Central Petroleum

CTP.AX

MST Access
A research platform of MST Financial

26 October 2026

FY27 Step Change

NEED TO KNOW

- **FY26 results – higher prices and margins offset lower volume**
- **New wells PV14 and PV15 – scope for 40% production increase**
- **Otway and Cooper exploration set for CY27**
- **NT gas markets changing – CTP still well placed**

Full-year results set up big FY27: FY26 results showed the underlying strength of the business as NT Govt. contracts boosted prices and margins. However, oil offtake constraints and some pipeline restrictions reduced volumes. CTP is set to materially increase production and cashflow in FY27.

PV14 and PV15 aim to lift CTP's total attributable production by 40%: PV14 has been completed, and CTP expects it will commence production by end-October. While initial flow rates were under expectations final rates will not be known until steady-state production is achieved. PV15 has spudded and CTP expects stronger results from this well. CTP is confident of lifting PV production from 5.8TJ/d to plant capacity of 14TJ/d.

Otway and Cooper drilling planned for CY27: Activity is underway to progress an exploration well at Enterprise North in the Otway Basin, while in the Cooper Basin there are at least 7 drill-ready prospects focusing on proven targets, with the plan to drill 2 wells in 2027.

NT gas market changing; CTP still in the box seat: With first gas from the Beetaloo entering the NT market and the Gas Reservation legislation being introduced to Parliament, the NT gas market is changing shape. This is not bad news for CTP, which remains in a box seat with proven reserves and a majority of sales volumes contracted for 3 years.

Investment Thesis

Contracted, CPI-linked cashflow now converts fully to cash: CTP's gas sales agreements with the NT Government secure a market for the majority of firm production to the end of 2034 at CPI-linked pricing with take-or-pay, from one of the lowest-risk counterparties in the sector. Against FY26 net operating cashflow of A$10.3m, the completion of the final delivery to repay previously overlifted gas will release an expected A$7m per year in future cash flow, a step-change.

Funded, near-term production growth at low subsurface risk: The PV program is funded from existing cash and an expanded A$15m finance facility. The processing facility is in place and well below capacity, tie-in distances are short and offtake is contracted, leaving well deliverability as the principal residual risk.

Valuation and Risks: CTP Stacks Up on Every Metric

Our base-case NPV is A$0.24/share (unchanged), highlighting CTP's substantial undervaluation. At current prices, FY27E P/OCF is 1.2x, P/E is 2.4x and EV/EBITDAX 1.2x. The share price implies a gas price of ~A$6.70/GJ, well below our FY26 forecast of A$10.00/GJ and CTP's latest realised prices of ~A$10.10/GJe. Successful PV wells PV14 and PV15 have the potential to add significant value. Key risks include potential production issues, lack of exploration success and unsuccessful PV development wells.

Equity Research Australia

Energy

Michael Bentley, Senior Analyst
michael.bentley@mstaccess.com.au

Central Petroleum is the NT's largest onshore gas operator, with a portfolio of gas and oil assets focused on the Amadeus Basin. Its strategy is to unlock and commercialise the vast energy potential of the Central Australian basins to take advantage of a predicted tight supply/demand balance in the domestic gas market. www.centralpetroleum.com.au

Valuation	**A$0.240** *(unchanged)*
Current price	**A$0.056**
Market cap	**A$42m**
Net debt	**A$5.0m** *(30 June 2026)*

Upcoming Catalysts / Next News

Period	
End-October	1QFY27 production report
2QFY27	PV14 steady-state production
2QFY27	PV15 production
CY27	Otway and Cooper drilling

Share Price (A$)



Source: FactSet, MST Access.

This report has been prepared and issued by the named analyst of MST Access in consideration of a fee payable by: Central Petroleum (CTP.AX)

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Figure 1: Financial summary, year-end 30 June

Central Petroleum Limited (ASX:CTP)

Year-end 30 June		
Share Price	A$/sh	0.056
52 week high/low	A$/sh	0.10/0.05
Valuation	A$/sh	0.24
Market Cap (A$m)	A$m	42
Net Cash / (Debt) (A$m)	A$m	(5)
Enterprise Value (A$m)	A$m	47
Shares on Issue	m	753
Options/Performance shares	m	54
Potential Diluted Shares on Issue	m	807

CTP Relative to XEJ 12 months



Ratio Analysis	2025A	2026A	2027E	2029E	2029E
EPS	0.91	0.13	2.42	6.83	5.31
P/E (x)	6.1	48.1	2.4	0.8	1.1
EPS Growth (%)	-46%	-86%	1806%	183%	-22%
CFPS (A¢)	1.92	1.38	4.89	8.27	6.84
P/CF (x)	2.9	4.4	1.2	0.7	0.8
DPS	–	–	–	–	–
Dividend Yield (%)	–	–	–	–	–
EV / EBITDA (x)	2.2	5.0	1.7	0.0	-0.8
EV / EBITDAX (x)	2.0	2.4	1.2	0.0	
EV / boe (x)	47.4	69.4	44.2	-0.2	-19.8
EV / PJe (x)	7.9	11.6	7.4	0.0	-3.3

Assumptions (Yr end Jun)	2025A	2026A	2027E	2029E	2029E
Brent Oil Price (US$/bbl)	72.18	73.00	74.8	76.7	78.6
Exchange Rate (A$1:US$)	0.648	0.648	0.648	0.648	0.648
Gas Price (A$/GJ)	8.66	9.99	10.25	10.51	10.77

Production	2025A	2026A	2027E	2029E	2029E
Gas (TJ/d)	12.3	11.7	18.5	55.7	39.0
Gas (PJ)	4.5	4.3	6.8	20.4	14.2
LPG (kt)	–	–	–	–	–
Oil / Condensate (mmbbl)	0.03	0.02	0.02	0.02	0.02
Total (mmboe)	**0.78**	**0.73**	**1.15**	**3.42**	**2.39**
Gas (mmboe)	0.75	0.71	1.13	3.40	2.37
LPG (mmboe)	–	–	–	–	–
Oil / Condensate (mmboe)	0.03	0.02	0.02	0.02	0.02
Year End Reserves 2P (mmboe)	**12.6**	**12.6**	**11.4**	**8.0**	**5.6**

Reserves and Resources As at 30 June 2026	Working Interest	1P Gas (PJ)	2P Gas (PJ)	1P Liquids (mmbbl)	2P Liquids (mmbbl)	2C Gas (PJ)
Mereenie (OL 4 / OL 5)	25%	28.6	39.1	0.31	0.37	45.6
Palm Valley (OL 3)	50%	8.5	9.2	–	–	6.5
Dingo (L7)	50%	10.2	22.0	–	–	–
Total		**47.2**	**70.2**	**0.31**	**0.37**	**52.1**

NET ASSET VALUE (WACC 10.0%)	1 Nov 26	A$m	Risking	A$m	A$ps
Risked NPV - Mereenie - OL4 & OL5 (25%)		86	100%	86	0.11
Risked NPV - Palm Valley - OL3 (50%)		30	100%	30	0.05
Risked NPV Dingo - L7 & PL30 (50%)		51	100%	51	0.07
Risked NPV - Enterprise North - PEP 169 (20%)		25	65%	16	0.02
Risked NPV - Cooper Basin (49%)		3	65%	2	0.01
Total Operations		**194**		**184**	**0.26**
Net Cash / (Debt)		(7)	100%	(7)	(0.01)
Admin / Corporate / Other		(42)	100%	(42)	(0.06)
Exploration (risk-adjusted)		23	50%	12	0.02
Mereenie & Palm Valley 2C gas (risked)		39	65%	25	0.03
TOTAL VALUATION		**207**		**172**	**0.24**

Profit & Loss (A$m)	2025A	2026A	2027E	2028E	2029E
Oil / Condensate Revenue	3	1	3	3	3
LPG Revenue	–	–	–	–	–
Gas Revenue	40	43	69	102	88
Revenue	**43**	**45**	**72**	**105**	**90**
Operating Costs	(18)	(18)	(20)	(23)	(18)
Government Resource Taxes	(4)	(5)	(5)	(9)	(7)
Exploration & Development Expenses	(2)	(6)	(13)	(4)	(2)
Other Net Income / Expense	(3)	(5)	(4)	(6)	(4)
EBITDA	**17**	**11**	**30**	**64**	**59**
EBITDAX	**19**	**17**	**42**	**68**	**61**
Depreciation & Amortisation	(7)	(7)	(9)	(11)	(12)
EBIT	10	4	20	52	48
Net Interest Expense	(3)	(3)	(2)	(1)	2
Net Profit before-tax	7	1	18	51	49
Tax Expense / Benefit	–	–	–	–	(9)
Underlying NPAT	**7**	**1**	**18**	**51**	**40**
Exceptional items / non-recurring	–	6	–	–	–
Reported NPAT	**7**	**(5)**	**18**	**51**	**40**

Cash Flow (A$m)	2025A	2026A	2027E	2029E	2029E
Pretax Profit	7	1	18	51	49
D&A & Other Non-Cash Items	8	9	19	11	11
Tax Paid	–	–	–	–	(9)
Cash from Operating Activities	**14**	**10**	**37**	**62**	**51**
Development Capex	(9)	(4)	(35)	(10)	(5)
Acquisitions/Other (Net of Sales)	1	(11)	(4)	–	–
Dividends Paid	–	–	–	–	–
Free Cash Flow	**4**	**(6)**	**(2)**	**52**	**47**
Cash Provided by Financing	(2)	(1)	(3)	(8)	(14)
Net Change in Cash	**2**	**(7)**	**(5)**	**43**	**32**

Balance Sheet (A$m)	2025A	2026A	2027E	2029E	2029E
Cash & short term deposits	27	20	15	59	91
Receivables	7	8	12	17	15
Inventories	4	5	8	13	18
Property, Plant and Equipment	58	61	89	90	85
Capitalised exploration	8	14	11	11	10
Intangibles and Goodwill	2	2	2	2	2
Other assets	8	8	8	8	8
Total assets	**114**	**118**	**145**	**200**	**229**
Creditors	5	6	8	12	10
Borrowings	23	26	23	14	–
Other liabilities	45	52	62	70	75
Total liabilities	**73**	**83**	**93**	**96**	**86**
Shareholder equity	41	34	52	104	143
Shareholder Equity + Total Liabilities	114	118	145	200	229

Source: CTP, MST estimates.

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Full-Year FY26: A Preview of What's to Come

Profit, cash generation and opportunity

CTP reported an **underlying net profit after tax of A$1.0m for FY26**, compared to A$6.2m for FY25. Despite higher operating margins and average sales prices for gas, the year saw a decline in crude and condensate volumes due to the suspension of oil sales. Exploration expense (not including the A$5.9m impairment charge) was ~A$4m higher than in FY25 as the Palm Valley PV14 well costs incurred in FY26 were expensed. The expensing of the well is due to the fact that it is classified as an appraisal well as no reserves are allocated to it. On commencement of gas production, part of the PV14 and PV15 drilling expense will be able to be capitalised (we estimate ~25%).

The statutory loss for FY26 was A$4.9m vs a profit of A$6.7m in FY25, as CTP recorded a A$5.9m impairment charge resulting from the rationalisation of the group's exploration portfolio.

Underlying EBITDAX at A$17.0m for the year was down 8.7% from FY25 (A$18.6m), driven by lower volumes.

Higher sales prices were reflected in improved sales margins of A$4.96/GJe, up 5% from FY25, and a positive growth in sales revenue, which grew 3% on FY25 to reach A$44.7m.

Following the higher prices experienced in 2HFY25, average realised portfolio prices again exceeded A$10/GJe, reaching A$10.10/GJe, representing a 10% increase on FY25's average realised portfolio price.

Overall, FY26 was a difficult year for production, particularly for crude and condensate which saw volumes nearly halve from their FY25 levels due to offtake constraints. However, new contracts, higher realised sales prices, the potential for additional volumes from PV14 and PV15 and strong reserves have set CTP up comfortably for a significantly more profitable year in FY27.

Overview of FY26 results

FY26 vs. FY25 summary

Figure 2: Review of FY26 vs. FY25

Profit & Loss (A$m)	FY25A	FY26A	Change	Comment FY26 v FY 25
Production				
Gas (TJ/d)	12.3	11.7	(0.6)	
Gas (PJ)	4.5	4.3	(0.2)	Natural decline PV
Oil / Condensate (mmbbl)	0.0	0.0	(0.0)	Suspension of oil sales
Total (mmboe)	**0.8**	**0.7**	**0.0**	
Oil / Condensate Revenue	3.4	1.4	(2.0)	Suspension of oil sales
Gas Revenue	39.6	43.3	3.7	Higher prices from NT Govt. contracts
Total Sales Revenue	**43.0**	**44.8**	**1.7**	
Operating Costs	(17.5)	(18.5)	0.9	Generally higher cost environment
Government Resource Taxes	(4.3)	(4.7)	0.4	
Exploration & Development Expenses	(1.7)	(5.7)	4.0	Expensing of PV14 in FY26 as classified appraisal
Other Net Income / Expense	(2.6)	(5.0)	2.4	Higher G&A costs
Underlying EBITDA	**17**	**11**	**(6.0)**	
Underlying EBITDAX	**19**	**17**	**(2.1)**	
Depreciation & Amortisation	(6.7)	(6.5)	(0.2)	
EBIT	10.1	4.3	(5.8)	
Net Interest Expense	(3.9)	(3.3)	(0.5)	
Pretax Profit	6.2	1.0	(5.2)	
Tax Expense / Benefit	–	–	–	
Underlying Profit	**6.2**	**1.0**	**(5.2)**	
Reported Profit	**6.7**	**(4.9)**	**(11.7)**	Including A$5.9m impairment charge

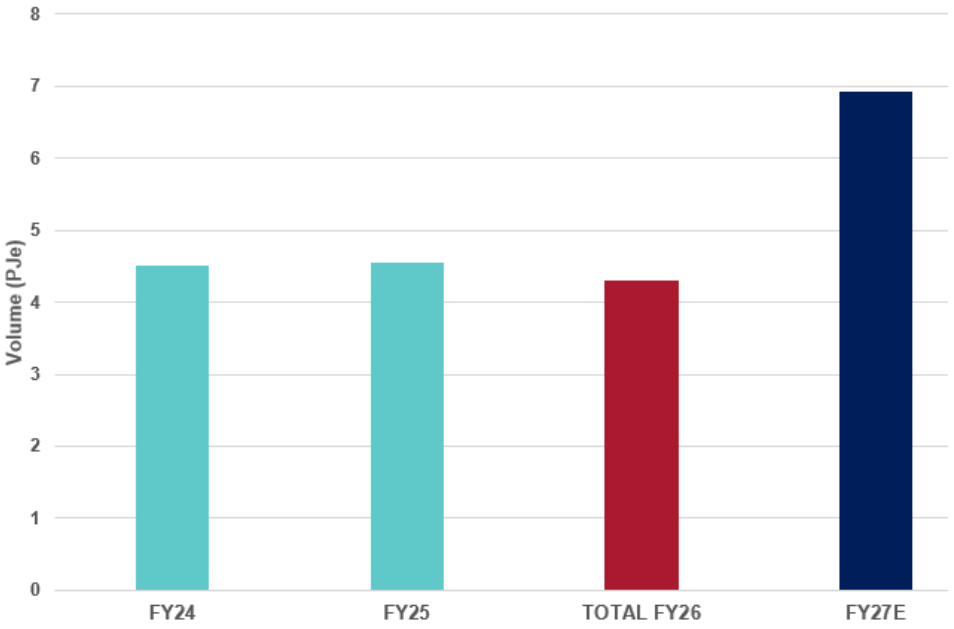
Source: MST, CTP.

Sales volume: oil dampens total volumes but gas strong

Full-year review: FY26 saw a decline in overall production volumes due to challenges across different fields, including natural decline at Palm Valley and revised oil specification requirements at Mereenie resulting in the interruptions to oil and gas production in the first half and suspension of oil sales from mid-June. Oil and condensate sales volumes halved to 14.8Mbbls from FY25 levels (30Mbbls). However, gas production returned to full capacity by mid-year, and sales volumes at Dingo reached their highest level on record for the third consecutive year.

Outlook: We expect production to increase materially in FY27 following continued tight NT supply. New contracts include the supply of 1.3 PJ of gas to McArthur River Mining Co across CY2026 and CY2027, as well as the signing of multi-year gas contracts with the NT Government, which support two new Palm Valley wells which are targeting an increase in gas production of 40% when commissioned in the first half of FY27.

Figure 3: Sales volume: FY26 vs. FY27E, FY25 and FY24 (PJe)



Source: CTP, MST

Sales prices: a milestone year, prices above A$10/GJe for 2HFY26

Full-year review: FY26 saw an average realised portfolio price of A$10.10/GJe (including an average gas price of A$9.96/GJ), which represents a 14% increase on FY25.

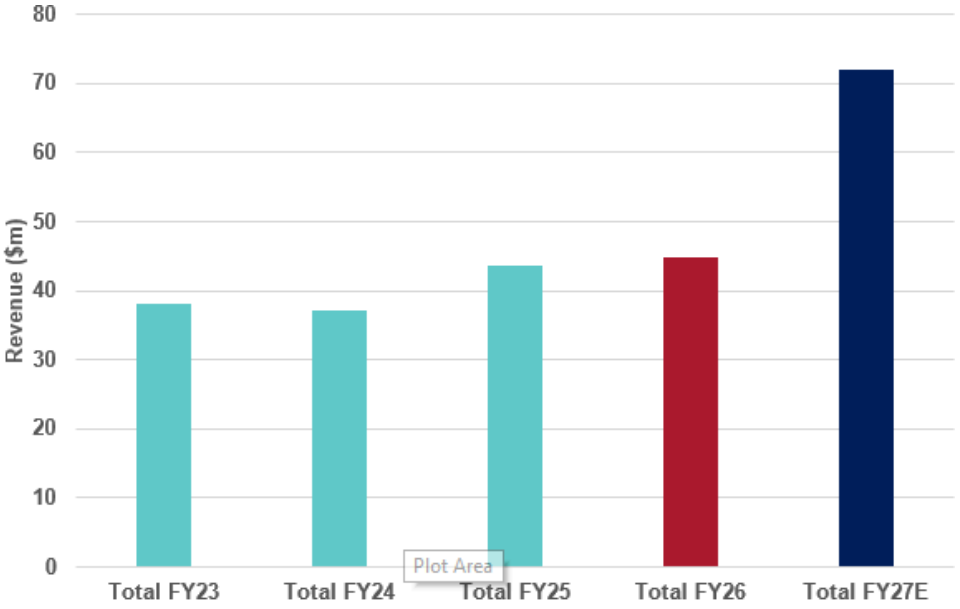
Outlook: CTP has increased gas price security through its new multi-year gas contracts with the NT Government, under which 98% of next year's gas production, and over 80% of gas production over the next three years, is contracted under CPI-linked fixed-price arrangements. Due to the recent cessation of gas purchases for overlift repayment, alongside increasing sales volumes following the Palm Valley drilling program,we expect operating margin to continue to expand into FY27 along with pricing remaining above A$10/GJe.

Revenue

Full-year review: CTP finished the year with sales revenue of A$44.7m, including A$0.8m released from deferred take-or-pay balances, up 3% from FY25. Despite the slight drop in net sales volumes from FY25, the increase was mainly driven by an increase in average realised prices, up 10% to A$10.10/GJe.

Outlook: We expect revenues to jump significantly in FY27 off the back of additional gas production from the new Palm Valley wells and new higher-priced, multi-year gas contracts secured from 2026 to 2034.

Figure 4: Revenue, FY23–FY26 (A$m)



Source: CTP, MST.

Margins

Full-year review: Higher portfolio pricing from new supply contracts supported a 5% increase in operating margin, which grew to A$4.96/GJe.

Outlook: We expect margins to continue to increase as a higher proportion of gas is delivered into the new multi-year gas contracts and annual we expect cash flows to benefit from a A$7m increase following completion of the final repayment of overlift gas in May 2026.

Balance sheet: a significant cash-building year – set up for growth and capital management

The cash balance at the end of FY26 was A$20.4m, down from A$27.5m at 30 June 2025.

Net debt was A$5.0m at 30 June 2026, compared to a **net cash** position of A$3.9m in 2025, which reflects the A$11.2m investment to acquire exploration tenements in the Otway and Cooper Basins, as well as a A$4.4m cost associated with the drilling program at Palm Valley.

This financial year, however, saw CTP complete its final delivery to repay previously overlifted gas in May, which CTP expect will release A$7m per year in future cash flow.

Reserves – The Key to Sustainable Production

Reserves remain strong at 72.4 PJe (vs. 73.1 PJe in FY25)

The key to an oil and gas company's production levels and its longevity are its reserves. Reserves also provide confidence in the underlying valuation.

Net proved and probable (2P) oil and gas reserves at 30 June 2026 were 72.4 PJe, which included the 7%-upwards revision of the 2P reserves at Mereenie gas following strong performance from the newest production wells.

Figure 5: CTP reserves, FY26 vs. FY25

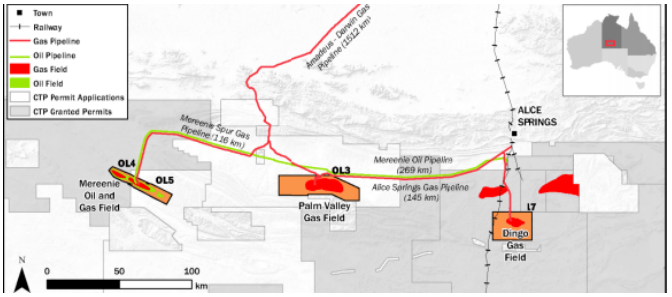
Reserves As at 30 June 2026	Units	Working Interest	1P FY26	1P FY25	2P FY26	2P FY25
Mereenie Oil	mmbbl	25%	0.3	0.3	0.4	0.4
Mereenie gas	PJ	25%	28.6	28.9	39.1	37.9
Palm Valley	PJ	50%	8.5	9.6	9.2	10.3
Dingo	PJ	50%	10.2	19.0	22.0	22.6
TOTAL	**PJe**				**72.4**	**73.1**

Source: CTP.

Palm Valley Appraisal Update

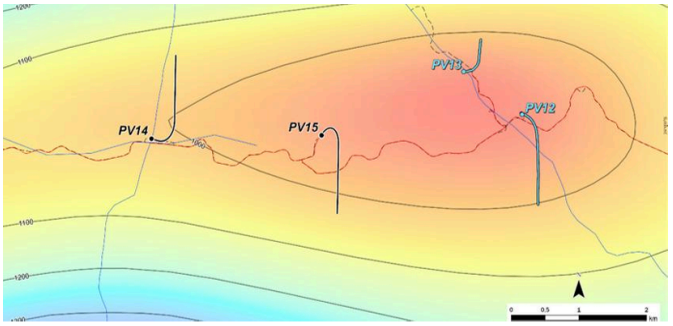
The Palm Valley Joint venture FID approval for two new Palm Valley wells (PV14 and PV15) was made in April, following the signing of the new NT Government gas sales agreement (GSA). Site preparation and procurement were completed during the June quarter and drilling commenced on PV14 in late July. The Palm Valley plant's sales capacity is approximately 14 TJ/d (100% JV), against 5.8 TJ/d at the end of the June quarter. The 2 new wells aim to deliver at least 10 PJ of gas (on a gross basis) over the wells' operating lives and fully utilise Palm Valley's gas plant capacity. CTP has guided that, if successful, the two wells should increase CTP's share of total gas production capacity across its three producing fields by circa 40%.

Figure 6: Location of CTP's producing assets



Source: CTP

Figure 7: Palm Valley wells



Source: CTP

PV14 – completed: final rates to be determined

The PV14 well at Palm Valley has been drilled and is being completed as a gas producer. CTP expects the well to be tied into the Palm Valley facility and commissioned by the end of October. The well is targeting the northern flank of the Palm Valley anticline.

3.2 TJ/d rate below expectations; steady production to determine final rates

A short-duration flow test was conducted through the rig, and gas flows of 3.2 TJ/d (100% JV) were measured.

CTP expects that the well will produce at 3–4TJ/d, which is below pre-drill expectations; however, it should be noted the flow rate was increasing when testing was completed.

Although the flow test returned no water to surface, subsequent flows to a vacuum (i.e. being 'sucked up' from the reservoir) at surface showed evidence of water production. The water may be residual and could clean up with production. Palm Valley has intersecting natural fractures, and lower fractures may be a water conduit.

CTP has noted it will take time and a steady rate to determine how much water there is (if any) and how it will be dealt with. The worst-case scenario with respect to water ingress is that it could cause production to cease.

PV12 flowed water initially – continues to produce after 4 years

It should be noted that PV12 initially contacted water but has now been successfully producing for over 4 years.

PV15 – spudded: expectations of higher rates than PV14

PV15 was spudded on 18 October. PV15 is scheduled to take approximately 51 days to reach a total vertical depth of 2,031 metres. PV15 is a deviated well and will be drilled at an angle of approximately 78 degrees through the Pacoota Formation reservoir targeting the southern flank of the Palm Valley gas field (PV14 targeted the northern flank). PV15 is only the second well after the successful PV12 well to target the southern flank, closer to crest of field.

CTP has stated that a strong PV15 result would achieve the target aggregate Palm Valley production at plant capacity of around 14 TJ/d (100% JV).

Exploration: Otway and Cooper in 2027

Otway and Cooper Basins provide East Coast market exposure

CTP completed the acquisition of interests from ADZ Energy in January 2026, acquiring a 20% beneficial interest in PEP169 in the onshore Otway Basin in Victoria and a 49% beneficial interest in a Cooper Basin package in South Australia. Tenement payments of A$11.2m were made in FY26.

Activity is underway with operator ADZ to progress an exploration well at Enterprise North in PEP169, and to reprocess seismic data to assist in optimising locations for drilling two Cooper Basin targets in PEL677 and the retention leases. These are conventional targets in mature, infrastructure-rich basins located within the East Coast gas market and CTP expect these to be drilled in CY2027.

The move into the Otway and Cooper represents the most significant change to CTP's profile in several years. Otway and Cooper gas, if successful, would be delivered into the market in which the AEMO forecast shortfall is concentrated and where prices are A$12–13/GJ.

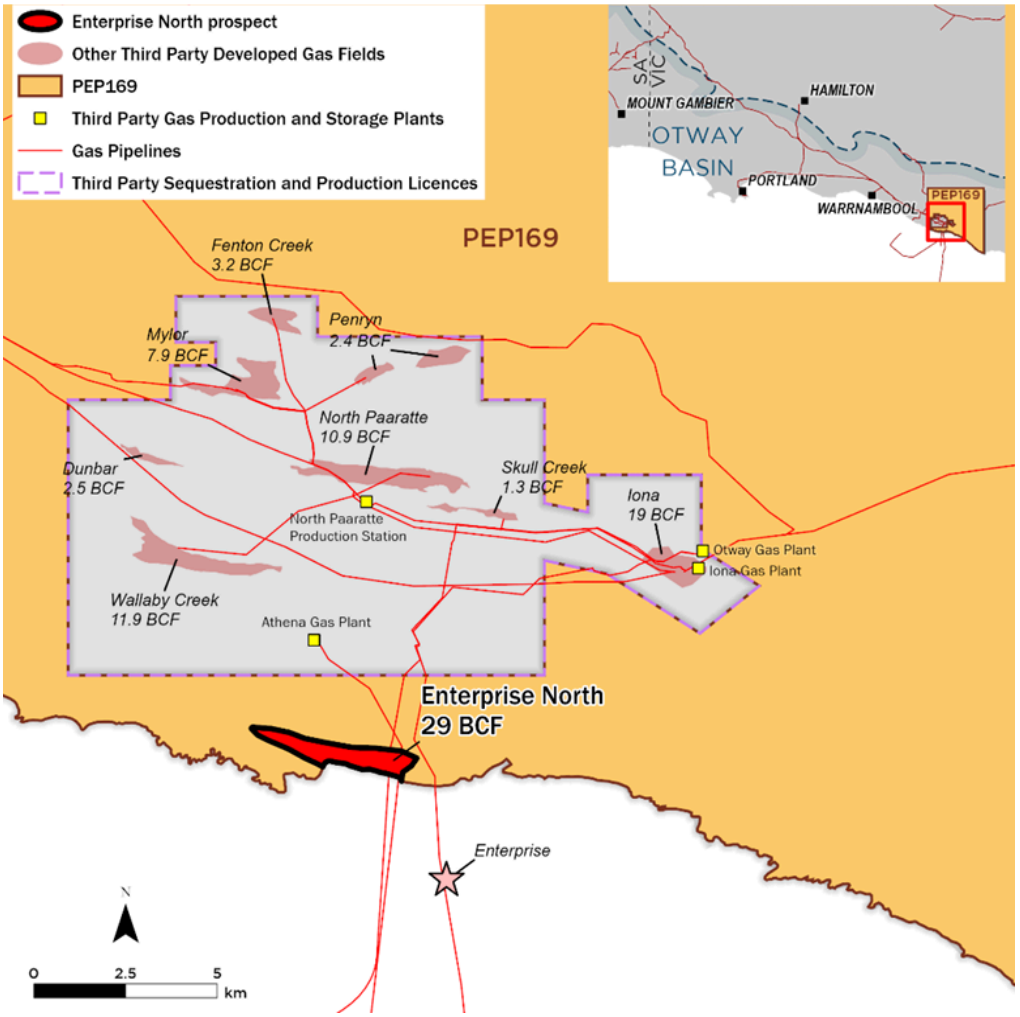
Otway: Victorian demand; world-class formation

The initial focus in the Otway is the onshore Enterprise North prospect, an amplitude-supported prospect 2.5km up dip and along the spill path from the producing Enterprise field. The field sits in the world-class Waarre Formation, with nearby discoveries having flow rates of >50 TJ/d.

Enterprise North is close to existing pipelines and the Iona, Otway and Athena gas plants.

The drilling is targeting up to 29 Bcf gas in place (~16 Bcf net to CTP) which equates to ~A$200m revenue at prevailing prices; this could roughly double CTP's annual group equity gas production.

Figure 8: Location of Enterprise North



Source: CTP.

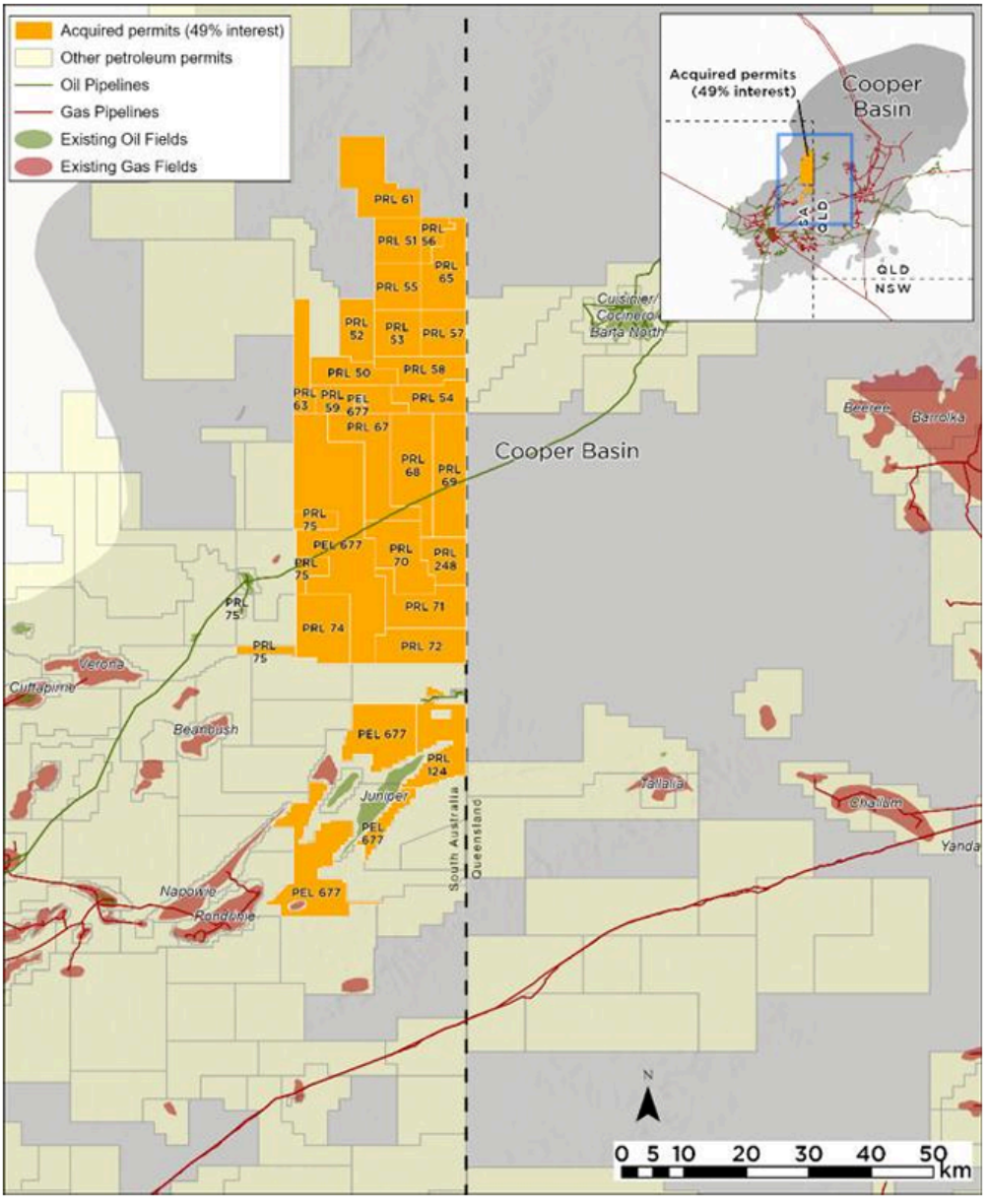
Cooper: drill-ready options; two wells planned in CY2027

The Cooper Basin is an established oil and gas province with a long history of discoveries and production.

CTP's 17 prospects and leads are relatively underexplored after acreage suspension from 2016 to 2025, but have extensive existing seismic coverage and established reservoir and seal mapping to reduce exploration risk. At least 7 of the prospects are near drill-ready, and the drilling program will focus on Birkhead oil and Patchawarra gas targets – both proven Cooper Basin targets. The plan is to drill 2 wells in 2027.

Again, the region is infrastructure-heavy with pipelines, oil export facilities and trucking to support fast commercialisation, higher margins, lower capital costs and access to global liquids and Australian East Coast gas markets.

Figure 9: Cooper Basin prospects



Source: CTP.

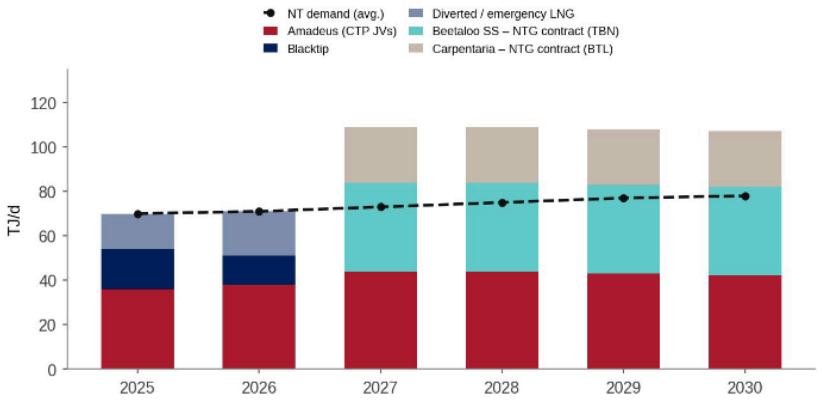
Amadeus sub-salt: Mt Kitty retained

CTP retains a 30% interest in EP125, the helium-rich sub-salt discovery with measured concentrations of 9% helium and 11.5% hydrogen. Operator Santos is required to drill the appraisal well by early 2028 under the minimum permit commitment schedule, and CTP continues to seek farm-out opportunities for the prospect.

The NT Gas Market: Beetaloo Supply Commences

The most material change to the NT gas market is that Beetaloo supply has commenced. Both pilot projects are funded, and TBN has delivered first gas. The equity market is concerned with respect to CTP's position in the NT market and that Beetaloo volumes will create oversupply and strand CTP's uncontracted production. There appears to be more opportunity than risk for CTP, as any new gas supply would first be applied to replace the circa 30TJ/d of gas being diverted from Inpex LNG.

Figure 10: NT gas supply build-up vs. demand, 2025–30 (TJ/d)*



*Source: AEMO GSOO; company reports. *Note that the volumes indicated for Beetaloo in 2027 and beyond are the contracted full-year rates with the NT Govt. and do not allow for any delays or part-year deliveries.*

Implications for CTP – still in the box seat

The NT market appears to be moving from shortfall towards balance, rather than into oversupply.

Composition is more important than the aggregate. The incremental volumes are pilot-scale, appraisal-stage supply from wells with limited production history, delivered through infrastructure that has either not yet been commissioned or is commissioning, into a market where diverted LNG remains the expensive alternative. A delay to stimulation or commissioning would remove the projected surplus.

CTP – in production, contracted and supported by certified reserves

At 30 June 2026, 2P reserves were 72.4 PJ net to CTP, inclusive of 47.3 PJ of 1P, representing a 2P reserves-to-production ratio of approximately 15 years.

Beetaloo volumes are being sold as appraisal gas under 'Beneficial Use of Gas' legislation, with reserves yet to be booked. For a customer assessing surety of supply over a 10-year horizon, these are not equivalent positions, and CTP has demonstrated the point by contracting 10.5 PJ through to 2034. In CY26 there was an 'emergency' shortfall in NT gas supply, which was filled by Inpex LNG and reverse flow from the Northern Gas Pipeline (NGP) (the reverse flow NGP gas was as a result of Inpex maintenance shutdowns and industrial action in June and July 2026). The Amadeus Basin has been a long-term, steady supplier to the market. Beetaloo gas will replace the 'emergency' supply into the NT.

Beetaloo supply could re-open the NGP – opportunity into East Coast

Beetaloo supply is also the mechanism by which the NGP could re-open. The pipeline has a 90 TJ/d capacity and requires approximately 20 TJ/d of minimum throughput for the nitrogen removal unit to operate and for the NGP to be open. It has been closed for the majority of the past two years as the offshore Blacktip field could not sustain sufficient volume for the minimum threshold. Beetaloo volumes of 40–65 TJ/d would comfortably restore NGP operations. Re-opening of the pipeline could once again provide CTP with a route to the East Coast market (see section below for potential gas price ramifications).

Customer contracting delay a risk

The more relevant risk is not oversupply but contracting behaviour, specifically that NT customers defer commitments in anticipation of Beetaloo volumes in an attempt to arbitrage a future price differential. CTP has addressed this directly. With 10.5 PJ contracted to the end of 2034 at a fixed CPI-escalated price, in addition to its existing 6-year GSAs running to December 2030, 98% of firm production is already committed for CY27 and >80% for the next 3 years. As an established producer with amortised infrastructure costs, CTP could be expected to have a cost advantage over new Beetaloo production.

Policy: The Domestic Gas Reservation Scheme

Status: settings announced, legislation pending

The Gas Market Review report was released on 22 December 2025, and the Australian Government accepted all 18 recommendations. On 7 May 2026, the Government announced the Domestic Gas Reservation Scheme, under which LNG exporters will carry a Domestic Supply Obligation (DSO) equivalent to 20% of their annual LNG export volumes, commencing 1 July 2027 and pro-rated for the second half of that year. A draft Design Framework was released on 25 May 2026, and consultation closed on 30 June 2026. Resources Minister Madeleine King introduced the Domestic Gas Reservation Bill to Parliament on 14 October 2026. This bill has to clear both houses before licence applications open on 1 January 2027. The scheme itself is due to start on 1 January 2028.

Exporters will be required to physically supply gas to domestic buyers rather than merely offer it, with compliance linked to export approvals rather than to penalties alone. Export contracts entered into before 22 December 2025 are grandfathered, which excludes the long-term foundation contracts underwriting the existing LNG projects and materially limits the near-term volume effect.

The scheme is intended to replace the Australian Domestic Gas Security Mechanism (ADGSM), the Conditional Ministerial Exemption regime, the A$12/GJ price cap under the Gas Market Code of Conduct and the Heads of Agreement with the East Coast LNG exporters.

Existing regulations remain in force in the interim, and the ADGSM was not activated for either the June or September 2026 quarters.

Northern Territory: Darwin's obligations the key

The more consequential potential issue for CTP is the treatment of NT-based LNG exporters.

The Government has indicated a national scheme, rather than an East Coast–only one, and has stated it will work with the WA Government on alignment with WA's existing 15% reservation policy.

Darwin hosts two LNG facilities, and the NT has already relied on diverted LNG as an emergency backfill at prices understood to be in the range of A$17–18/GJ. If NT exporters carry a domestic supply obligation and are able to acquit it within the NT, the effect would be to convert that emergency supply into a standing obligation, adding competing volume to CTP's home market.

The exposure draft treats the NT and East Coast as a single physical market for DSO purposes, but the NT is connected to the East Coast only through the NGP, which has been closed for most of the past two years. The NT market could not absorb 20% of LNG production. The framework allows the Minister to reduce an exporter’s obligation for infrastructure constraints, and lets exporters meet it through third-party supply, but the variation is conditional on the exporter pursuing arrangements to overcome the constraint. How that test applies to NT exporters remains untested.

CTP's firm production is contracted to December 2030 and, under the new GSA, to the end of 2034, on take-or-pay terms. 98% of the expected production for next year, and 82% of the expected production for the next 3 years, is contracted for CTP. Any exposure is confined to uncontracted volumes from 2028, the same volumes exposed to Beetaloo supply.

Potential outcome – lower East Coast prices

The stated purpose of the scheme is to place downward pressure on domestic prices and to address the structural shortfall forecast (AEMO) in the southern states from 2029. To the extent it succeeds, it reduces the potential price CTP could receive if Amadeus or any future Otway and Cooper gas is piped to the East Coast . Grandfathering limits how much additional volume reaches the market before the early 2030s, and the forecast southern shortfalls are structural.

Conclusion – fairly neutral at this stage for CTP

The obligation for the gas reservation falls on LNG exporters. CTP does not export, and accordingly has no domestic supply obligation, no compliance cost and no exposure to the export approval linkage. The same applies to the Beetaloo pilot producers. The direct effect on CTP is nil. The indirect effects on CTP's markets are more relevant.

The current status of the policy appears to be neutral for CTP's contracted cashflow, mildly negative for the pricing of uncontracted volumes from 2028, and mildly negative for potential East Coast pricing. Offsetting this is the potential for CTP to become an emergency supplier for any domestic shortfall from the LNG projects. We will revisit the assessment when legislation is passed and the treatment of NT exporters is further clarified.

Valuation: Base-Case of A$0.24 (Unchanged)

Stock appears substantially undervalued

Our base-case valuation is shown in Figure 11.Our valuation remains unchanged as A$0.24 per share. The producing assets are valued on a risked NPV basis **Considering the relatively low risks to price and volume, the stock continues to trade at a significant discount and should continue to re-rate, in our view.**

Figure 11: CTP valuation summary

	A$m Valuation Unrisked	Risking	A$m	Valuation A$ps
Risked NPV - Mereenie - OL4 & OL5 (25%)	86	100%	86	0.11
Risked NPV - Palm Valley - OL3 (50%)	30	100%	30	0.05
Risked NPV Dingo - L7 & PL30 (50%)	51	100%	51	0.07
Risked NPV - Enterprise North - PEP 169 (20%)	25	65%	16	0.02
Risked NPV - Cooper Basin (49%)	3	65%	2	0.01
Total Operations	**194**		**184**	**0.26**
Net Cash / (Debt)	(7)	100%	(7)	(0.01)
Admin / Corporate / Other	(42)	100%	(42)	(0.06)
Exploration (risk-adjusted)	23	50%	12	0.02
Mereenie 2C gas (risked)	39	65%	25	0.03
TOTAL VALUATION	**207**		**172**	**0.24**

Source: MST.

Core Amadeus Basin assets – undervalued

The Amadeus Basin assets – Mereenie, Palm Valley and Dingo – provide underlying production, earnings and cashflow which we believe is fundamentally undervalued by the market.

Core production assets (less corp. costs) contribute A$0.17 to base case

The core production assets of Mereenie, Palm Valley and Dingo (less corporate costs) make up A$0.17 of our A$0.24 valuation, suggesting that the market is placing a significant discount on assets that have locked-in contracts with one of the lowest-risk customers in the gas sector.

NT Government contracts underpin valuation – upside potential

The key underpinning of our valuation relates to the NT Government contracts. Further contracts with the NT Government would lead to an increase in our valuation.

Gas price – assumption A$10.00/GJ

While precise details on the NT Government gas offtakes are unclear for commercial-in-confidence reasons, CTP has been receiving average prices around or over A$10/GJ since the commencement of the contracts at the start of CY25. Our view is that the pricing will be around A$10/GJ for the NT Government contracts.

PV14 and PV15 wells – lifts valuation

We have been conservative in our valuation of Palm Valley. We have taken into consideration the capex for PV14 and PV15 (A$46m), but have conservatively modelled a 50% success rate (contribution from PV14 alone). This has lifted our valuation of Palm Valley, but substantial upside remains if both PV14 and PV15 are successful. The conservative valuation reflects the inherent risk of drilling, and we will await the results of the program before further adjusting our forecasts and valuation for Palm Valley.

Valuation of Enterprise North (EN)

We have included in our valuation a preliminary estimate for EN. We use the same gas pricing assumptions as for the rest of the company's assets. As the valuation is preliminary in nature, we have risked it at 65%. We assume first production in FY28 at 36 TJ/d, declining over 5 years.

Catalysts: upside potential driven by multiple sources

We see further upside potential to the share price and our valuation from multiple sources, which include:

- increased production from Palm Valley from new wells
- further GSAs for Mereenie gas
- higher cashflow from new NT Government contracts than we currently assume in our valuation
- additional capital returns via dividends or further share buy-backs
- exploration program – exploration and appraisal remain a source of potential valuation upside within CTP via the potential to increase reserves and thus increase production and/or the life of the assets. Key focus will be on the Otway Basin drilling and the Cooper Basin and the sub-salt exploration program if a JV partner can be found. Our valuation reflects minor upside from exploration
- establishment of helium production at Mereenie – we have not considered the potential value of helium in our valuation due to its early stage. The project is on hold and we await further information on costs and validity of extraction before taking this into our valuation
- a potential takeover due to CTP's value proposition.

Risks

Key risks to our valuation and to the share price include:

- lack of drilling success at Palm Valley
- further gas contracts for Mereenie not materialising
- lack of success from Otway and Cooper Basin drilling
- Mereenie Stairway development not proceeding
- Oversupply in NT market
- Lower prices from gas reservation policy
- sub-salt exploration not proceeding or lack of success
- further government regulation affecting pricing
- the gas price, a key sensitivity for CTP’s cashflow and valuation
- operational issues at existing assets.

Personal disclosures

Michael Bentley received assistance from the subject company or companies in preparing this research report. The company provided them with communication with senior management and information on the company and industry. As part of due diligence, they have independently and critically reviewed the assistance and information provided by the company to form the opinions expressed in this report. They have taken care to maintain honest and fair objectivity in writing this report and making the recommendation. Where MST Financial Services or its affiliates has been commissioned to prepare content and receives fees for its preparation, please note that NO part of the fee, compensation or employee remuneration paid has, or will, directly or indirectly impact the content provided in this report.

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The companies and securities mentioned in this report, include:

Central Petroleum (CTP.AX) | Price A$0.056 | Valuation A$0.240;

Price, target price and rating as at 26 October 2026 (not covered)*

Additional disclosures

This report has been prepared and issued by the named analyst of MST Access in consideration of a fee payable by: Central Petroleum (CTP.AX)

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