East Coast Supply Project

24 March 2025

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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 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 and contingent resources contained in this presentation are at 30 June 2024. Amplitude Energy prepares its petroleum reserves 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 and is qualified in accordance with ASX Listing Rule 5.41. 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 the Board of Directors of Amplitude Energy Limited, Level 8, 70 Franklin Street, Adelaide 5000.

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Strategically-aligned partner for the East Coast Supply Project (ECSP) secured

Three-well program approved, aiming to deliver up to 90 TJ/day[1] to the domestic gas market from 2028

- O.G. Energy is a strategically-aligned and well funded partner, validating the attractiveness of ECSP
- Additional gas supply for Australian customers in the structurally short East Coast domestic market
- Potentially enough gas for >600,000 Victorian homes for >10 years from reserves and resources[1,2]
- Low-cost conventional production, with AGP unit opex around A$1/GJ at 90 TJ/day[1]
- O.G. Energy to fund 50% of project costs; AEL to fund its 50% share from cash, underlying organic cashflow and debt
- Brownfield tie-back, leveraging existing pipelines and plant, minimising environmental impact
- Opportunity to provide tolling services or peaking capacity during winter period with 150 TJ/day of installed capacity at AGP

[1] Indicative only, not guidance. This forward-looking statement is subject to the qualifications on page 2 of this presentation. | [2] Conversion of resources require development in subsequent campaign/s.

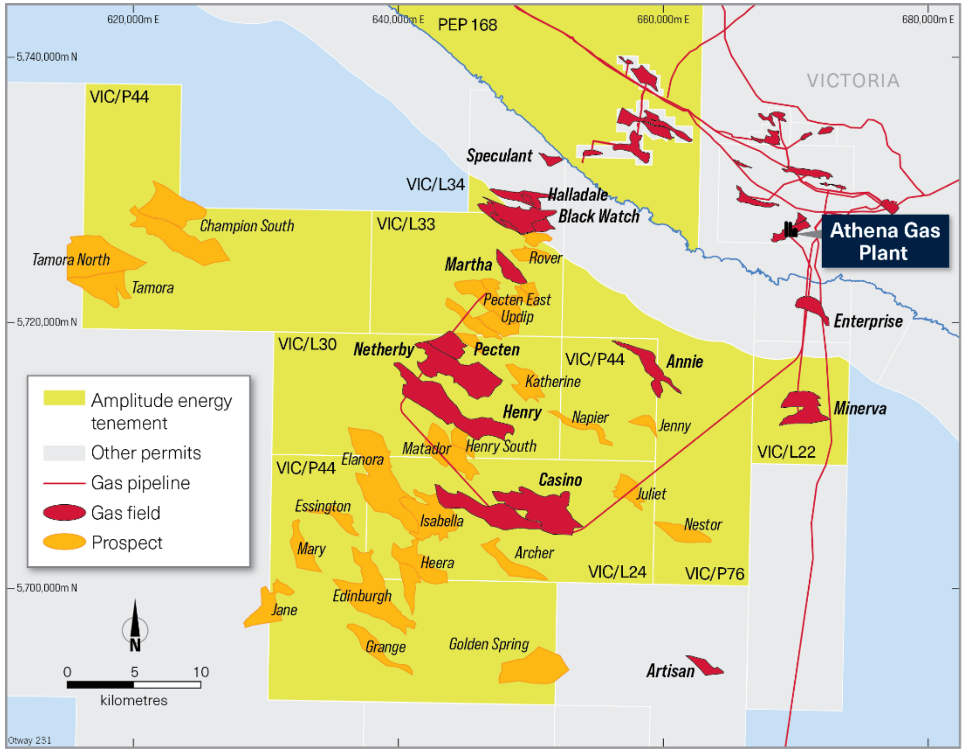
Joint venture alignment in the offshore Otway Basin

Unlocking the preferred three well brownfield development in the Otway Basin and delivering on our strategy

Summary of the Otway Basin JV agreements

Key agreements	▪ O.G. Energy to acquire Mitsui's[1] 50% Otway Basin assets, including AGP[2] ▪ O.G. Energy to acquire 50% of VIC/P44 & VIC/P76, containing Annie & Nestor ▪ AEL and O.G. Energy have entered an interim joint venture agreement (IJVA) to progress the East Coast Supply Project (ECSP) — Alignment and agreement on the preferred 3-well ECSP programme ▪ Aligning interests across the offshore Otway Basin supports further developments post ECSP, including potentially Elanora and Nestor
ECSP	▪ Boards of AEL and O.G. Energy have approved the 3-well ECSP drilling programme ▪ Upon drilling success at Isabella and Juliet, plan to proceed to immediately develop these discoveries, together with Annie
O.G. Energy funding of ECSP	▪ O.G. Energy will participate in 50% of all point-forward project costs, from signing ▪ O.G. Energy to fund Amplitude Energy ~$25mm[3] for historical ECSP costs expended
Steps to completion	▪ Customary Federal and state regulatory approvals[4]

Amplitude Energy Otway Basin interests

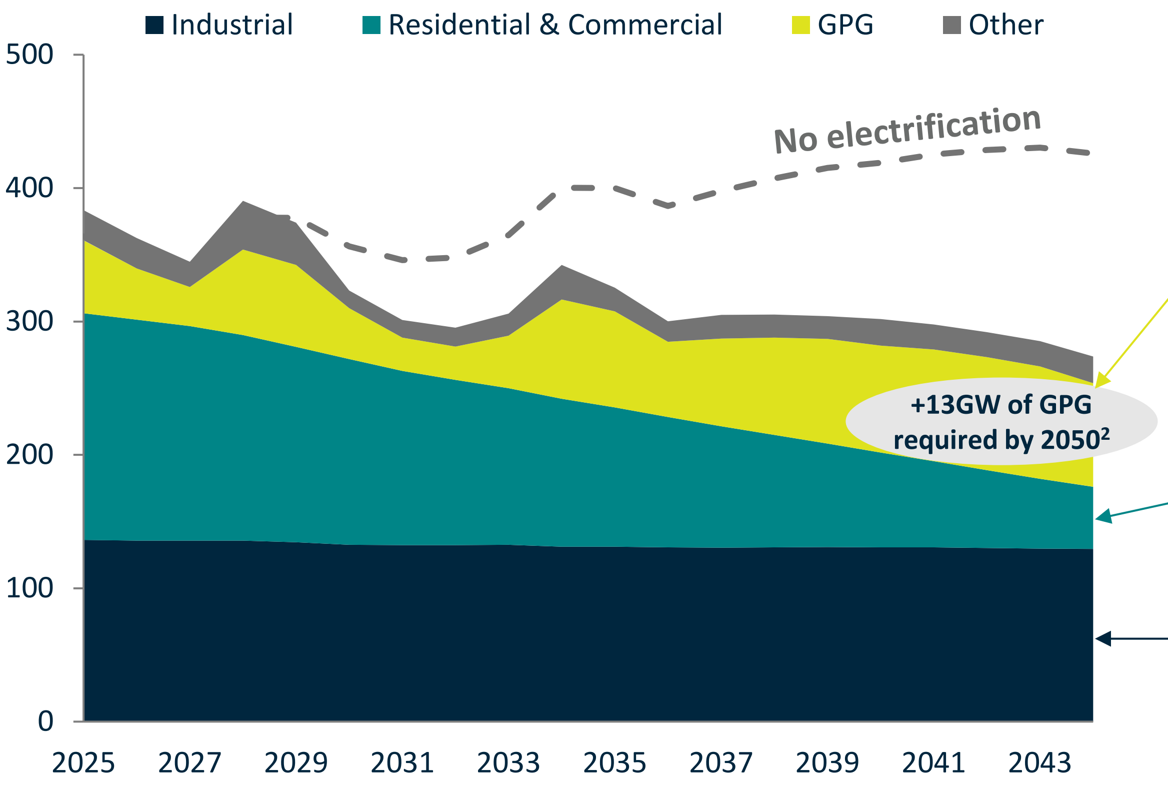


[1] Mitsui E&P Australia ("MEPAU") | [2] VIC/L24, VIC/L30, VIC/L33, VIC/L34, VIC/PL37, VIC/PL32(V), VIC/PL42, PL 251 (onshore Victoria) and PL 228 (onshore Victoria). The agreements referred to in this presentation do not relate to PEP 168 or VIC/L22 | [3] Up to 31 January 2025. Does not include separate back costs funding arrangements for VIC/P76 (Nestor), amounting to ~$0.5mm up to 31 January 2025. Payment of back costs, subject to completion of the Mitsui / O.G. Energy transaction, is in the form of a carry from completion | [4] No assurances can yet be given as to timing of completion or whether approvals will ultimately be granted. In the event that the Otway Sale Transaction does not complete, the IJVA provides for the parties to seek O.G. Energy's 50% participation in the ECSP under alternative ownership structures

AEMO forecasts robust gas demand for Southeast Australia for decades to come…

Industrial demand remains flat as it is difficult to electrify and GPG demand is expected to grow to firm more renewables

Southern States domestic demand forecast, PJ p.a.[1]



Increase in gas powered generation due to:

- increased need for firming
- coal retirements
- electrification[1]

"The NEM is forecast to need 15 GW of gas-powered generation… Of the existing 11.5 GW capacity, about 9.3 GW is forecast or announced to retire, so that capacity would be replaced and another 3.5 GW added"[2]

Residential and commercial gas consumption is assumed to decline rapidly, driven by electrification and energy efficiency.

The "no electrification" dotted line reflects gas demand if this does not occur.[1]

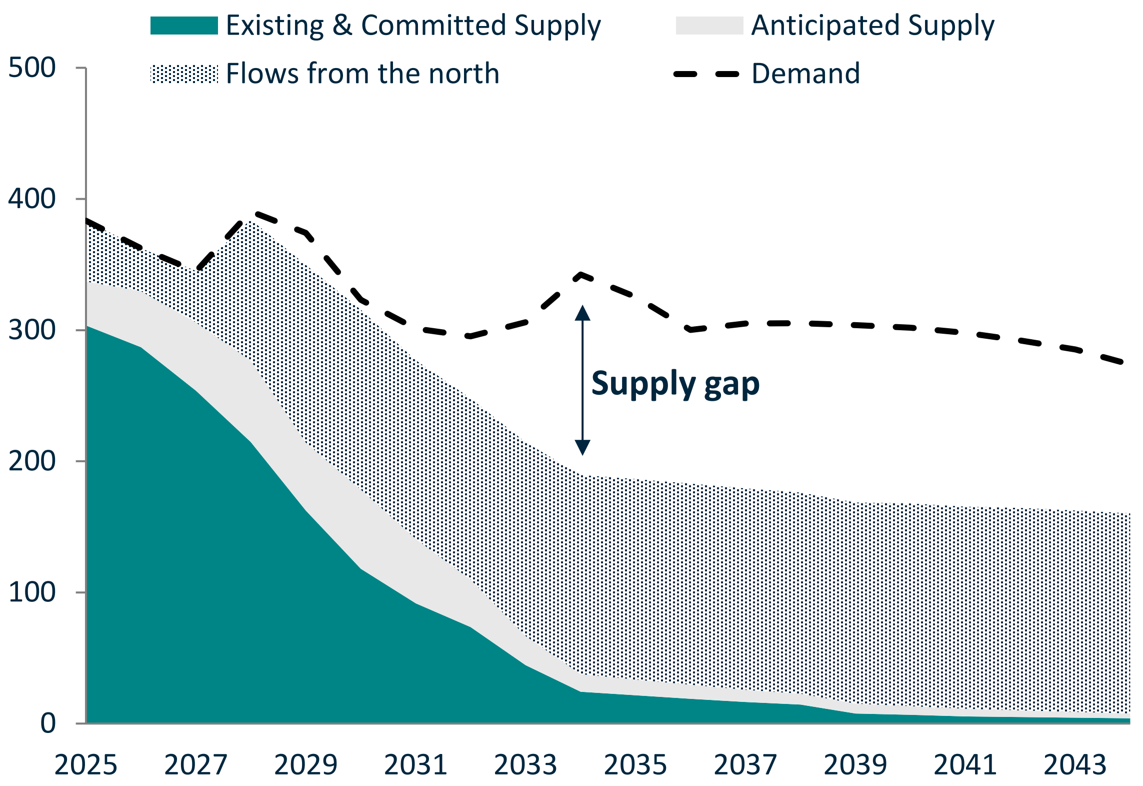
Industrial consumption (e.g., fertiliser, mineral processing, primary metal, paper and chemical producers, oil refining, large food processors, mining) use gas for high temperature heat or gas as a feedstock, which is difficult to electrify.[1]

[1] Source: AEMO 2025 Gas Statement of Opportunities, Step Change scenario, National Electricity and Gas Forecasting Portal. Southern States include Victoria, NSW, SA and Tasmania. Other includes losses and energy efficiency | [2] Source: AEMO 2024 Integrated System Plan, Step Change scenario

… leading to urgent demand for new domestic gas supply

Significant market opportunity to close the supply gap

Southern States supply forecast, PJ p.a.[1]



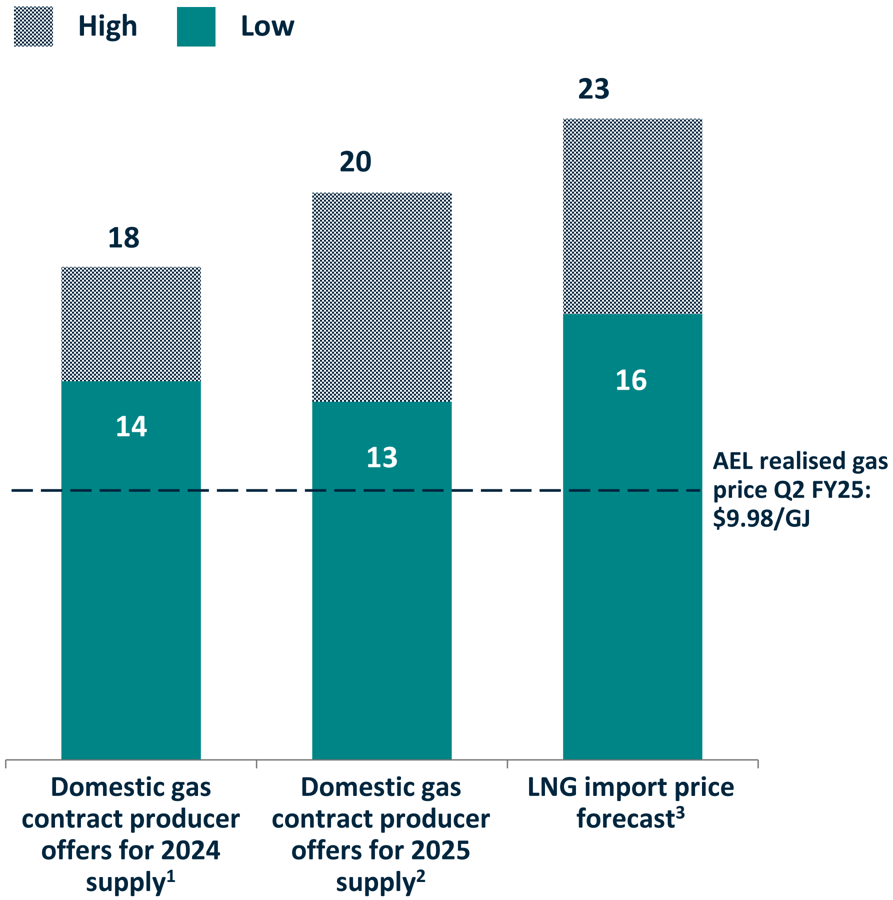
- Legacy Gippsland Basin fields, historically the largest and lowest cost source of gas supply, are depleting rapidly
- Anticipated new supply and gas flows from Queensland at maximum capacity are not sufficient to offset this decline
- ECSP and additional gas from existing basins such as the Otway and Gippsland are uniquely placed to meet the supply gap
  - ~6,500 PJs of reserve and resource across offshore Victoria[2]
  - Longer term energy security
  - Brownfield tie-backs to existing infrastructure, close to market
  - Lower transport costs
  - Lower emissions compared to LNG imports
  - Supporting local economy through jobs and economic activity in regional Australia

[1] AEMO 2025 Gas Statement of Opportunities, Step Change scenario, Figure 41 | [2] Geoscience Australia, Australia's Energy Commodity Resources 2024: Gas, 15 July 2024.

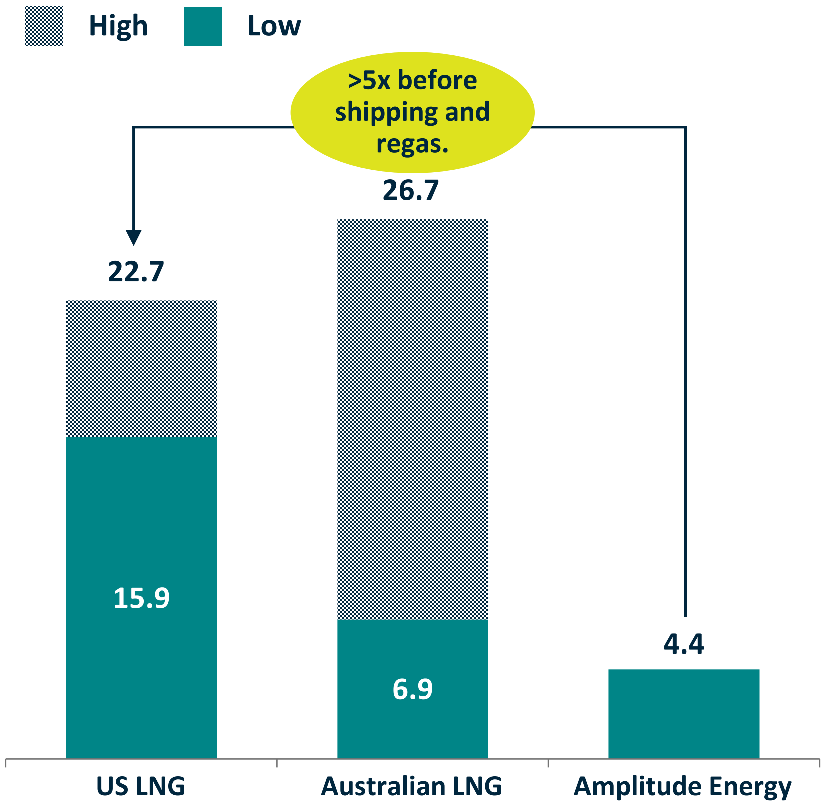
Additional domestic gas and LNG imports needed to replace declining supply

Lower cost and lower emissions domestic gas supports energy security for Australian customers and benefits the Australian economy through jobs and taxes

East Coast contracted gas prices, A$/GJ



Emissions intensity, $kgCO_2$-e/GJ[4]



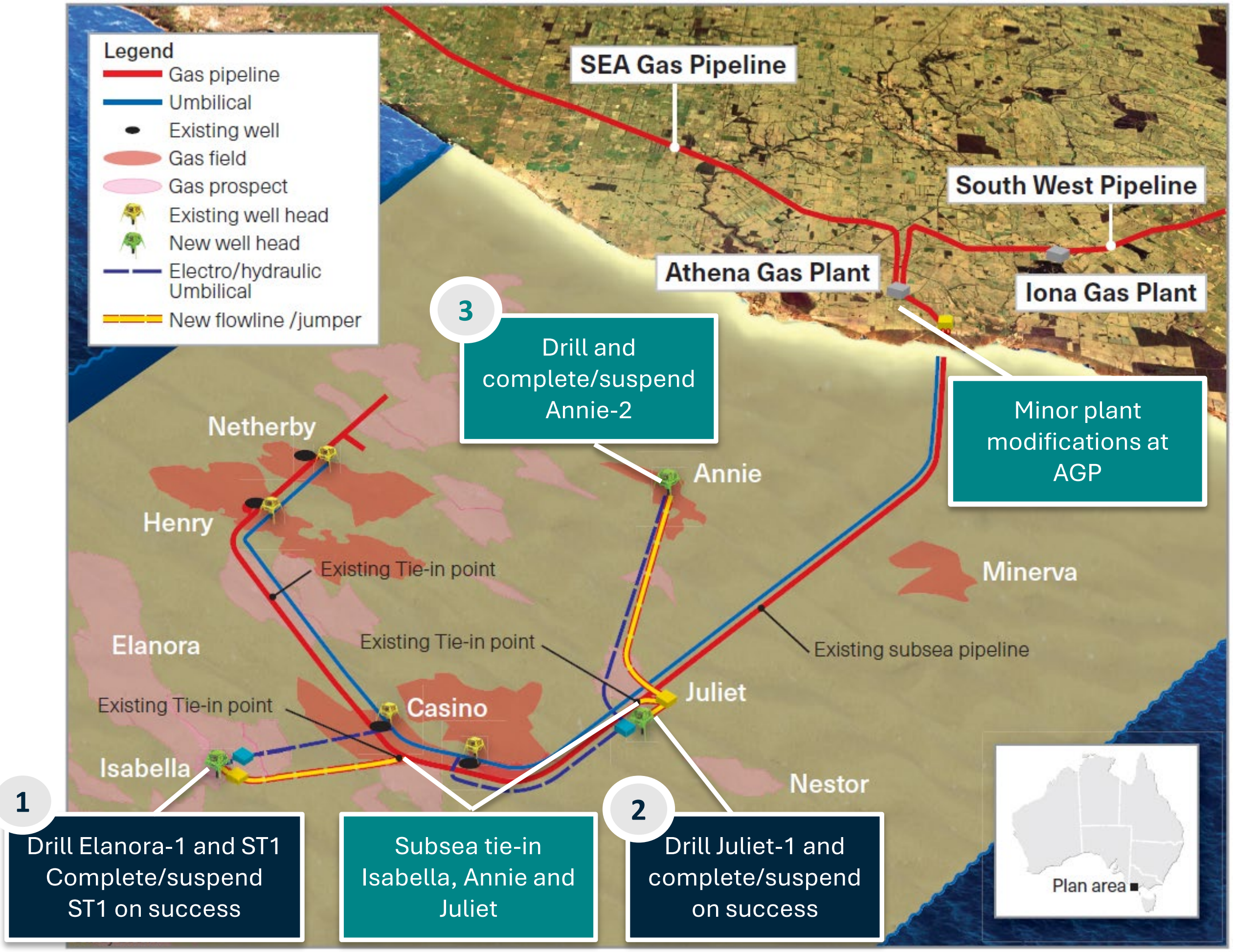
- To close the gap between Southeastern Australian gas supply and demand, additional domestic gas and LNG imports will be needed
- In addition to being lower cost and lower emissions, locally sourced domestic gas:
  - Supports long-term energy security for Australian customers
  - Benefits the Australian economy through jobs and taxes
  - In FY24, Amplitude Energy contributed over $164 million to the Victorian economy and supported over 571 jobs across the state[5]

[1]ACCC Gas Inquiry Report, December 2023, Page 87, Chart 4.8 | [2]ACCC Gas Inquiry Report, December 2024, Page 26, Chart 2.7 | [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] 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 FY24 published data for Scope 1 and 2. | [5]ACIL Allen, The economic contribution of Amplitude Energy, November 2024, refer to our website https://amplitudeenergy.com.au/news/investing-in-local-economies-how-amplitude-energy-is-supporting-victorias-future.

Brownfield project unlocking value of existing infrastructure

World class exploration success rates in the Offshore Otway Basin delivering on our strategy into the next decade

Otway Basin



Low-risk 3-well exploration & development program

- Prioritising backfill for the Athena Gas Plant of up to ~90 TJ/day gross production, with first gas targeted in CY2028
- Targeting 2P + 2C equivalent to >10 years reliable production at Athena[1]
- First exploration well at Elanora, with sidetrack to Isabella, second exploration well at Juliet
  - Targeting 358 Bcf[2] (179 Bcf net to AEL) of gross mean unrisked prospective resource across Elanora, Isabella and Juliet
  - 98% probability of gas discovery
- Third well at Annie-2, intending to develop 65 PJ[3] gross 2C (32.4 PJ net to AEL)
- First rig slot on track for late CY2025, with second & third wells to be drilled in CY2026
- Attractive project economics upon successful development
  - Project comfortably exceeds internal investment hurdle rates[4]
- Strong interest from gas customers in long-term GSAs

Indicative only, not guidance. This forward-looking statement is subject to the qualifications on page 2 of this presentation. | [1] Conversion of resources require development in subsequent campaign/s. | [2] 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 and are shown on page 31 of this presentation. | [3] Annie 2C resource on net AEL share is 32.4 PJ and is included on a gross basis as part of the Otway Basin 2C number in the FY23 Reserves and Contingent Resources ASX release on the 25 August 2023. 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. | [4] Based on AEL internal mid-case assumptions

ECSP drilling and development is phased over 2025—2028

The ECSP will be executed in two phases, with well completion conducted in the first phase, maximising cost efficiency

Phase 1

Phase 1 estimate A$240-270mm[1]

Phase 2

Phase 2 preliminary cost indication A$140-185mm[2]

(three well success case)

Upon exploration success

Upon Phase 2 FID

Elanora/Isabella, Juliet and Annie well drilling

Well completion, subsea tree installation & other rig costs

Subsea development and plant modification

Funding sources

Existing cash, underlying organic cashflow and RBL debt availability

Additional potential debt finance becomes available, post drilling and once FID taken

2025 2026 2027 2028

All figures presented on a point-forward, net to Amplitude Energy (50%) basis. Figures are in 2025 dollar terms. Indicative only, not guidance. These forward-looking statements are subject to the qualifications on page 2 of this presentation.
[1] Assumes commercial success in each well exploration well. This cost estimate range includes reasonable time allowances and project contingencies, however is subject to various execution risks, including variables outside of Amplitude Energy's control. | [2] This range includes reasonable time allowances as well as scope for cost escalation and other contingencies, however is subject to contractor pricing and various execution risks, including variables outside of Amplitude Energy's control.

With exploration success, ECSP is transformational for Amplitude Energy

From 2028, ECSP has the potential to:

- Increase Group production to >100 TJ/d
- Double Group revenue from FY24 levels
- Grow Group earnings ~3x from FY24 levels
- Increase Group reserves & resources by more than 60%
- Extend the life of the Athena Gas Plant by over a decade[1]
- Provide significant margin expansion and value accretion to AEL's portfolio

Indicative only, not guidance. This forward-looking statement is subject to the qualifications on page 2 of this presentation. | [1] Conversion of resources require development in subsequent campaign/s.

#1

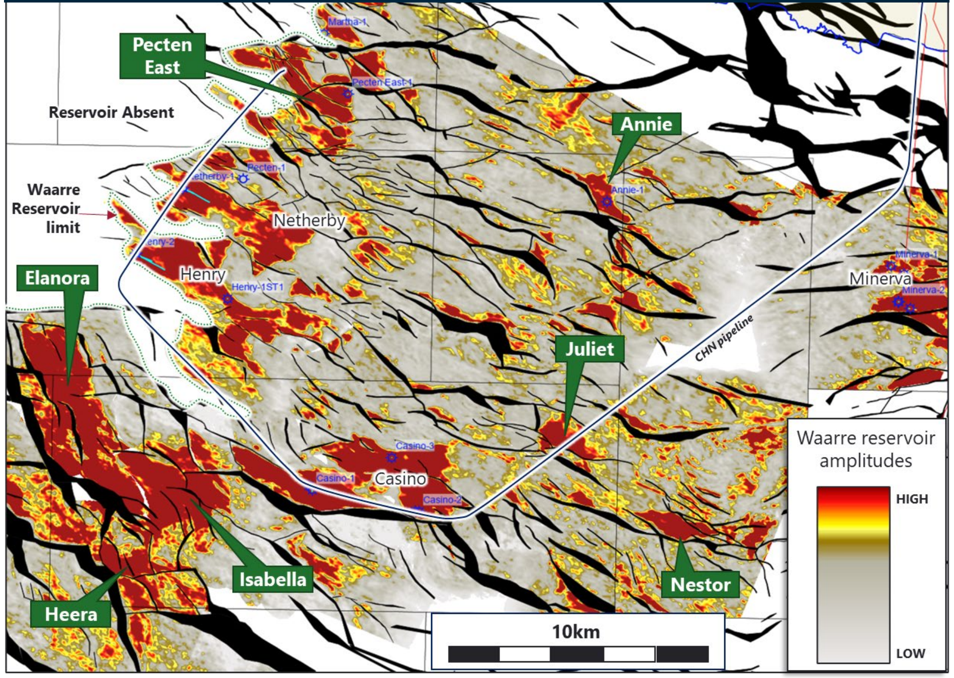
ECSP subsurface review

Exploration success rates in the Offshore Otway Basin are world class

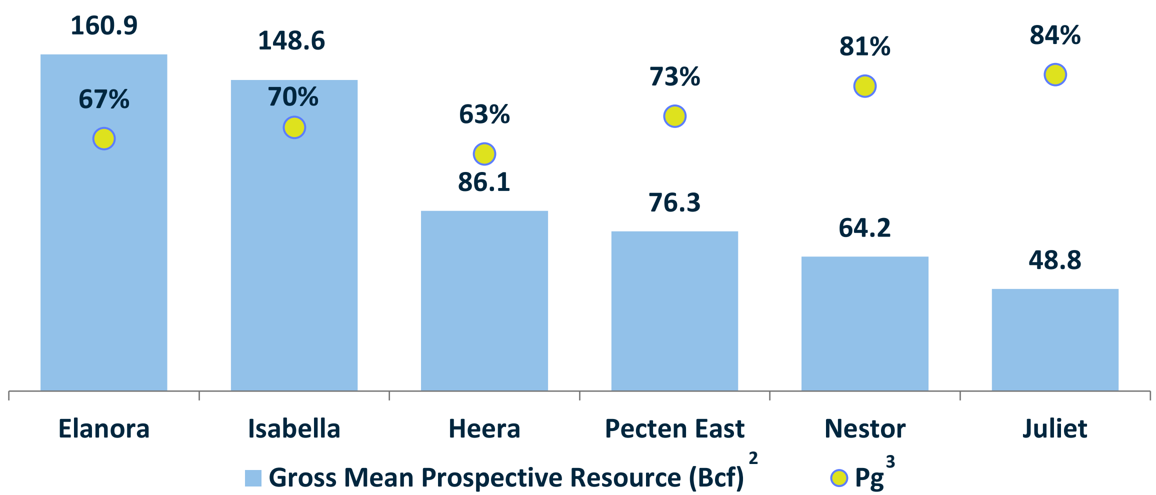
94% success rate for seismic amplitude supported prospects

- ECSP prospects identified using modern seismic interpretation techniques on the same 3D dataset as the CHN fields
- Gas properties expected to be similar to CHN analogues
- ECSP prospects are within existing production licences and are akin to low-risk field-extension drilling projects

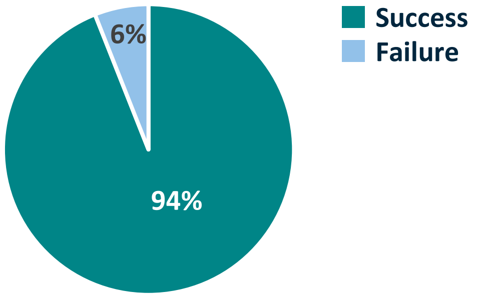
Waarre Formation seismic amplitude map - AEL Offshore Otway fields



Otway Basin, top Waarre Formation prospective resource highlights[1]



All seismic amplitude-supported targets drilled, Offshore Otway Basin

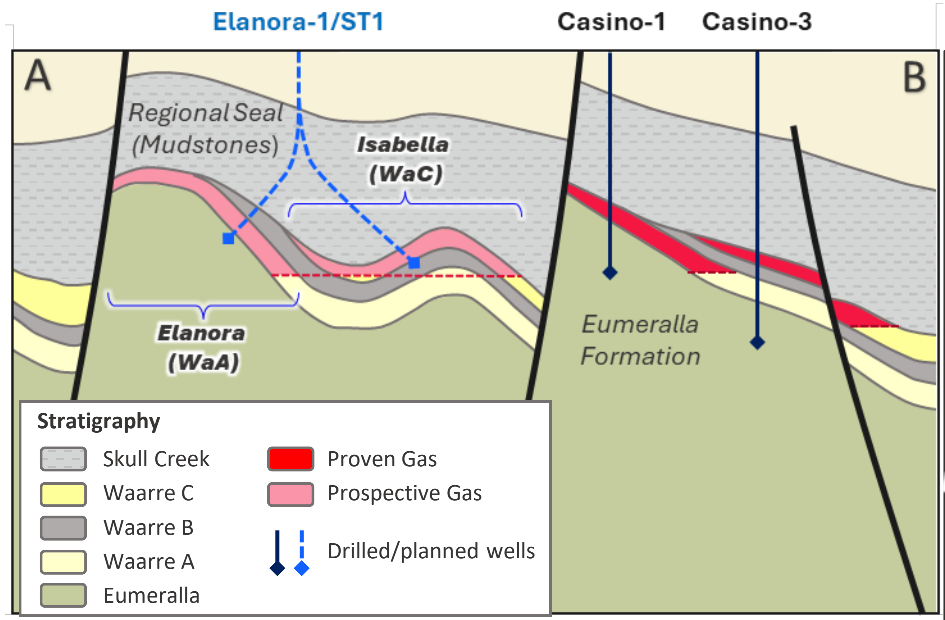


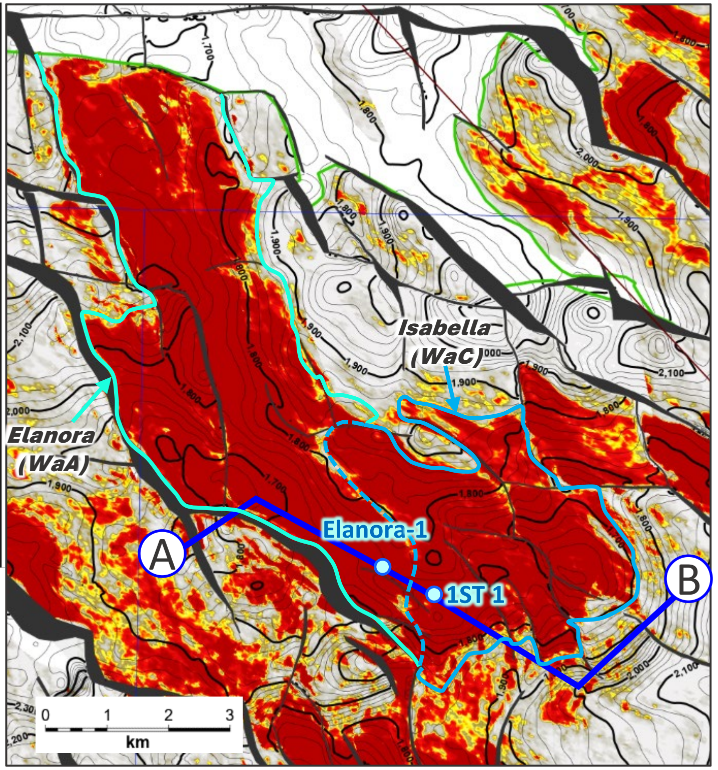
16 successful of 17 wells drilled[4]

[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. Refer also to page 31 | [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] Pg is chance (or probability) of encountering a measurable volume of mobile hydrocarbons. | [4] Incorporates exploration wells drilled in Offshore Otway Basin by Amplitude Energy and other operators.

Elanora/Isabella: largest potential resource booking

Targeting >300 Bcf gross mean unrisked prospective resource with 90% chance of discovering gas





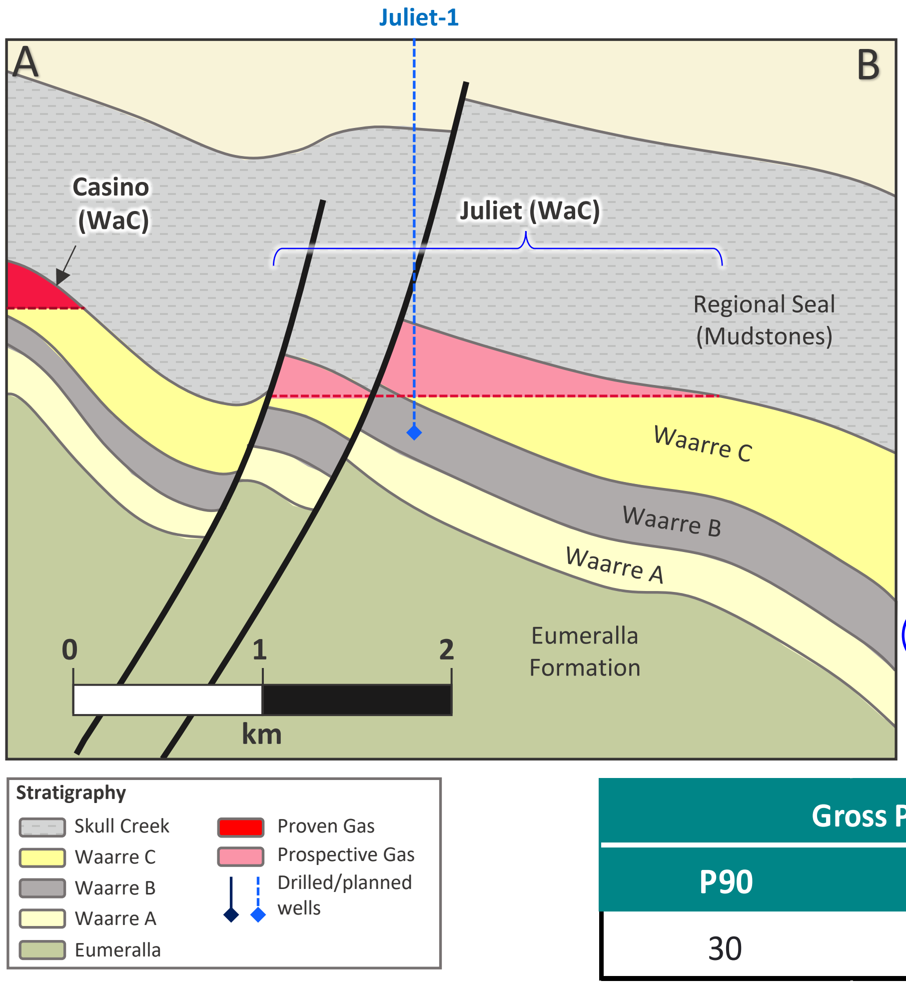
Gross Prospective Resource Summary (Bcf)[1]				
	P90	P50	Mean	P10
Elanora	56	131	161	307
Isabella	56	124	149	276

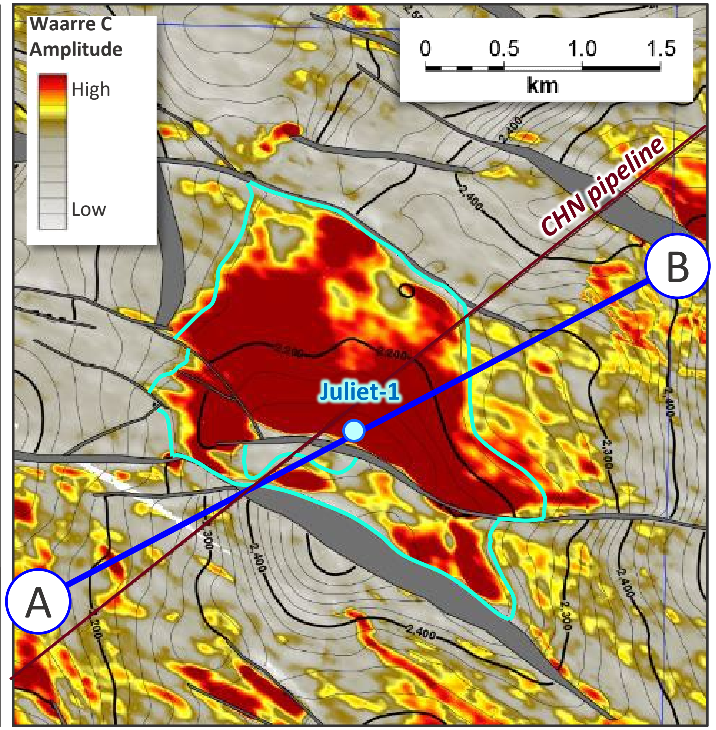
- Twin exploration well to test Waarre Formation reservoir targets at Elanora and Isabella prospects from a single surface location
- Both prospects are large, amplitude supported targets within base regional seal closure
  - Combined 90%[2] chance of discovering gas
- Intended well location is ~6km from an existing tie-in point in the CHN pipeline
- Elanora to be developed in a subsequent campaign upon exploration success, further extending the life of AEL's Offshore Otway Basin assets

[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 and are shown on page 31 of this presentation | Indicative only, not guidance. This forward-looking statement is subject to the qualifications on page 2 of this presentation. 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. [2] 90% chance of finding gas in at least one of Isabella or Elanora is based on individual chances of success of 70% and 67% respectively.

Juliet: low risk, directly under existing pipeline

49 Bcf gross mean unrisked prospective resource with an 84% chance of discovering gas





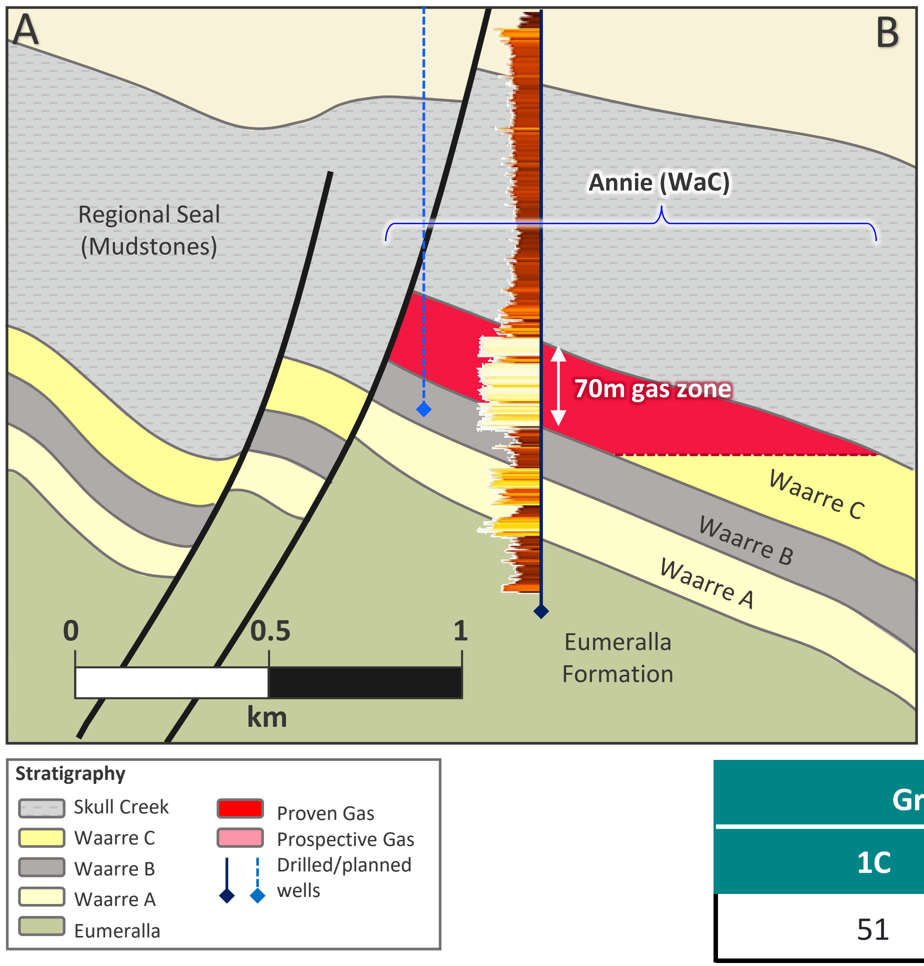
- 4km east of Casino gas field in ~63 metres water depth
- Located directly under the CHN pipeline and an existing tie-in point
- Strong Waarre C seismic amplitude response, directly analogous to Casino field
  - Pg = 84%
- Excellent reservoir quality proven in all offset wells

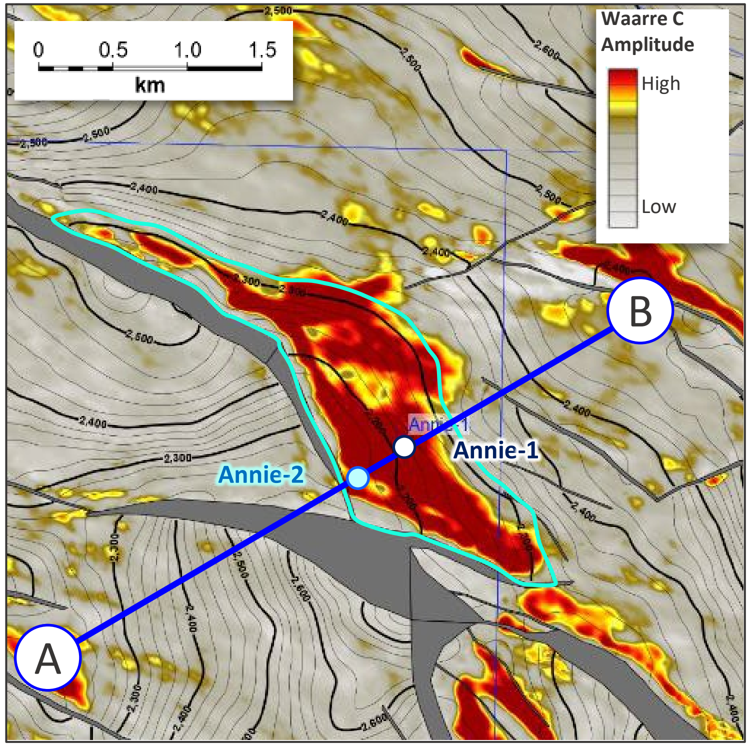
Gross Prospective Resource Summary (Bcf)[1]			
P90	P50	Mean	P10
30	46	49	71

[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 and are shown on page 31 of this presentation | Indicative only, not guidance. This forward-looking statement is subject to the qualifications on page 2 of this presentation. 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

Annie: 2019 discovered resource

65 PJ gross 2C discovered gas resource, 10 km from existing pipeline tie-in point





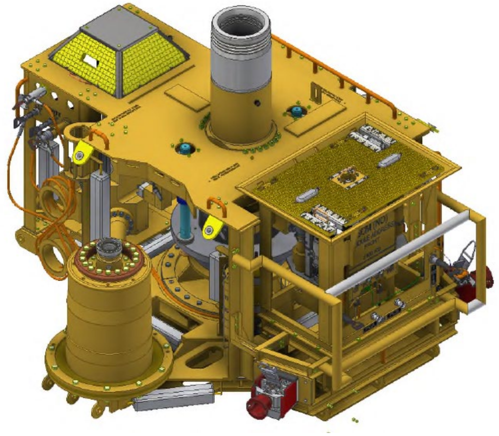
- Annie-1 (2019) discovered a 70 metre thick, high-quality gas-bearing Waarre C reservoir
- Seismic amplitudes define the extent of the gas pool with high confidence
- To be developed by a single, vertical well at the crest of the structure
- CO_2 levels in Annie reservoir expected to be blended down with other ECSP fields

Gross Contingent Resource Summary (PJ)[1]		
1C	2C	3C
51	65	77

[1] Annie 2C resource on AEL's 50% net share is 32.4 PJ and is included on a gross basis as part of the Otway Basin 2C number in the FY23 Reserves and Contingent Resources ASX release on the 25 August 2023 | Indicative only, not guidance. Projects are preliminary in nature and not yet sanctioned. This forward-looking statement is subject to the qualifications on page 2 of this presentation. 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

#2
ECSP execution

ECSP execution planning well progressed



Rig contracted as part of the Otway Basin consortium to reduce risk and costs

- Transocean Equinox semi-submersible rig expected to arrive in the Otway in coming weeks
- Specialist shallow-mid water depth rig, capable of managing harsh weather conditions
- Strong rig performance over the last 12 months
- Mobilisation/de-mobilisation costs for rig spread over consortium members

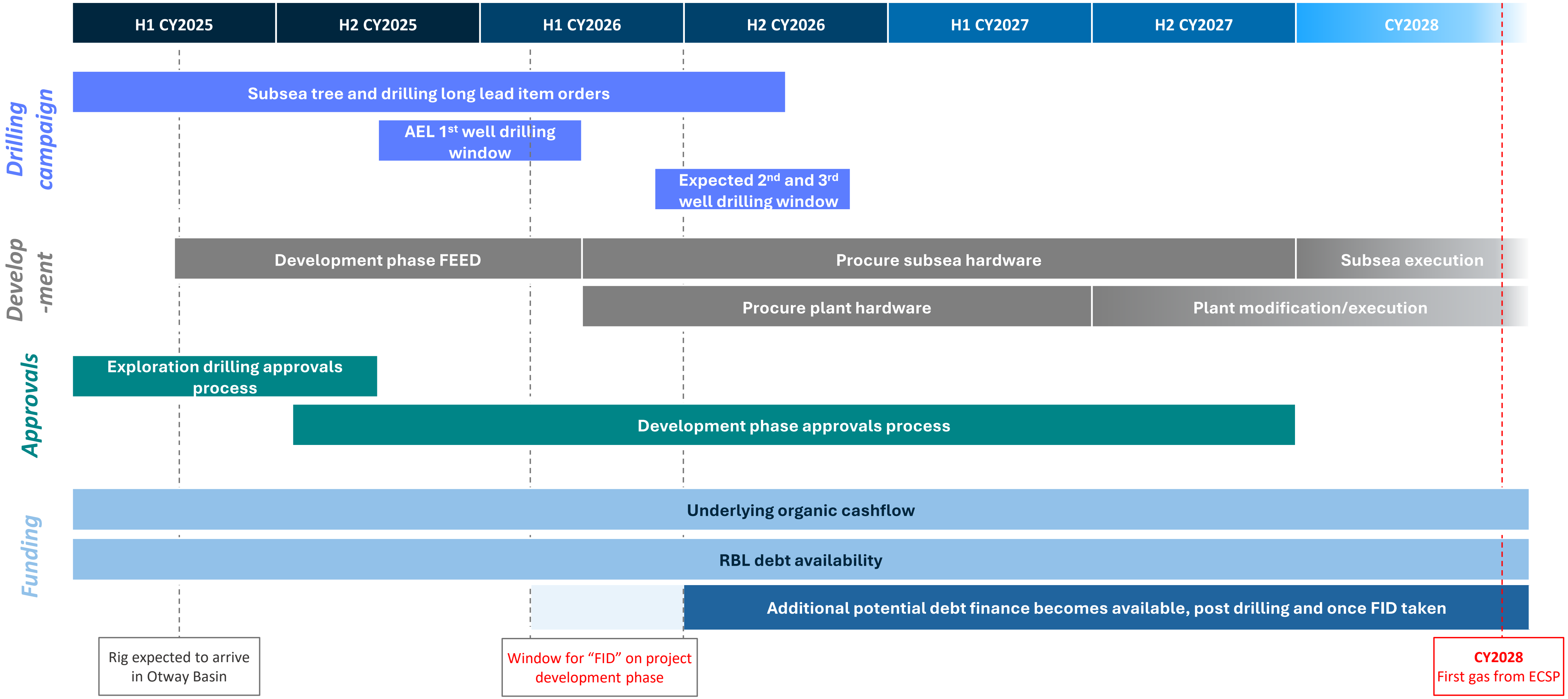
Vast majority of drilling costs and rates now known or contracted

- Budget includes allowance for weather and non-productive time based on historical performance in the Otway
- Intend to case, complete with a subsea tree, and suspend both Isabella and Juliet on success (plug & abandon in case of failure)
- Annie development well to be cased and completed with a subsea tree immediately post drilling
- Key long-lead regulatory approvals to enable exploration drilling have been submitted

Engineering and approvals for ECSP development phase underway

- Plan to utilise existing pipeline tie-in points.
- Minor AGP plant modifications required
- Seeking to coordinate development programme with other operators in the area to optimise efficiency and cost
- Development phase contracts to be informed by drilling results. Tendering in Q3 CY2025
- Approvals and licencing progressing in accordance with project plan

ECSP timeline aims to achieve rapid commercialisation and optimise economics

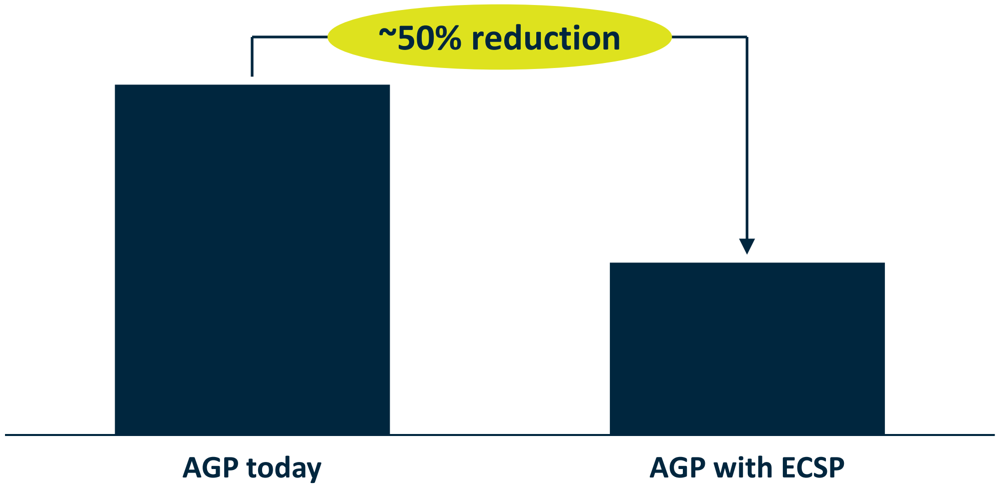


ECSP will reduce Athena emissions

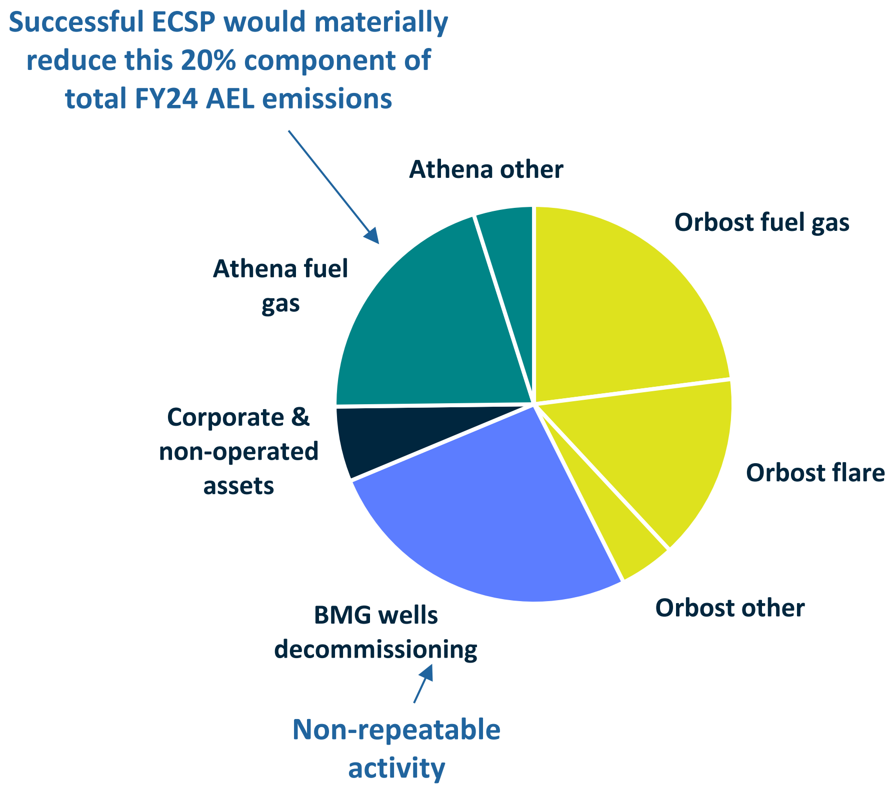
ECSP will increase production and reduce Athena Gas Plant Scope 1 emissions, significantly lowering emissions intensity

- Current Athena emissions ~60kt CO_2-e per annum, 100% gross
  - Scope 1 + Scope 2 well below Safeguard Mechanism threshold of 100kt CO_2e
- ECSP allows reduction in fuel gas use for compression, and associated emissions, due to high reservoir pressure of new ECSP fields
- Negotiating power purchase agreement for behind-the-meter solar PV to reduce Athena Scope 2 emissions

AGP emissions[1], kt CO_2-e, gross Scope 1 + 2



Breakdown of FY24 net organisational emissions[2]



[1] AGP forecast excludes any ECSP project and construction-related emissions but is based on current assumptions regarding ECSP production and AGP operation, which will continue to be refined as field development plans are matured
[2] Organisational emissions comprise Scope 1, Scope 2 and relevant Scope 3 emissions (embedded energy and business travel) on an equity share basis. For FY24 net organisational emissions totalled 124.5kt CO_2-e

#3
ECSP commercialisation & funding

ECSP gas commercialisation

ECSP gas is expected to be highly valued given its proximal location to major demand centres (VIC & SA) and Iona gas storage

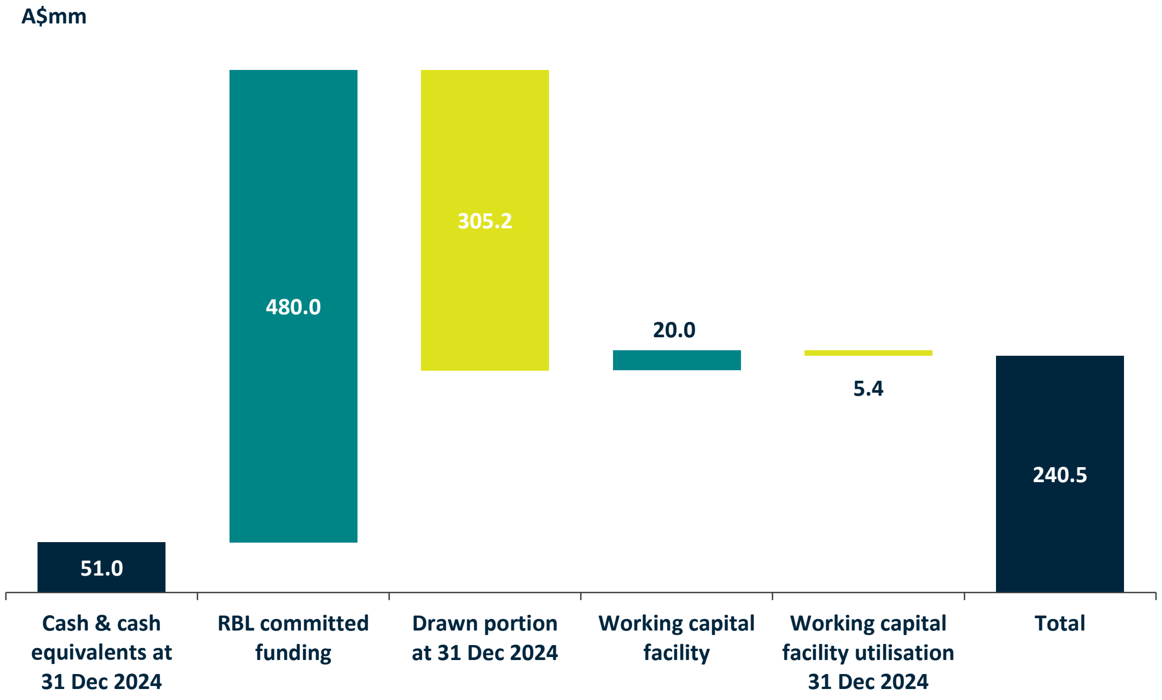
Contract volumes	▪ De-risk investment and optimise cost of funding ▪ Contracting ~70% of ECSP production under foundation GSAs of ~4–6 year duration
GSA counterparts	▪ Strong interest in foundation GSAs from creditworthy blue-chip customers — Long-term supply, backed by conventional reserves — Strategically located supply, close to Iona gas storage and short Victorian and South Australian markets — Low emissions-intensity gas
Pricing	▪ Pricing moving towards LNG import parity ▪ Attractive backdrop for gas pricing discussions
Uncontracted gas volumes	▪ Balance of gas likely to be marketed on a short-term or spot basis — Maintain upside exposure to prevailing spot prices and value optimisation opportunities (e.g., winter peaking capacity)

Significant committed undrawn funding under the existing RBL

Amplitude Energy's reserves based loan (RBL) facility provides financial flexibility and liquidity

- Reserves based loan (RBL) increased & extended in Dec 2024
  - Facility limit increased to $480mm; committed and available
    - Current borrowing base above this level
  - Maturity extended to Sep 2029
  - Strong lending group
  - $20mm working capital facility
- Drawn to $305.2mm, with cash on balance sheet of $51.0mm at Dec 2024; net debt $254.2mm
- Facility limit reduces according to a pre-agreed schedule, from $480mm in Sep 2026 to $216mm at maturity
  - Sculpted to reflect existing 2P borrowing base/expected cash flows
- Opportunity to reshape facility limit reduction schedule once ECSP gas discoveries enter development

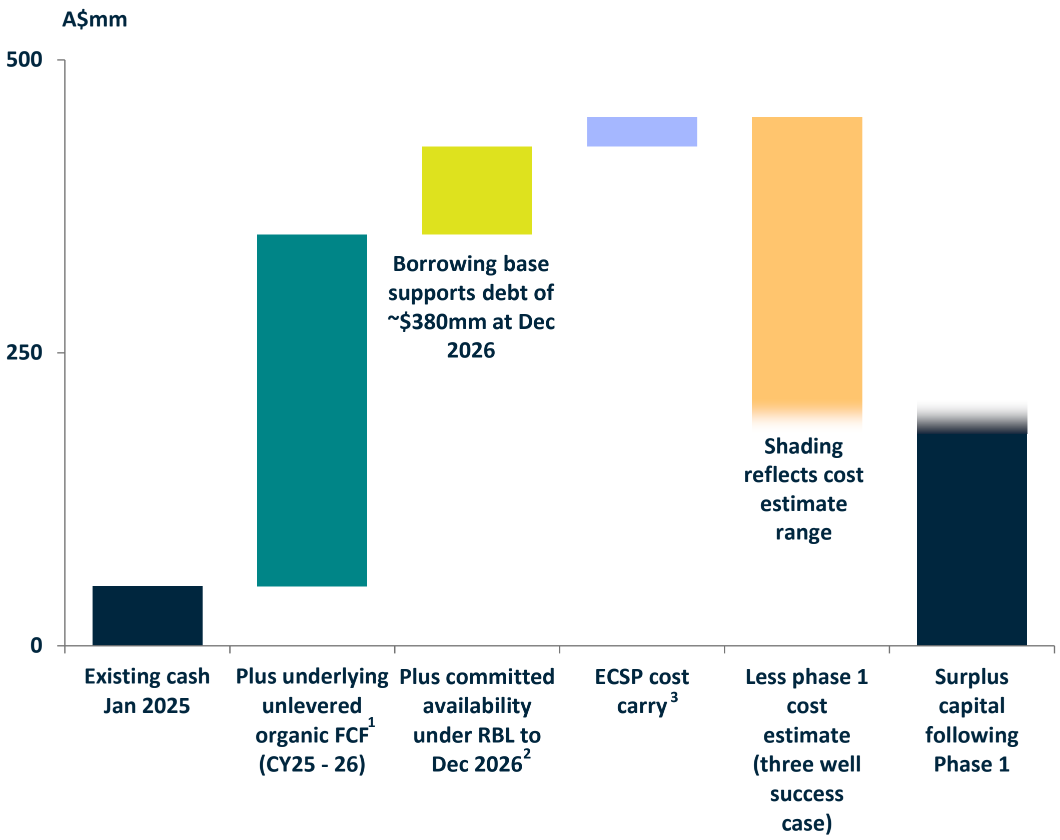
Liquidity overview



Indicative sources & uses of ECSP funding

Existing funding sources are sufficient to fund the preliminary indicative cost estimate of the ECSP three well success case

Phase 1 sources & uses



Phase 2 funding sources

Surplus capital following Phase 1

Underlying unlevered organic FCF (CY27 - H1 CY28): ~$150mm p.a.[1]

Potential for reshaped & amended RBL facility upon subsea development FID of ECSP volumes

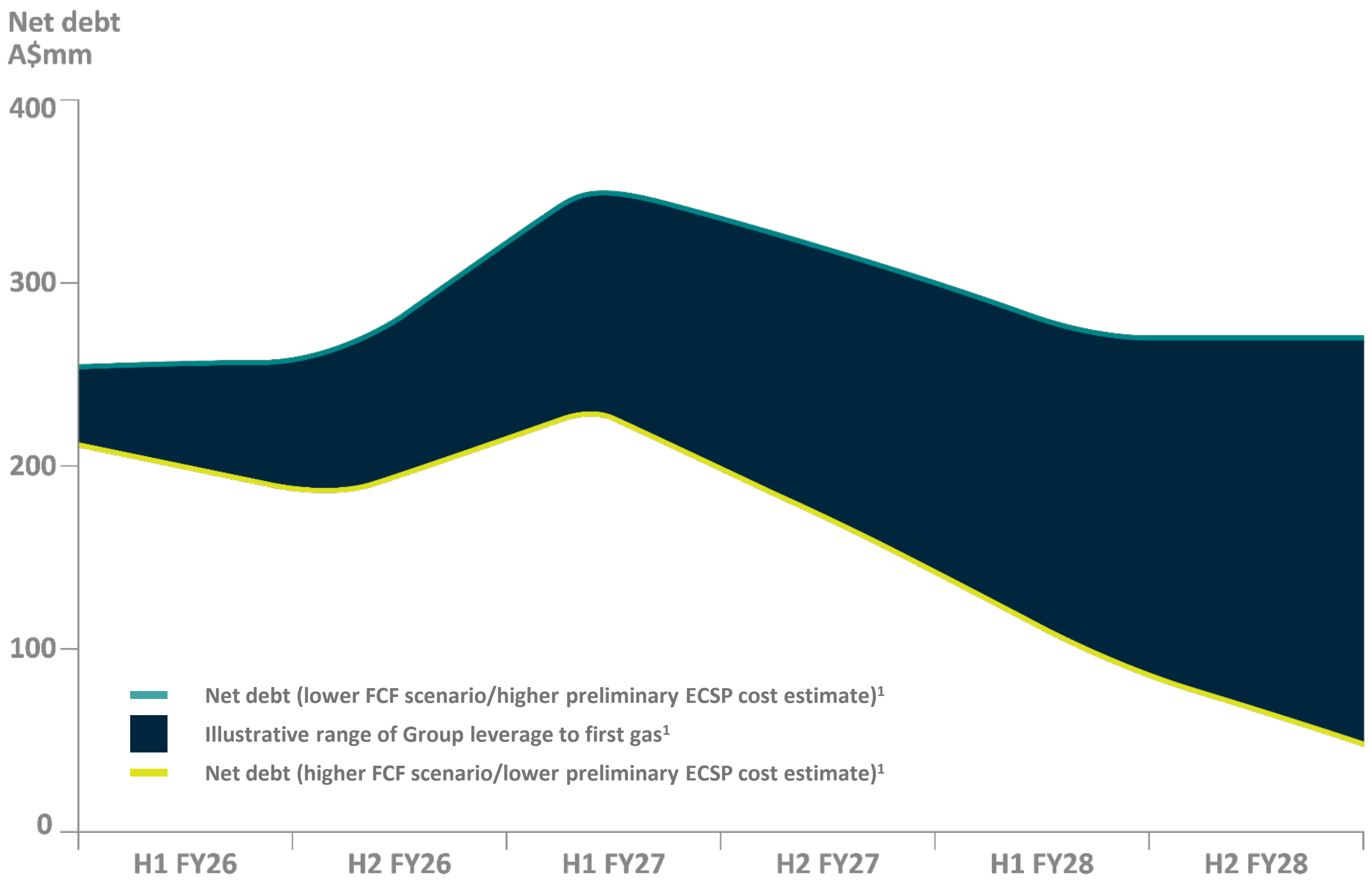
Additional potential debt finance

- Expected underlying organic FCF is greater than the indicative cost estimate of each ECSP phase
- Opportunity to reshape RBL once ECSP gas discoveries enter development
- Third pool of debt capital remains under consideration for phase 2
  - Potential to further reduce blended cost of ECSP funding
- Options include
  - Customer financing
  - Other forms of vanilla debt capital

Note: excludes restoration spend and other non-recurring and non-underlying items. AEL will seek RBL lender consent for additional forms of debt, such as ECSP customer financing or other forms of debt finance.
[1] Refer page 30 for basis of underlying organic FCF assumption | [2] Assumes no change to gross drawn debt of $305mm as at 31 Dec 2025 | [3] Financial impact of the O.G. Energy refund of ECSP back costs. Payment of back costs, subject to completion of the Otway Sale Transaction, is in the form of a carry from closing. No assurances can yet be given as to timing of completion, or whether approvals will ultimately be granted. In the event that the Otway Sale Transaction does not complete, the IJVA provides for the parties to seek O.G. Energy's 50% participation in the ECSP under alternative ownership structures.

Illustrative Group leverage trajectory to first gas (indicative only, not guidance)

Based on preliminary indicative ECSP cost estimates (three well success case) & illustrative underlying organic FCF generation



- Indicative only and does not constitute net debt guidance or free cashflow guidance
- Assumes three well success case
- Range of illustrative net debt outcomes
  - Includes impact of ECSP spend based on phase 1 cost estimate range and phase 2 preliminary cost indication range
  - Range of free cashflow generation
    - Lower scenario: average Orbost processing rates of 59.3 and spot gas prices of $12-19/GJ (non-peak/peak)
    - Higher scenario: average Orbost processing rates of 64.5 and spot gas prices of $13-21/GJ (non-peak/peak)
- Illustrative peak net debt around H1 FY27

[1] Illustrative range of Group leverage to first gas includes a low free cashflow (FCF) scenario that assumes average Orbost rates of ~59.3 TJ/d and a high FCF scenario assuming average Orbost rates of ~ 64.5 TJ/d (both average realised rates, after annual shutdown and assumed planned and unplanned downtime). Low FCF scenario assumed spot gas price assumption for FY26 is $12-19/GJ (non-peak/peak), high FCF scenario assumes A$13-21/GJ (non-peak/peak). High end of net debt shaded range reflects low FCF and high end of phase 1 drilling cost estimate and phase 2 preliminary cost indication. Low end of net debt shaded range reflects high FCF scenario together with the low end of phase 1 drilling cost estimate and phase 2 preliminary cost indication. This forward-looking statement is subject to the qualifications on page 2 of this presentation and does not represent net debt guidance (or cashflow guidance). AEL believes these assumptions are reasonable. However, these assumptions are subject to change due to various factors and may cause actual results to differ from those presented in the indicative trajectory above. Except as required by applicable law or the ASX Listing Rules, AEL may not update any assumptions, whether because of new information or future events.

#4
ECSP next steps

Plans in place to manage and mitigate key elements of ECSP project risk

Vast majority of drilling contracts locked in	Risk mitigation through rig consortium	FX hedging
Appropriate risk controls in contracting terms	Detailed engineering	Allowances for weather, non-productive time based on historical performance
Vendor management	Regulatory approvals	Project contingency

ECSP is the next step in unlocking value embedded in Amplitude Energy

On exploration success, this project could deliver >10 years of reliable production from 2P reserves and 2C resources[1] in the Otway

Value proposition

- Targeting >350 Bcf in gross mean unrisked resources[2]
- High margin conventional production
- Significantly value accretive; project comfortably exceeds internal investment hurdle rates[3]
- Further running room in the Otway Basin in a subsequent campaign/s

Strategic rationale

- Structurally short domestic market, prices moving to LNG import parity
- Existing Otway production in decline; 150 TJ/day installed capacity largely unused
- Brownfield development which extends asset life and defers restoration

Funding capacity

- Existing funding sources sufficient to cover the current estimated cost of both phases of the ECSP
- Additional funding options under consideration to ensure lowest cost of capital

Indicative only, not guidance. This forward-looking statement is subject to the qualifications on page 2 of this presentation. 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. [1] Conversion of resources require development in subsequent campaign/s. | [2] 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 and are shown on page 31 of this presentation. | [3] Based on AEL internal mid-case assumptions

#4

Appendix

About O.G. Energy

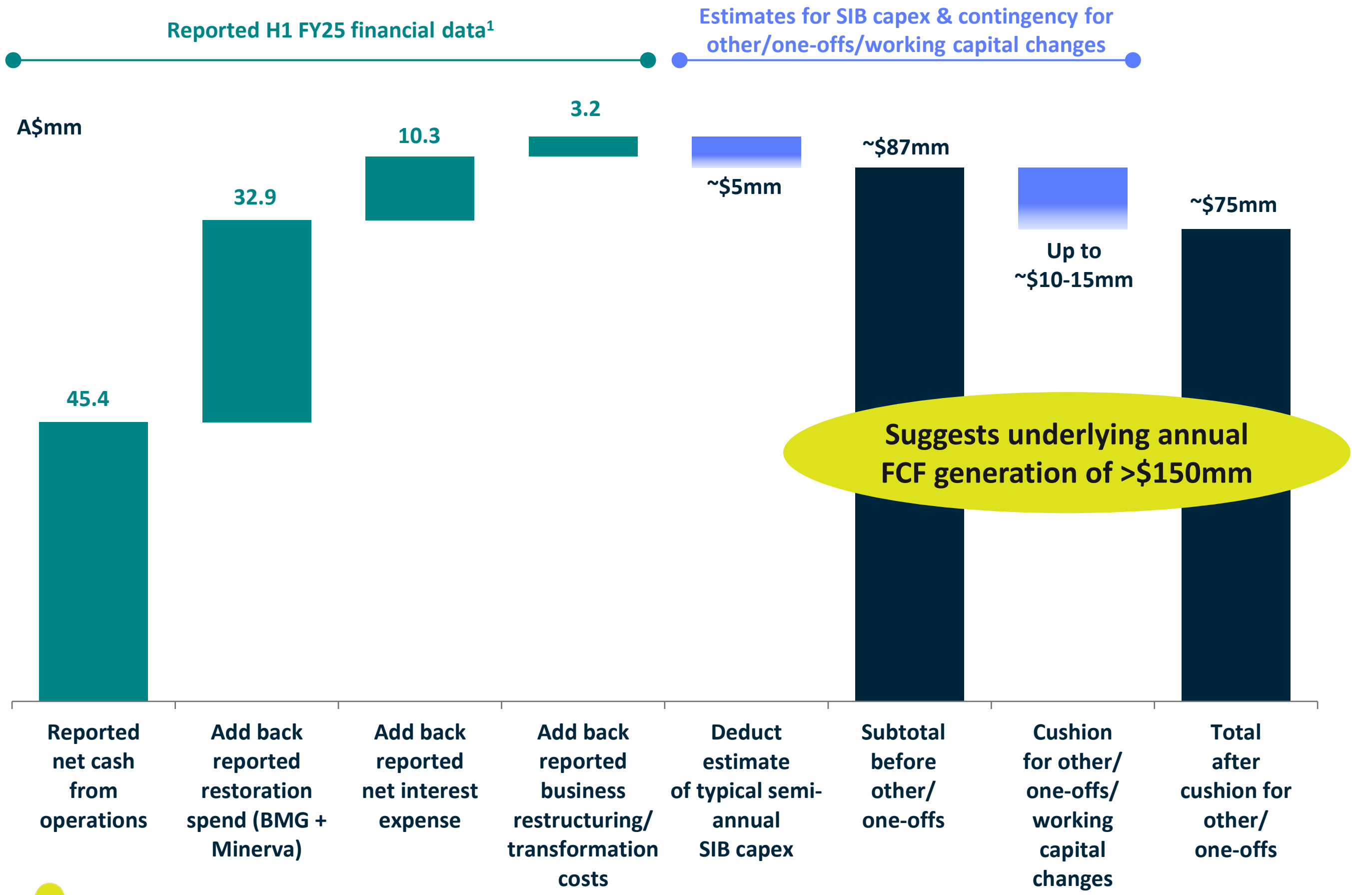
O.G. Energy is the oil & gas arm of Ofer Global

- **Deep experience in the Otway Basin:** 40% non-operating partner with Beach Energy in its offshore Otway Basin interests, where that JV has drilled nine new wells since O.G. Energy joined the project in 2019, the largest ever drilling campaign in the Otway Basin, which included 2 successful exploration wells
- **Committed to the future of the Otway Basin:** In addition to ECSP, O.G. Energy will participate in additional wells in its separate Otway Basin campaign, demonstrating its commitment to bringing needed Otway gas supply to the East Coast domestic market
- **Global Deep-Water Experience:** In addition to its Otway Basin experience, O.G. Energy has non-operated interests in five fields in the deep-water U.S. Gulf of Mexico where it partners with companies like Occidental Petroleum, Repsol and LLOG Exploration Co.
- **Gas in Australian and New Zealand:** 72% owner of ASX-listed / NZ headquartered Echelon Resources (formerly known as New Zealand Oil & Gas), whose portfolio is gas-focused, including interests in multiple onshore gas fields in the Northern Territory and the offshore Kupe gas field in New Zealand

AEL is now generating strong underlying organic free cashflow

H1 FY25 financial results demonstrate an ability to generate ~A$150mm of underlying organic free cashflow on an annualised basis

What does Amplitude Energy's H1 FY25 underlying unlevered free cashflow (FCF) generation suggest for annual FCF generation?



- Indicative only, and not guidance
- Select expected items for H2 FY25
  - Higher Orbost rates prior to planned shutdown
  - Impact of planned shutdowns on production & costs
  - Potential for higher spot pricing in May & June
- Potential for further margin expansion into FY26 & FY27
  - Improving average gas price realisations, and ongoing work to reduce cost base/efficiency improvements
- CHN in decline
- Cushion for up to ~$10-15mm per half for other/one-offs
- Known one-off items in the near to medium term
  - General visual inspections for Otway & Gippsland offshore pipelines[2]
  - CHN umbilical maintenance[2]
  - Further PEL92 drilling
  - Minerva

[1] Reported net cash from operations, restoration spend, and net interest expense are sourced directly from the H1 FY25 Consolidated Statement of Cash Flows (p.17 of AEL's half-year financial report). The add back of business restructuring/ transformation costs is sourced directly from the reconciliation to underlying EBITDAX (page 11 of AEL's half-year financial report) | [2] See full year FY25 guidance, page 21 of 27 August 2024 investor presentation

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]	
Elanora	VIC/L24	50	56.1	28.1	131.5	65.8	160.9	80.5	307.0	153.5	67%
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]			**264.9**	**151.9**	**510.9**	**285.9**	**584.9**	**324.6**	**1,011.0**	**552.7**	

[1] 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 | [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 | [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. Arithmetic addition of independent probabilistic resource estimates will underestimate the Low estimate and overestimate the High estimate