Santos

Focus on tier-1 basins.
Growing free cash flow.
Delivering shareholder returns.

2026 Investor Briefing Day

26 May 2026

Santos

Agenda/Speakers

Session one

01 09:00am
Opening
Kevin Gallagher, Managing Director and Chief Executive Officer

02 09:30am
Finance
Lachlan Harris, Chief Financial Officer

03 09:40am
Market Outlook
Tracey Winters, Chief Strategy Officer

04 09:50am
Marketing and Trading
Sean Pitt, EVP Marketing, Trading and Shipping

05 10:00am
Reserves & Resources
Mark Burgoyne, VP Subsurface

Morning tea break

Session two

06 10:40am
Oil & LNG Growth Hubs
Bruce Dingeman, EVP and President Alaska
Brett Darley, Chief Operating Officer Australia and PNG Upstream O&G

07 11:10am
Midstream and Energy Solutions
Alan Stuart-Grant, EVP Midstream and Energy Solutions

08 11:20am
Operations Excellence and Technology
Steve Trench, EVP Operations and Technical Services

09 11:30am
Wrap up and Q&A
Kevin Gallagher, Managing Director and Chief Executive Officer

Disclaimer and important notice

This presentation contains forward-looking statements that reflect Santos' expectations at the date of this report (including with respect to Santos' strategies and plans relating to climate change). These statements are based on management's current expectations and reflect judgements, assumptions, estimates and other information available as at the date of this document and/or the date of Santos' planning processes. However, a range of variables could cause actual results or trends to differ materially from the statements we have made. These variables include but are not limited to: price or currency fluctuations, actual demand, geotechnical factors, drilling and production results, gas commercialisation, development progress, operating results, engineering estimates, reserves and resource estimates, loss of market, industry competition, environmental and climate-related risks, carbon emissions reduction and associated technology risks, physical risks, legislative, fiscal and regulatory developments, economic and financial market conditions in various countries, approvals, conduct of joint venture participants and contractual counterparties, cost estimates, reputational risk, social licence and stakeholder risk and activism.

No representation or warranty, express or implied, is given as to the accuracy, completeness or correctness, likelihood of achievement or reasonableness of any forward-looking information contained in this presentation. Forward looking statements do not represent guarantees or predictions of future performance, and involve known and unknown risks, uncertainties and other factors, many of which are beyond Santos' control, and which may cause actual results to differ materially from those expressed in the statements contained in this presentation.

All references to dollars, cents or $ in this document are to United States currency, unless otherwise stated.

Underlying profit, EBITDAX (earnings before interest, tax, depreciation, depletion, exploration and evaluation expensed, change in future restoration assumptions and impairment) and free cash flow from operations (operating cash flows less investing cash flows net of acquisitions and disposals and growth development project capex, less lease liability payments) are non-IFRS measures that are presented to provide an understanding of the performance of Santos' operations. The non-IFRS financial information is unaudited; however, the numbers have been extracted from the audited financial statements. Free cash flow breakeven is the average annual US$ oil price at which cash flows from operating activities (before hedging) equals cash flows from investing activities. Excludes one-off restructuring and redundancy costs, costs associated with asset divestitures and acquisitions, and growth development capex. Includes lease liability payments. Forecast methodology uses corporate assumptions.

The estimates of petroleum reserves and contingent resources contained in this presentation are as at 31 December 2025. Santos 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 Mr Steve Lawton, who is a full-time employee of Santos and is a member of the SPE.
Mr Lawton meets the requirements of a QPRRE and is qualified in accordance with ASX Listing Rule 5.41. Conversion factors: For periods prior to and including 31 December 2025: 1 PJ of sales gas equals 171,937 boe; 1 tonne of LPG equals 8.458 boe; 1 barrel of condensate equals 0.935 boe; 1 barrel of crude oil equals 1 boe. For 1 January 2026 onwards, 1 barrel of condensate equals 1 boe, with sales gas, LPG and crude oil conversion factors unchanged.

INTRODUCTION

01 02 03 04 05 06 07 08 09

Strait of Hormuz disruption

A structural shift in global LNG and oil supply has implications for energy security and market stability over the longer term

What happened

Qatar LNG Exports

Halted

Force majeure

Infrastructure

Damaged

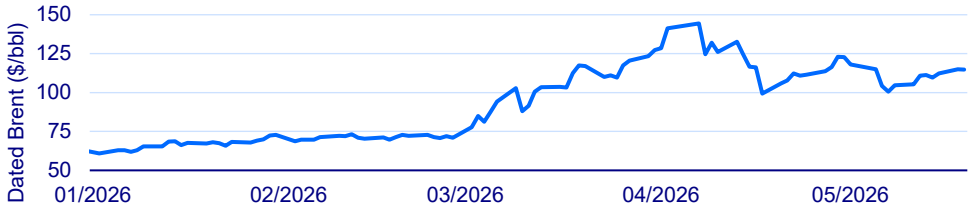
Including two LNG trains (12.8 Mtpa capacity)

Strait crossings

Significantly down

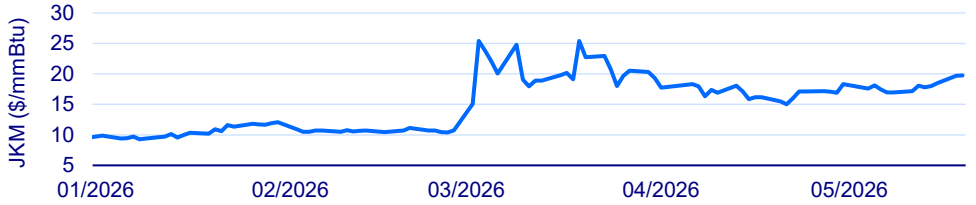
Versus pre-conflict levels

Market impact[1]



Global oil supply impacted[2]

~13%



Global LNG supply impacted[3]

~20%

Implications for Santos

LNG and crude are shipped via Pacific sea lanes direct to Asian buyers, unimpacted by shipping disruptions in the Strait of Hormuz

A non-Hormuz supply chain is an increasingly important differentiator for Asian buyers
Santos' PNG and Australian LNG portfolio directly benefits from that shift

Qatar's North Field East delays reduce near-term supply overhang into Asian markets
Barossa and Pikka add incremental cash flow as new volumes come online into a tighter-than-expected market

1. S&P Global Energy, © 2026 by S&P Global Inc, Platts Dated Brent and JKM (LNG Japan/Korea DES spot cargoes) prices, extracted 20 May 2026
2. Gulf output below pre-war levels as of April 2026, as a share of estimated pre-war global supply. Source: IEA, Oil Market Report, May 2026
3. IEA, The Middle East and Global Energy Markets, 2026

Our growth strategy

Low Carbon Fuels

- Develop new low carbon fuels as energy markets and customer demand evolve

Build and Grow

- Build scale through disciplined development of fewer, larger-scale oil and gas upstream basins
- Leverage and grow advantaged infrastructure footprint
- High return, low-cost development of oil & LNG assets in Australia, PNG and Alaska

Backfill, Sustain and Decarbonise

- Operations excellence and technology-driven transformation through digital and AI innovation, reducing unit cost, driving efficiency and improving safety across operations
- Low-cost, infrastructure-led backfill opportunities
- Higher returns and reduction in emissions and emissions intensity

Operations update

Strong, reliable base business delivering as Barossa and Pikka phase 1 come online

Australia

- Barossa online and ramping; each of the six wells has confirmed capacity of ~300 mmscf/d
- GLNG upstream production increased 1.5 per cent over the first quarter 2026. 101 cargoes shipped in 2025; 24 cargoes in Q1 2026
- Cooper Basin production restored to pre-flood levels
- Moomba Central Optimisation FID taken Q1 2026, targeting >$600 million in capex and opex cost savings, with a pay back period of six years

PNG

- Santos operated fields provided 14 per cent of PNG LNG supply in Q1 2026
- Optimised Angore-Hides split and high uptime supporting higher LNG throughput, ~0.5 mmboe (Santos share) above target for Q1 2026
- 116 cargoes shipped in 2025; 28 cargoes in Q1 2026
- Papua LNG FID targeted H2 2026; APF Tie-In and KPS FSO projects in execution

Alaska

- First oil from Pikka phase 1 with oil flow through the Lease Automated Custody Transfer meter into the Pikka sales oil line; plateau targeted Q3 2026
- 28 development wells drilled; 22 stimulated and flowed back in line with pre-drill expectations
- Quokka-1 appraisal confirmed 177 mmboe 2C net
- Quokka and Horseshoe Units represent North Slope growth runway

2026 guidance: Production and sales 101–111 mmboe | Capex ~$1.95–2.15 billion | Unit production cost $6.95–7.45/boe

A decade of transformation and growth

Capital discipline transformed Santos into a portfolio of three tier-1 assets, doubling production and significantly reducing unit cost

Disciplined low-cost operating model

	2016[1]	2026
Market capitalisation	A$6.5 billion	~A$26.8 billion[3]
Production	~57.7 mmboe	101–111 mmboe[4]
Unit production cost	~$10.35/boe	$6.95–7.45/boe[4]
Total dividends declared dividend suspended 2016 & 2017	15 cps[5]	23.7 cps[6]
Lost time injury frequency rate per million hours worked	0.12	0.05[2]
Net emissions intensity Scope 1 & 2	63 ktCO2e/mmboe	39 ktCO2e/mmboe[2]
Free cash flow from operations	($739) million	$1,777 million[2]

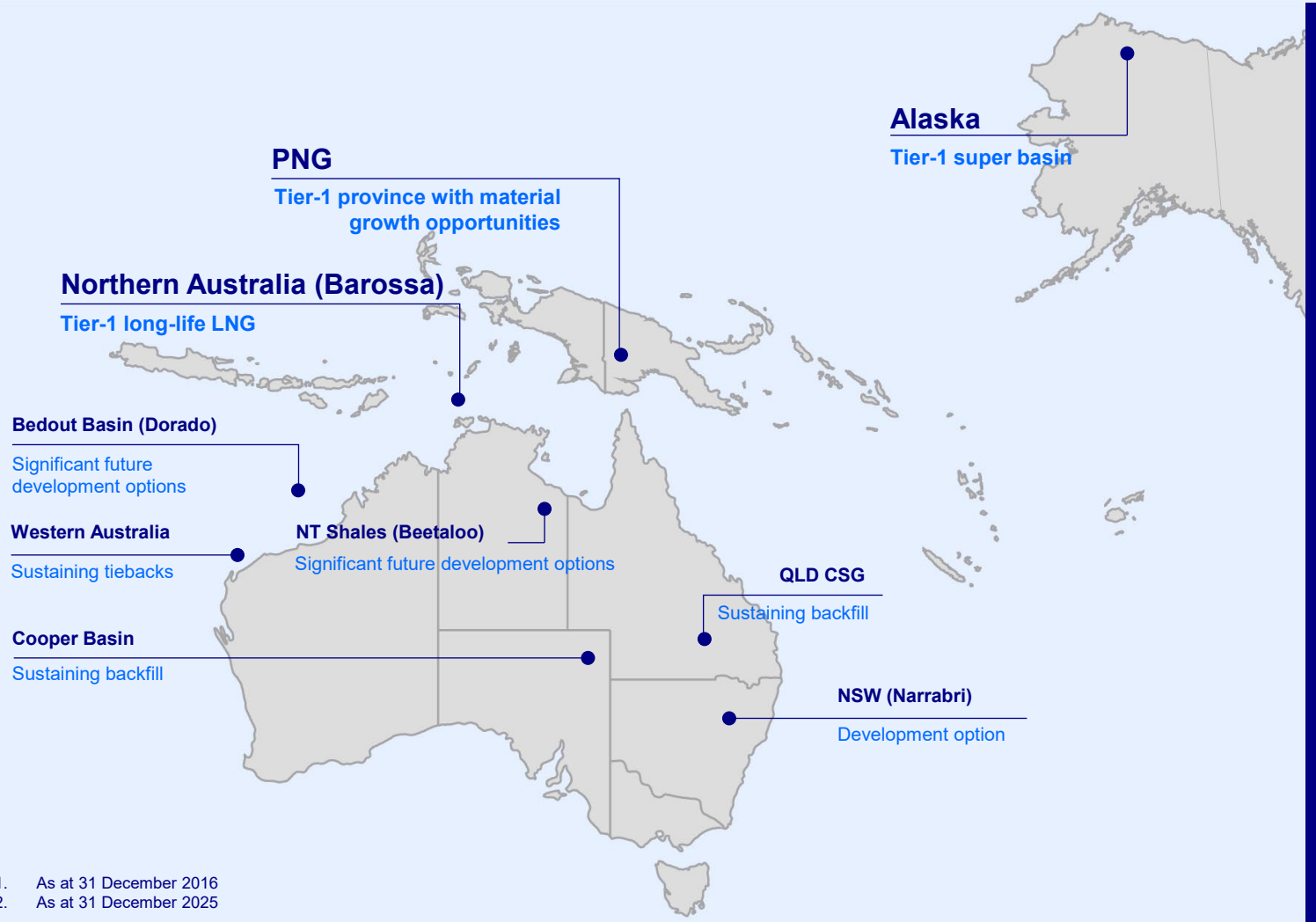
Total shareholder returns have increased by more than ~220 per cent since 2016

Cost discipline through the cycle	**Unit production cost reduced by 30 per cent from 2016 to 2026** **Gearing cut from 39 per cent to 26.9 per cent at end of peak capex period**
Proven shareholder returns	**FY25 free cash flow from operations of $1.8 billion supported $770 million in cash returns** **~$4.6 billion returned to shareholders; 1.3x Santos' entire market cap since early 2016**
High quality asset base	**Strategic acquisitions delivered three tier-1 assets** **LNG capacity has more than doubled through strategic M&A**

1. As at 31 December 2015
2. As at 31 December 2025
3. Market capitalisation as at 22 May 2026
4. Production and unit production cost consistent with 2026 guidance
5. 2015 dividends declared
6. 2025 dividends declared, paid in 2025 and 2026

Santos' portfolio of tier-1 assets

Three tier-1 assets underpinned by material low-cost growth, long development runway and exposure to diversified attractive markets



Portfolio transformation to build scale

Strategic acquisitions and organic growth reshaped Santos into a larger, more diversified, higher-margin business with significant growth optionality

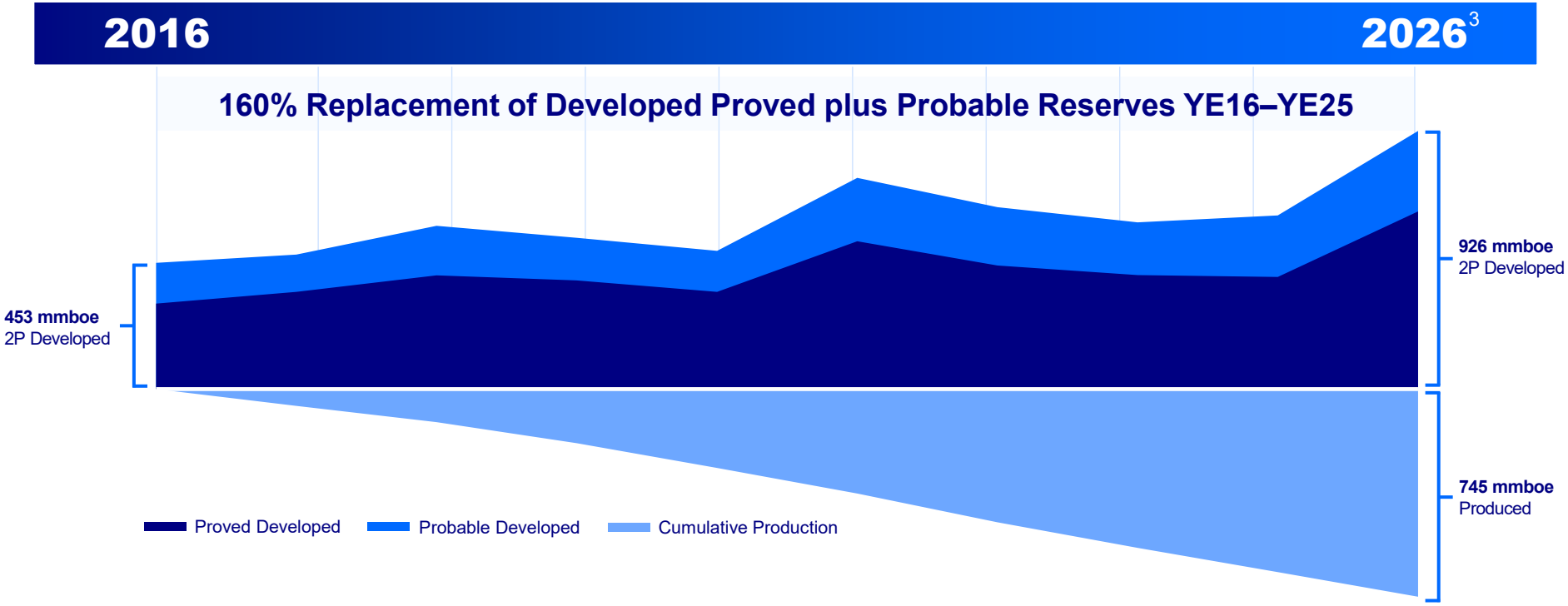
Reserves and resources grown through the decade

2016	2026
889 mmboe 2P reserves 1,571 mmboe 2C contingent resources[1]	1,484 mmboe 2P reserves 3,212 mmboe 2C contingent resources[2]

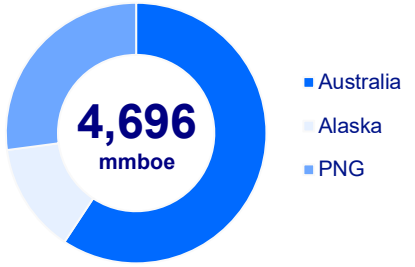
1. As at 31 December 2016
2. As at 31 December 2025

A reserves base built for value

High-quality reserve base delivering decades of premium returns, 70 per cent of proved reserves developed

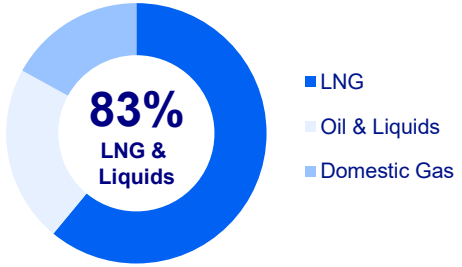


Diverse Reserves & Resource Base[3]



1,484 mmboe 2P reserves
3,212 mmboe 2C contingent resources

LNG and Liquids Focus



Continued Growth & Transformation

Central North Slope of Alaska is estimated to contain ~3 billion barrels of undiscovered, technically recoverable oil[1]

Beetaloo Basin is estimated to contain more than 430 tcf of undiscovered gas-in-place, on a basin-wide P50 basis[2]

In the prolific Papuan Basin in PNG, Santos holds reserves and contingent resources equivalent to approximately 30 years of current production

1. P50 Undiscovered Oil per USGS Fact Sheet 2020-3001: https://doi.org/10.3133/fs20203001
2. The Beetaloo Sub-basin – Australia's next gas supply, Department of Mining and Energy, Northern Territory, page 4
3. Reserves and contingent resources as at 31 December 2025

Focus is on major oil and gas tier-1 basins

Advantaged infrastructure across three regions, supported by domestic gas and low-cost midstream capability

Tier-1 basins – scale, margin, infrastructure advantage

Australia	PNG	Alaska
Long-term Beetaloo shale development opportunities and potential Bedout basin development	**Conventional gas with significant backfill opportunities and material oil upside potential**	**Large scale, premium priced oil growth opportunities following start-up of Pikka phase 1**

Strong base business

Midstream and Energy Solutions

Lower cost, improved efficiency & lower emissions

Australian Domestic Oil & Gas

Lower capital intensity, higher-margin business focused on meeting domestic gas & decommissioning commitments

Commercial and technical capability across the business

Marketing and Trading

Maximising revenue through leveraging premium products and creating additional value through opportunistic portfolio optimisation trading

Shareholder returns and growth

Consistent strategy, driving the disciplined low-cost operating model, low breakeven, and strong cash flow generation

Disciplined operating model

Continues to underpin how we operate and how we invest in growth

Additional $550–600 million free cash flow annually for every $10 movement in Brent[1]

Targeting <$35/bbl free cash flow from operations

Focused on base business operational excellence

Sustains production at 100–120 mmboe per year

Targeting $45–50/bbl free cash flow breakeven

Sustain the business AND invest in growth projects that deliver production and material reserves/ resource growth

Capital allocation framework

Balances sustainable shareholder returns with balance sheet strength[2]

Gearing target within 15–25 per cent

Minimum 60 per cent

of all free cash flow above free cash flow breakeven returned to shareholders, and up to 100 per cent when below target gearing range

Remaining 40 per cent

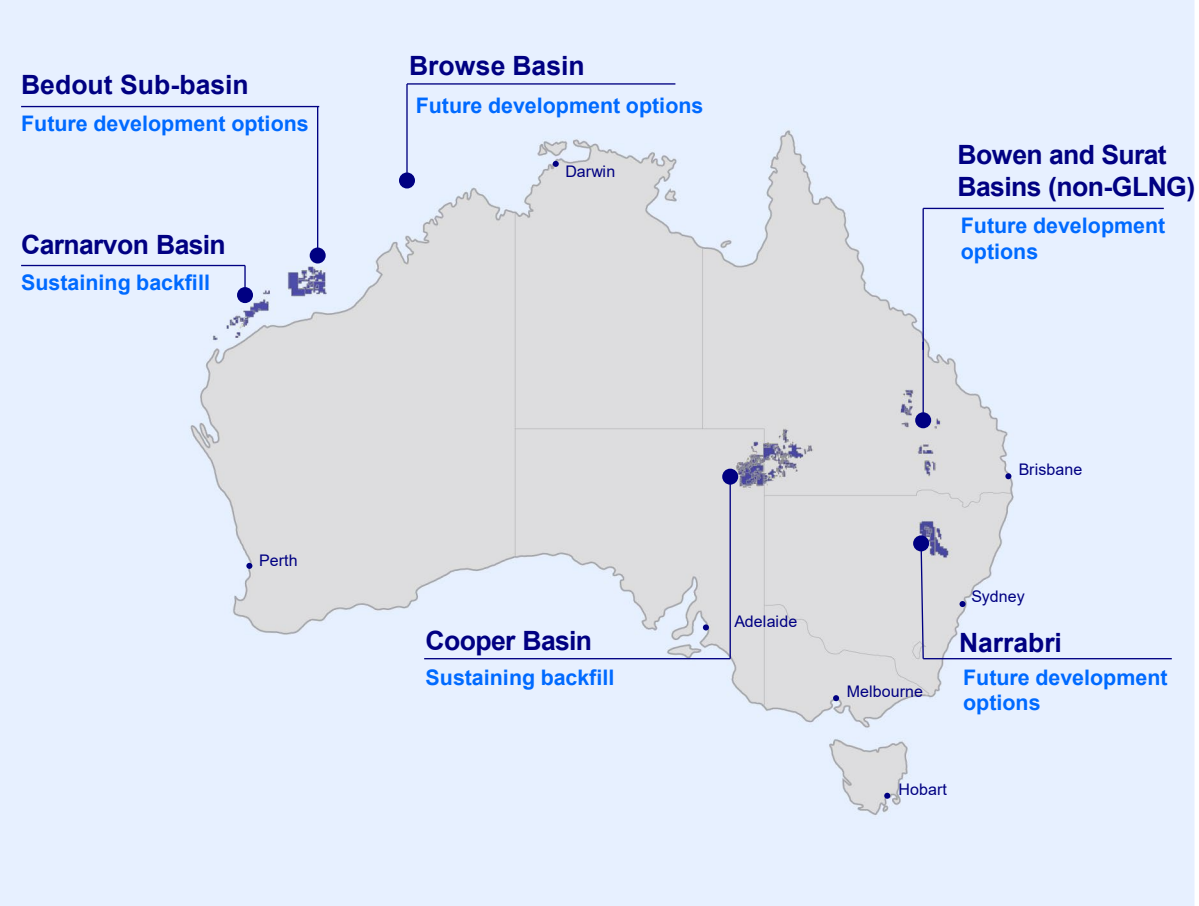
of all free cash flow above free cash flow breakeven to de-gear the business, or increase shareholder returns

Total shareholder returns

1. Once Barossa and Pikka phase 1 are at plateau rates
2. The timing of the transition to the revised capital allocation framework is subject to Board approval

Australian domestic O&G strategic review outcome

Lower capital intensity, higher-margin business focused on meeting domestic gas & decommissioning commitments



Cooper Basin

Investment prioritised in the Central Area with cumulative capex reductions of ~$300 million from 2027 to 2030, and $150 million savings annually from 2030

Bowen and Surat Basins (Eastern Queensland) Narrabri and Browse Basin

- Eastern Queensland, Crown Lasseter, Poseidon de-prioritised
- Taroom Trough being appraised by others
- Narrabri pursue approvals and further review following appraisal of Beetaloo in 2027

Carnarvon Basin

Pursue low-cost, near-field tie-back opportunities and fund decommissioning opportunities to support domestic gas commitments, social license

Dorado/Bedout Sub-basin

- Potentially a fourth growth basin
- Dorado high IRR project, potential to provide increased energy security
- Bedout Basin to be appraised for scale with three wells in 2027

LNG and oil development opportunity pipeline

Development pipeline across three regions, funded within disciplined allocation framework – from near-term development to exploration[1]

Australia

Beetaloo Appraisal	Appraisal of multi-tcf opportunity to support GLNG, DLNG growth and domestic markets
Bedout Exploration	Three-well exploration campaign
Dorado	FEED-ready, high-return, short payback cycle oil development

PNG

APF Tie-In	Converts 66 mmboe 2P undeveloped reserves[1] to developed reserves
CPF Expansion	Debottlenecking up to 1.6 mmboe per year
Papua LNG FID	New long-life foundational project, converting ~200 mmboe 2C to 2P[2] at FID
Mosa	Santos operated oil exploration well with PNG LNG backfill upside

Alaska

Pikka phase 1 Expansion	Opportunity for potential expansion up to 120,000 bopd gross plateau
Quokka	Permitting and engineering activities to mature current 2C resource of 177 mmbbl
Horseshoe	Appraisal and extension of current 2C resource of 46 mmbbl

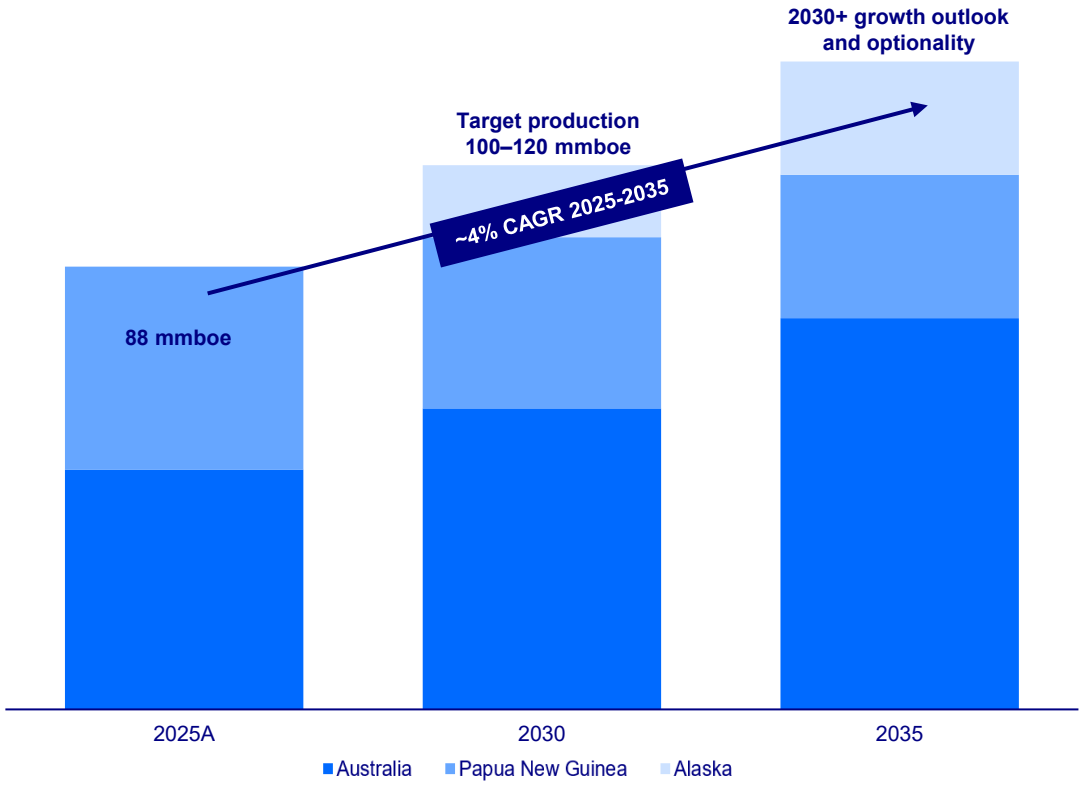
1. All references to 2P Reserves and 2C contingent resources are as at 31 December 2025
2. 2C to 2P conversion of ~200 mmboe requires FID and assumes Santos equity reduces to 17.7 per cent following government back-in. Conversion is subject to multiple contingencies and there is no certainty that FID will occur or that resources will be converted to reserves

Returns-led production growth, FCFBP target $45–50/bbl

Increasing production by 25 to 30 per cent[1] at ~4 per cent CAGR to 2035, within a $45-50/bbl all-in free cash flow break even

Production by region[2]

Santos share, 2025 to 2035 (mmboe)



Barossa and Pikka phase 1 delivering production growth

Barossa and Pikka production online delivering near-term production uplift

Peer leading long-term growth in LNG and oil

Focus growth investment across three regions to develop tier-1 basins in Alaska and Papua New Guinea and fully appraise Australia's Beetaloo and Bedout basins

Growing free cashflow

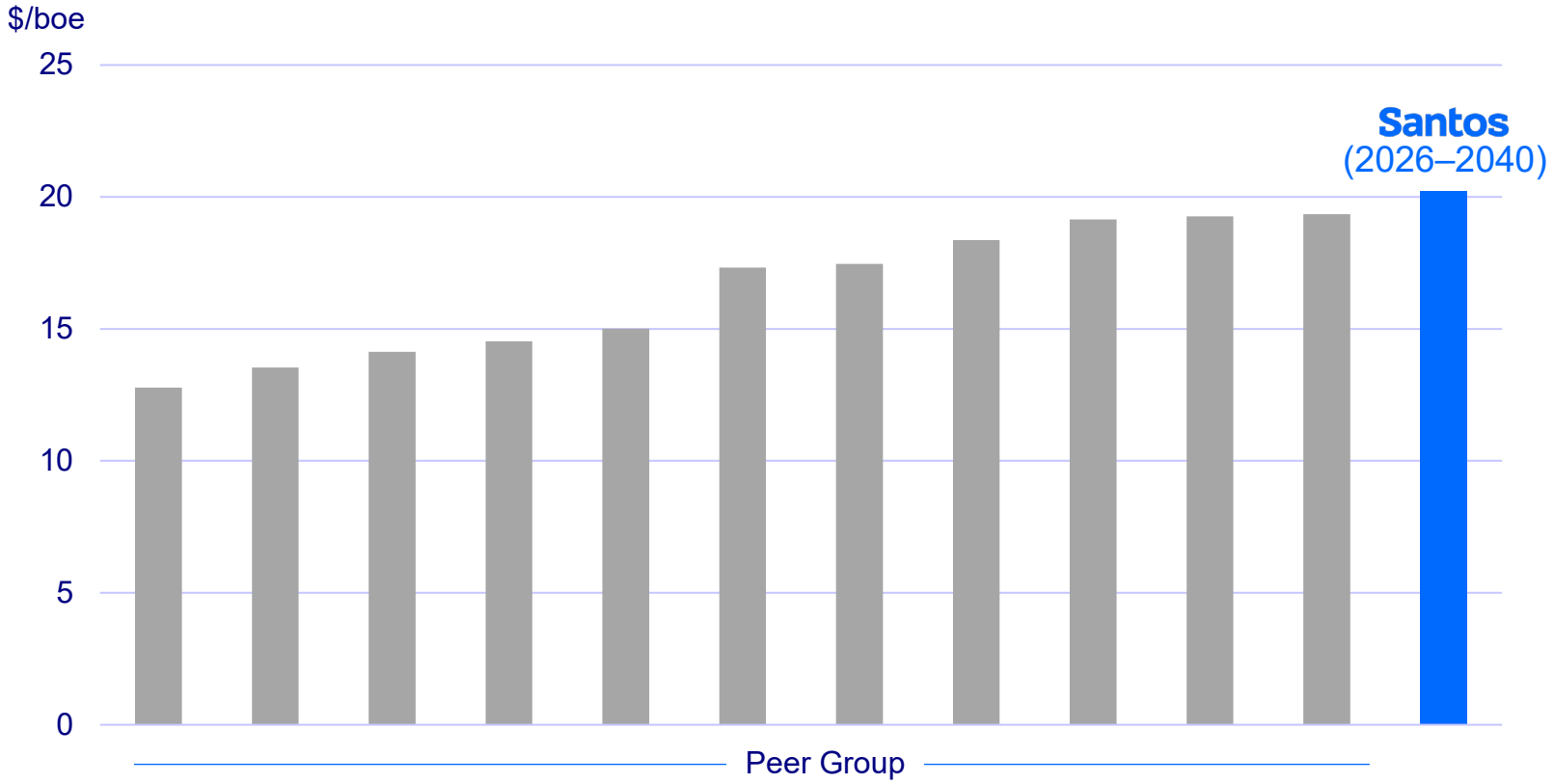
Production growth underpins free cashflow expansion as Santos moves past peak capex

1. Once Barossa and Pikka phase 1 are at plateau rates, compared to 2024 annual production levels
2. This is indicative only, not guidance

Highest cash flow per barrel

Santos is a global leader in cash flow margin generation per barrel

2026–2040 Cash flow per barrel peer benchmarking[1]



Stronger cash generation

Barossa and Pikka bring higher-margin barrels online from 2026

High-value barrels

Revenue per boe ranked third at $71/boe

Cash-generative barrels

Cash flow per boe ranked first at $20/boe

Advantaged portfolio

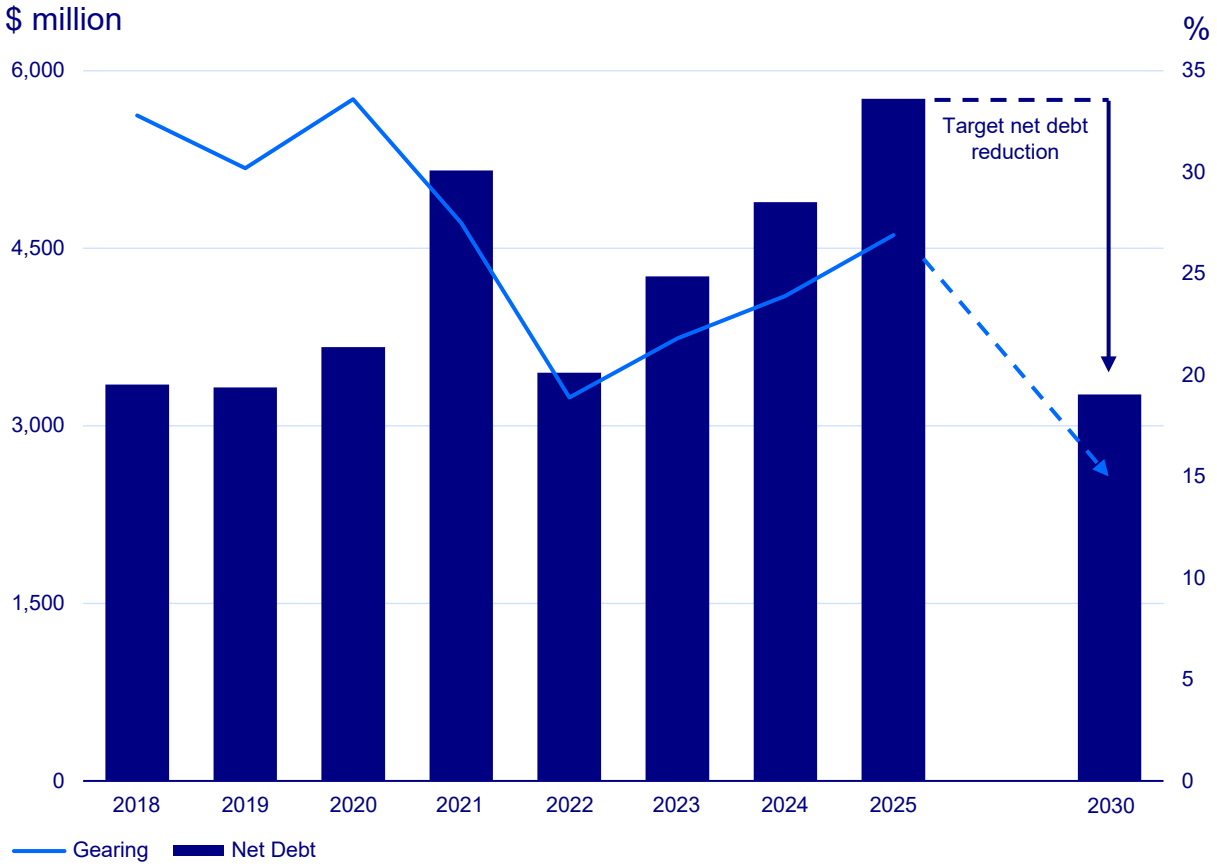
Santos reserves and resources rank strongly against global peers

1. Wood Mackenzie Corporate Sustainability and Analytics Service (CSAS). Peer companies include ExxonMobil, Chevron, ConocoPhillips, Shell, BP, TotalEnergies, Equinor, Eni, Devon, Occidental, Woodside. Cash flow per barrel is Wood Mackenzie's estimate of all-in cash flow per boe of production, excluding downstream costs e.g. refining. Nominal terms averaged annually over 2026-2040. Wood Mackenzie's base price scenario assumes a long-term Brent price of $65/bbl (real, 2026 terms)

Increased cash flows enable rapid de-gearing

De-gearing rapidly, at $75/bbl net debt reduces by ~$2.5 billion by 2030, with FCFBP target of $45–50/bbl and a minimum of 60 per cent returned to shareholders

Net Debt and Gearing[1]



Net debt reducing materially

At a Brent oil price above $75/bbl, net debt falls ~$2.5 billion by 2030. Target gearing to the bottom of the 15–25 per cent range

1. Gearing including leases

The Santos value proposition is clear

Growing free cash flow. Maximising shareholder value

High quality asset base

Geographic diverse portfolio of large-scale tier-1 growth opportunities

High margin, low cost & infrastructure advantaged significant resource base

Plan delivered within breakeven oil price target of $45–50/bbl

Growing free cash flow

Barossa and Pikka phase 1 delivering new production from 2026

All assets exposed to attractive end markets, realising premium prices

From 2027 every $10 realised oil price above the breakeven oil price will generate $550 million – $600 million in free cash flow

Shareholder returns

Disciplined capital allocation framework

Returning at least 60 per cent of free cash flow to shareholders

Reducing net debt by $2.5 billion by 2030

FINANCE

Shareholder returns and growth

Consistent strategy, driving the disciplined low-cost operating model, low breakeven, and strong cash flow generation

Disciplined operating model

Continues to underpin how we operate and how we invest in growth

Additional $550–600 million free cash flow annually for every $10 movement in Brent[1]

Targeting <$35/bbl free cash flow from operations

Focused on base business operational excellence

Sustains production at 100–120 mmboe per year

Targeting $45–50/bbl free cash flow breakeven

Sustain the business AND invest in growth projects that deliver production and material reserves/ resource growth

Capital allocation framework

Balances sustainable shareholder returns with balance sheet strength[2]

Gearing target within 15–25 per cent

Minimum 60 per cent

of all free cash flow above free cash flow breakeven returned to shareholders, and up to 100 per cent when below target gearing range

Remaining 40 per cent

of all free cash flow above free cash flow breakeven to de-gear the business, or increase shareholder returns

Total shareholder returns

1. Once Barossa and Pikka phase 1 are at plateau rates
2. The timing of the transition to the revised capital allocation framework is subject to Board approval

Capital allocation framework

Providing strong returns, through the cycle, underpinned by a strong investment grade balance sheet and cost discipline

Cost discipline

$45–50/bbl

FCFBP

Backfill and growth projects support a competitive all-in free cash flow breakeven

Balance sheet strength

15–25%

gearing

De-gearing to lower end of target gearing range while maintaining BBB-/Baa3/BBB investment-grade credit ratings

Returns to shareholders

≥60%

payout

Sustainable shareholder returns, growing with production and free cash flow

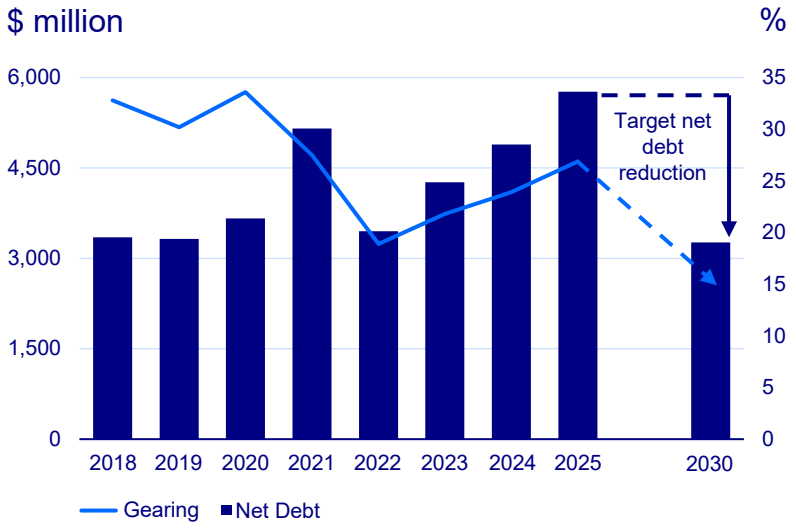
Free cash flow sensitivity:
For every $10 movement in Brent above the breakeven, Santos will receive $550–600 million free cash flow annually once Barossa and Pikka phase 1 reach plateau

Santos is now past peak capex:
Following the completion of Barossa and Pikka, the portfolio is now positioned to sustain production between 100–120 mmboe before further investment in major growth

Strong balance sheet

Positioned to remain resilient and support long-term value through the commodity price cycles with an investment grade balance sheet

Net Debt and Gearing[1]



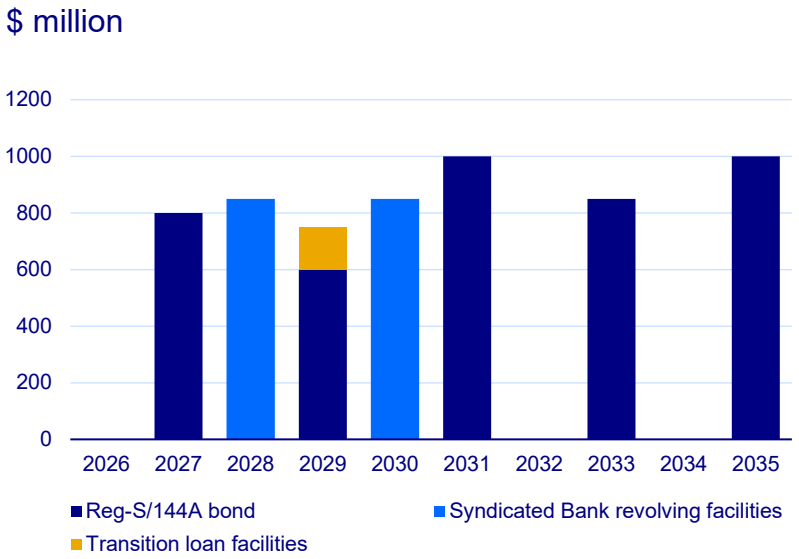
Liquidity[2]

$4.3 billion

Investment grade credit ratings S&P, Fitch and Moody's

Moody's upgraded from stable to positive

Drawn debt maturity profile



Protecting the cost base

FX hedging[3]
2026: A$1,846 million @ 0.6422
2027: A$1,585 million @ 0.6586

Commodity hedging

17.2 mmbbl of Brent zero-cost collars. Weighted average floor $67.10/bbl, ceiling $98.69/bbl. April to December 2026

Strong funding profile

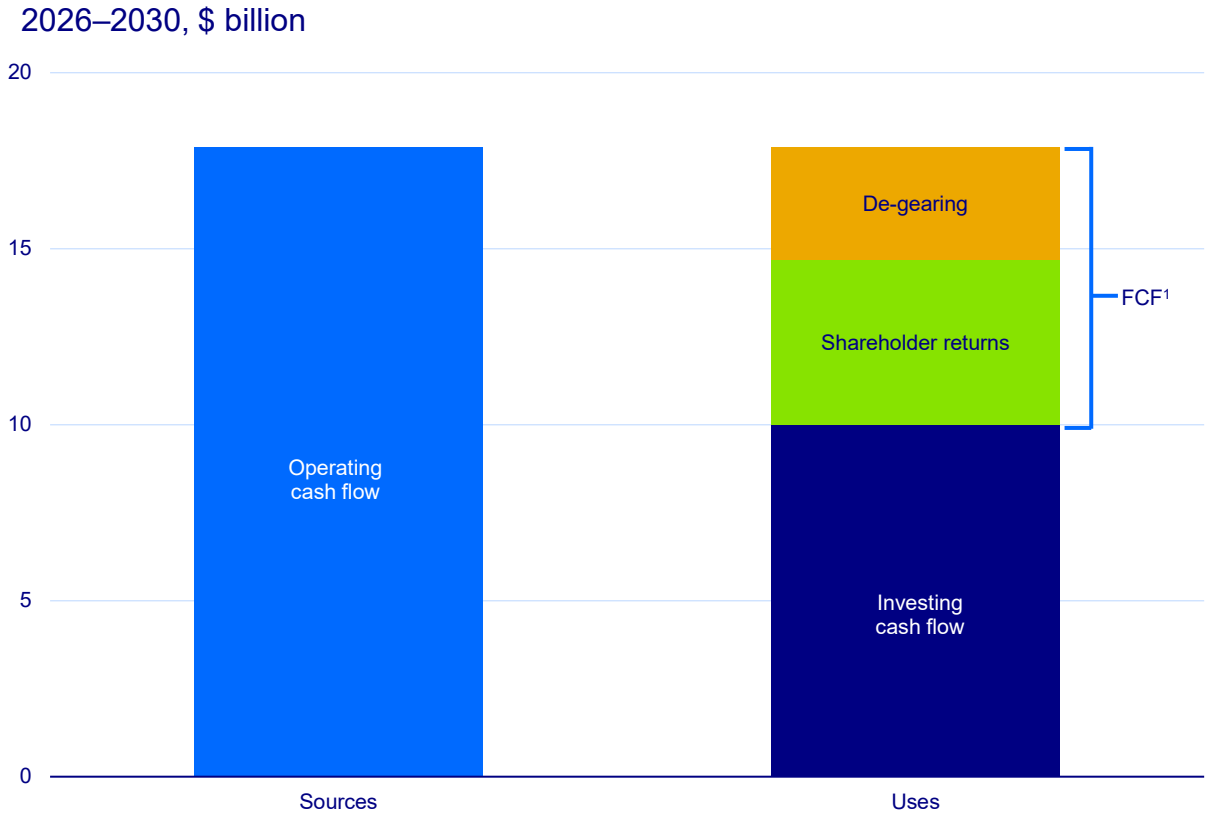
No debt maturities due until September 2027

1. Gearing as at 31 December 2025, 21.5 per cent excluding operating leases, 26.9 per cent when included
2. Liquidity as at 31 December 2025; Cash $1,772 million, undrawn committed facilities $2,545 million
3. Relates to full calendar years 2026 and 2027

Sources and uses of cash

Positioning for growth through balance sheet strength, ability to fund development projects from the balance sheet

Sources and uses at $75/bbl



Funding future growth

Free cash flow breakeven of $45–50/bbl, with phased execution and rigorous capital allocation, will allow growth projects to be funded within capital allocation framework

Project financing Papua LNG

Papua LNG is expected to be project financed by the ring-fenced, incorporated joint venture company for up to 60 per cent of project costs. ECA and commercial bank engagement is strong, financing is progressing well

Sequenced developments

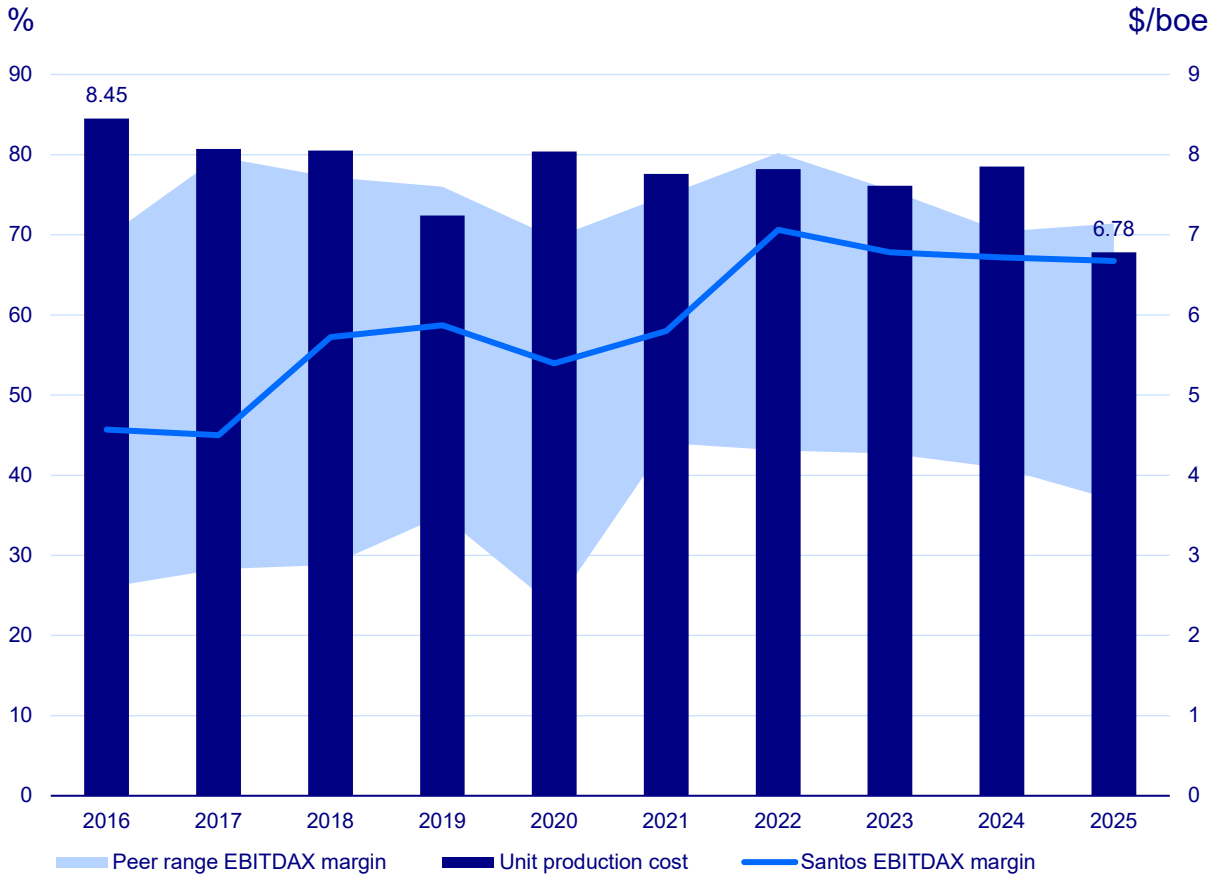
Sequenced development enables advancing parallel growth opportunities and preserving balance sheet and financial flexibility. Financial flexibility to execute Papua and up to two growth projects subject to working interest and phasing

1. FCF at $75/bbl, based on the mid-points of the $45–50/bbl breakeven and $550–600 million per $10/bbl Brent movement sensitivity range

Growing margins through the decade

EBITDAX margin has expanded as unit production cost has fallen. The EBITDAX margin has increased by 46 per cent over 10 years

EBITDAX margin versus peers[1] / Unit production cost



Higher margin barrels	**Lower unit cost and advantaged barrels are driving higher EBITDAX margins**
Record low unit production cost	**Unit production cost has reduced by 20 per cent since 2016. Since 2021, Santos has been delivering top-quartile EBITDAX margins in peer group**
Structural cost savings delivered	**$50 million run rate, targeting >$150 million annually**

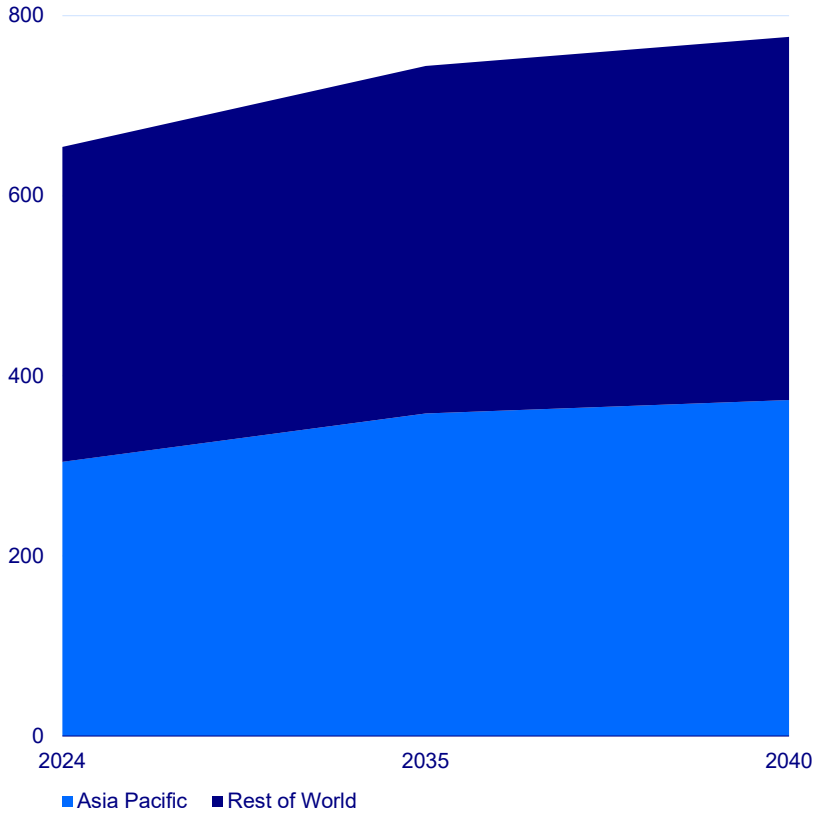
1. Peer group includes ExxonMobil, Chevron, BP, Shell, TotalEnergies, Eni, Diamondback, EOG, ConocoPhillips, Devon, Occidental, Equinor, Woodside and Beach Energy

MARKET OUTLOOK

Oil and gas meets half of global energy demand

Global energy demand continues to rise to 2040 and beyond. Asia Pacific accounts for more than 55 per cent of demand growth to 2040

Global energy demand by region[1]



~20 per cent

Growth in global energy demand by 2040[1]

>55 per cent

Asia Pacific share of global energy demand growth, led by India and Southeast Asia[1]

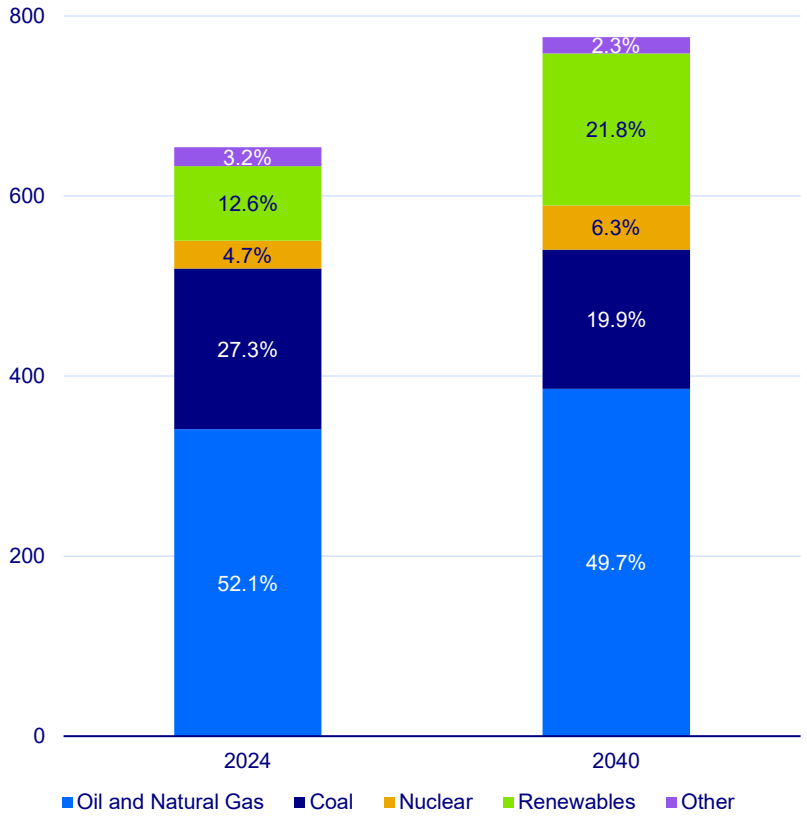
Market share maintained

Oil and gas continues to supply ~50 per cent of global energy demand[1]

~15 per cent

Growth in global oil and gas demand by 2040[1]

Global energy demand by source[1]



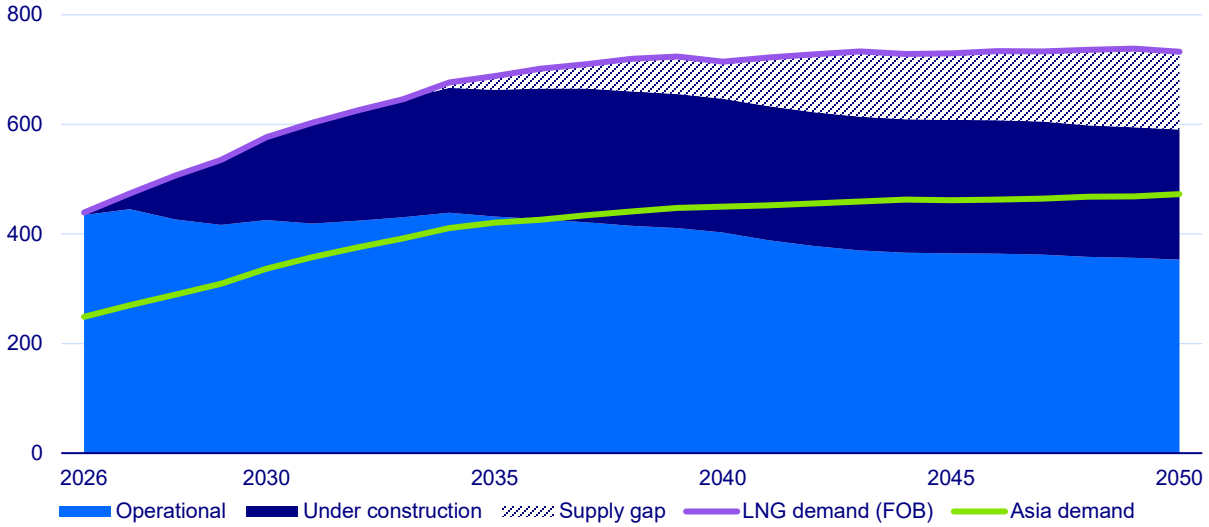
1. IEA World Energy Outlook, October 2025. Based on Current Policies Scenario (CPS). All figures are relative to 2024

Asia is the growth engine of global LNG demand

Global LNG demand grows by more than 60 per cent by 2040. Asia accounts for three-quarters of total growth

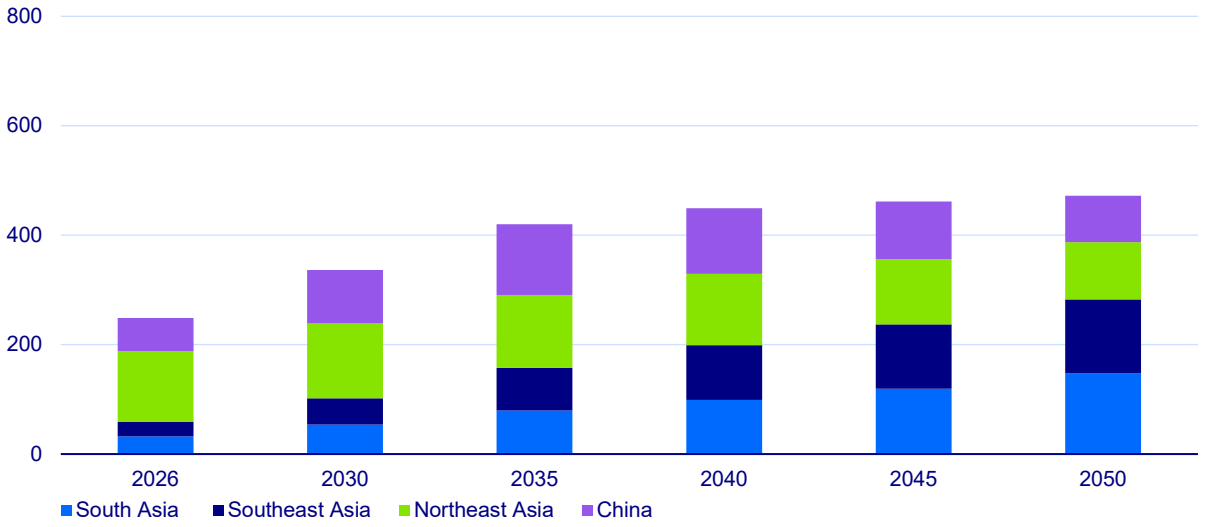
Global LNG demand and supply[1]

Mtpa



Asia LNG demand growth[1]

Mtpa



Supply gap

>65 Mtpa of new supply must reach FID to meet 2040 demand[1]

Asia demand triples

South and Southeast Asia LNG imports increase from ~60 Mtpa today to ~200 Mtpa by 2040[1]

Shift to market tightness

Driven by supply disruption in the Middle East and project delays/cancellations

Opportunity for growth

New Pacific Basin supply best placed to meet Asian demand

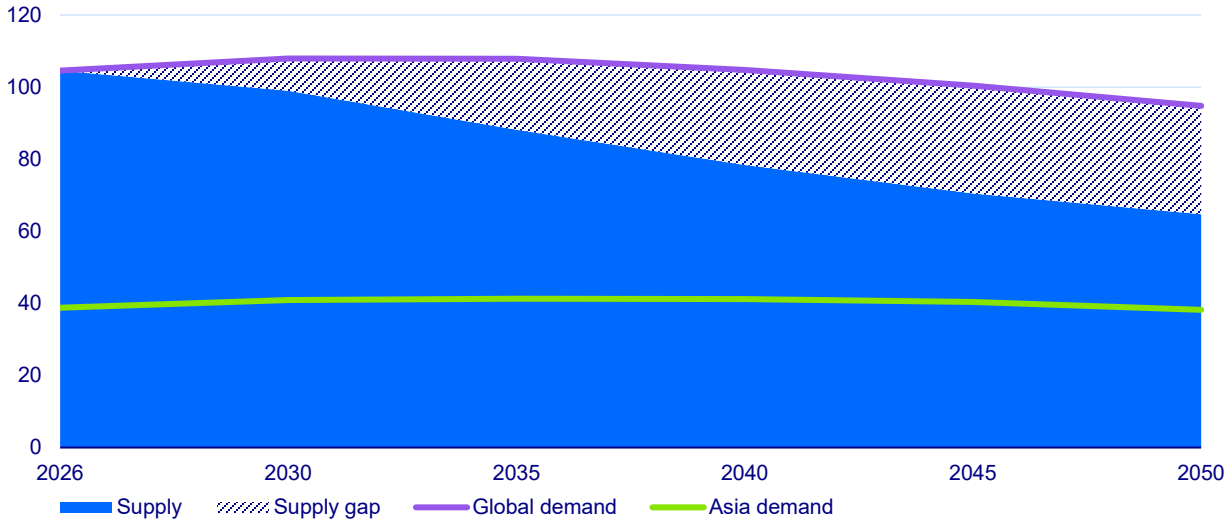
1. Wood Mackenzie, Global Gas Strategic Planning Outlook, April 2026. LNG supply shown after the price response required to balance the market to 2034

Oil demand resilient with looming supply gap

Petrochemicals, aviation and emerging Asia sustain oil demand through the 2040s

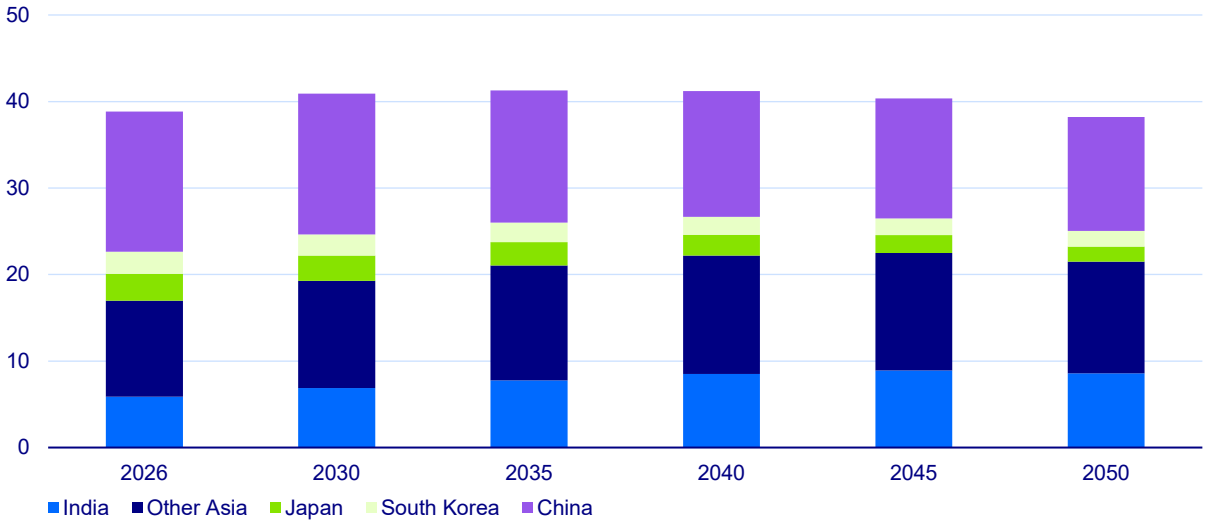
Global oil supply-demand[1]

mmbbl/d



Asia oil demand by country[1]

mmbbl/d



Supply gap

Prices >$70/bbl required from mid 2030s to incentivise enough new supply to offset decline and meet demand[1]

Petrochemicals

Petrochemical feedstock demand drives growth through 2040 and beyond[1]

Aviation

Jet fuel demand grows through to the early 2040s with no scalable alternative[1]

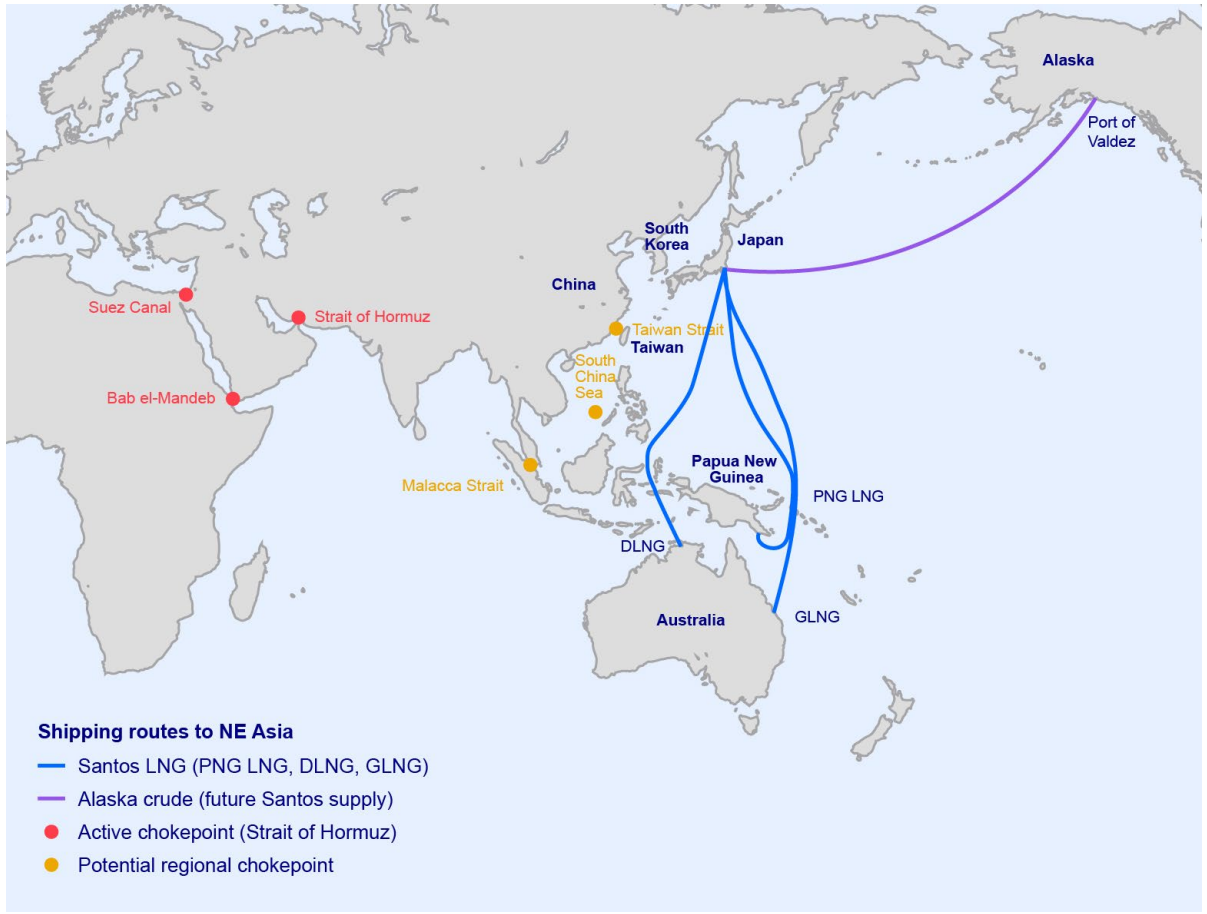
Long plateau

Wide range of demand forecasts with peak global oil demand pushed out, OPEC and IEA CPS forecast structural growth through 2050

1. Wood Mackenzie, Macro Oils Strategic Planning Outlook, April 2026

Santos supply hubs have a strategic advantage

Geography and geopolitics are strategic advantages for Santos' oil and LNG supply hubs in Alaska, Papua New Guinea and Australia



Geopolitically secure supplier to North Asia

Energy security is a growing priority for premium North Asian buyers

Regional relationships matter

Australia exports ~90 per cent of LNG to Asia[1] and imports ~80 per cent of refined liquid fuels, predominantly from Asia[2]

Direct Pacific routes, no chokepoints

Secure and reliable supply commands a premium in the current market

Shorter voyages, lower shipping costs, lower emissions

Alaska, Papua New Guinea and Australia oil and LNG supply hubs distinctly advantaged by location

1. Department of Industry, Science and Resources (DISR), Future Gas Strategy, May 2024
2. RBA, Statement on Monetary Policy, May 2026 (~80 per cent of refined fuel demand met by imports; bulk from Asian suppliers including Singapore, South Korea, Malaysia)

MARKETING & TRADING

Premium pricing across products

Santos' unique differentiators delivering industry-leading pricing through the 2030s

Barossa and PNG LNG

>$1.50/mmBtu

Average premium to total Australian LNG export prices[1]

Higher energy content, reliable and secure supply equivalent to >14 per cent to Brent

Australian Liquids

~$8/bbl

FOB premium 2026 YTD to Brent

Light sweet quality with strong demand. Current premiums to Brent exceed $20/bbl

Australian LPG

~$50–100/Mt

FOB premium to Saudi CP

Driven by Oceania and petrochemical demand. Middle East Gulf supply is constrained, leaving the US Gulf Coast as the alternative – at higher freight cost and longer voyages

ANS Crude[2]

~$5–20/bbl

ANS to ICE Brent differential[3]

Pacific Basin location commands freight-advantaged pricing into Asian refineries and provides diversification of supply. Peak ANS premium to Brent of ~$20/bbl in 2026

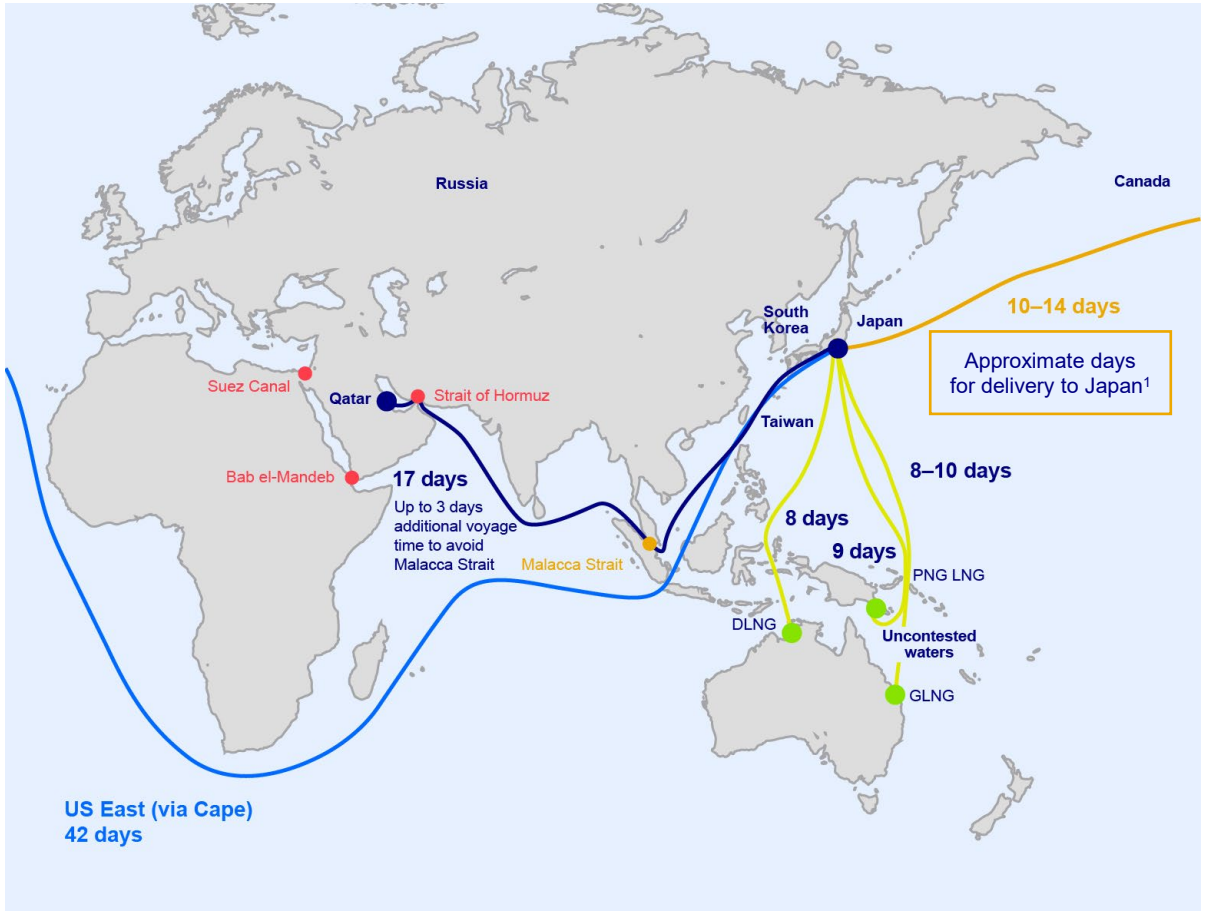
Strategically positioned portfolio of assets with premium specifications

Marketing strategy backed by 100 per cent equity supply

1. Difference between Santos average realised LNG price and total Australian LNG export price, averaged Q1 2024 to Q1 2026. Source: Santos data, EnergyQuest
2. Alaska North Slope Crude
3. Argus Media, ANS USWC to ICE Brent CMA differential, 12-month average to May 2026

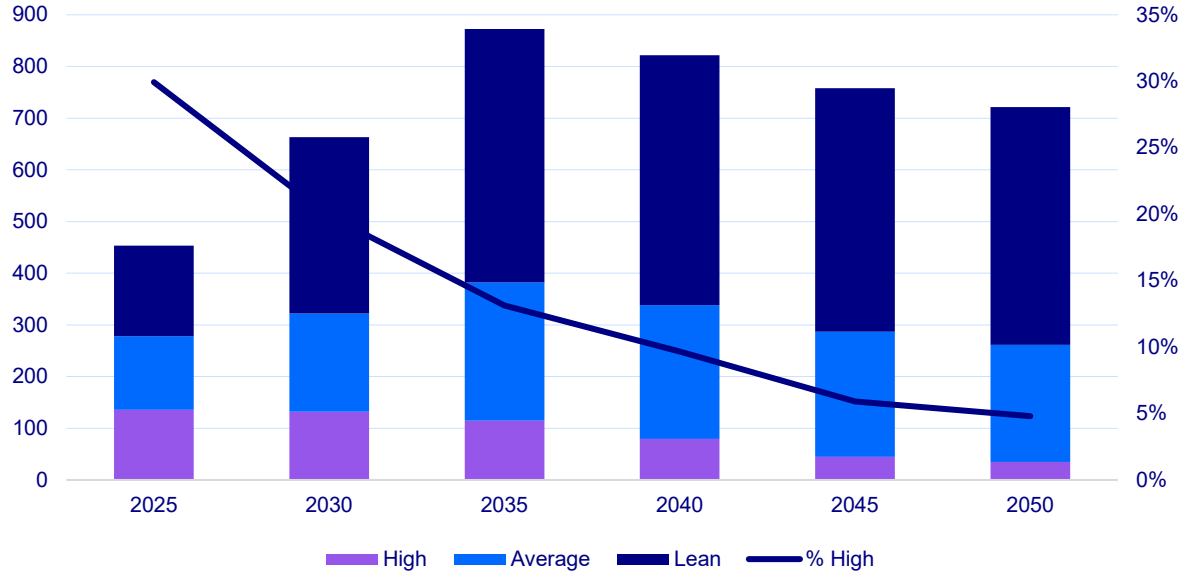
Advantaged LNG portfolio

Santos' delivers optimal LNG to premium Asian buyers. Right quality · Right location · Right specification



Global supply of high heating value LNG[2]

LNG supply, Mtpa, % high heating value



Santos' LNG portfolio specification[3]

Current	75% High/Average HV	25% Lean
2040	~80% High/Average HV	~20% Lean

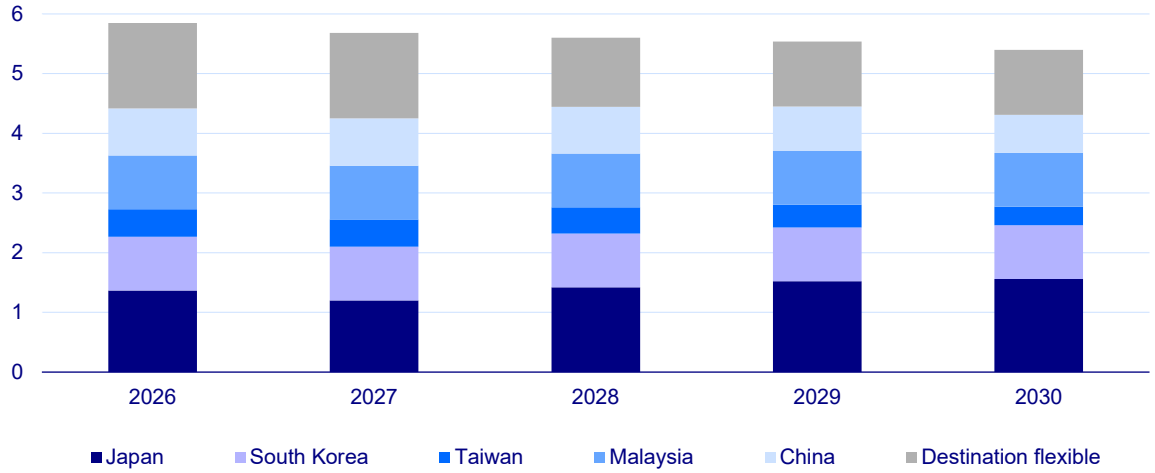
1. Kpler, assumed average speed of 16 knots to Sodegaura LNG Terminal
2. Wood Mackenzie LNG Tool, Q1 2026 dataset. dataset includes Operational, Under Construction, Possible, and Probable Development projects. "High" heating value LNG is defined as equal to or greater than 1,075 Btu/scf, "Average" is between 1036 and 1074 Btu/scf, "Lean" is less than or equal to 1,035 Btu/scf
3. Current based on 2026 Santos portfolio equity volumes. 2040 estimate based on equity volumes

Realised LNG pricing premium

~14.6 per cent average portfolio Brent slope equivalent in 2025, a structural pricing premium to LNG peers

Contracted LNG volumes by buyer country[1]

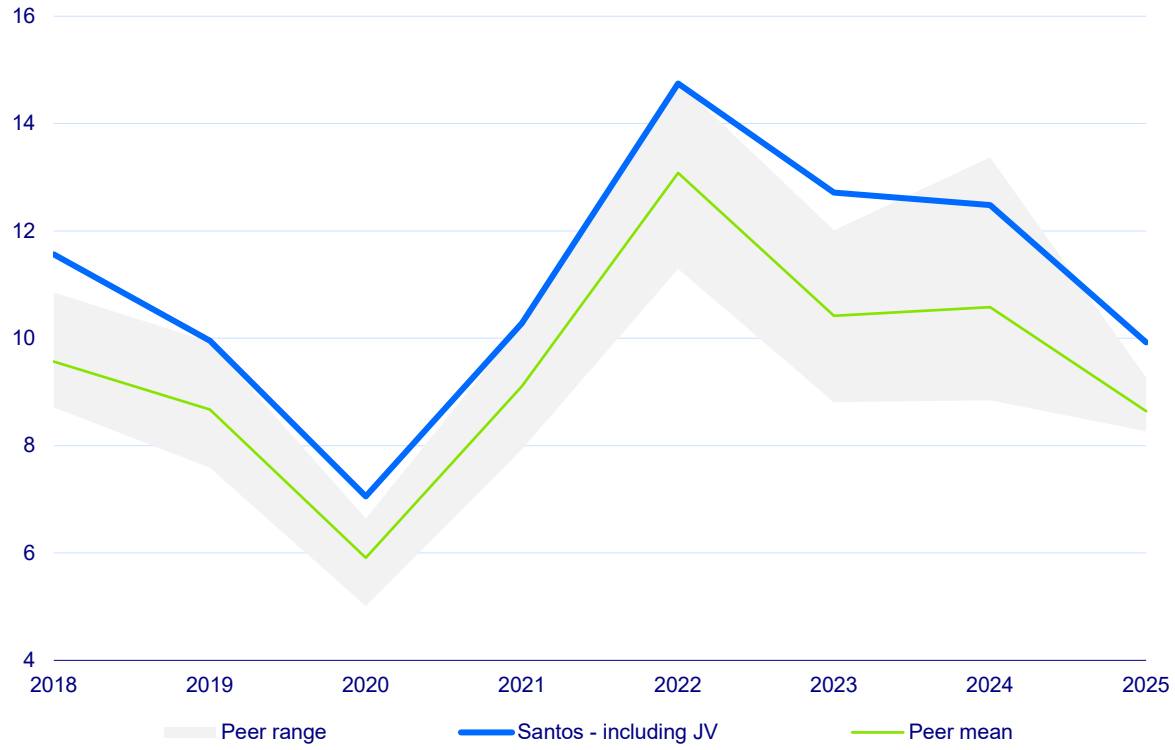
LNG volume contracted, Mtpa



Market	Key buyers	Contract
JKT[2]	Utilities, city gas, industrial	Long-term, oil-linked
China	Integrated energy	Long-term, oil-linked
Malaysia	National oil company	Long-term, oil-linked
Trading / portfolio	Majors, commodity traders	Mid-term, portfolio supply

Realised LNG pricing[3]

LNG price, $/mmBtu



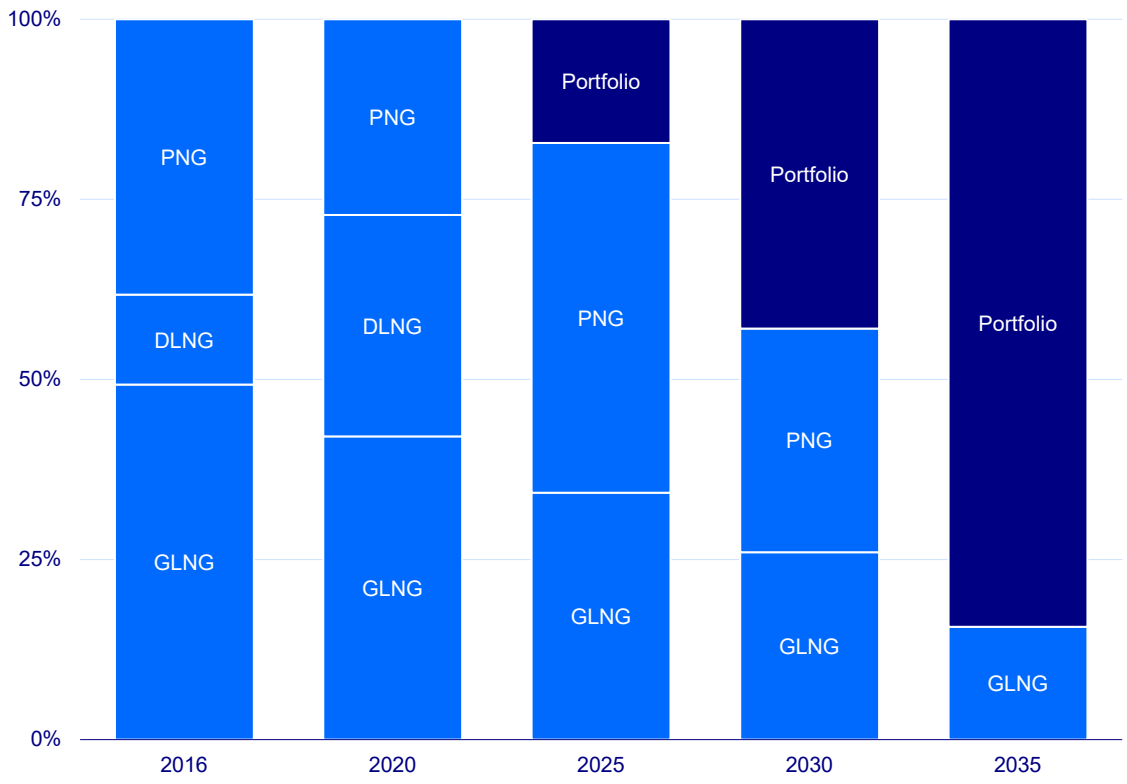
1. Santos outlook. Destination flexible volumes reflect contracts with no fixed import market
2. Japan, South Korea, Taiwan
3. Wood Mackenzie, Weighted Average Price of Gas (WAPOG) of Santos vs Peers. Contracts only, DES equivalent, Santos LNG Corporate, April 2026

Equity marketing delivering value

Equity marketed LNG supply, enabling portfolio marketing and optimisation to deliver tangible value to shareholders

Santos LNG contracted volume mix[1]

% contracted volume



~14.6%

Premium pricing
Average realised slope to Brent in 2025

~80%

Contracted target
~20 per cent preserves spot exposure upside

0.5 Mtpa

Supply-backed optimisation
Delivered YTD26. Mid and long-term contracts enable Santos to capture incremental margin going forward

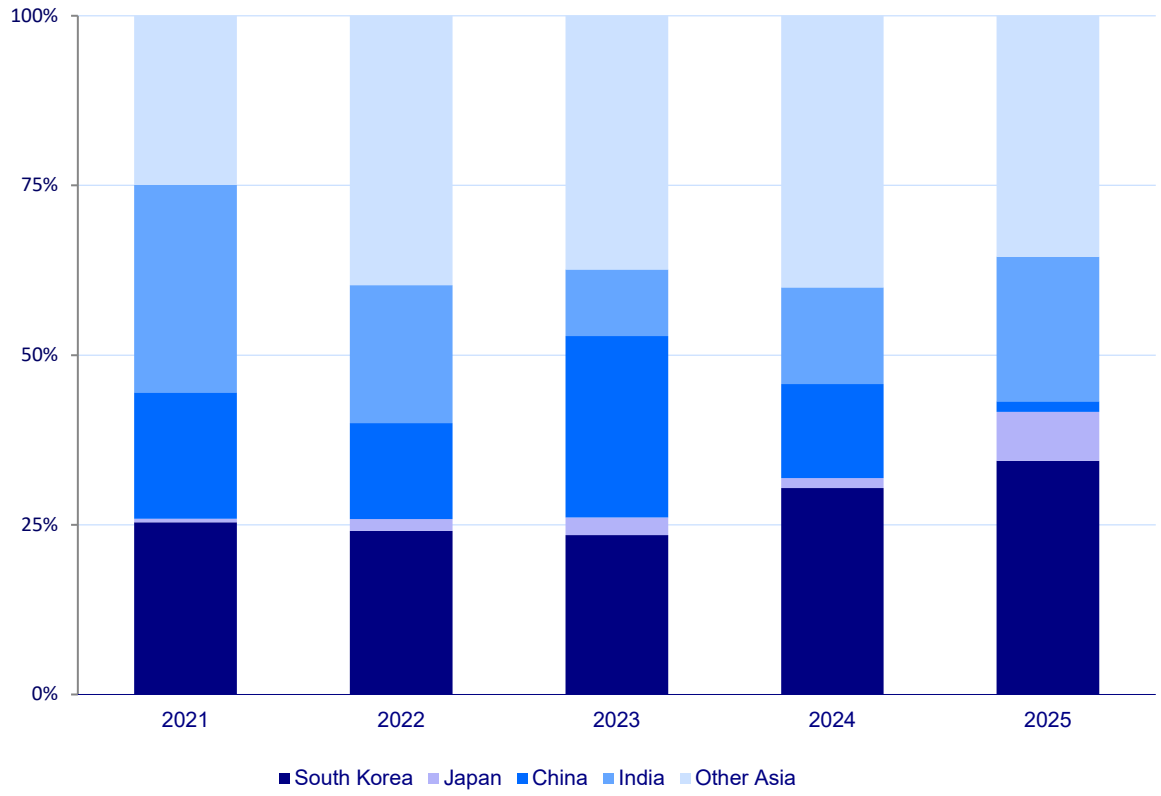
1. Santos outlook. Portfolio tranche shows portfolio contracts and portfolio volumes available. All Barossa volumes categorised under Portfolio

Strong demand for crude into Asia

Strong demand and pricing for Santos' Alaskan crude volumes into Asia

Asia crude oil imports from the US[1]

% share by country



~$20/bbl

Peak ANS premium over Brent in 2026[2]

~30–32° API

High diesel and jet yields, preferred by complex Asian refineries

100%

Santos Alaska crude is expected to be sold to Asian refineries

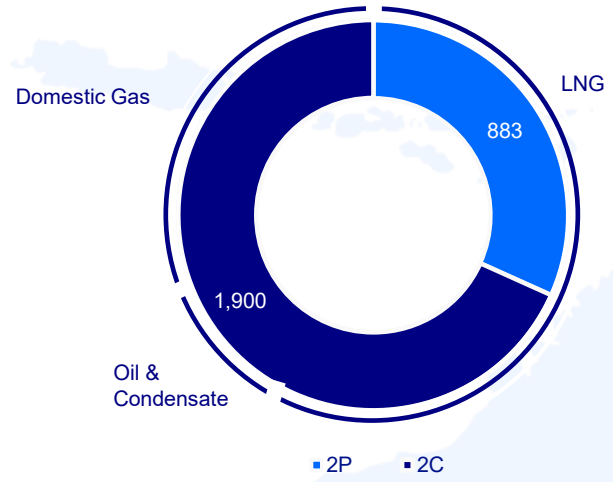
1. EIA Crude Oil Exports by Destination, March 2026
2. Argus Media, ANS USWC differential to ICE Brent CMA

RESERVES AND RESOURCES

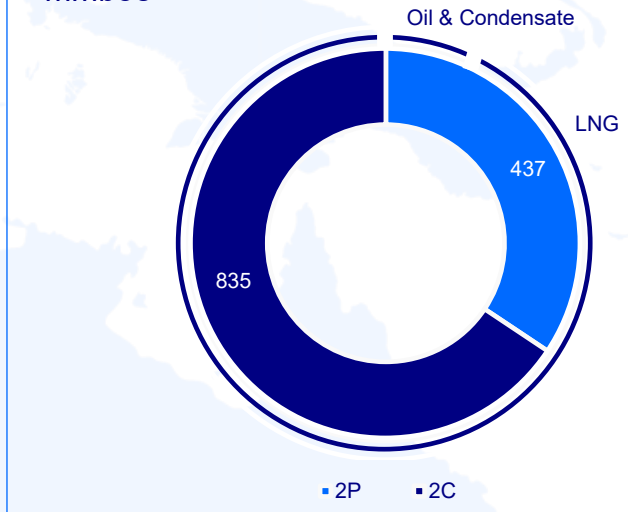
Resource depth around existing infrastructure

Three growth hubs. 10-year 1P reserves life index, 17-year 2P reserves life index[1], 3.2 billion 2C contingent resource to sustain and grow the business over the long term

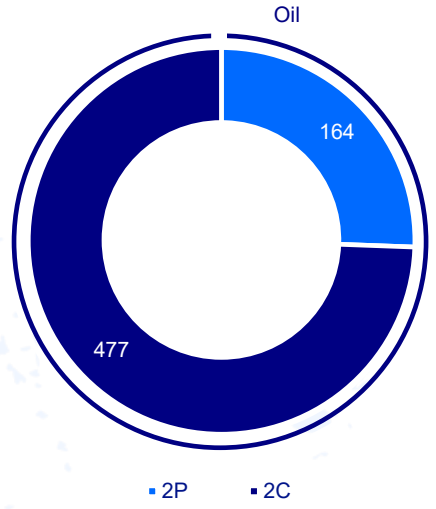
Australia
mmboe



PNG
mmboe



Alaska
mmboe



Scale and optionality

4,696[2] mmboe

2P reserves : 1,484 mmboe

2C contingent resources: 3,212 mmboe

LNG & liquids focus

83 per cent

Liquids & LNG

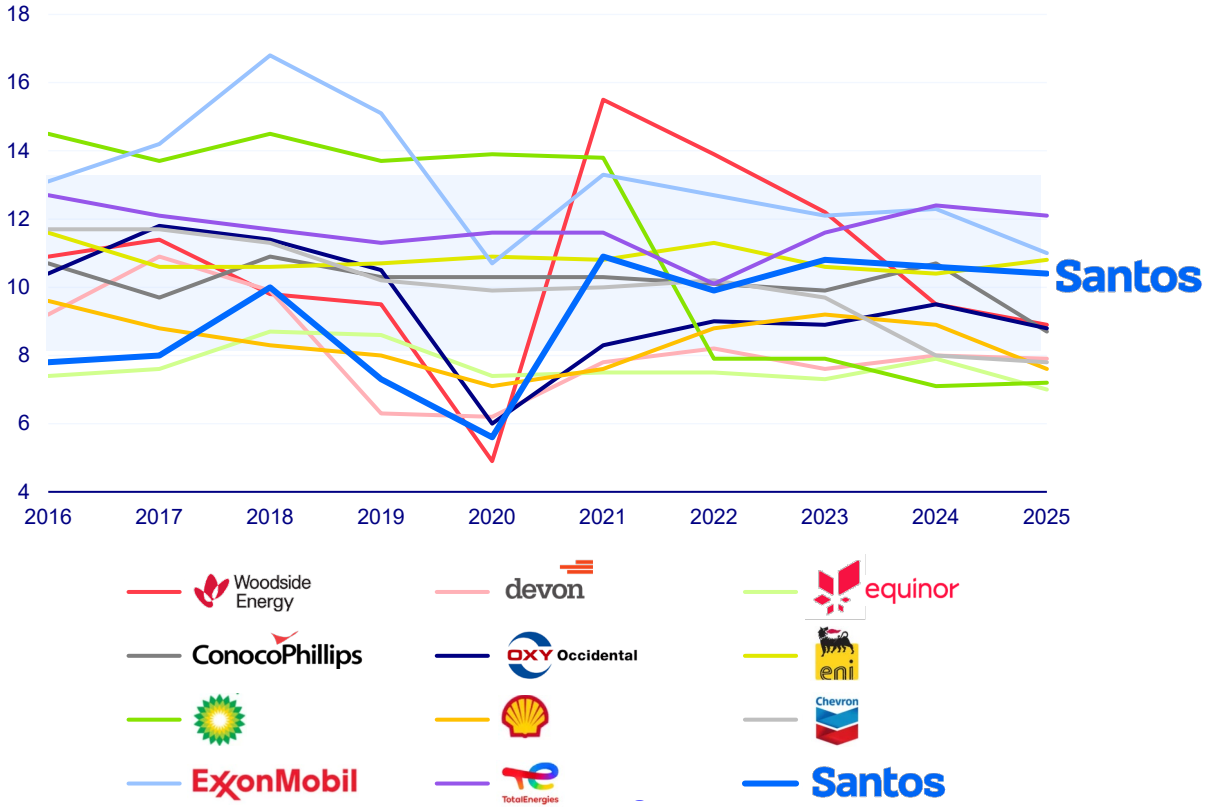
1. Reserves life is YE Reserves divided by that year's production
2. Reserves and contingent resources as of 31 December 2025

Capitally efficient reserves replacement

1P reserves life index maintained at peer-leading levels through production growth

Reserves life index in the efficient zone

1P Reserves Life Index[1,2] (Years)



Top end of global peers

Santos 1P reserves life: ~10 years. Top end within peer group. Built and maintained while production grew >40 per cent

3.2 billion boe competing for capital

2C contingent resource competing across 3 operated growth hubs. Each with funded pathways to development

Cost per barrel improving

Development cost trending down into better projects

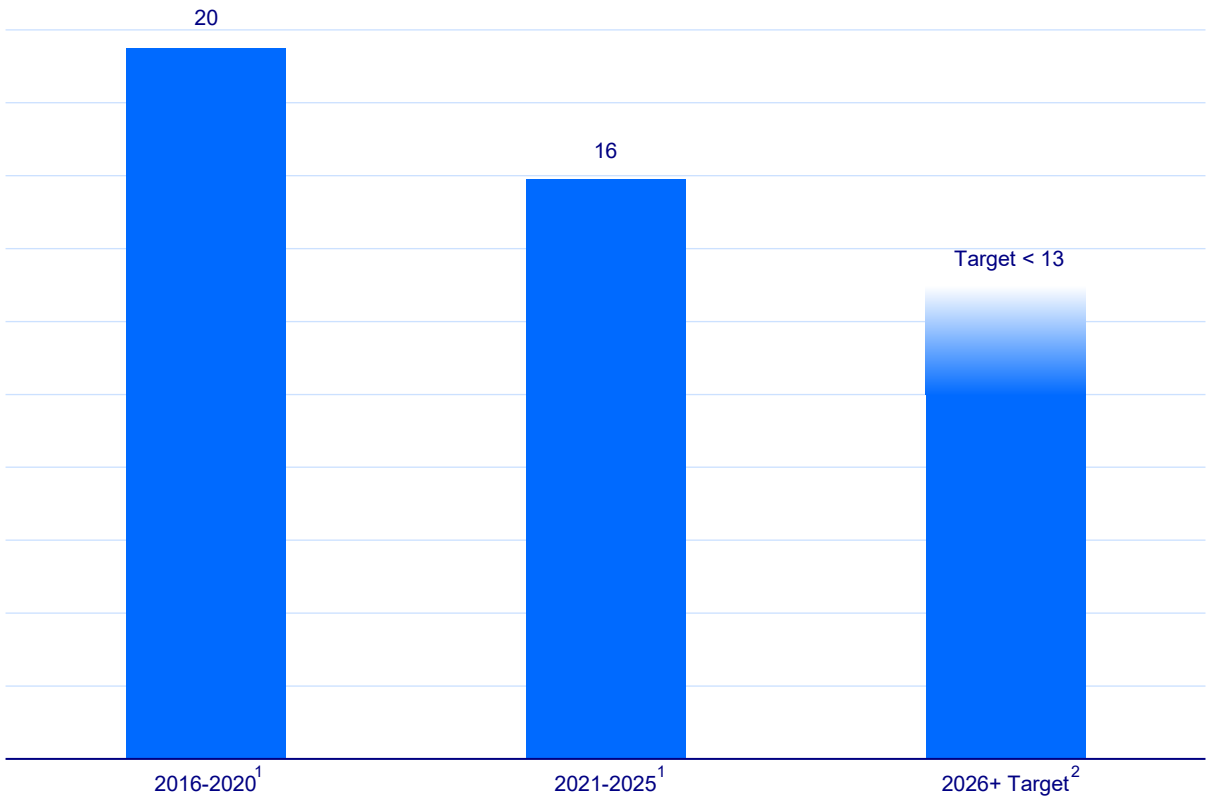
1. 1P Reserves Life Index = YE 1P Reserves divided by that year's production
2. S&P Global Energy, ©2026 by S&P Global Inc. Publicly available

Replacement cost trending down

Portfolio transition underway, supported by depth in advantaged resource portfolio

Organic 2P Developed Reserve Replacement Unit Cost[1,2]

$/boe



Advantaged portfolio

Transitioning investment to higher quality tier-1 assets

Internal competition drives efficiency

3.2 billion boe of 2C competing with attractive prospective opportunities across three hubs

Resource depth

Providing optionality on timing and sequencing of projects

Adding value

Operated positions proximal to existing infrastructure

1. Replacement costs represent investing cash flows on E&E and O&G assets divided by newly developed 2P reserves (organic only), normalised to 2026 real terms using US CPI data
2. Target average finding and development cost of future oil and gas reserves developments from existing 2P undeveloped, 2C and prospective opportunities 2026 to 2035. Normalised to 2026 real terms using US CPI forecast

BREAK

Developing large scale basins to support backfill and growth across Oil & LNG Hubs

Development pipeline across three regions, funded within disciplined allocation framework – from near-term development to exploration[1]

Australia

Beetaloo Appraisal	Appraisal of multi-tcf opportunity to support GLNG, DLNG growth and domestic markets
Bedout Appraisal	Three-well exploration program in 2027
Dorado	FEED-ready, high-return, short payback cycle oil development

PNG

APF Tie-In	Converts 66 mmboe 2P undeveloped reserves[1] to developed reserves
CPF Expansion	Debottlenecking up to 1.6 mmboe per year
Papua LNG FID	New long-life foundational project, converting ~200 mmboe 2C to 2P[2] at FID
PNG In-fill	Four new drills targeting short-cycle liquids production
Mosa	Santos operated oil exploration well with PNG LNG backfill upside

Alaska

Pikka phase 1 Expansion	Opportunity for potential expansion up to 120,000 bopd gross plateau
Quokka	Permitting and engineering activities to mature current 2C resource of 177 mmbbl
Horseshoe	Appraisal and extension of current 2C resource of 46 mmbbl

1. All references to 2P Reserves and 2C contingent resources are as at 31 December 2025
2. 2C to 2P conversion of ~200 mmboe requires FID and assumes Santos equity reduces to 17.7 per cent following government back-in. Conversion is subject to multiple contingencies and there is no certainty that FID will occur or that resources will be converted to reserves

OIL & LNG GROWTH HUBS UNDERPINNED BY LARGE SCALE TIER-1 BASINS

Operational updates

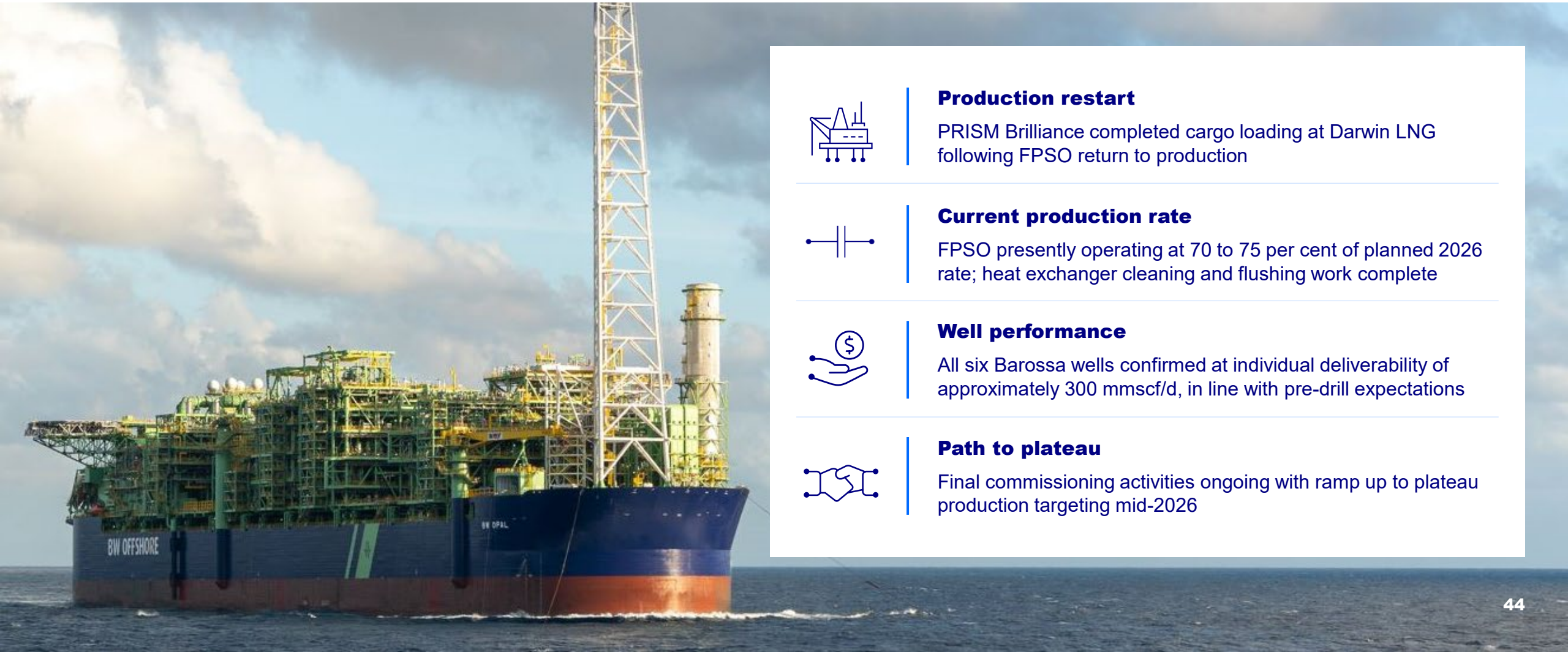
Reliable base business performance, with Barossa ramp-up strengthening Santos' LNG portfolio

	Australian Domestic Oil & Gas		Australia LNG		PNG LNG
					
	Cooper	**WA offshore gas**	**GLNG**	**Barossa / DLNG**	**PNG LNG**
Status	Producing	Producing	Producing	Commissioning	Producing
Plant Capacity[1]	400 TJ/d	390 TJ/d	8.6 Mtpa	3.7 Mtpa	8.3 Mtpa
Upstream Liquids Capacity[1]	8,630 bbl/d	11,700 bbl/d	None	8,080 bbl/d	25,280 bbl/d
Operations / Projects	MCO project FID Executed Key Term Sheet with SA Govt. to supply 20 PJ per year	Halyard 2 continues to produce ~80 mmscf/d Harriet Alpha platform safely removed ahead of schedule	5.8 Mtpa run rate in Q1 with 24 cargos shipped 63 wells drilled year to date, on track to deliver 184 by year end	Barossa first cargo January 2026 Continuing Barossa production ramp to full rates	8.6 Mtpa run rate in Q1 with 28 cargos shipped APF tie-in and KPS FSO project FIDs
Working interest	66.6%	100%	30%	43.4% DLNG / 50% Barossa	39.9%
Operator	Santos	Santos	Upstream – Santos Downstream – GLNG OPL	Santos	ExxonMobil
Joint venture partners[2]	• Beach Energy	None	• TotalEnergies • Petronas • KOGAS	• SK E&S • INPEX • Eni • JERA • Tokyo Gas	• ExxonMobil • Kumul Petroleum • ENEOS Xplora • MRDC

1. Gross
2. Plant joint venture partners – upstream partners may differ

Barossa / Darwin LNG – project update

Barossa at 70 to 75 per cent of planned rates; plateau targeted mid-2026



Production restart

PRISM Brilliance completed cargo loading at Darwin LNG following FPSO return to production

Current production rate

FPSO presently operating at 70 to 75 per cent of planned 2026 rate; heat exchanger cleaning and flushing work complete

Well performance

All six Barossa wells confirmed at individual deliverability of approximately 300 mmscf/d, in line with pre-drill expectations

Path to plateau

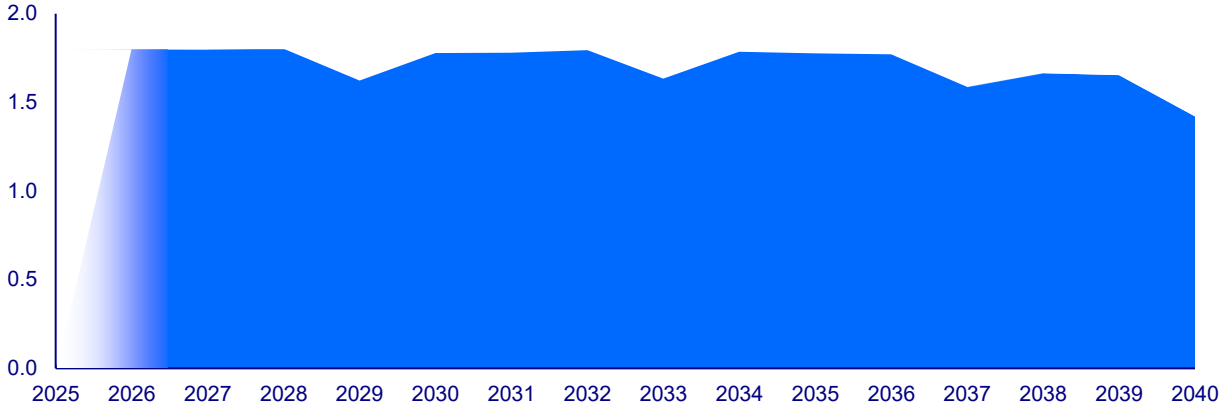
Final commissioning activities ongoing with ramp up to plateau production targeting mid-2026

Barossa / Darwin LNG

20-year production supplying low-cost, high heating value LNG to proximal markets

Barossa LNG Sales[1]

Mtpa (STO share)



Barossa / Darwin LNG

~3.7 Mtpa

First cargo in January 2026

~635 mmscf/d

Export capacity from the FPSO to DLNG, gross

~300 mmscf/d

Individual well deliverability confirmed across all six wells

Barossa gas fully utilises DLNG Train 1

Until 2038, with Caldita tie-back to support future backfill

<$7/boe unit production cost

Unit production cost at steady state

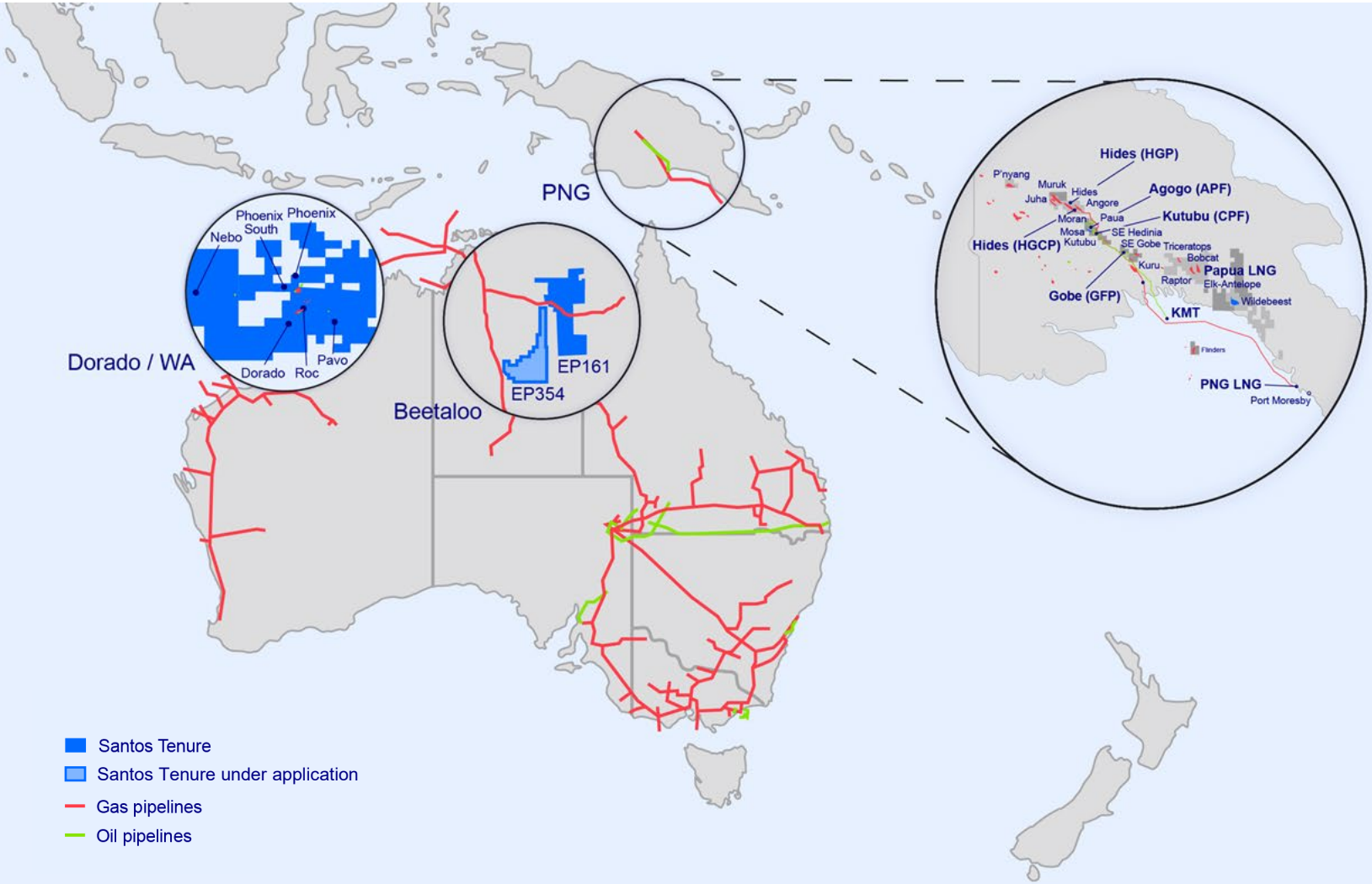
Abated LNG production opportunities

Through Bayu-Undan CCS

1. Indicative only (not guidance). Commissioning and ramp continuing through 2026

Australia & PNG Growth Opportunities

LNG and integrated gas and oil assets with material growth potential



Papua New Guinea

Papua LNG, P'nyang, Muruk, Juha, APF Tie-in, Mosa, Infill Oil

Beetaloo / Onshore shales

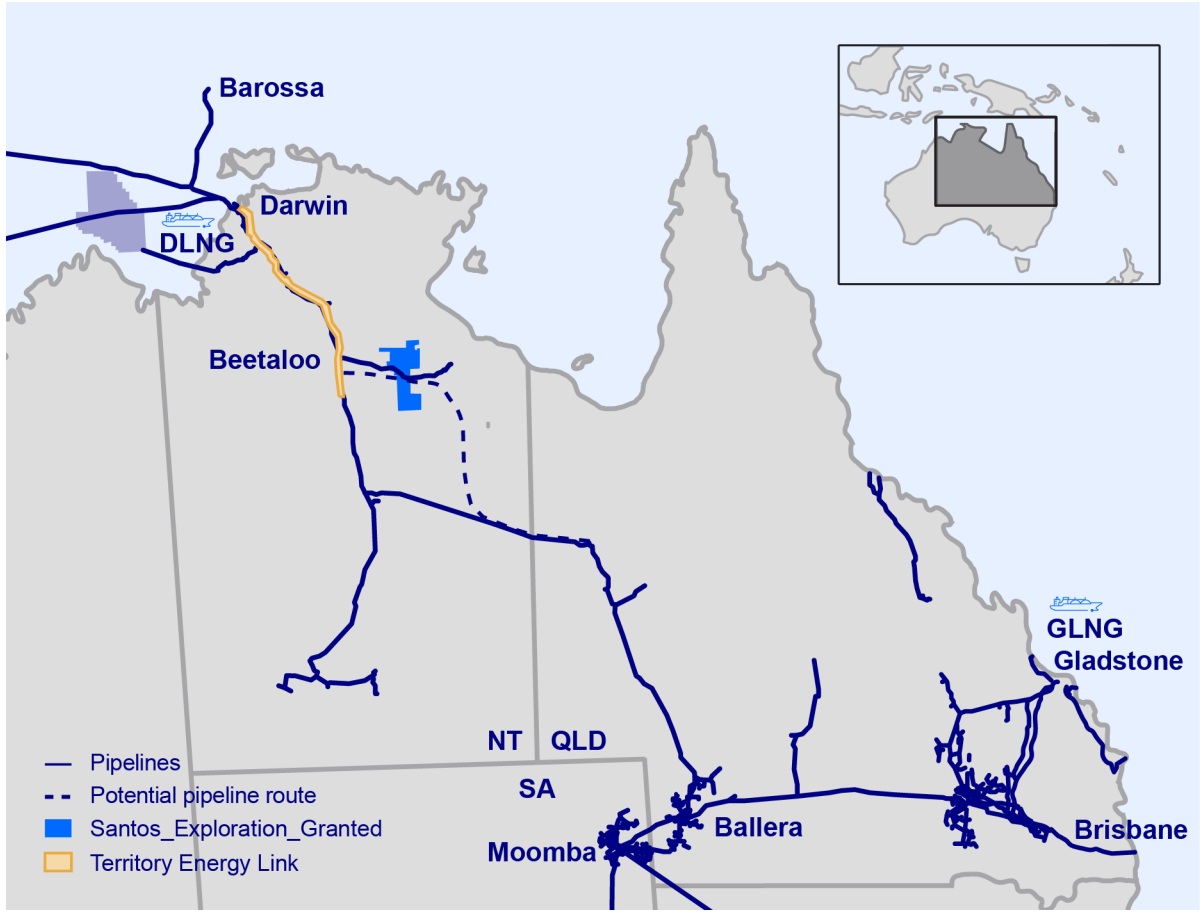
Beetaloo

Dorado / Bedout Basin

Dorado, Pavo, Ara, Higgs, Goats Eye, Hutton, Yuma

Beetaloo: Unlocking the next major gas province

World-class shale play targeting <$6/mmBtu LNG with evacuation options east and north to existing Santos infrastructure



Estimated >430 tcf Beetaloo gas in place[1]

The Beetaloo Basin is estimated to contain more than 430 tcf of undiscovered gas-in-place, on a basin-wide P50 basis. Santos acreage has the potential to supply up to 10 Mtpa LNG and the east coast market for 50+ years

Multiple export pathways

Unique access to GLNG's existing capacity, DLNG's Train 2 expansion, and the east coast market

Development targeted appraisal spudding 2026

Success supports FID of a 500 TJ/d development concept with expansion potential up to 3,000 TJ/d

CCS connection

Evacuation options can connect to Moomba CCS & future Bayu-Undan CCS hubs

Supportive jurisdiction

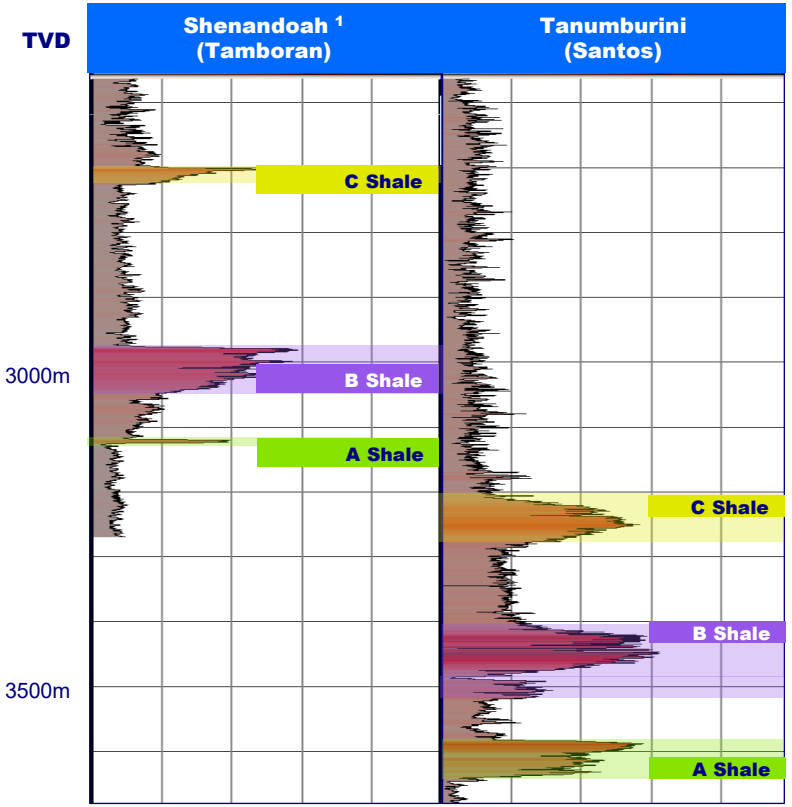
Prioritised resource opportunity of strategic importance to the Northern Territory

1. The Beetaloo Sub-basin: Australia's next gas supply. Department of Mining and Energy, Northern Territory, page 4

Beetaloo: high quality, stacked shale targets

Higher quality shales with deeper, thicker, higher pressure, multi-stacked targets with high total organic carbon; targeting 20.5 mmscf/d per well 2026 / 2027 appraisal wells

Well Logs



~360,000 acres[2]

Gross, surface acreage in Santos' EP161 within the dry gas window;

Comparable geology to the Marcellus and Utica fairways which achieve 15 to 35 per cent recovery factors

Three shale targets

Allows integrated, capital efficient development

>200 m net thickness

Supporting higher density development and greater volumes

Deeper shale targets

With high Total Organic Carbon (TOC) source rocks

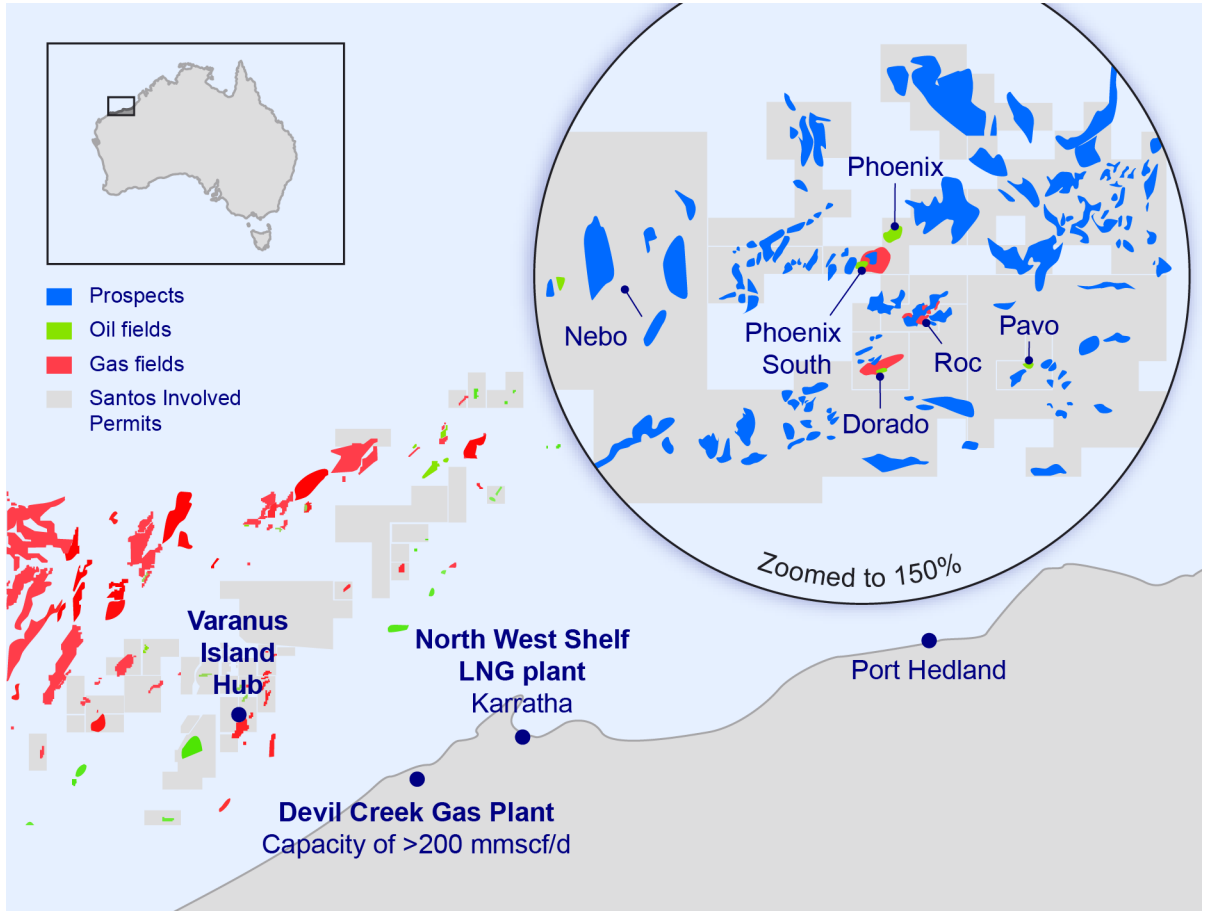
Higher pressures

Over pressured formations increase deliverability

1. 2024 Shenandoah S-1 and Shenandoah S-1H Well Completion Report (open file: https://geoscience.nt.gov.au/gemis)
2. Subject to appraisal well results

Bedout Basin: Dorado oil development with gas upside

Dorado oil project with targeted exploration drilling to build on the discovery and testing the potential to become another growth basin



Largest undeveloped oil project in Australia

High quality oil development in shallow water

20-year production

Dorado field appraised with 11,100 bbl/d well test on Dorado-3

292 mmboe, Gross Bedout Basin 2C resource[1]

Dorado: 213 mmboe; Pavo: 34 mmboe (gross 2C resource)

Primary approval secured

Phase 1 Offshore Project Proposal (OPP) approved, including Pavo tie-back and production licence awarded

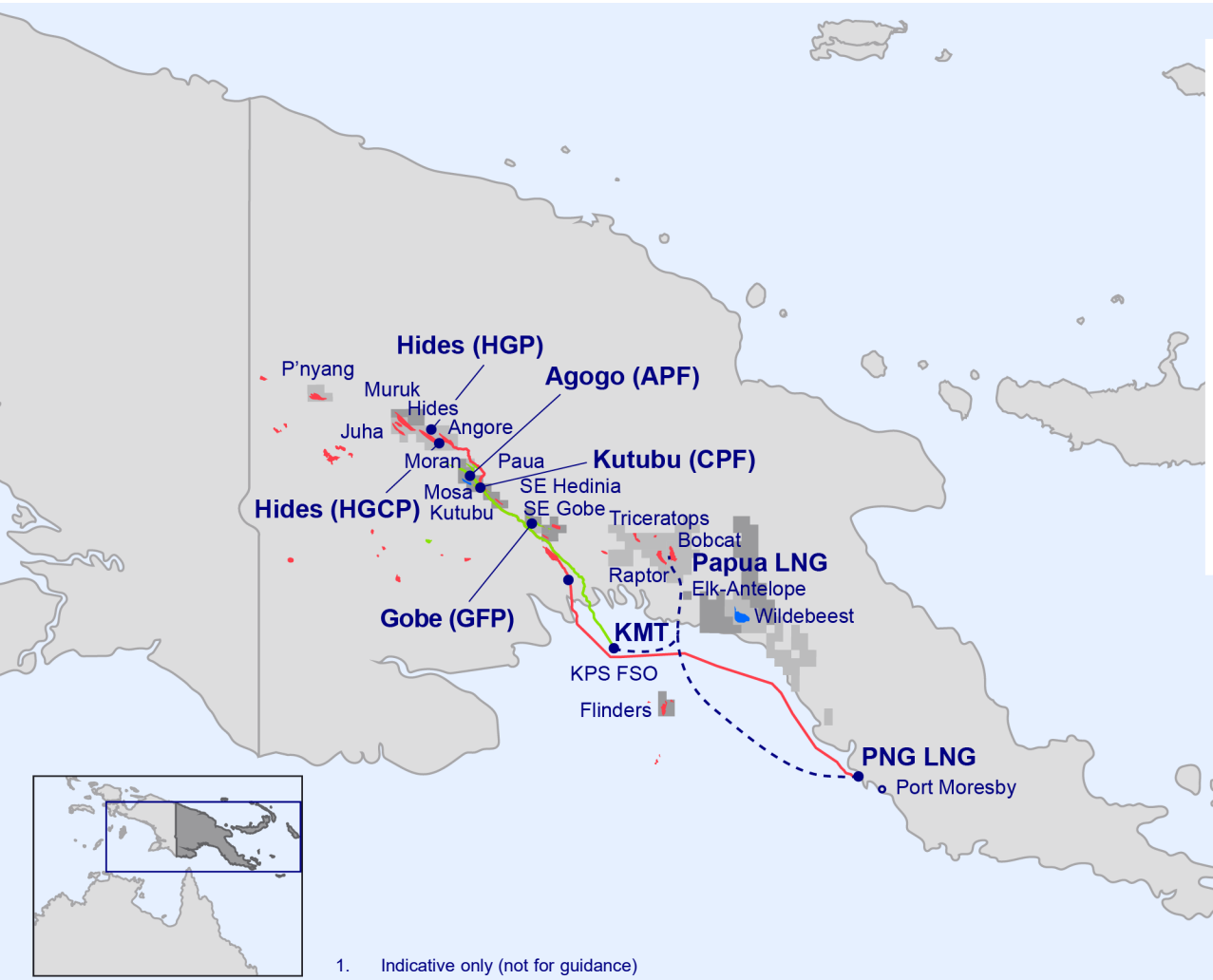
Building resource scale

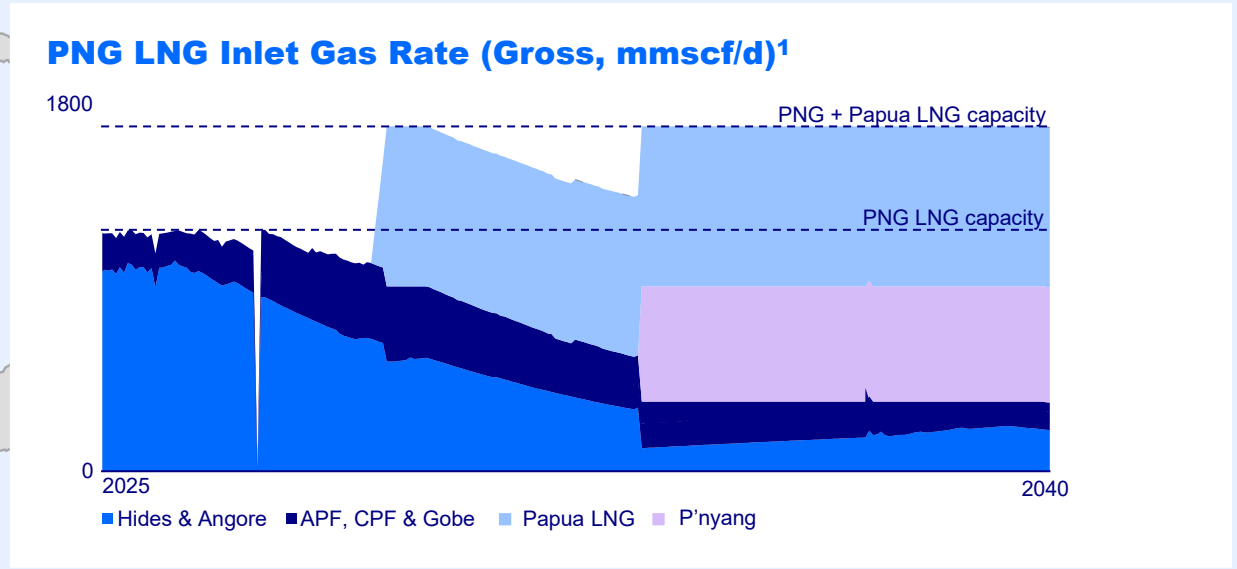
Three exploration wells planned for 2027 to test integrated oil and gas prospects in northern part of basin, to prove scale potential

1. 2C contingent resources as at 31 December 2025. Net Santos: Bedout Basin 230 mmboe; Dorado 170 mmboe; Pavo 24 mmboe

Papua New Guinea

World class asset close to Asian markets with PNG LNG backfill and expansion runway





Santos operated
Santos non-operated
Prospects
Gas fields
Oil fields
Gas pipelines
Oil pipelines
Pipeline
Facilities

1. Indicative only (not for guidance)

Near term PNG LNG backfill strategy

Multiple opportunities to backfill PNG LNG before Papua LNG comes online

APF Tie-In Project

Development of associated gas from Agogo and Moran oil fields to supply up to 135 mmscf/d[1]

Execute phase – target startup Q2 2028

CPF Expansion

Added compression to increase CPF gas export capacity by ~55 mmscf/d[1]

Target FID ready 2027 for startup 2029

APF Expansion

Modify existing facilities to increase gas export capacity by ~50 mmscf/d[1]

Target FID ready 2028 for startup 2030

Gobe Extension of Field Life

Extend field life by optimising existing infrastructure and unlocking potential reserve additions

Target extension beyond 2028

Field Optimisation

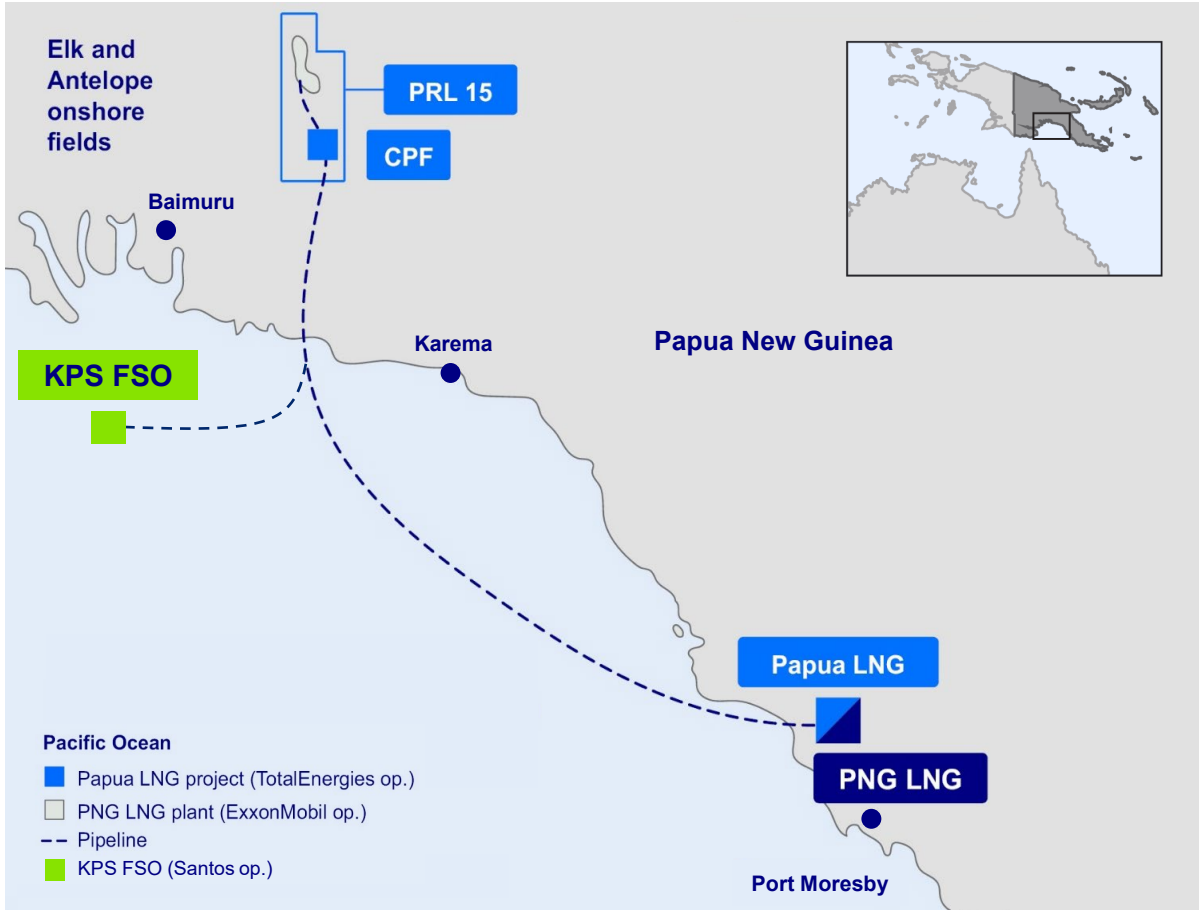
Well interventions and AI capability to optimise production, including 0.7 mmboe incremental 2026 production

Ongoing

1. Gross

Papua LNG: growth asset with multiple value streams

Infrastructure access fee, processing toll and project finance add substantial project economic contributions



Up to 6 Mtpa

Gross annualised production, providing 1 Mtpa and 11 mmboe / year STO production

~$14.5 billion[1] capex (gross)

EPC rebid completed, delivering ~$4 billion CAPEX reduction. Gross capex includes ~$700 million in approximately 2039

FID target 2H 2026

Environmental permits issued; Development Forum planned mid-2026; well progressed in securing project financing

39.9 per cent of PNG LNG access fee and tolling

One-off payment compensates PNG LNG owners for infrastructure access and processing toll reservation

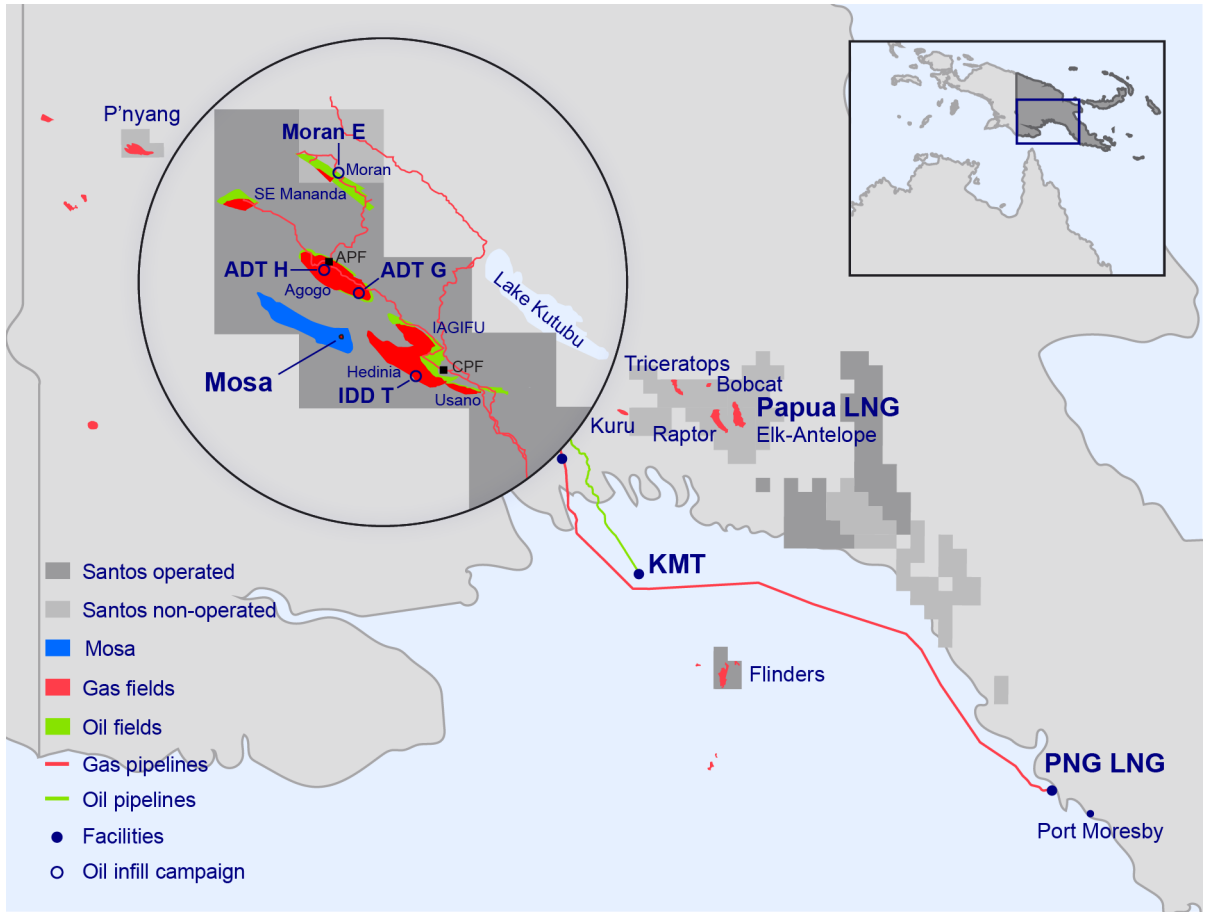
Integration with Floating Storage Offloading Vessel

Material cost reduction from integration with Kutubu Pipeline System FSO

1. As indicated by Operator, Total Energies, April 2026

PNG oil: high returns, using existing infrastructure

Low-cost, short cycle oil production from infill drilling. Growth potential from 50,000+ bbl/d (gross) Mosa opportunity with short tieback to existing Santos infrastructure



Mosa oil prospect

50,000+ bbl/d Mosa prospect[1]

Identified using modern LiDAR topographical mapping, seismic data & surface geology

Toro / Digimu sandstones

High quality reservoirs produced at Kutubu, Hedinia, Agogo and Moran fields

Low development cost, ~3km tieback from infrastructure

To existing Santos-operated Central Production Facility

Oil infill drilling

Incremental short cycle oil production

Plan to drill four infill oil wells in 2027, convertible to gas as APF Tie-in comes online

31 per cent IRR

Payback of 3.8 years; cost sharing with PNG LNG; incremental value to APF Tie-In

1. 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 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 recoverable hydrocarbons. 50,000 bbl/d is unrisked. Chance of discovery = 39 per cent

ALASKA

Pikka phase 1 – project update

First oil achieved; intermittent production during commissioning with plateau of 80,000 bbl/day (gross) targeted Q3 2026

First oil flow achieved through LACT[1]

Ramping to 20,000 bbl/day (gross) with intermittent production as key subsystems are progressively brought online

Plateau of 80,000 bbl/day (gross) target Q3 2026

Production holds at 20,000 bbl/day (gross) pending STP[2] start-up and establishment of water injection

Continuous operations

Remaining late-stage commissioning activities include NPF[3] produced water management and gas compression system start-ups

Ramp up and plateau

STP start-up combined with continued well stock inventory build drives plateau attainment

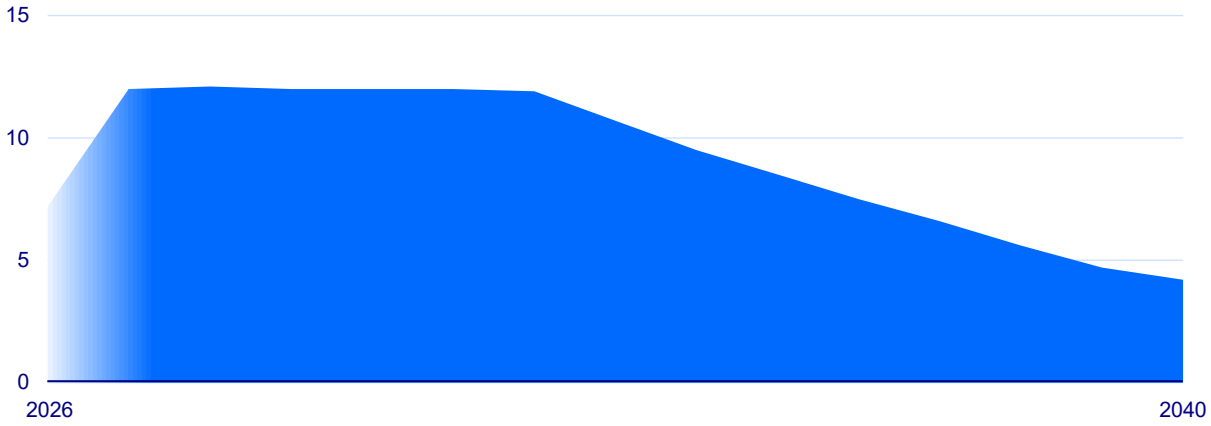
1. LACT refers to the Lease Automated Custody Transfer meter
2. STP refers to Seawater Treatment Plant
3. NPF refers to Nanushuk Processing Facility

Pikka phase 1: platform for Alaskan growth

Pikka field potential (all phases): ~400 mmboe gross 2P; ~600 mmboe gross 2C; prospective resource upside

Pikka phase 1 production

mmboe (STO share)



Pikka phase 1

~80,000 bopd

Plateau rate target Q3 2026

80,000 bopd
Phase 1 plateau rate 5–6 years

164 mmboe 2P net to Santos[1]; 252 mmboe 2C Pikka Unit upside

<$8/boe
Unit production cost

High margin barrels; stable US fiscal regime with established tax and royalty structure

+12.1 mmboe/yr
Production net to Santos

14-year phase 1 2P reserves life[2]

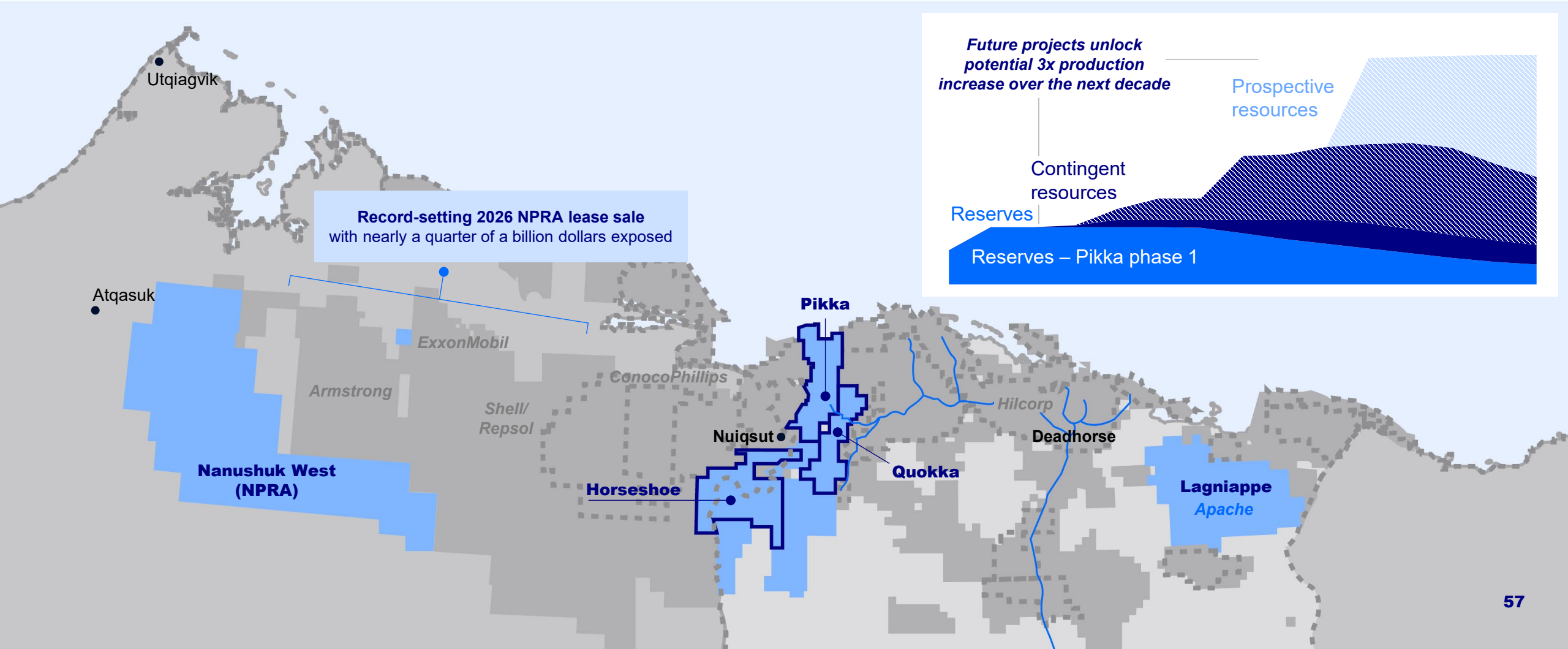
Net zero scope 1 and 2
From first oil (Santos equity share)

Project footprint only; electrified operations with low carbon intensity

1. Reserves and contingent resources as at 31 December 2025
2. 2P Reserves life as at 31 December 2025 using production of 12.1 mmboe/yr

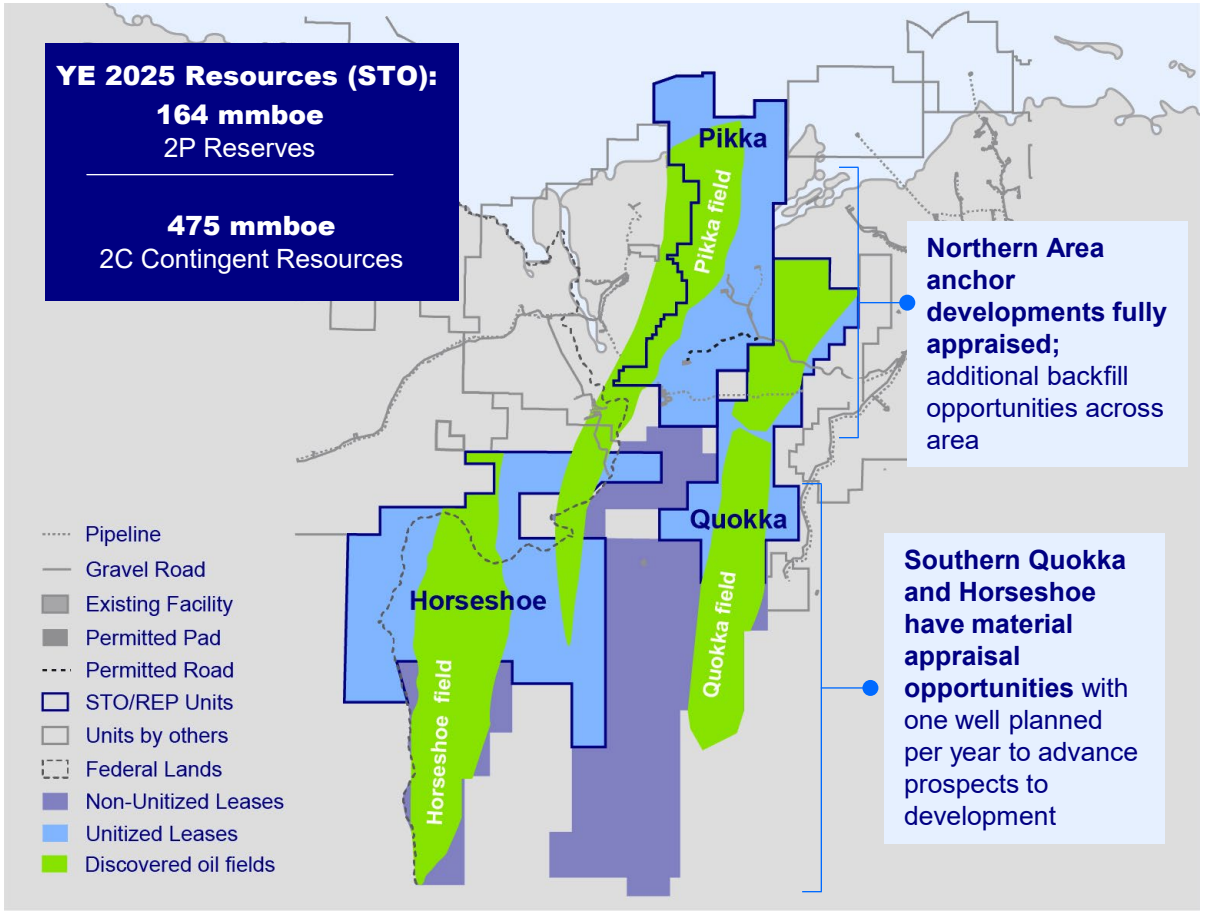
Alaska: Santos at the heart of the Nanushuk

Alaska North Slope renaissance led by Nanushuk, positions Santos as an early mover with a material resource base



Alaska: three fields, material resource base

Quokka and Horseshoe of similar potential scale to Pikka underpinning a long development runway



Pikka phase 1 establishes cash flow

Delivers 80,000 bopd (gross) on plateau, developing 164 mmboe 2P reserves[1] of high margin oil

Core infrastructure in place

Established facilities, roads and camps reduces future development costs and improves returns

Potential for additional Pikka-scale developments

Planned exploration and appraisal within region estimated to contain ~3 billion barrels of undiscovered technically recoverable oil[2]

Disciplined appraisal program

Disciplined appraisal program maximises value from each well to lower overall program cost

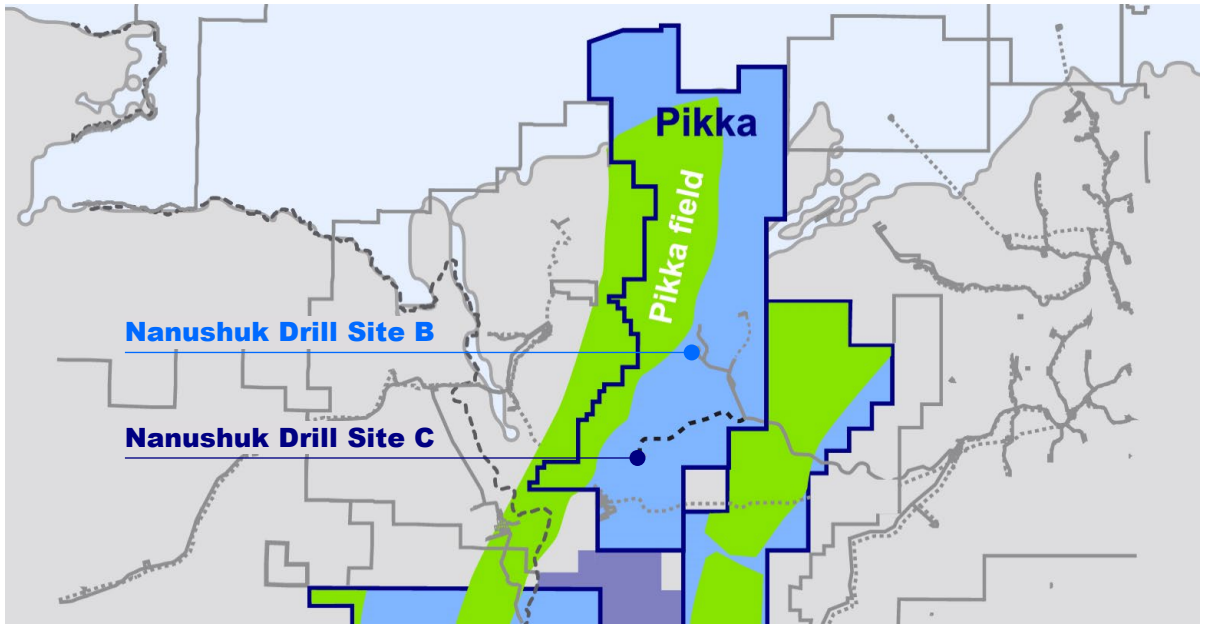
Low-cost, short-cycle growth

Development costs of $10–15 per barrel support growth within Santos' operating model

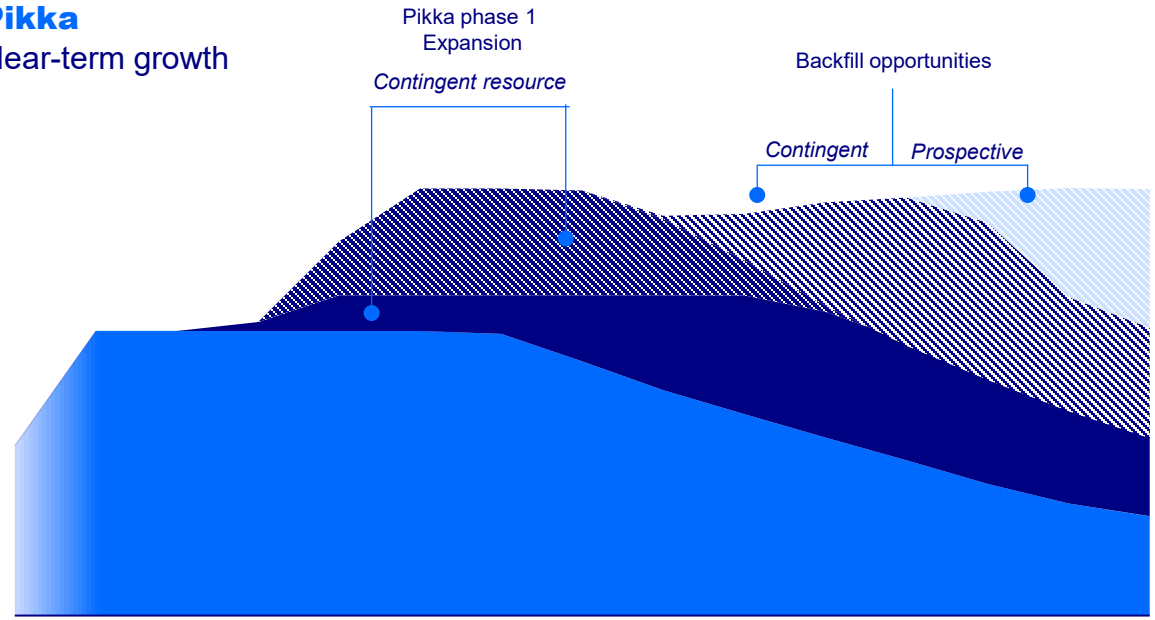
1. Reserves and contingent resources for Pikka, Quokka and Horseshoe Units as at 31 December 2025
2. P50 Undiscovered Oil per USGS Fact Sheet 2020-3001

Pikka: potential 1 billion barrel field[1]

~400 mmbbl gross[1] 2P entering production; additional 2C resource of ~600 mmbbl gross supporting staged development beyond



Pikka
Near-term growth



Second drill site ready for FID in 2026

Nanushuk Drill Site C fully appraised; major permits in place for 2026 FID

Low incremental cost to grow

Next development stage requires single drill site and connecting infrastructure only

Continuous drilling captures efficiencies

Uninterrupted drilling program and project team retention maintain the learning curve

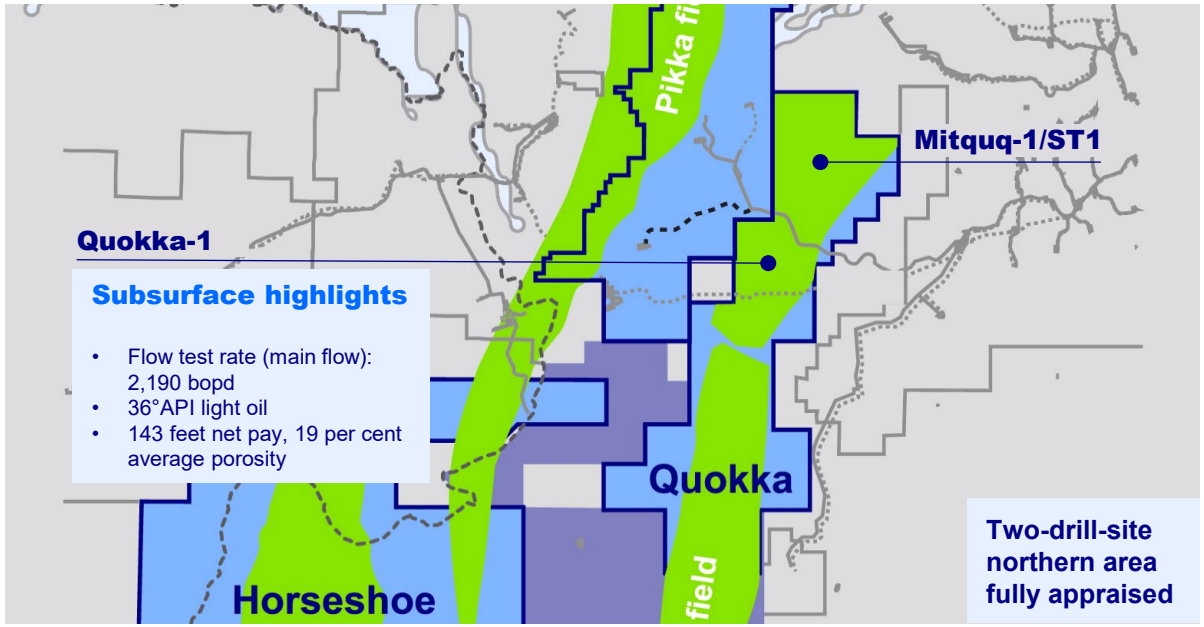
Expansion opportunities under evaluation

Facility expansion scoped once performance is known; Quokka synergies being assessed

1. As at 31 December 2025, 2P 164 mmbbl net Santos; 2C 252 mmbbl net Santos

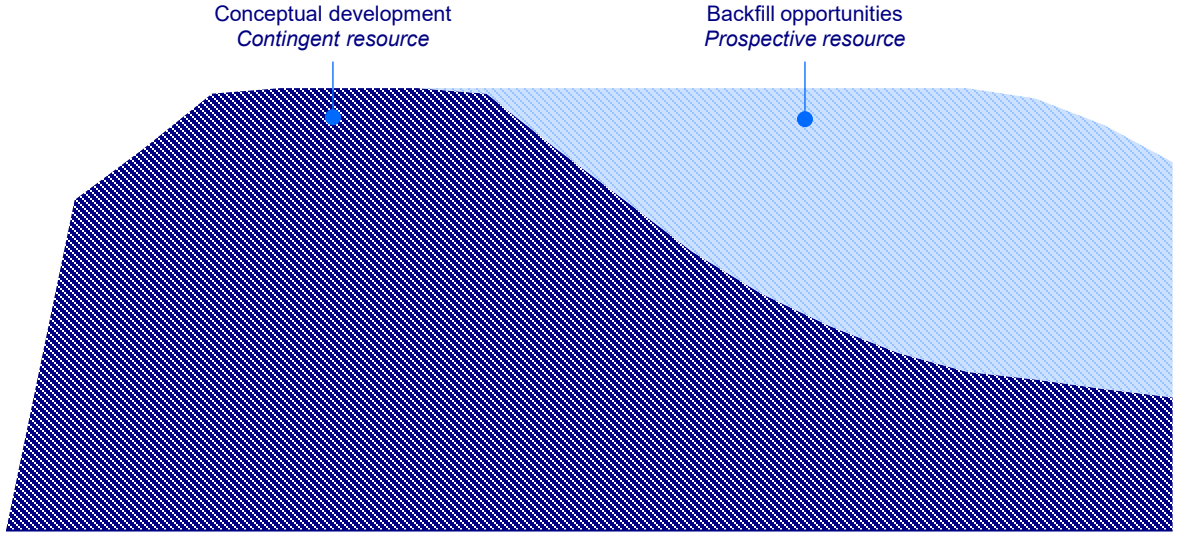
Quokka: pathway to development advancing

~450 mmbbl gross 2C resource supports future development with Pikka sized potential[1]



Quokka

Pikka-scale potential



Material resource confirmed

Quokka-1 supports a 177 mmbbl 2C resource (Santos share) across a two-drill site development area

Development pathway advancing

Major permitting underway; development seismic planned for winter 2026/27

Pikka infrastructure lowers costs

Established Pikka roads, camps, pipelines and seawater treatment reduce development costs

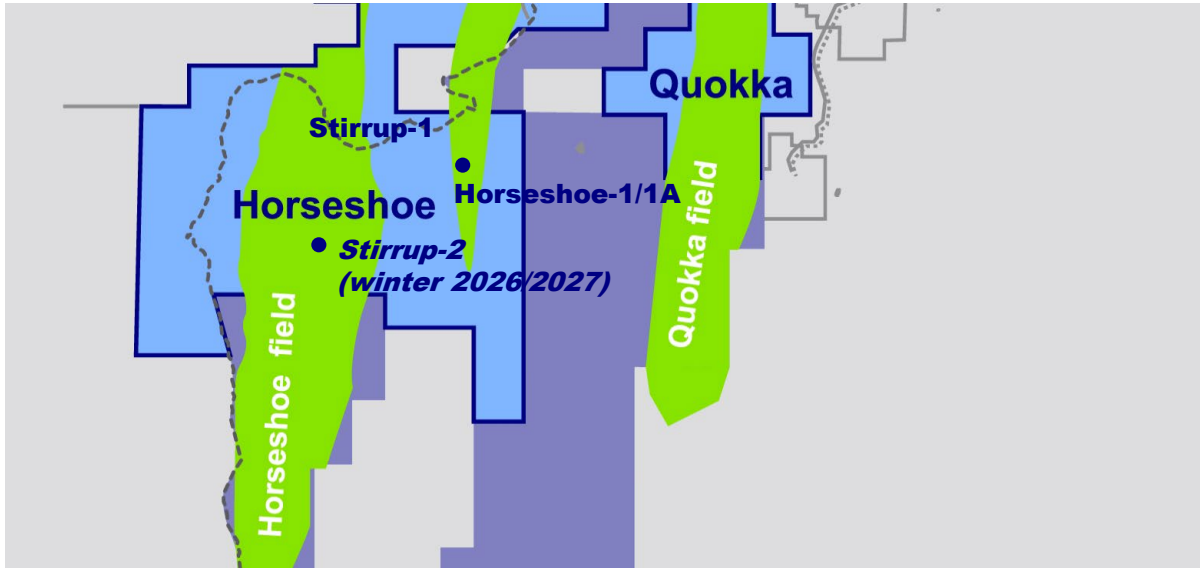
Southern Quokka upside retained

Southern Quokka highly prospective, yet to be appraised – would augment a Quokka or Horseshoe development

1. As at 31 December 2025; 2C 177 mmbbl net Santos; well results and higher working interest to be incorporated in YE 2026

Horseshoe: material upside

Appraisal targeting Pikka size field potential beyond current 2C resource of ~100 mmbbl gross[1]



Stirrup-1 subsurface highlights

- Highest flow rate of any single stage stimulation vertical Nanushuk well: 3,520 bopd
- 97 feet of high-quality net pay
- 17 per cent average porosity 39° API light oil
- Increased grain size relative to Pikka underpins deliverability

Additional large-scale upside

Current assessment suggests potential for standalone development

Reservoir quality established

Stirrup-1 and Horseshoe-1/1A confirm high-quality Nanushuk reservoir and fluids across two separate discoveries

De-risking continues

Drilling north of Stirrup-1 has de-risked the Nanushuk 0 feature

Next well: winter 2026/27

Stirrup-2 planned for winter 2026/27 – next step to converting subsurface potential to resource

Three fields across Santos' core Nanushuk play

~400 mmbbl gross 2P entering production; >1,000 mmbbl gross 2C slated for staged development; appraisal advancing to unlock Pikka scale potential at Quokka and Horseshoe

1. As at 31 December 2025; 2C 46 mmbbl net Santos

Santos

MIDSTREAM & ENERGY SOLUTIONS

Midstream & Energy Solutions portfolio

Creating long-term value through simplification, infrastructure optimisation and energy solutions capability

	East Coast Gas and Liquids		LNG		West Coast Gas
					
Midstream Infrastructure	Moomba, Port Bonython		Gladstone LNG	Darwin LNG	Varanus Island & Devil Creek
CCS Hubs	Moomba CCS & Low Carbon Fuels			Bayu-Undan CCS	WA CCS
2025 Reliability	99.8%	100%	100%	Commissioning	98.8%[1]
Nameplate Capacity	400 TJ/d gas 70 PJ storage 20 mmboe/yr liquids		8.6 Mtpa LNG[2] 54 PJ storage	3.7 Mtpa LNG Approvals to 10 Mtpa	390 TJ/d (VI) 220 TJ/d (Devil Creek)
CCS storage Capacity	Up to 20 Mtpa			Up to 10 Mtpa	Up to 5 Mtpa
Working Interest	66.7%		30%	43.4%	100%
Tolling	Internal + third party		Integrated	Internal + third party	Internal
Pipeline Network	14+ main trunklines, ~2,850 kilometers, Santos operated (including GLNG trunklines)				

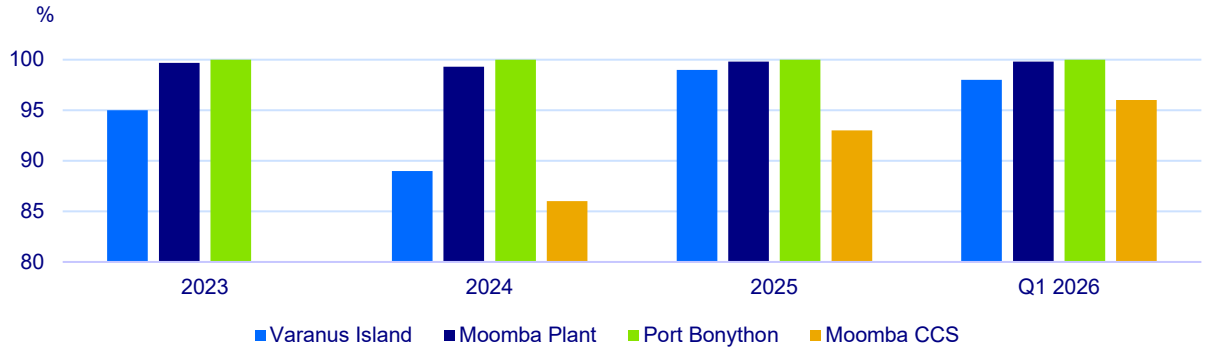
Delivering higher margins, unlocking value through operational efficiency, decarbonisation, CCS

1. Varanus Island Plant
2. Maximum capacity

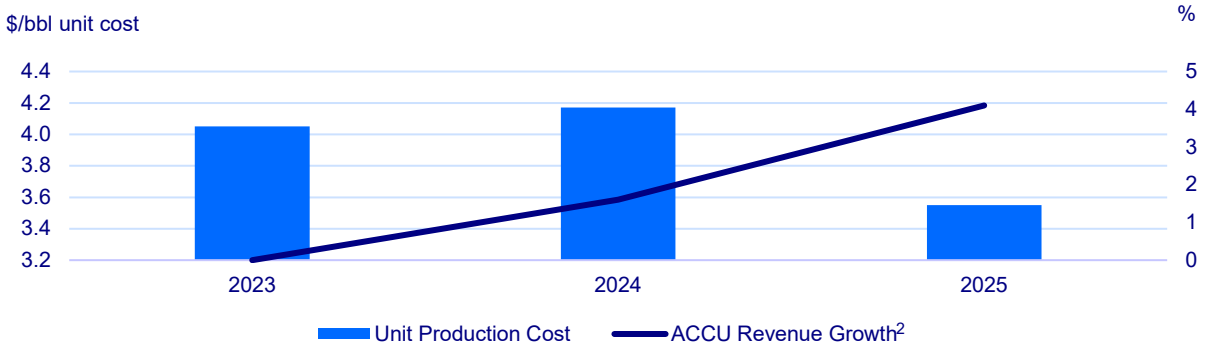
Strong midstream portfolio performance

Integrated infrastructure delivering reliable, low-cost processing

Reliability



Improved cost performance[1]



>95 per cent midstream reliability 3-year average, 2025 at ~100 per cent[1]

High-reliability consistently processing upstream volumes and increasing upstream production

15 per cent reduction in 2025 unit production cost

Improving cost performance through centralised campaign maintenance and shutdown execution

6 per cent EBITDAX 3-year CAGR[1]

Increasing revenue from higher STO Upstream throughput and Moomba CCS ACCU generation

Infrastructure investment extending asset life

DLNG online and processing Barossa gas post successful life extension project

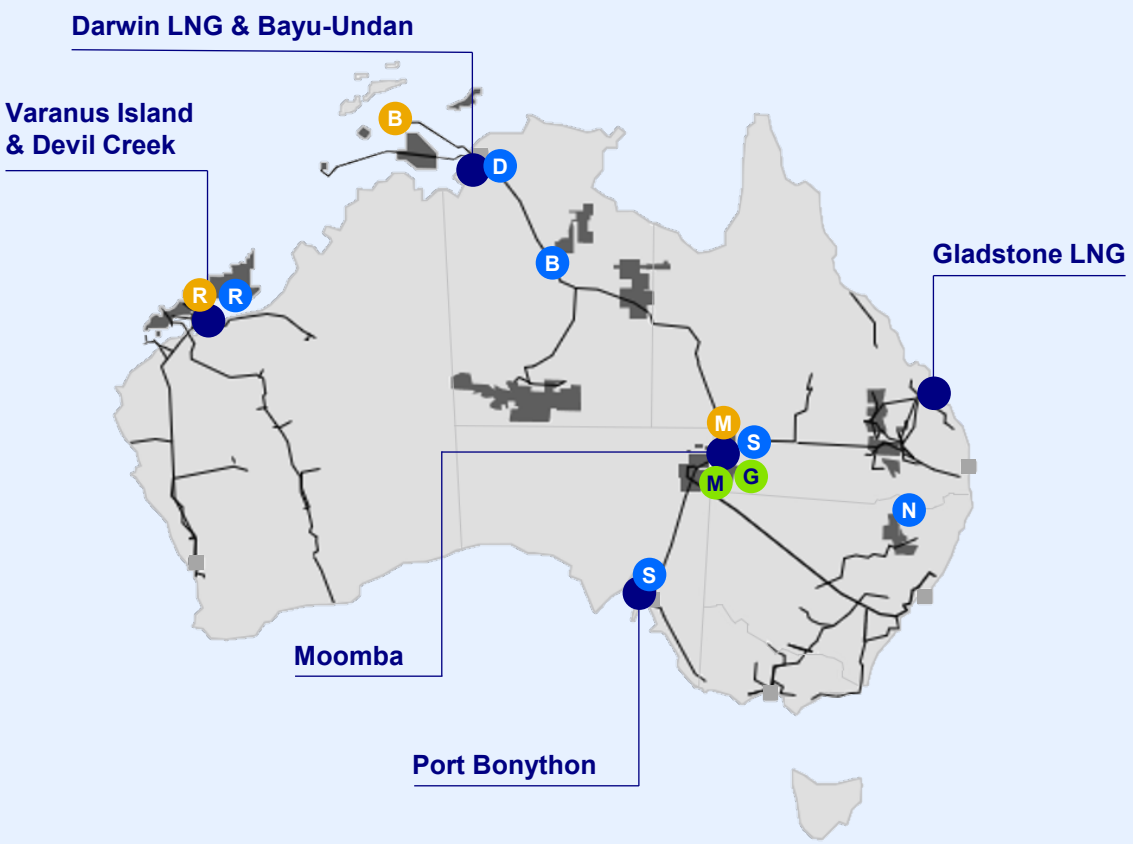
Centralised midstream capability and discipline

To realise full potential across midstream assets

1. 2023 to 2025 includes Moomba, Port Bonython, Varanus Island
2. ACCU revenue growth proportion of total revenue of the Midstream & Energy Solutions business

Midstream platform unlocking value

Advantaged infrastructure across three regions, supported by domestic gas and low-cost midstream capability underpinned by value creation optionality



Upstream development adjacencies

- D DLNG T2
- B Beetaloo pipeline
- S Storage
- N Narrabri pipeline
- R Varanus Island and/or Reindeer / Bedout gas

CCS to decarbonise at scale

- B Bayu-Undan CCS
- R WA CCS
- M Moomba CCS

Low Carbon Fuels & Power

- G Cooper Geothermal
- M Moomba Central Optimisation power

Carbon management at scale

Moomba CCS continues to perform above expectation, proving the technology and enabling growth targeted from Santos reservoir emissions in the medium-term


Moomba CCS Plant

2 MtCO2e stored[1] permanently stored

29 per cent reduction in Santos net emissions intensity[2]

~1.2 million Australian Carbon Credit Units received[3]

Monitoring and verification continuing to plan

Low-cost CCS solution

Wells performing better than expected. No wells required until at least 2028

Phase 2 pacing to customer demand

Customer demand shifting to the right due to geopolitical volatility

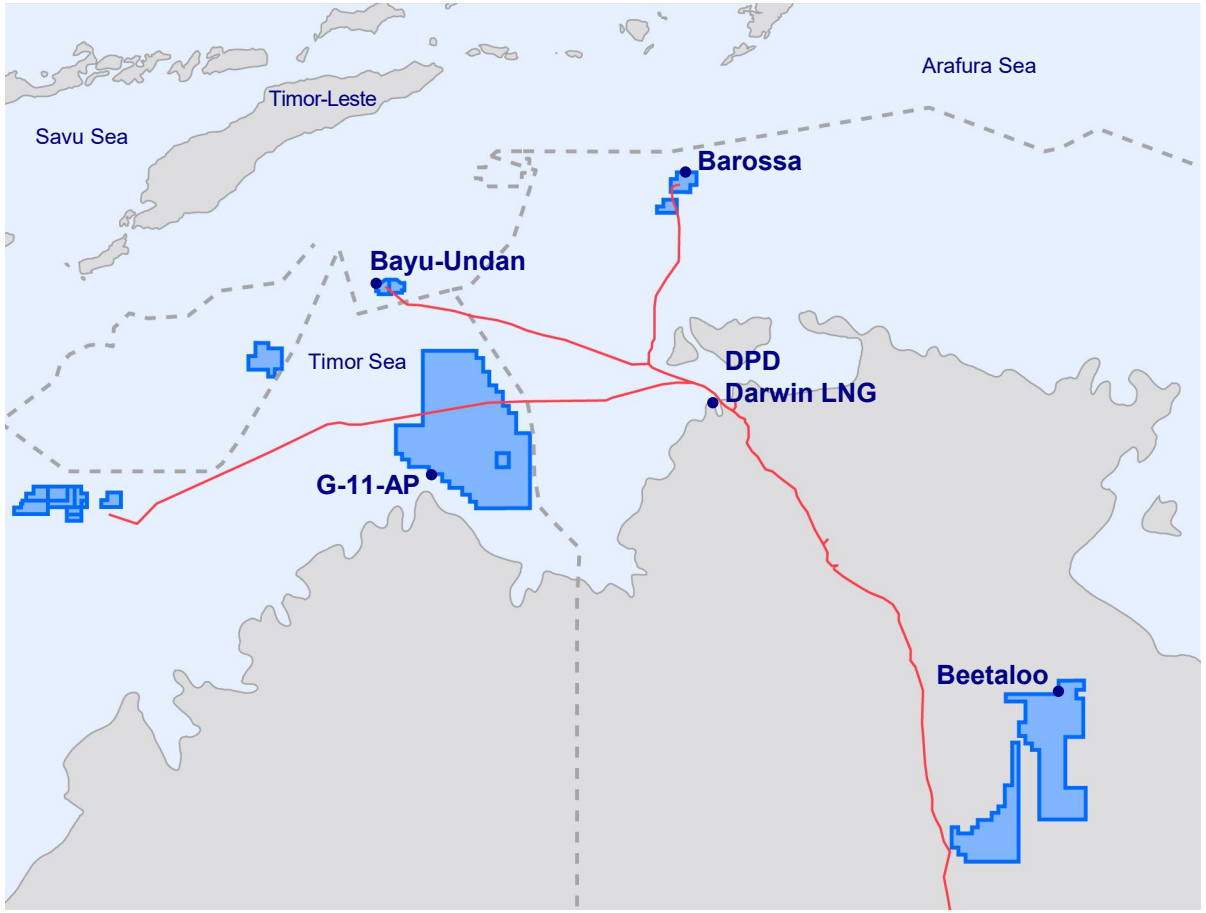
Up to 20 Mtpa storage potential for 50 years

Across the Cooper Basin

1. From project start-up in September 2024 to 30 April 2026
2. For calendar year 2025, emissions intensity has reduced by approximately 29 per cent since 2019-20
3. Total operated ACCUs issued cover the project's contribution to emissions reduction from its start-up in September 2024 to 30 September 2025

Bayu-Undan CCS

Intention to make Timor-Leste a regional leader in carbon storage, up to 10 Mtpa storage with initial focus on Barossa (2.3 Mtpa)



Cessation of production in 2025

Suspension of operations nearing completion; end state is a normally unattended NUI facility in 2H 2026

Repurposing existing infrastructure for CCS

Enables physical, competitive solution to safeguard compliance

Engineering FEED complete

Targeting FID ready in 2026

Progressing cooperation agreement

With Timor-Leste on regulatory and fiscal regimes

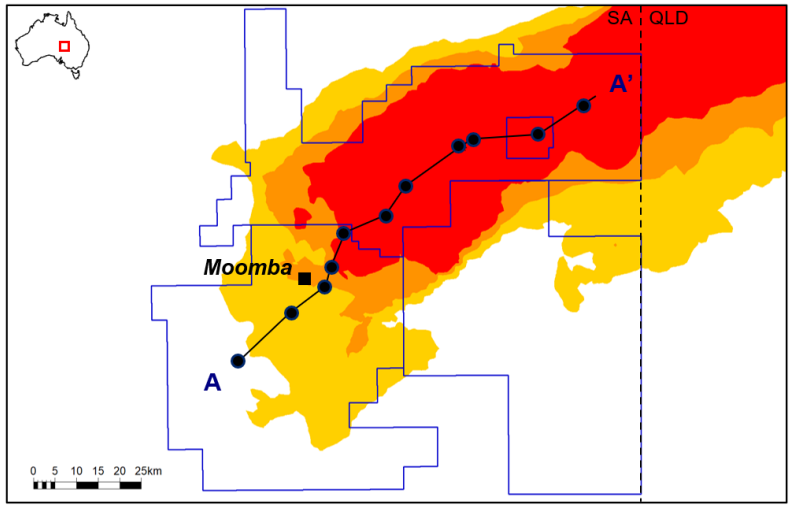
Plentiful third-party CO2 volumes nearby

Lowest cost project in the region to build a hub

Geothermal in the Cooper Basin

Cooper Basin is Australia's premier geothermal resource; potential to provide low carbon energy for decarbonisation

Basement temperature



Below 150°C | Above 150°C | Above 180°C | Above 200°C

Geothermal Exploration Licenses

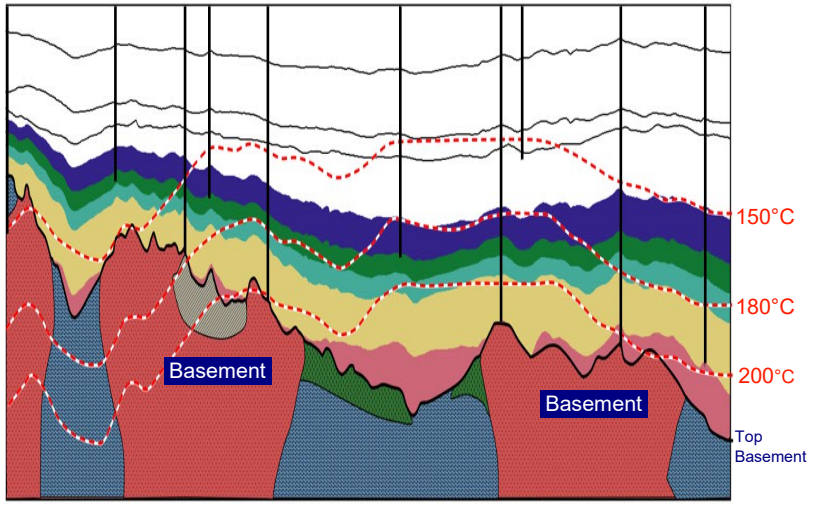
Low-cost pilot project in planning stages

To de-risk and demonstrate potential for cost-competitive, low carbon, firm power generation to offset fuel gas usage at Moomba

Drive down cost of power generation

Incorporate techniques from US Shale industry

Over 45 wells drilled to 200°C[1]



World Class Geothermal Resource

High geothermal gradient across the Cooper Basin with huge running room

Leverage existing capability

Drilling, subsurface & surface expertise applied to decarbonisation

Enhanced Geothermal Systems (EGS)

Uses fracture stimulation to circulate fluid through hot rocks from injector to producer wells

1. Santos operated wells with bottom hole temperature of 200°C or higher

OPERATIONS EXCELLENCE & TECHNOLOGY

Santos operations excellence and technology

A safer, lower-cost operator. Unlocking more value through technology

Operations excellence

Culture that delivers – safe, reliable, low-cost performance

World-class safety culture

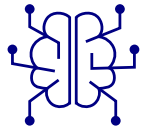
Asset reliability and process safety rigour

Leading drilling and completions performance

Continuously improving operating standards

Technology delivering value

Digital technology unlocking cost reduction and production uplift



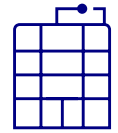
AI and smart technologies optimising infrastructure performance

Digitising and automating drilling and completions activities

Scaling team efficiency with AI

Remote Operating Centre capabilities

Centralised operating capability improving reliability and efficiency



Remote facilities monitoring and optimisation from integrated hubs

Pilot capability supporting drilling and completions

Longer-term pathway to expanded remote and autonomous operations

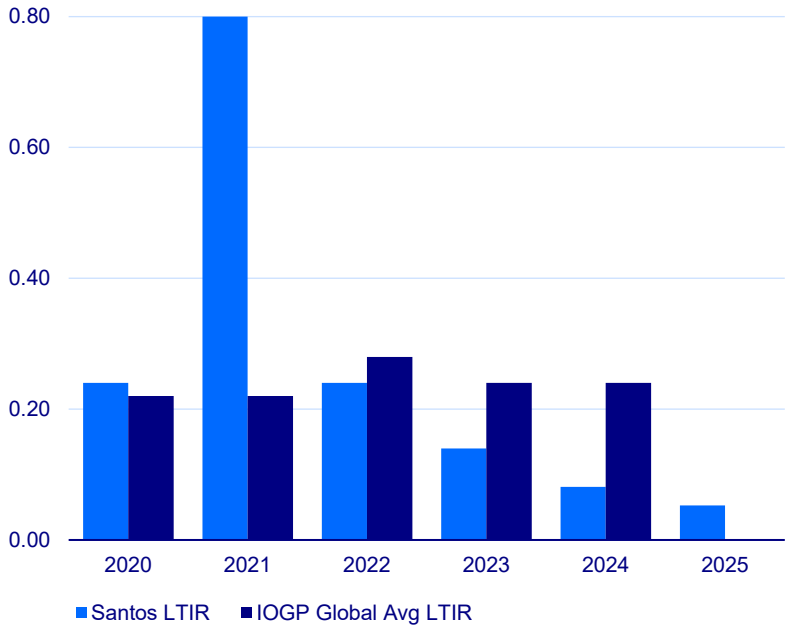
Proven performance with considerable upside

Operational Excellence

Disciplined execution across the base business is delivering record personal safety, process safety and asset reliability outcomes

Lost time injury rate[1]

Rate per million hours worked



Record safety

Best on record lost time injury rate & total recordable injury rate

10+ year best loss of containment incident rate

World-class reliability

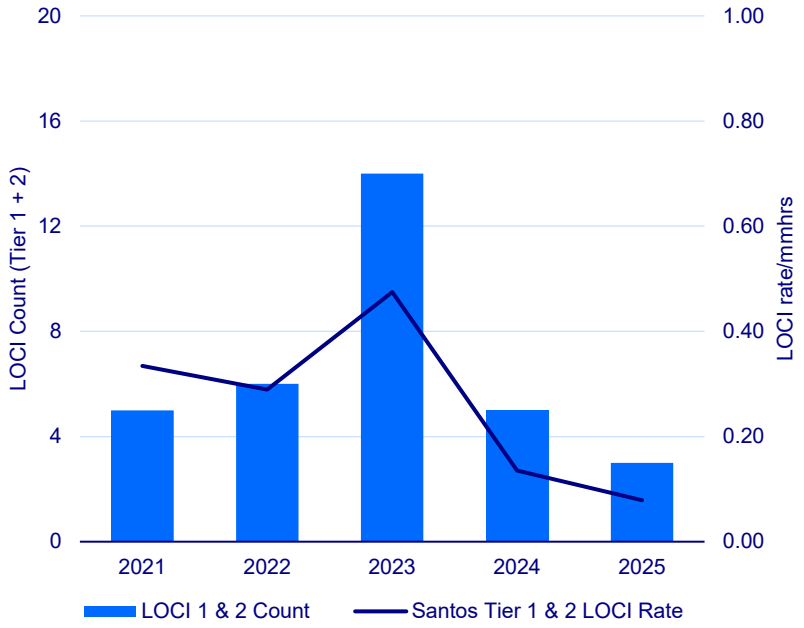
Sustained 99 per cent LNG reliability[3]; 10 per cent improvement in PNG operated gas reliability since 2022

Reliability delivering measurable upside

Reliability improvement delivered ~7.6mmboe cumulative production gain[4] at Varanus Island plant and PNG operated gas assets

Loss of containment incident rate[2] Tier 1 and 2

LOCI Count, rate per million hours worked



Reliable operations protect production, reduce risk and support strong cash generation

1. IOGP 2025 safety performance data not available at the time of publishing this presentation
2. Loss of containment incident is where the unplanned or uncontrolled release of hydrocarbon breached all containment barriers
3. Average over three years production-based reliability
4. Cumulative 3-year production gains relative to 2022 asset reliability baseline for 2023 to 2025

Technology delivering measurable value

Cost reduction and production uplift across drilling, completions, projects and facilities

Santos' technology program – applying digital and AI capability across the integrated value chain

>$64m

Potential annual benefit by 2029[1]

AI-driven oilfield technology

$28 million in benefits delivered in 2025, scaling to potentially >$64 million annually by 2029[1] through production optimisation opportunities

Up to ~$70m

Potential capex reduction[1]

Machine learning pressure model

Industry-first machine learning bottom hole pressure model replacing physical downhole gauges

20%

Increase in rate of penetration

Drilling automation

Connected to the rig control system, monitored from operating centre. Consistently applying optimal parameters, eliminating human error

80%

Increase in US frac installation productivity

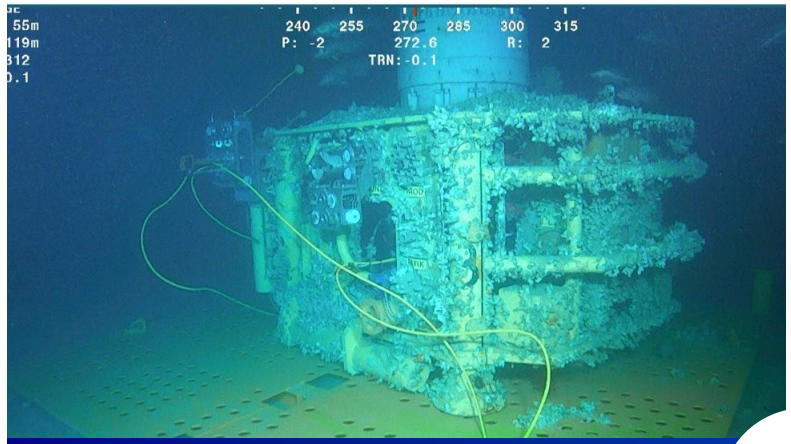
High performance well stimulation capability

Using bulk proppant and fluid handling systems to improve the average number of frac stages per day in 2026 from 2023 baseline

1. Gross

Santos' capability across offshore decommissioning

Disciplined self-execution team established to manage continuous offshore decommissioning program, demonstrating fast learning implementation, delivering zero recordable injuries, on-schedule, under-budget decommissioning performance



2024/2025

Low cost

MEFF Well Decommissioning

Best-in-class[1] well decommissioning duration comparative operations globally[2]

2025

Schedule efficiency

Ningaloo Vision FPSO Removal

New benchmarks for time from suspension of operations to FPSO sail away[3]

2026

Scope achieved

Harriet Alpha Platform Removal

Largest Santos platform successfully removed under budget, and largest offshore platform removal in Australia to date

1. UKCS Decommissioning Benchmarking Report 2024
2. Does not include unplanned cyclone delays
3. Sail away achieved in 73 days from cessation of production

Remote operating centre capabilities

Bringing together people and technology. Scaling to further lower costs and increase uptime across global portfolio

Santos operations vision: One centralised and remote operating centre, expanding capability

Centralised capability

Centralised operations hub now **reaching into remote drilling** and completions through the Integrated Remote Operations Centre

Lower cost

Reduces operating and maintenance overheads through centralised technical support and more efficient execution

Higher reliability

A single monitoring and control centre **improves response times**, strengthens oversight and **supports higher asset uptime**

Scales with growth

Establishes an **operating model** that can be repeated as additional assets and activities come into scope

INVESTMENT OUTLOOK

Key takeaways

Global instability has reset forecast for LNG supply with implication for energy security and market stability, favouring Santos' geographic advantage for its premium price products

Focus on tier-1 basins. Growing free cash flow. Delivering shareholder returns.

- Barossa is online and ramping up. Pikka phase 1 online, with production plateau on track for the third quarter
- Capital allocation framework will drive shareholder value - delivering disciplined growth within target breakeven price of $45–50/bbl, and a minimum returned to shareholders of 60 per cent of free cash flow
- The cash flow inflection point is now and by the end of 2026 for every $10 the realised oil price is above the Santos free cash flow break even price, Santos will generate $550-600 million in free cash flow
- Targeting gearing at the lower end of the range, through net debt reduction of $2.5 billion by 2030, reducing annual interest by ~$150 million
- Strategic review has re-purposed the Australian domestic oil and gas business to a lower capital intensity, higher margin business focused on meeting domestic gas and decommissioning commitments
- Capex reductions in the Cooper Basin of approximately $300 million from 2027 to 2030, $150 million annually thereafter
- Leveraging our midstream position and technology to create long-term value through simplification, infrastructure optimisation and energy solutions capability, delivering lower cost, improved efficiency and lower emissions
- Santos will focus its growth investment on LNG and oil across three regions to develop tier-1 basins in Alaska and PNG whilst fully appraising Beetaloo and Bedout basins, providing scale, margin and infrastructure advantage

The Santos value proposition is clear

Growing free cash flow. Maximising shareholder value

High quality asset base

Geographic diverse portfolio of large-scale tier-1 growth opportunities

High margin, low cost & infrastructure advantaged significant resource base

Plan delivered within breakeven oil price target of $45–50/bbl

Growing free cash flow

Barossa and Pikka phase 1 delivering new production from 2026

All assets exposed to attractive end markets, realising premium prices

From 2027 every $10 realised oil price above the breakeven oil price will generate $550 million – $600 million in free cash flow

Shareholder returns

Disciplined capital allocation framework

Returning at least 60 per cent of free cash flow to shareholders

Reducing net debt by $2.5 billion by 2030

Q&A

Santos

Definitions and abbreviations

ACCU	Australian Carbon Credit Unit. Each ACCU issued represents one tonne of carbon dioxide equivalent (tCO2e)
carbon capture and storage (CCS)	A process in which greenhouse gases, including carbon dioxide, methane and nitrous oxide from industrial and energy-related sources, are separated (captured), conditioned, compressed, transported and injected into a geological formation, that provides safe and permanent storage deep underground
contingent resources (2C)	Those quantities of petroleum that are estimated, on a given date, to be potentially recoverable from known accumulations by application of development projects but that are not currently considered to be commercially recoverable owing to one or more contingencies
contingent storage resources	Those storage quantities of discovered storage resources estimated, as of a given date, to be accessible in discovered geologic formations but the applied project(s) are not yet considered mature enough for commercial development because of one or more contingencies
EBITDAX	Earnings before interest, tax, depreciation and depletion, exploration and evaluation expensed, net impairment loss/reversal and change in future restoration assumptions
FEED	front-end engineering design
FFV	fuel, flare and vent
FID	final investment decision
free cash flow breakeven (unhedged) – from operations	The average annual US$ oil price at which cash flows from operating activities (before hedging) equal cash flows from investing activities. Excludes one-off restructuring and redundancy costs, costs associated with asset divestitures and acquisitions, and growth development project capex. Includes lease liability payments. Forecast methodology uses corporate assumptions
free cash flow breakeven (hedged) – from operations	The average annual US$ oil price at which cash flows from operating activities (before hedging) equal cash flows from investing activities. Excludes one-off restructuring and redundancy costs, costs associated with asset divestitures and acquisitions, and growth development project capex. Includes lease liability payments. The calculation then takes into account the impact of hedging by calculating the notional hedge proceeds received from free cash flow breakeven before hedging as the strike price. Forecast methodology uses corporate assumptions
free cash flow from operations	Operating cash flows less investing cash flows (net of acquisitions and disposals and growth development project capex) less lease liability payments
IOGP	The International Association of Oil and Gas Producers
loss of containment incident (LOCI)	LOCI is a subset of LOPC, where the release breached secondary containment and posed harm to people or the environment. The incident could have been reasonably or practicably prevented by Santos through design, installation or maintenance
loss of primary containment (LOPC)	LOPC stands for an unplanned or uncontrolled release of any material hydrocarbon from primary containment. Tier classification of LOPC is based on rate of release as per API 754
lost time injury rate (LTIR)	The number of lost time injuries (fatalities + lost time injuries) per million work hours
moderate harm injury	A work-related injury where the worker's recovery takes greater than three months
moderate harm rate	The number of actual moderate harm injuries and above per million work hours
net debt	Reflects the net borrowings position and includes interest-bearing loans (net of cash), commodity hedges and interest rate and cross-currency swap contracts (inclusive of amounts classified as held-for-sale) and lease liabilities
net emissions	In the context of Santos' emissions reduction hierarchy and targets, net emissions are Santos equity share of emissions less carbon credits
net emissions intensity	Calculated by dividing Scope 1 and 2 equity share emissions by equity share of production over the same period
production cost	The costs associated with producing gas and liquid hydrocarbons, including extracting, processing, storing, repairs and maintenance and overhead costs allocated to the above activities
reserves	Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied
reserves replacement ratio	The change in petroleum reserves (excluding production) divided by production, expressed in per cent. Organic reserves replacement ratio excludes net acquisitions and divestments
Scope 1 emissions	Direct greenhouse gas emissions that occur from sources that are owned or controlled by the reporting company
Scope 2 emissions	Indirect greenhouse gas emissions from the generation of purchased or acquired electricity, steam, heating or cooling consumed by the reporting company, from sources that are not owned or controlled by the reporting company
target	When referenced in the context of Santos, an outcome sought that Santos has identified a potential pathway or pathways toward delivery, subject to conditions and assumptions
total recordable injury rate (TRIR)	The number of recordable injuries (fatalities + lost time injuries + restricted work day cases + medical treatment cases) per million hours worked
underlying profit	Underlying profit excludes the impacts of asset acquisitions, disposals and impairments, as well as items that are subject to significant variability from one period to the next, including the effects of commodity hedging

For the complete Santos glossary, refer to the 2025 Annual Report

Definitions and abbreviations

Units of measure	
bbl	barrel
boe	barrels of oil equivalent
kt	thousand tonnes
ktCO2e	kilotonnes carbon dioxide equivalent
mmbbl	million barrels
mmboe	million barrels of oil equivalent
mmBtu	million British thermal units
ML	million litres
Mt	million tonnes
MtCO2	million tonnes of carbon dioxide
MtCO2e	million tonnes of carbon dioxide equivalent
Mtpa	million tonnes per annum
PJ	Petajoules, 1 joule x 10^{15}
ppm	parts per million
t	tonne
TJ	Terajoules, 1 joule x 10^{12}

Conversion factors	
Sales gas	1PJ = 171,937 boe
Crude oil	1 barrel = 1 boe
Condensate (pre-2026)	1 barrel = 0.935 boe
Condensate (2026+)	1 barrel = 1 boe
LPG	1 tonne = 8.458 boe
LNG	1 PJ = 18,040 tonnes
LNG	1 tonne = 52.54 mmBtu

For a comprehensive online conversion calculator tool, visit: **santos.com/conversion-calculator**

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