Amplitude Energy investor presentation

February 2026

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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 60-63) of Amplitude Energy's FY24 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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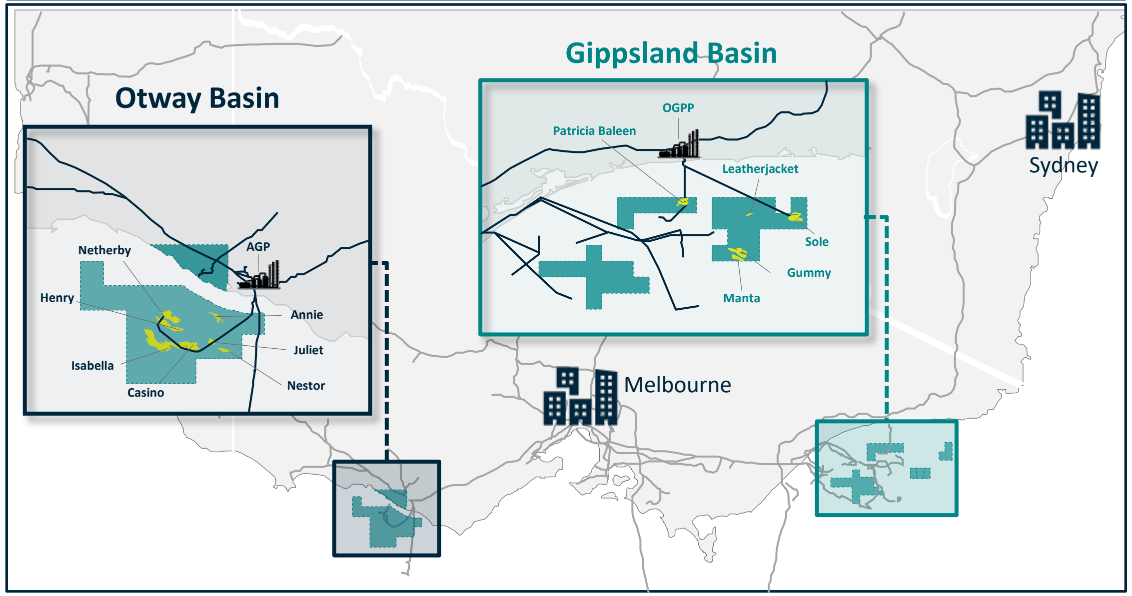
Amplitude Energy overview

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

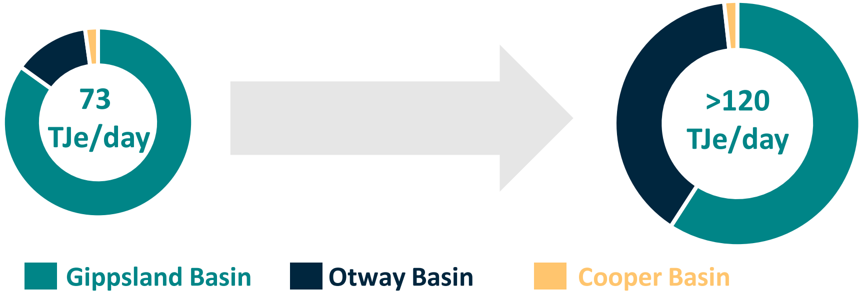

Strong cash flow generation from producing assets


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]

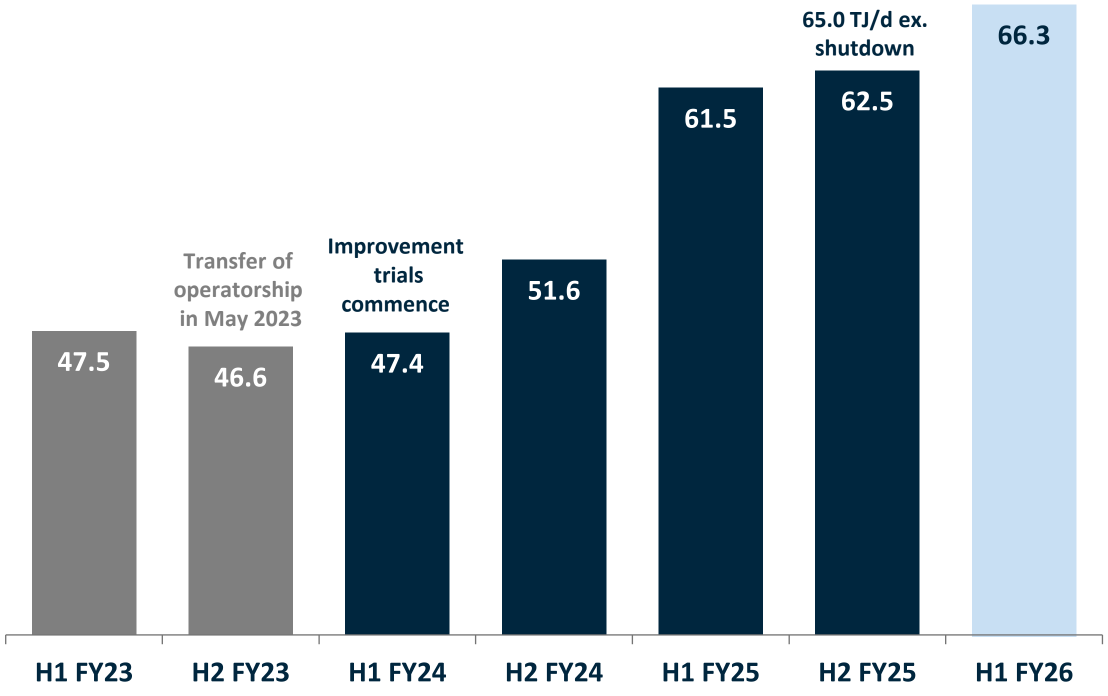


[1] Targeted production post expanded East Coast Supply Project (“ECSP+”) is indicative and subject to a number of variables including exploration success, Final Investment Decision, field resources, resource composition and field pressures.

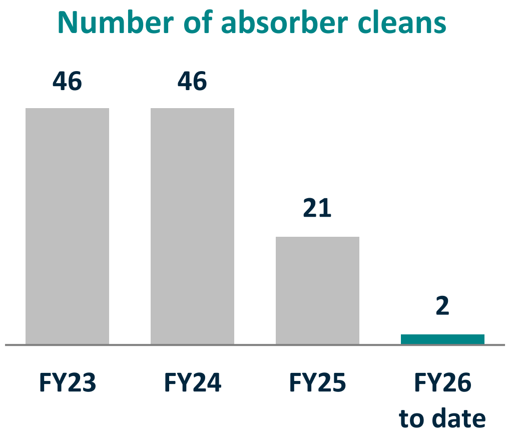
Orbost production continues to increase

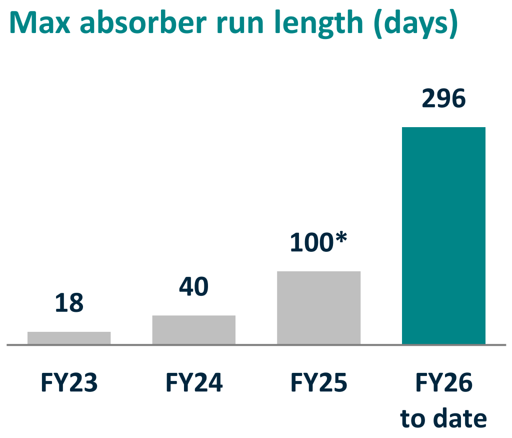
New production records set at Orbost Gas Processing Plant (OGPP), with potential for further increases from debottlenecking

OGPP average processing rate, TJ/d



Select OGPP operational KPIs





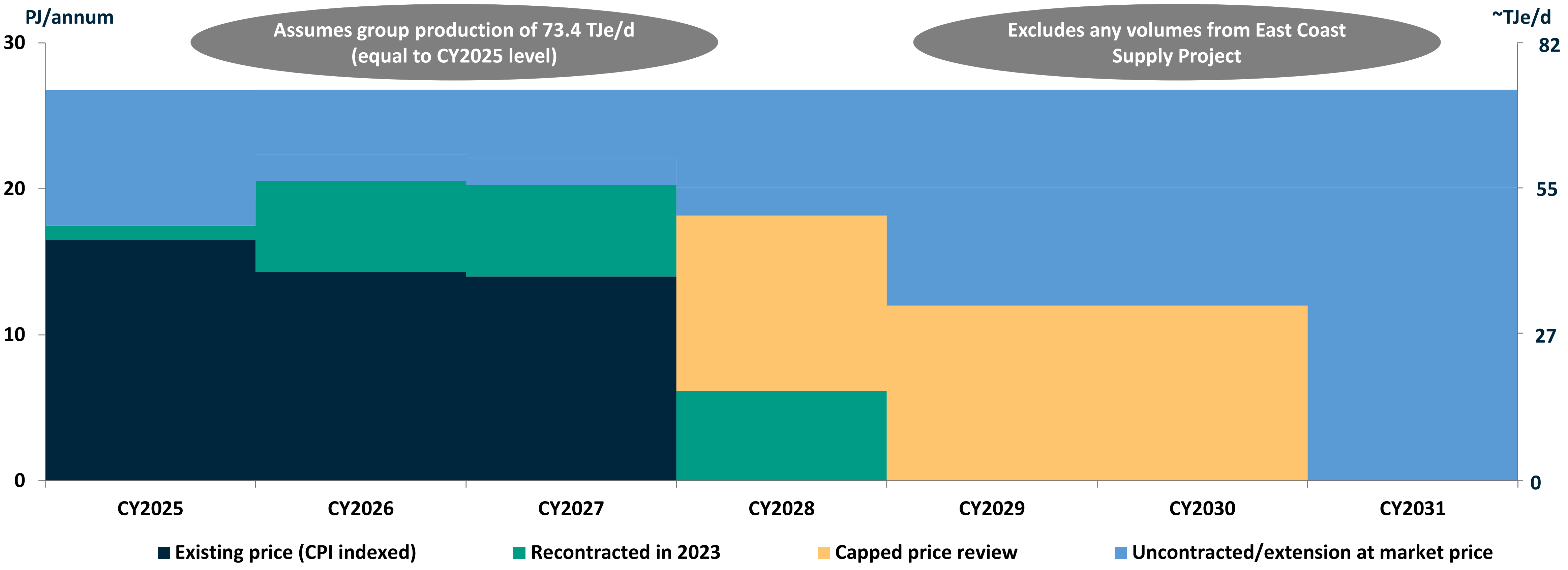
- OGPP sulphur removal system no longer a constraint on production
  - Record absorber unit run-time
  - System redundancy provided by polisher and H_2S scavenger injection
  - Chemical clean-in-place of absorbers recently utilised successfully
- Focus now on debottlenecking the inlet pipeline and further plant reliability improvements
  - Record production rate of 71 TJ/day achieved recently

*As at end of FY25

Increasing exposure 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]

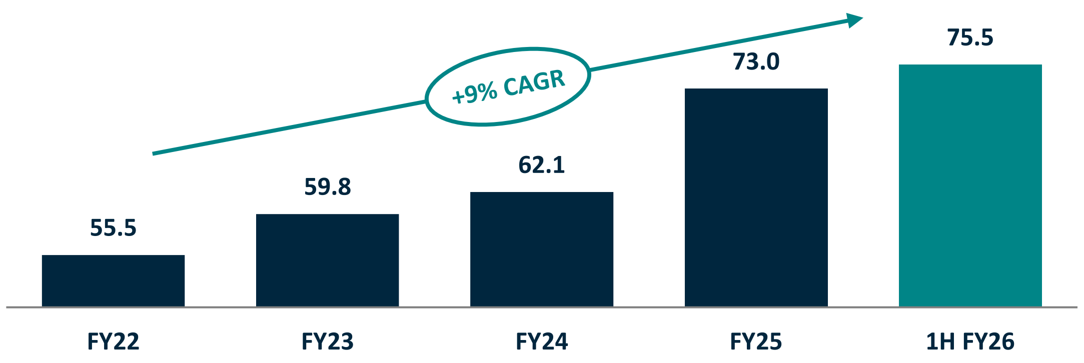


[1] Net to Amplitude Energy's equity share, the annual contract quantity volumes shown are indicative only and assume group production of 73.4 TJe/day from 1 January 2026, which is equal to the production rate for CY2025. This forward-looking statement is subject to the qualifications on page 2 of this presentation. There can be no guarantee that these production levels will be achieved, notwithstanding CY2025 average group production levels. The annual contract quantity volumes shown are for illustrative purposes only and do not constitute production guidance.

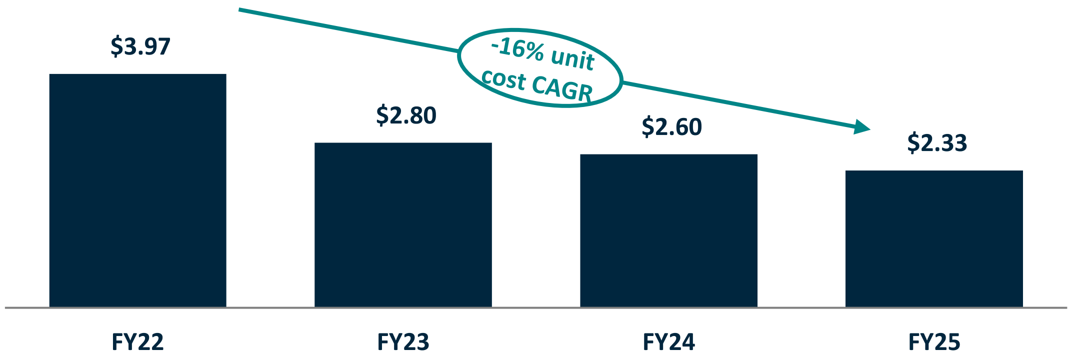
Track record of operational and financial performance

Increased production and operational leverage has generated substantial margin expansion

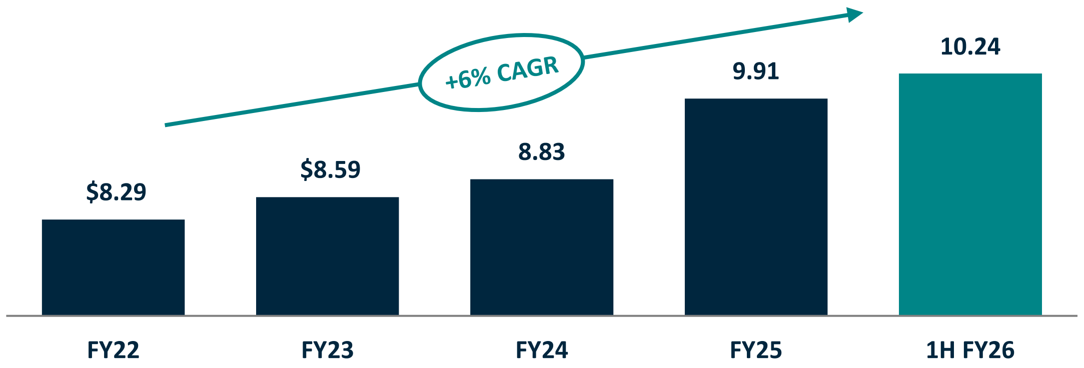
Production, TJe/day



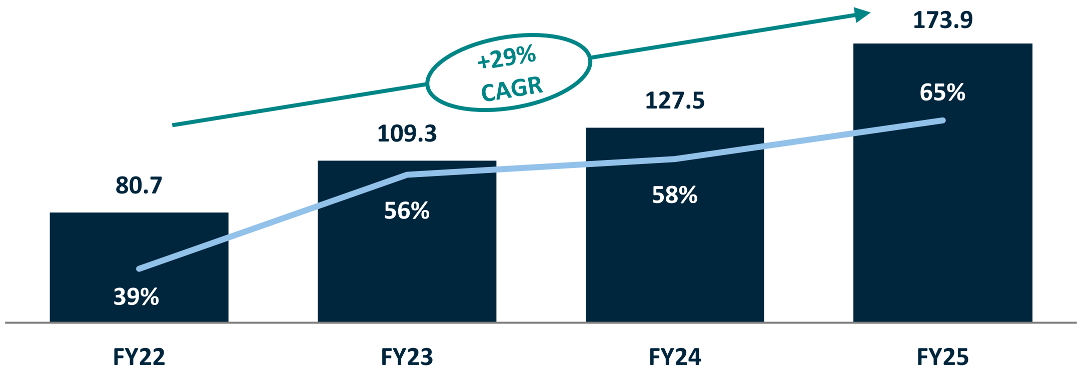
Production expenses[1], $ per GJ produced



Average realised gas price, $ per GJ sold



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

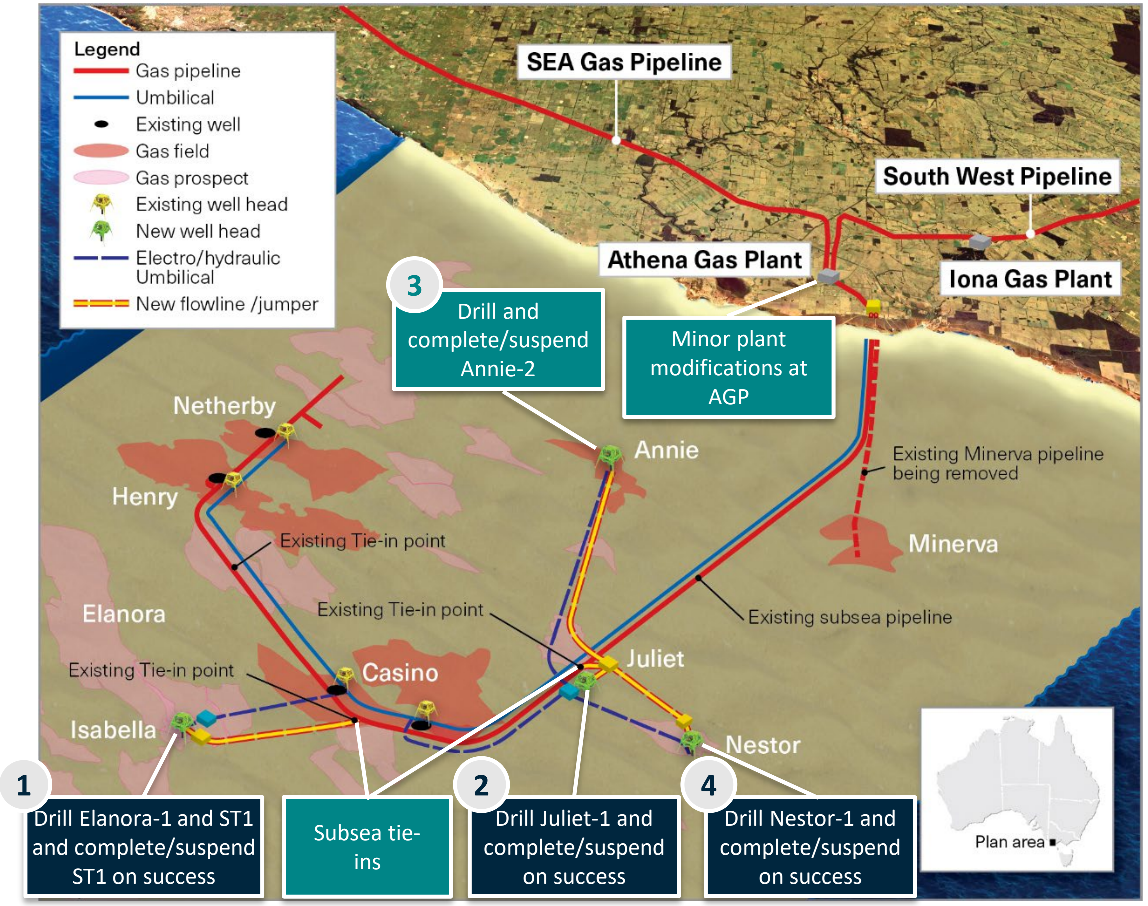


[1] Production expenses comprise labour, materials, overheads, insurance, license costs, JV management and carbon offset costs, but excludes third-party product purchases, transport and trading costs, royalties, pipeline general visual inspection (GVI) costs and non-cash depreciation and amortisation | [2] Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment

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



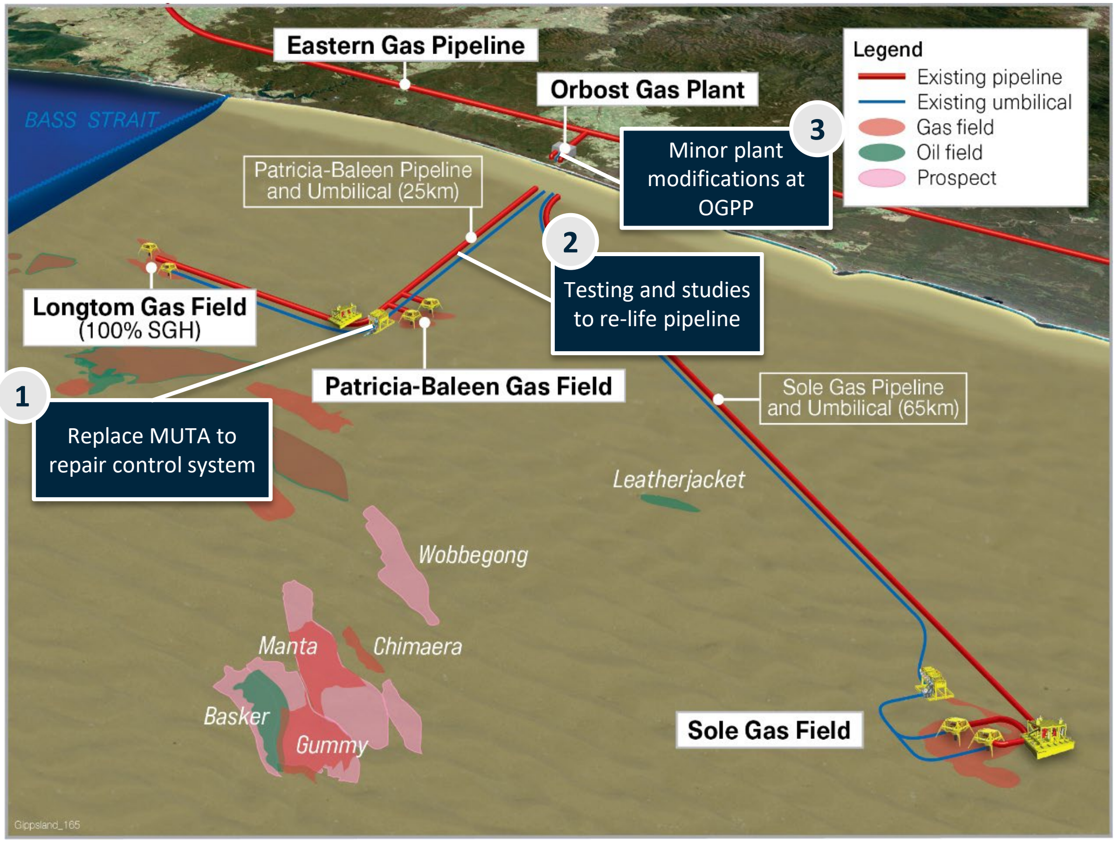
- ECSP+ is targeting 2P equivalent to >8 years reliable production at AGP on success[1], with first gas targeted in CY2028
- Capital efficient development, allowing completion cost savings following exploration success with a 'one touch' approach
- Takes advantage of existing AGP gas processing capacity of up to 150 TJ/d, allowing for peak supply
- Strong gas customer interest for ECSP+ supply; active negotiations with multiple counterparties for foundation GSAs
- Juliet, Nestor & Annie fields all ideally suited to resource recovery efficiency through single well drilling & production
- ECSP+ returns expected to comfortably exceed internal investment hurdle rates[2]
- Largest exploration project 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 15 of this presentation. This total reflects arithmetic summation of independent probabilistic resource estimates. | [2] Based on AEL internal mid-case assumptions

Patricia Baleen restart

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 ~4-5 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	▪ Reservoir suitability and equipment assessment underway together with engineering tender for plant and pipeline restart work ▪ SELECT phase study 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] Expected rate based on the preliminary defined restart scope, which will be verified through Select Phase and FEED studies.

FY26 focus areas

Shareholder returns to be driven by increasing production into a tight market, operational leverage and de-risking growth

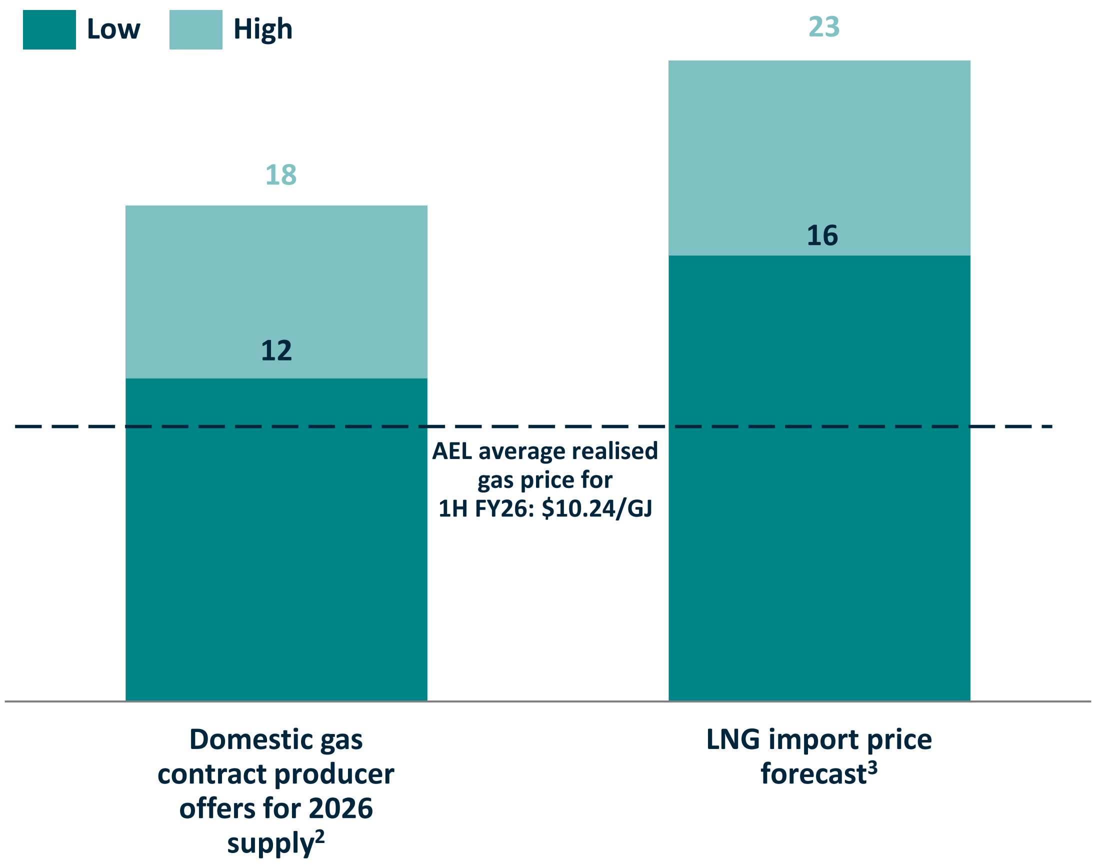
Progress the ECSP on schedule and budget to achieve FID	▪ Initial exploration drilling ▪ Development FEED ▪ Foundation GSAs
Maximise asset utilisation	▪ Increase OGPP capacity to >70 TJ/d instantaneous rate in the near term ▪ Reliability loss of <1% across AGP & OGPP ▪ Progress Patricia Baleen restart
Increase average realised gas prices	▪ Marketing & trading initiatives, including recontracting ▪ Progress opportunities to link our products to power generation
Reduce production costs, streamline systems & processes	▪ Reduce OGPP production cost to <$2/GJ ▪ Further organisational improvement initiatives

Appendix

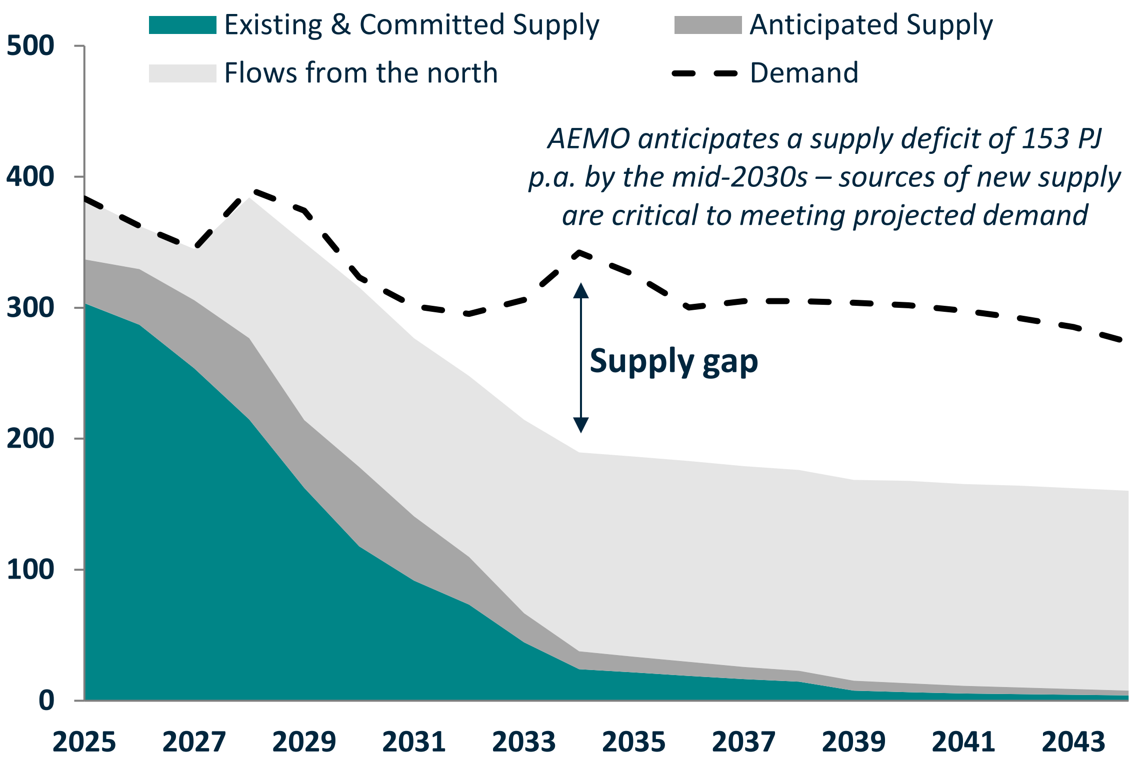
Urgent demand for new domestic gas supply

Federal agencies highlight risks of supply shortfalls during peak demand periods in the Australian Southern States from 2026 and an ongoing supply gap from 2028[1]

Australian Southern States contracted gas prices, A$/GJ



Southern States AEMO supply forecast, PJ p.a.[4]

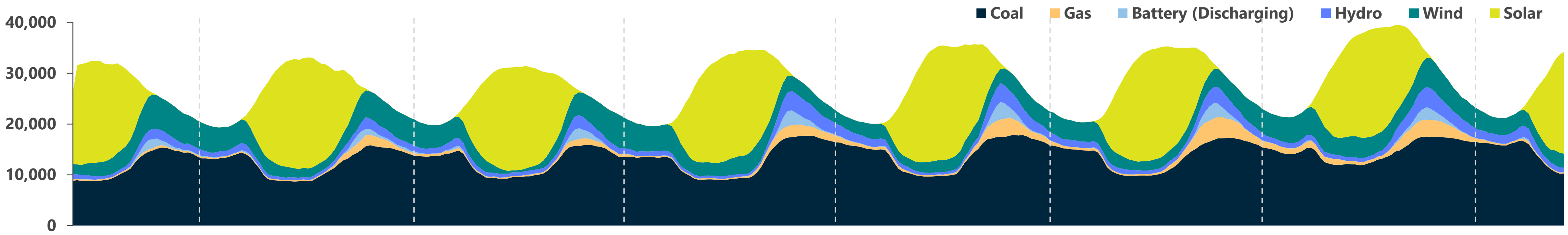


[1] ACCC Gas Inquiry, June 2025 Interim Report. | [2] ACCC Gas Inquiry, June 2025 Interim Report, Page 41, Chart 2.12. Ranges reflect GSAs executed for Southern States supply only. | [3] EnergyQuest, East Coast Gas Outlook 2024, column indicates the "low" and "high" estimates for LNG imports from Port Kembla Energy Terminal into Sydney in 2026. | [4] AEMO 2025 Gas Statement of Opportunities, Figure 41.

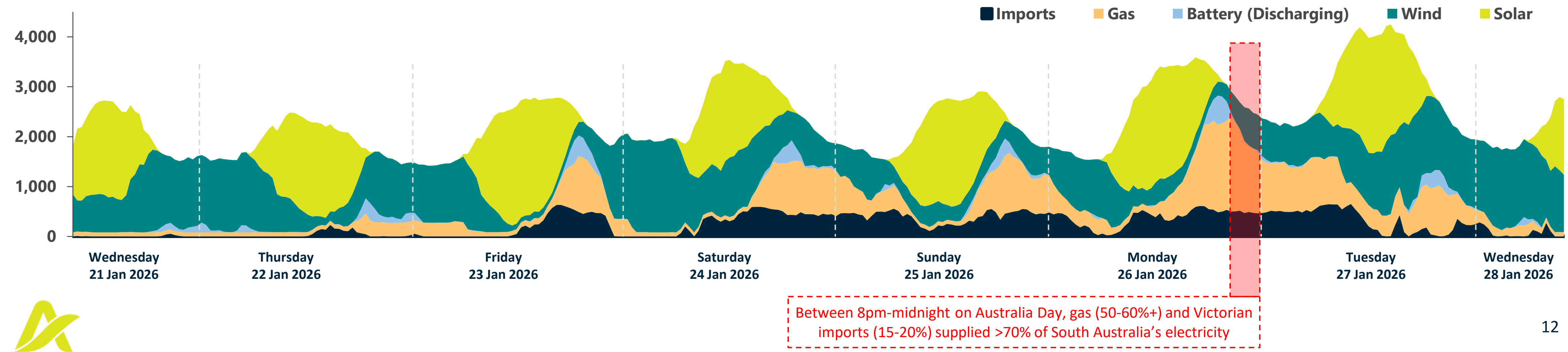
Increasing role of gas in providing flexible, reliable power for the electricity market

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

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



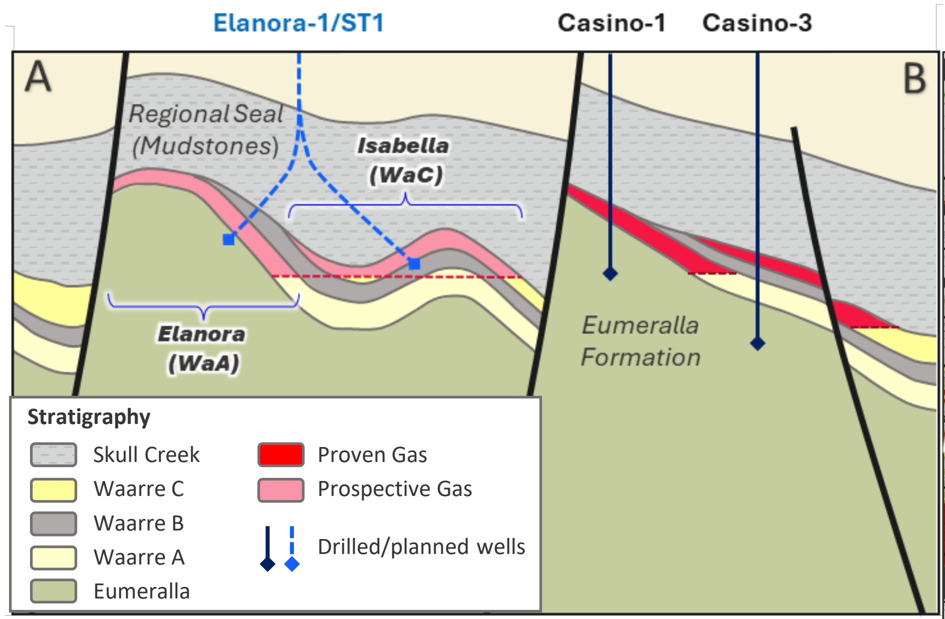
South Australian electricity supply by type (average ~70% renewables in CY2025), MW[1]

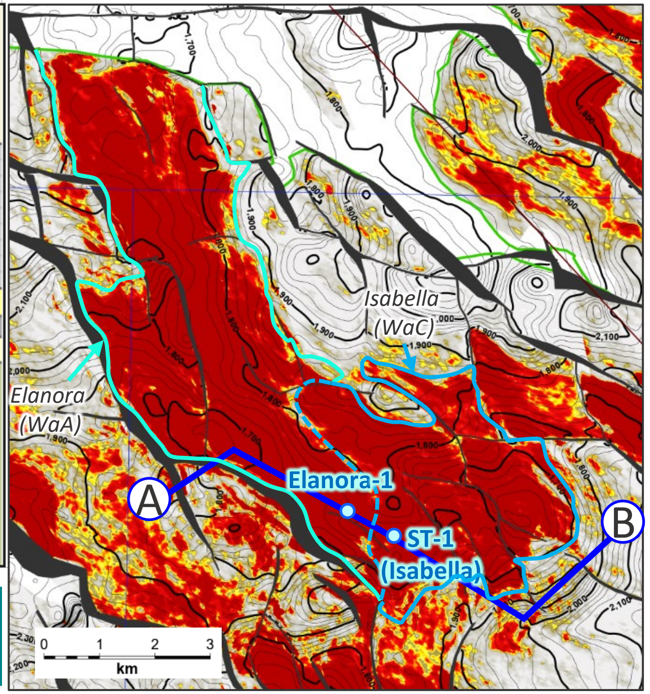


[1] Data sourced from www.opennem.org.au. Excludes exports | [2] Electricity refers to the National Electricity Market (NEM), incorporating all Australian states and territories excluding Western Australia and the Northern Territory

Current drilling activity

Targeting two separate prospects with one well





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 reservoir targets at Elanora and Isabella prospects from a single surface location
- Isabella sidetrack ("ST-1") currently being drilled
  - Waarre C Formation sands 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 is 14-18 days
- Elanora prospect found to be water-bearing on 10 Feb
  - Waarre A Formation sands target

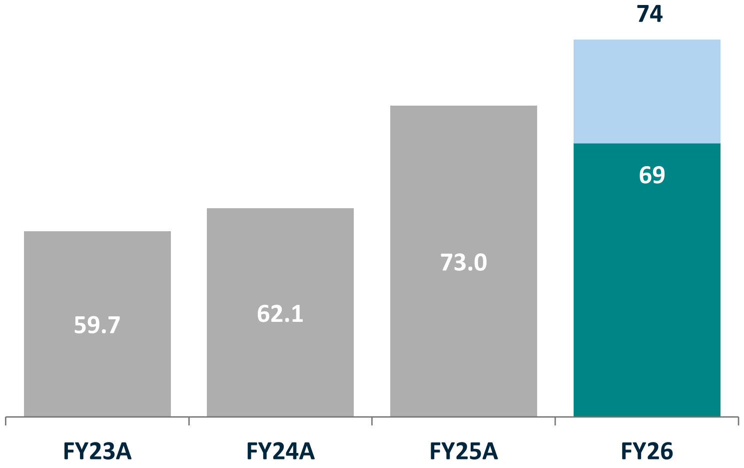
[1] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and AEL's 50% net share of each prospect, were announced to ASX on 9 February 2022. Net figures are reported according to AEL's economic interest and net of contractual royalties.

FY26 guidance

Focus on higher gas production driving cost efficiencies, cash generation and deleveraging, ahead of ECSP

FY26 production: 69 – 74 TJe/day

Annual PJ-equivalent			
21.8	22.7	26.6	25.2 – 27.0

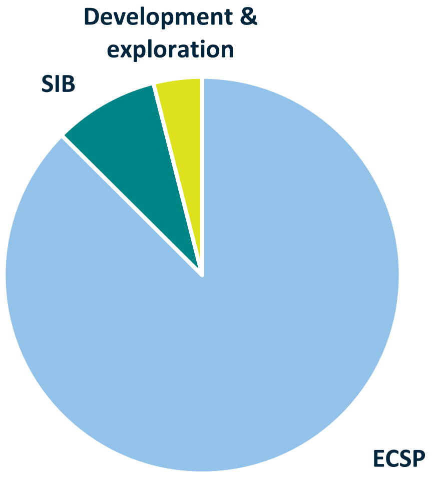


- Reflects confidence that recent OGPP production rates will be sustained
  - Guidance does not assume increases in nameplate capacity through debottlenecking
  - Range reflects different scenarios for absorber runtime, clean times and plant uptime
  - No planned maintenance shutdown in FY26
- Natural decline at CHN fields and PEL 92

FY26 production expenses: $54 – 60mm[1]

- Reflects achieved & expected production cost savings, primarily at OGPP
  - Partly offset by general cost inflation
  - Implied production unit cost $2.00 - 2.38/GJ
- Other cash expenses & costs of sales of $24 – 28m[1,2]
- Excludes ~$16m for general visual inspection (GVI) of Sole and Patricia Baleen pipelines in FY26
  - Irregular activity (required once per ~5 years)
  - Supports Patricia Baleen field re-life

FY26 capex: $125 – 150mm[3]



- ECSP capex includes Elanora/Isabella drilling and development phase long-lead orders & FEED costs
  - Reflects AEL's 50% share and ~$28m cost carry by O.G. Energy
  - Guidance to be updated upon development FID
- Excludes decommissioning expenditure
  - Residual Minerva infrastructure removal may take place post FY26

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

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