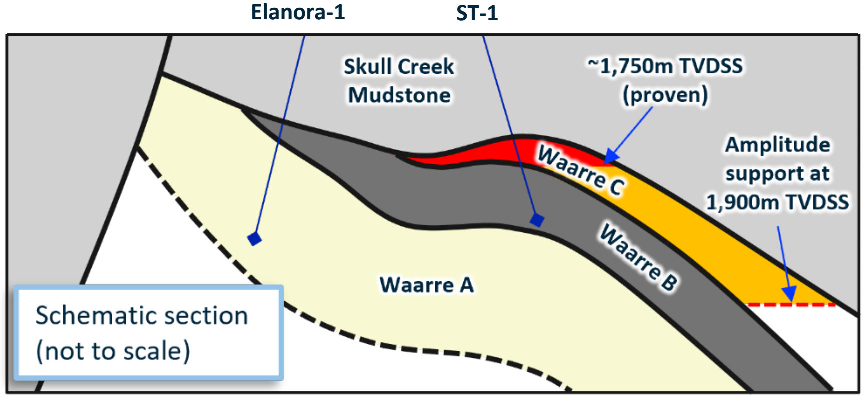


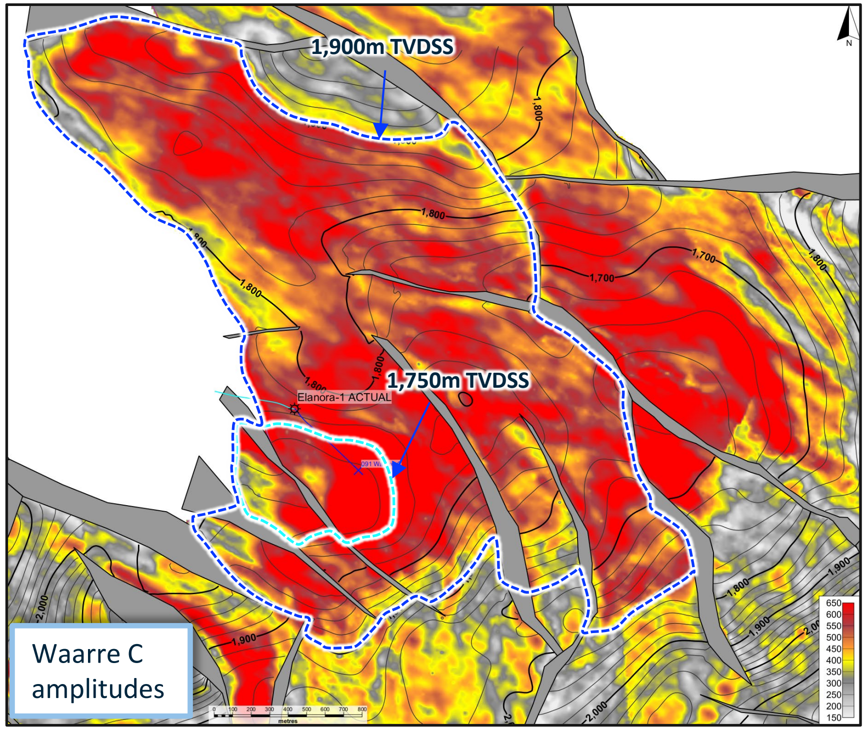
- Taken together ECSP resources would extend the life of the AGP by over a decade on success[1], with first gas targeted in CY2028
- First foundation contract for ECSP supply now signed with EA; active GSA negotiations with multiple other customers
- Takes advantage of existing AGP gas processing capacity 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 21 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

Isabella update

Upcoming flow test at Isabella gas discovery to inform resource volume estimates





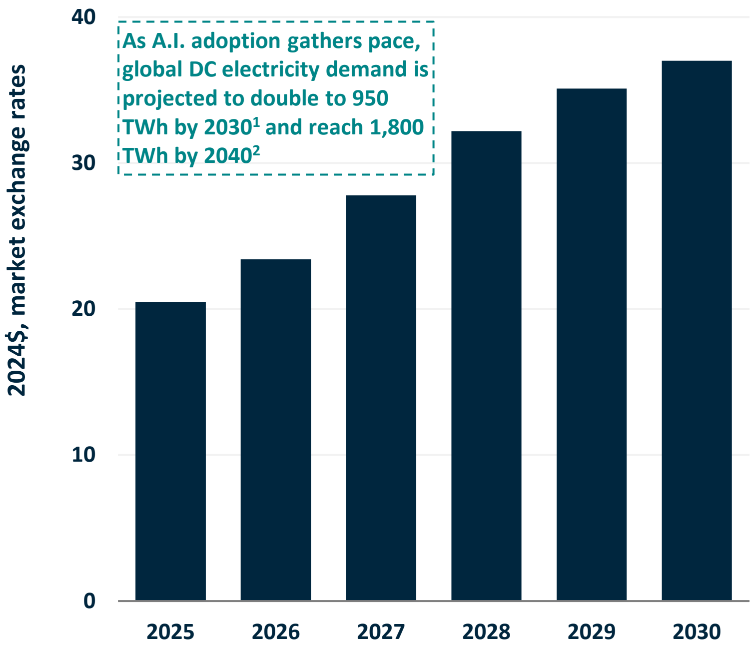
- Isabella field being drilled as a planned sidetrack ("ST-1") from the earlier Elanora-1 well
- ST-1 intersected gas in the primary Waarre C reservoir target on 1 March
  - ~11m gross pay / ~8m net pay
  - Wireline tests imply gas water contact is below the Waarre C reservoir intersection, indicating potential for a larger gas accumulation
  - Preliminary data from Isabella implies high deliverability and ~5% CO_2 levels
  - Expecting to complete and flow test Isabella sidetrack in the next week
  - If flow test confirms minimum commercial gas volume, Isabella to be suspended as a future ECSP producing well
- Elanora seismic response analysis being undertaken; expected in mid-CY2026
- Overall drilling programme currently within approved schedule and budget

TVDSS = True vertical depth subsea. Refer to page 21 of this presentation for further information regarding the Isabella prospect.

Increased domestic gas supply crucial to Australia's energy future

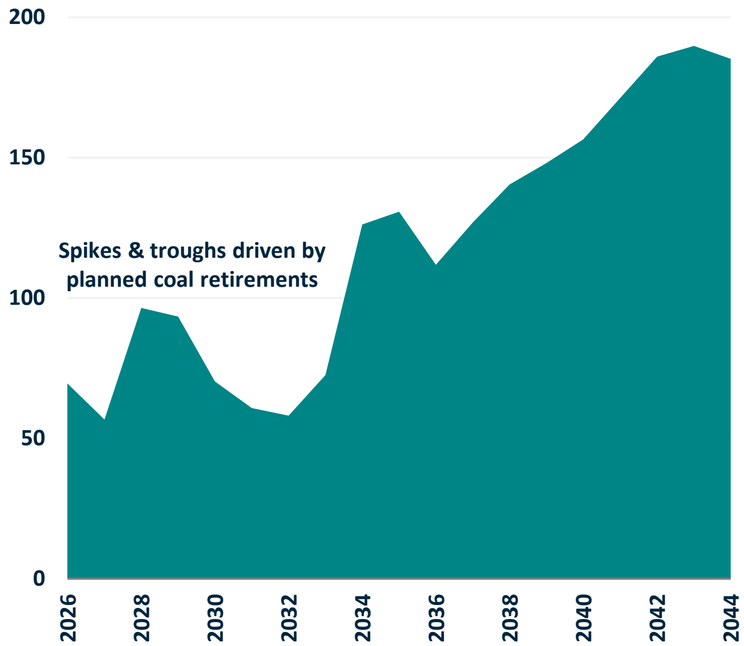
Structural gas demand growth being driven by data centre (DC) roll-outs and coal-to-gas switching, in Australia and worldwide

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

FY26 business priorities being delivered

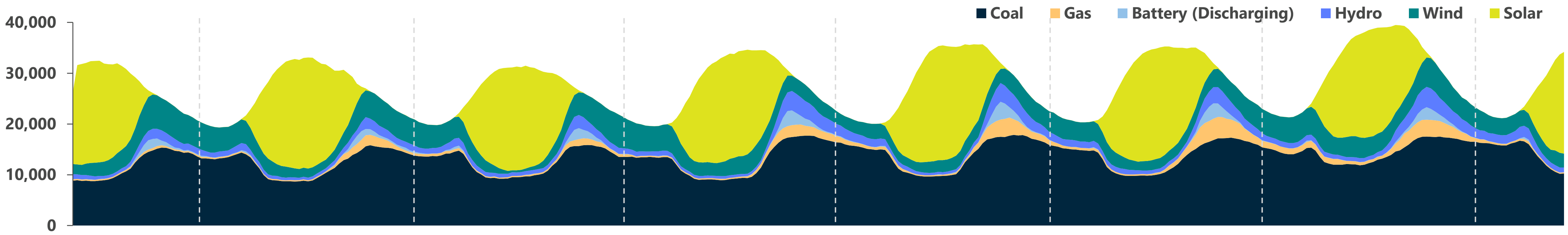
Progress the ECSP on schedule and budget to achieve FID	▪ Development FEED complete ▪ First well near complete, on schedule and budget ▪ Foundation GSA discussions on track
Maximise asset utilisation	▪ OGPP production capacity increased to >70 TJ/day ▪ AGP reliability loss of <1% ▪ Patricia Baleen restart progressed
Increase average realised gas prices	▪ 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

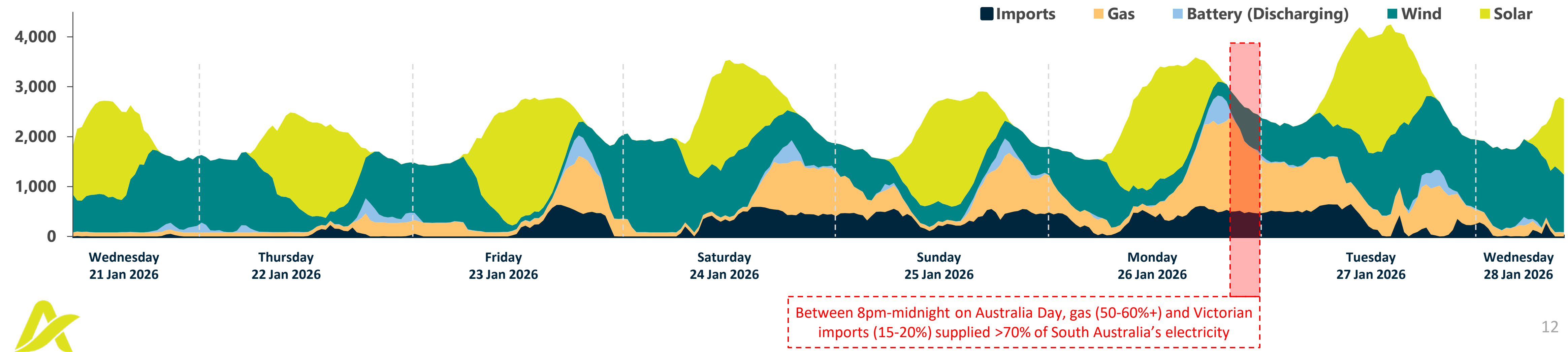
Increasing role of gas in the electricity market

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

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



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

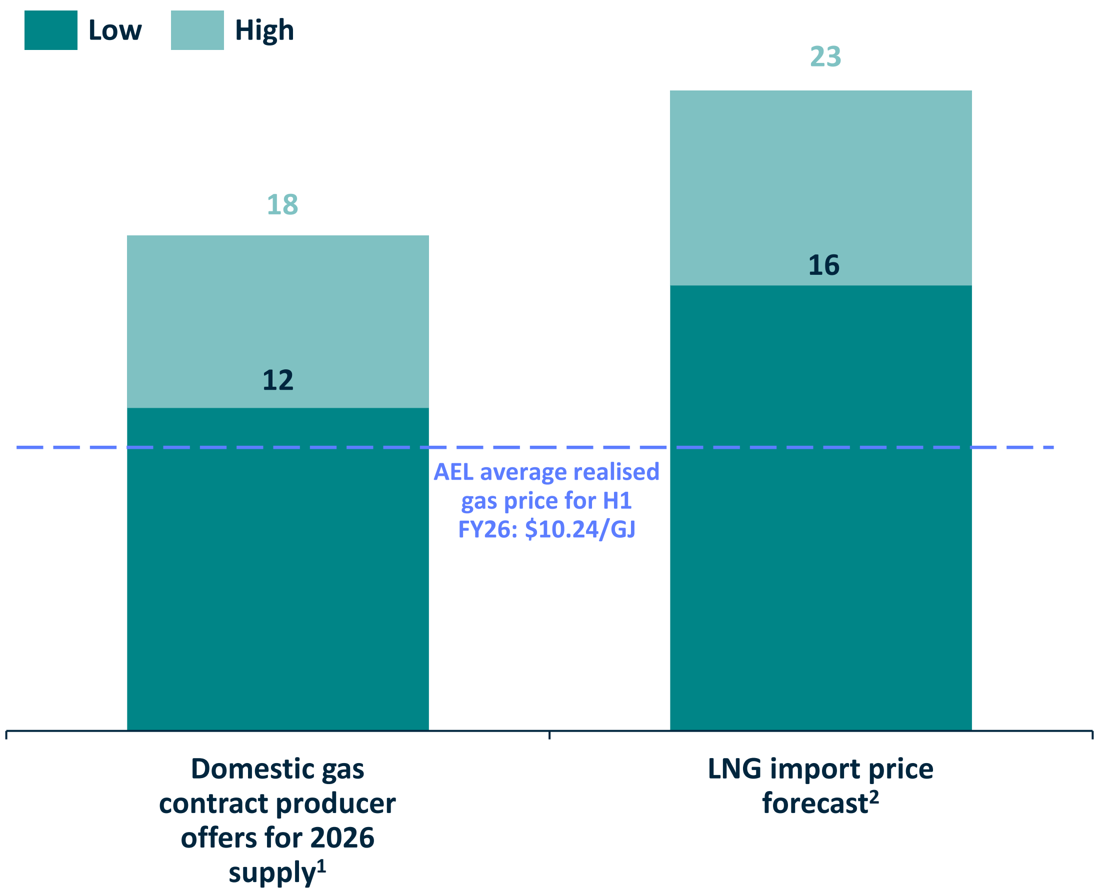


Data sourced from www.opennem.org.au. Excludes exports | [1] Refers to reported electricity supply in the National Electricity Market (NEM), incorporating all Australian states and territories excluding Western Australia and the Northern Territory

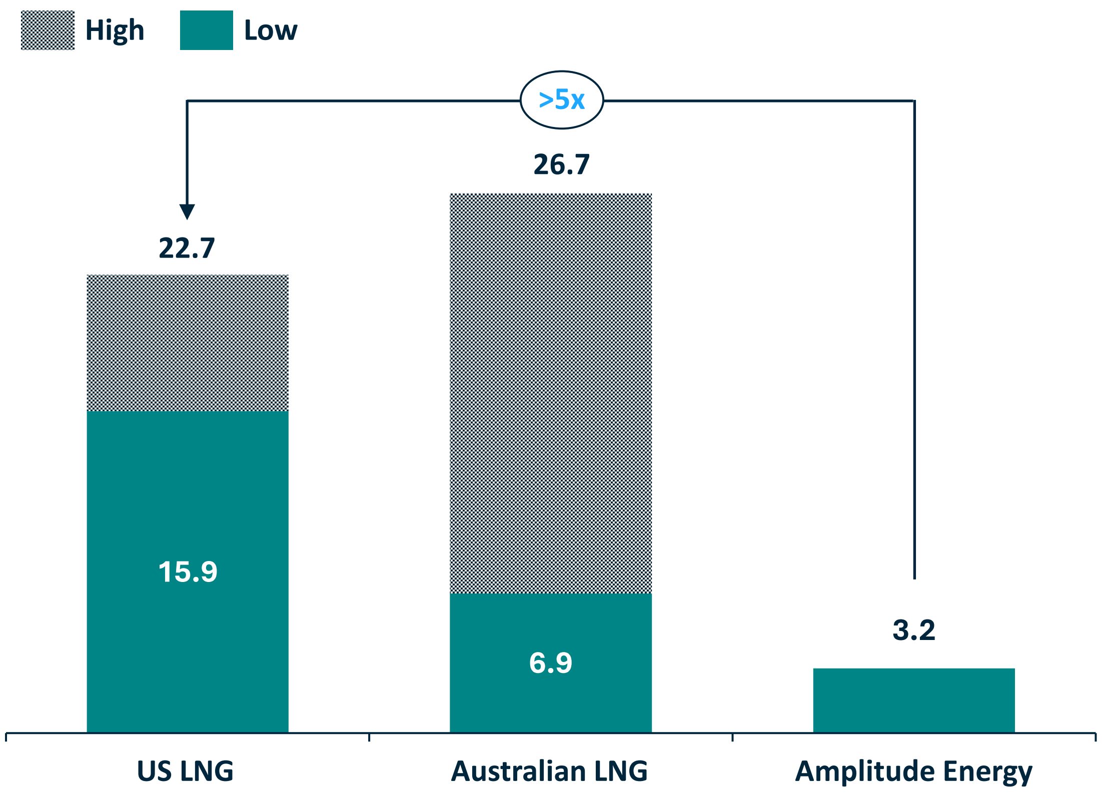
Domestic gas is the cheapest & lowest emissions option

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

Australian Southern States contracted gas prices, A$/GJ



Emissions intensity of producing LNG vs. domestic gas, $kgCO_2$-e/GJ[3]

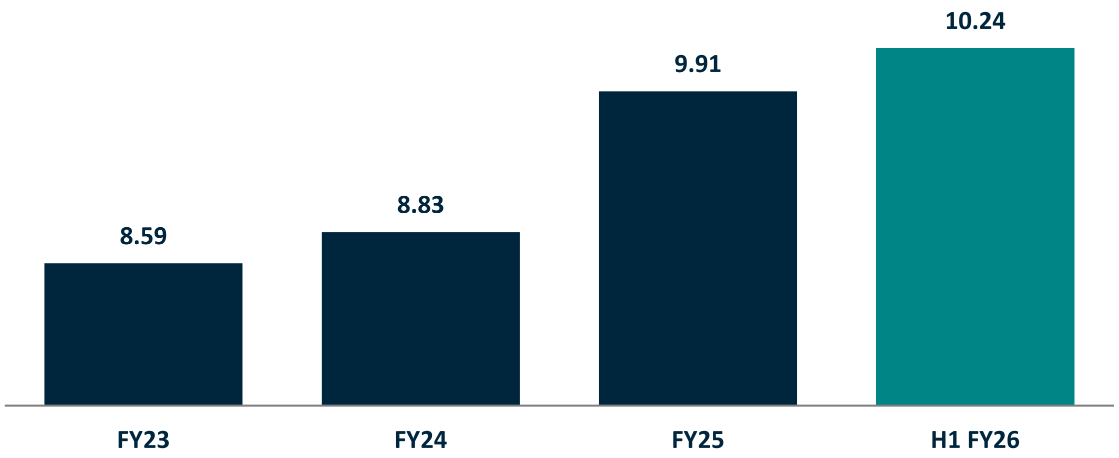


[1] ACCC Gas Inquiry Report, December 2025, Page 28, Chart 2.8 | [2] EnergyQuest, East Coast Gas Outlook 2024, column indicates the "low" and "high" estimates for LNG imports from Port Kembla Energy Terminal into Sydney in 2026| [3] Greenhouse gas emissions from the liquified natural gas industry in 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 $kgCO_2$e/GJ. Amplitude Energy data calculated from FY25 published data for Scope 1 and 2.

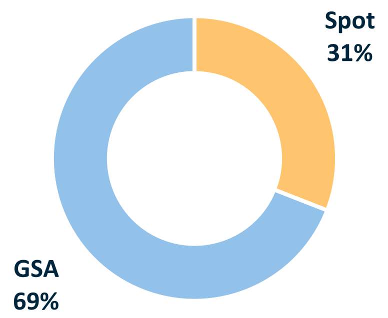
Gas trading & marketing opportunities

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

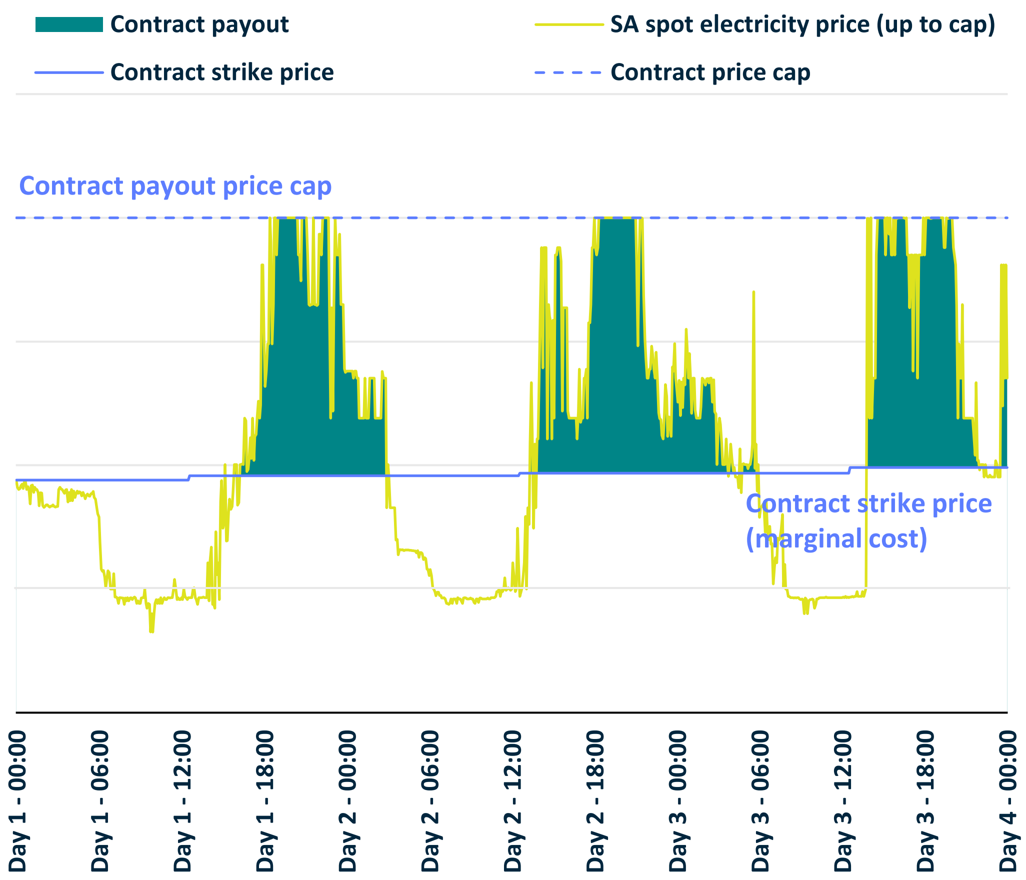
AEL realised gas prices, A$/GJ



H1 FY26 OGPP sales volume mix



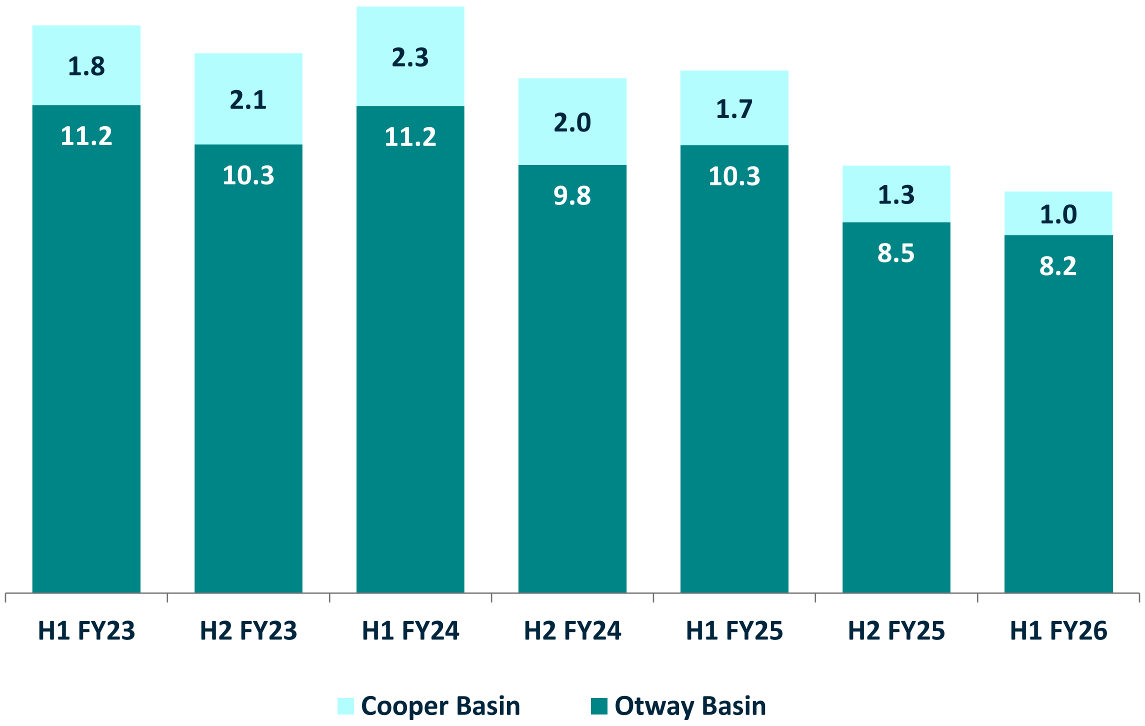
Spark spread contractual arrangement (illustrative)



Otway & Cooper Basins

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

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



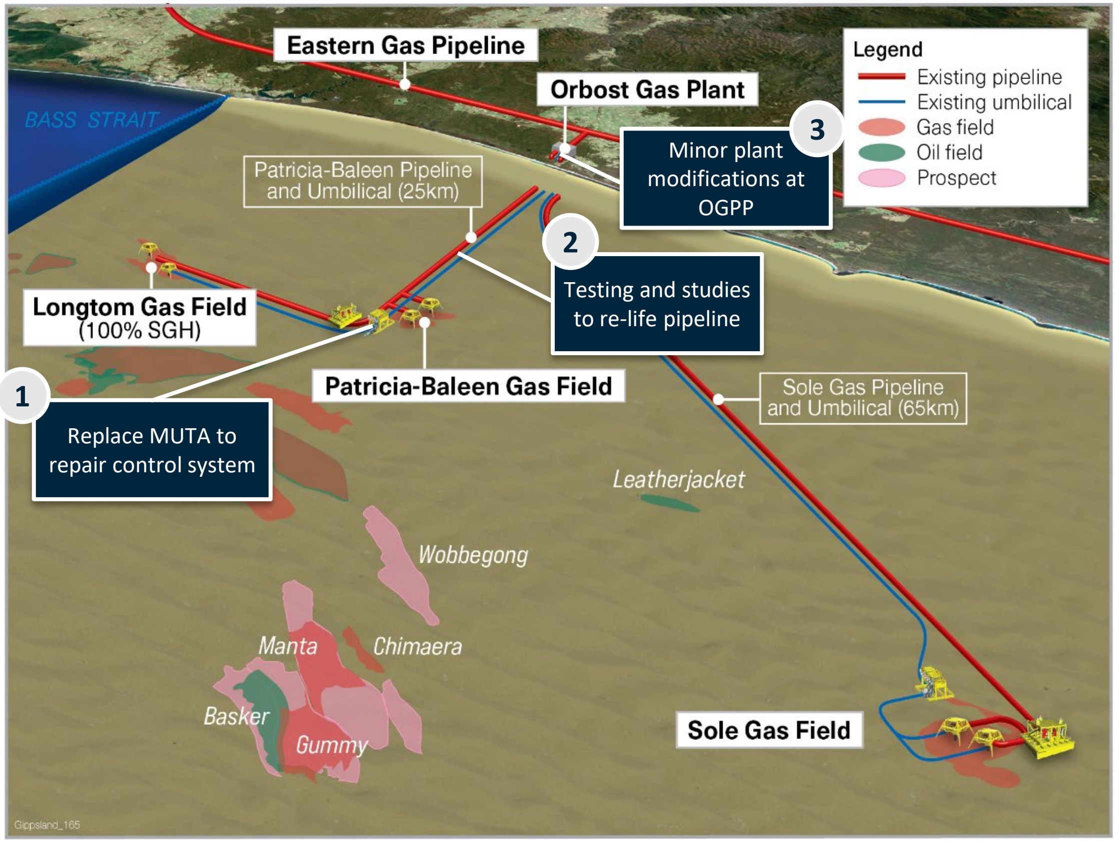
- Otway Basin \ Athena Gas Plant (AGP)
  - Excellent AGP reliability performance over 1H FY26
  - Natural decline as expected with current 3-well CHN[2] cycling pattern
  - Plans underway to bring Casino-4 well back into production and reduce CHN decline
  - FEED complete on AGP re-lifing for East Coast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

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.

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 – 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.

Record H1 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

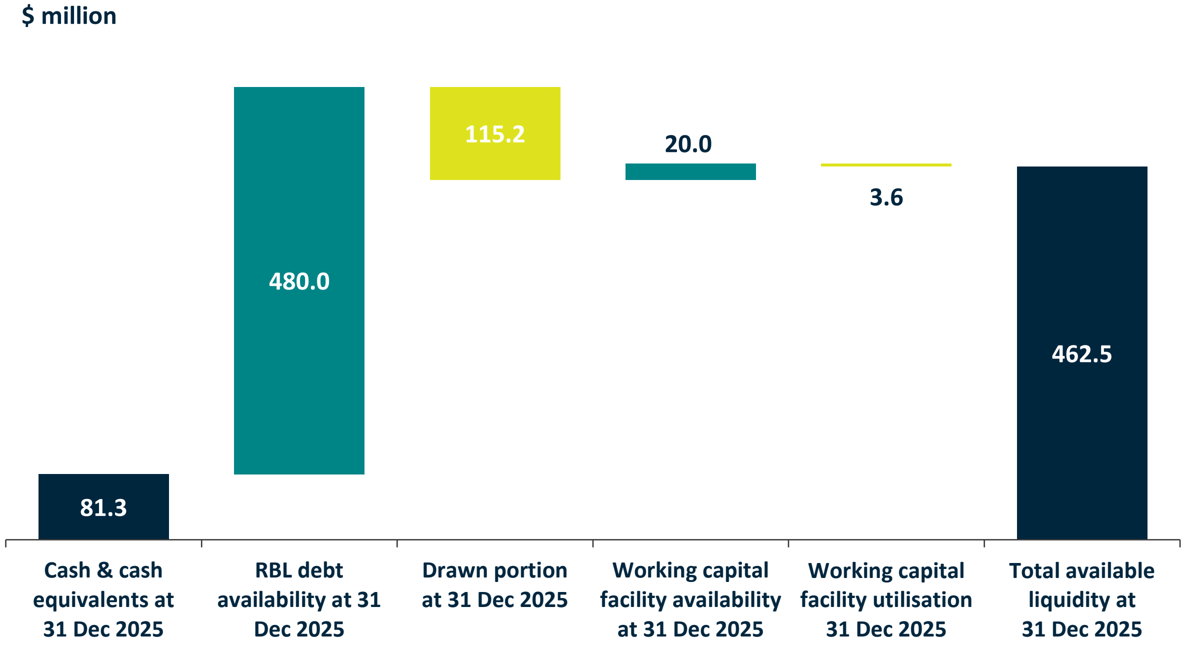
Significant capacity within debt facilities

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 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