# Drilling in Amadeus Takes a Turn; Spot Sales Bode Well for Future Gas

## Deep Target Swapped for Shallower Target…

The first exploration well in CTP's free-carried program, Palm Valley 12 (PV12), commenced in April. The primary target was the Arumbera Sandstone at a depth of 3,560m. Gas shows were recorded whilst drilling which indicated the potential for a new, significant gas resource at Palm Valley. The vertical well encountered fractures, drilling issues and increased costs and having reached 2,335m, it was decided to replace the original PV deep target with a shallower target at a depth of ~2,060m and drill laterally across the fractures.

## Shallower Target Potentially as Big Delivery to High Price Gas Market Earlier

While it is disappointing that the well will not reach its original target, the shallower target could be comparable in size to the deep target with reduced drilling risk and a higher chance of commercial success. If successful, gas could be delivered into the high-priced spot gas market in a short time frame. The revised lateral appraisal wells are each designed as a deviated well extending up to 1,000m and are similar to the successful PV13 appraisal well drilled in 2019. If the revised target is unsuccessful, a second lateral well will be drilled into the even shallower zone which represents the existing Palm Valley production reservoir.

## Spot Gas Sales – Very Strong Pricing

In early May, CTP began delivering uncontracted gas into the spot East Coast Gas Market (ECGM), supplying 61 TJ of gas into spot markets through May and June at an **average delivered price of $34/GJ**. This generated over $2m revenue net to CTP. Entry into the high-priced ECGM spot market shows the potential revenue generation from any drilling success at PV12 and subsequent wells in the Amadeus. ECGM spot and LNG netback prices remain strong as global energy markets continue to be tight. CTP is entering the ECGM at the right time, with the domestic market desperate for more gas and supply waning.

## Higher Prices Drive Cash Generation and Profit

Sales revenue was $42.2m for FY22 and $10.1m for Q4FY22, up 18.7% quarter on quarter (qoq). Unit sales prices across the portfolio grew 26.9% qoq to an average of $8.49/GJ due to CTP's new access to the high-priced ECGM spot market. The stronger pricing environment saw cash increase, with Net debt at $10.2m at 30 June, down from $15.0m at the end of March. We have increased our FY2022 NPAT forecast from A$28m to A$36m reflecting the higher prices received.

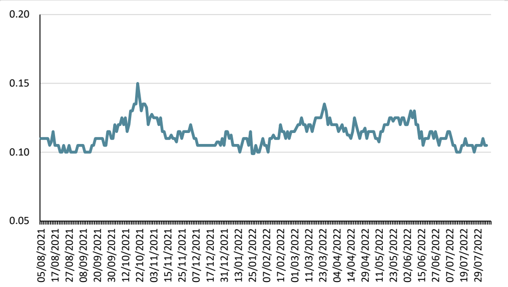
Central Petroleum (CTP) is the NT's largest onshore gas operator, with a portfolio of gas and oil assets focused on the Amadeus Basin and a significant coal seam gas (CSG) project in Queensland's Surat Basin. CTP has established a strong operational and exploration record. Its strategy is to unlock and 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

| | |
|---|---|
| **Stock** | ASX: CTP |
| **Price** | A$0.11 |
| **Market cap** | A$80m |
| **Valuation (per share)** | A$0.31 |

| **Next steps** | |
|---|---|
| 3Q2022 | Continued Amadeus drilling |
| 3Q onwards | Range Gas production test |

**CTP share price (A$) – 1 Year**




Source: FactSet.

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## Valuation $0.31/Share (unchanged) – Upside from Drilling Success

Our risked valuation is $0.31/share. The Amadeus Basin assets offer cash flow and attractive exploration options. In addition, the Range Gas Project has a significant contingent resource, in a basin that has historically been proven to reach production rapidly. The structurally stronger ECGM is a driver to potentially increase our valuation, particularly with a discovery at the current P2/P3 well. Key risks to the share price include lack of exploration success and poor production results at Range.



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## Exhibit 1 – Company summary (year-end 30 June)

| | | |
|---|---|---|
| Share Price | A$/sh | **0.11** |
| 52 week high/low | A$/sh | 0.04 - .02 |
| Valuation | A$/sh | 0.31 |
| Market Cap (A$m) | A$m | 80 |
| Net Cash / (Debt) (A$m) | A$m | 1 |
| Enterprise Value (A$m) | A$m | 79 |
| Shares on Issue | m | 726 |
| Options/Performance shares | m | 18 |
| Potential Diluted Shares on Issue | m | 744 |

**CTP Relative to XEJ 12 months**


| Ratio Analysis | 2020A | 2021A | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|
| EPS (A¢) | 0.75 | 0.03 | 4.94 | 0.60 | 1.19 | 2.33 | 2.21 |
| P/E (x) | 10.8 | 345.4 | 2.2 | 18.4 | 9.2 | 4.7 | 5.0 |
| EPS Growth (%) | | -95% | 14484% | -88% | 100% | 95% | -5% |
| CFPS (A¢) | 2.18 | 3.26 | 5.81 | 1.69 | 2.54 | 3.93 | 3.93 |
| P/CF (x) | 3.7 | 3.6 | 1.9 | 6.5 | 4.3 | 2.8 | 2.8 |
| DPS (A¢) | - | - | - | - | - | - | - |
| Dividend Yield (%) | - | - | - | - | - | - | - |
| EV / EBITDA (x) | 3.7 | 6.2 | 1.9 | 5.2 | 2.9 | 1.2 | 0.3 |
| EV / boe (x) | 52.7 | 66.6 | 86.3 | 75.6 | 52.0 | 30.6 | 8.1 |
| EV / PJe (x) | 8.8 | 11.1 | 14.4 | 12.6 | 8.7 | 5.1 | 1.3 |

| Assumptions (Yr end Jun) | 2020A | 2021A | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|
| Brent Oil Price (US$/bbl) | 50.40 | 53.75 | 89.32 | 86.7 | 80.6 | 79.6 | 81.2 |
| Exchange Rate (A$1:US$) | 0.671 | 0.747 | 0.727 | 0.700 | 0.700 | 0.700 | 0.700 |
| Gas Price (A$/GJ) | 5.34 | 5.71 | 6.11 | 6.32 | 6.45 | 7.64 | 7.79 |

| Production | 2020A | 2021A | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|
| Gas (TJ/d) | 31 | 27 | 13 | 17 | 20 | 19 | 18 |
| Gas (PJ) | 11.3 | 9.8 | 6.0 | 6.2 | 7.1 | 6.9 | 6.5 |
| LPG (kt) | - | - | - | - | - | - | - |
| Oil / Condensate (mmbbl) | 0.09 | 0.08 | 0.04 | 0.03 | 0.03 | 0.02 | 0.02 |
| **Total (mmboe)** | **1.96** | **1.72** | **1.03** | **1.06** | **1.22** | **1.18** | **1.10** |
| Gas (mmboe) | 1.88 | 1.64 | 0.99 | 1.03 | 1.19 | 1.16 | 1.08 |
| LPG (mmboe) | - | - | - | - | - | - | - |
| Oil / Condensate (mmboe) | 0.09 | 0.08 | 0.04 | 0.03 | 0.03 | 0.02 | 0.02 |
| **Year End Reserves 2P (mmboe)** | **27.7** | **26.1** | **25.1** | **24.0** | **22.8** | **21.6** | **20.5** |

| Reserves and Resources As at 31 December 2021* | Working Interest | 1P Gas (PJ) | 2P Gas (PJ) | 1P Liquids (mmbbl) | 2P Liquids (mmbbl) | 2C Gas (PJ) | 2C Liquids (mmbbl) |
|---|---|---|---|---|---|---|---|
| Mereenie (OL 4 / OL 5) | 25% | 31.5 | 40.3 | 0.4 | 0.4 | 45.6 | 0.0 |
| Palm Valley (OL 3) | 50% | 11.8 | 13.3 | - | - | 6.8 | |
| Dingo (L7) | 50% | 16.6 | 19.4 | - | - | - | |
| Range (ATP 2031) | 50% | - | - | - | - | 135.1 | |
| **Total** | | **59.9** | **73.0** | **0.4** | **0.4** | **187.5** | **0.0** |

| NPV Valuation | A$m | Risking | A$m | A$ps |
|---|---|---|---|---|
| Mereenie - OL4 & OL5 (25%) | 48 | 100% | 48 | 0.07 |
| Palm Valley - OL3 (50%) | 22 | 100% | 22 | 0.03 |
| Dingo - L7 & PL30 (50%) | 35 | 100% | 35 | 0.05 |
| Project Range - ATP 2031 (50%) | 102 | 75% | 76 | 0.11 |
| **Total Operations** | **207** | | **181** | **0.25** |
| Net Cash / (Debt) | (1) | 100% | (1) | (0.00) |
| Admin / Corporate / Other | (22) | 100% | (22) | (0.03) |
| Exploration (risk-adjusted) | 26 | 50% | 13 | 0.02 |
| Mereenie & Palm Valley 2C gas (risked) | 40 | 70% | 28 | 0.04 |
| Dingo & Palm Valley (Prospective) | 47 | 60% | 28 | 0.04 |
| **TOTAL VALUATION** | **297** | | **228** | **0.31** |

| Profit & Loss (A$m) | 2020A | 2021A | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|
| Oil / Condensate Revenue | 6 | 5 | 6 | 4 | 3 | 3 | 2 |
| LPG Revenue | - | - | - | - | - | - | - |
| Gas Revenue | 59 | 54 | 36 | 39 | 46 | 54 | 52 |
| **Total Sales** | **65** | **60** | **42** | **43** | **49** | **57** | **55** |
| Operating Costs | (28) | (24) | (8) | (13) | (12) | (12) | (11) |
| Government Resource Taxes | (5) | (4) | (3) | (3) | (4) | (4) | (4) |
| Exploration & Development Expen | (5) | (8) | (10) | (4) | (4) | (2) | (2) |
| Other Net Income / Expense | 1 | (5) | 25 | (8) | (8) | (8) | (8) |
| **EBITDA** | **28** | **18** | **47** | **16** | **22** | **31** | **29** |
| **EBITDAX** | **33** | **26** | **56** | **19** | **26** | **33** | **31** |
| Depreciation & Amortisation | (16) | (13) | (7) | (9) | (11) | (12) | (13) |
| EBIT | 12 | 6 | 40 | 6 | 10 | 18 | 16 |
| Net Interest Expense | (6) | (6) | (4) | (2) | (2) | (1) | 0 |
| **Pretax Profit** | 5 | 0 | 36 | 4 | 9 | 17 | 16 |
| Tax Expense / Benefit | - | - | - | - | - | - | - |
| **Net Attributable Profit** | **5** | **0** | **36** | **4** | **9** | **17** | **16** |
| Reported Profit | 5 | 0 | 36 | 4 | 9 | 17 | 16 |

| Cash Flow (A$m) | 2020A | 2021A | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|
| **Pretax Profit** | 5 | 0 | 36 | 4 | 9 | 17 | 16 |
| D&A & Other Non-Cash Items | 10 | 24 | 6 | 8 | 10 | 12 | 12 |
| Tax Paid | - | - | - | - | - | - | - |
| **Cash from Operating Activities** | **16** | **24** | **42** | **12** | **18** | **29** | **29** |
| Development Capex | (3) | (6) | (1) | (4) | (1) | (1) | (1) |
| Exploration Capex | (3) | (5) | (10) | (5) | (6) | (3) | (3) |
| Acquisitions/Other (Net of Sales) | 8 | 0 | 30 | - | - | - | - |
| Dividends Paid | - | - | - | - | - | - | - |
| **Free Cash Flow** | **20** | **16** | **71** | **9** | **17** | **27** | **27** |
| Cash Provided by Financing | (12) | (5) | (36) | (3) | (3) | (20) | - |
| **Net Change in Cash** | **8** | **11** | **35** | **5** | **14** | **7** | **27** |

| Balance Sheet (A$m) | 2020A | 2021A | 2022A | 2023A | 2024A | 2025A | 2026A |
|---|---|---|---|---|---|---|---|
| Cash & short term deposits | 26 | 37 | 22 | 27 | 40 | 48 | 75 |
| Receivables | 7 | 7 | 32 | 5 | 6 | 7 | 7 |
| Inventories | 3 | 2 | 2 | 3 | 5 | 7 | 9 |
| Property, Plant and Equipment | 108 | 54 | 56 | 52 | 44 | 36 | 27 |
| Capitalised exploration | 9 | 8 | 8 | 8 | 7 | 5 | 3 |
| Intangibles and Goodwill | 4 | 2 | 2 | 2 | 2 | 2 | 2 |
| Other assets | 4 | 64 | 6 | 6 | 6 | 6 | 6 |
| **Total assets** | **160** | **174** | **130** | **103** | **112** | **111** | **129** |
| Creditors | 5 | 10 | 8 | 5 | 6 | 7 | 7 |
| Borrowings | 71 | 67 | 31 | 23 | 20 | - | - |
| Other liabilities | 82 | 93 | 56 | 36 | 38 | 39 | 41 |
| **Total liabilities** | **158** | **170** | **95** | **64** | **64** | **46** | **48** |
| Shareholder equity | 2 | 4 | 35 | 39 | 48 | 65 | 81 |
| Shareholder Equity + Total Liabilitie | 160 | 174 | 130 | 103 | 112 | 111 | 129 |

Source: CTP, MST estimates.



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## 2022 Drilling: Palm Valley 12 Takes a Turn – But a Potential Silver Lining

CTP's drilling and appraisal program in 2022 has huge potential to add resources and production. The free-carry program (as a result of the farm-out of 50% of production assets to New Zealand Oil and Gas and Cue Energy) commenced in April 2022 with the Palm Valley 12 (PV12) deeps exploration well. The primary target was the Arumbera Sandstone at a depth of 3,560m. Gas shows were recorded, whilst drilling indicated the potential for a new, significant gas resource at Palm Valley.

In the end, it was decided to replace the original PV deep target with a shallower target in the lower P2/P3 interval of the Pacoota Sandstone at a depth of approximately 2,060m and drill laterally across the fractures.

### Success More Easily Commercialised…Spot Market Sales

While it was disappointing that CTP had to stop the PV12 deep drilling program, we see a silver lining. Having commenced a much lower-risk, shallower and less technical lateral program, successful gas finds could be more easily commercialised than a deep discovery. The gas could be sold into the high priced spot market.

### The Original Plan: Palm Valley Deep – Targeting 123 PJ (61.5 PJ Net to CTP)

- A deep exploration well with a shallower production lateral (PV12) if exploration target was unsuccessful
- Targeting a mean recoverable volume of 123 PJ (61.5 PJ net to CTP) in the deep Arumbera Sandstone, the productive interval at the Dingo Field
- If the deep test were to fail, the well would be plugged back and a 1,500m lateral well would be drilled at the Pacoota level and completed for immediate tie-in as a producing well
- Drilling commenced on 17 April 2022

Exhibit 2 (left) shows the original plan.

### The Outcome: What Happened During Drilling

The primary target for drilling was the Arumbera Sandstone at an anticipated vertical depth of 3,560m (PV Deep).

- Gas shows were recorded whilst drilling through both the currently productive P1 Sandstone and the P2/P3 Sandstones located 90m below the P1.
- The vertical PV12 well intersected a major fracture zone within the lower P2 Sandstone which resulted in total lost circulation while drilling. In addition to the drilling difficulties, costs (particularly diesel) had increased since the plan was originally created.
- Having reached a depth of 2,335m, it was decided on 12 July to replace the original PV Deep target with the shallower P2/P3 target at a depth of approximately 2,060m.
- The switch of target was prompted by the promising gas shows and the potential for the P2/P3 target to be as large as the PV Deeps target. The new target should have a lower drilling risk and a higher chance of commercial success and will allow better management of capital and accelerate the chances to deliver gas into a high-priced spot market.

### The Updated Plan: What Happens Now?

- It is planned to drill approximately 450m horizontally through the lower P2 Sandstone and then continue a further 450m horizontally into the P3 Sandstone.
- The presence of gas in the P2/P3 Sandstones indicates the potential for a new large gas resource.
- The new lower P2/P3 target could be comparable in size to the PV Deep target with reduced drilling risk. A lateral P2/P3 well is considered to have a higher chance of commercial success than drilling a further 1,225m to the deeper Arumbera Sandstone target.

Exhibit 2 (right) shows the updated plan.



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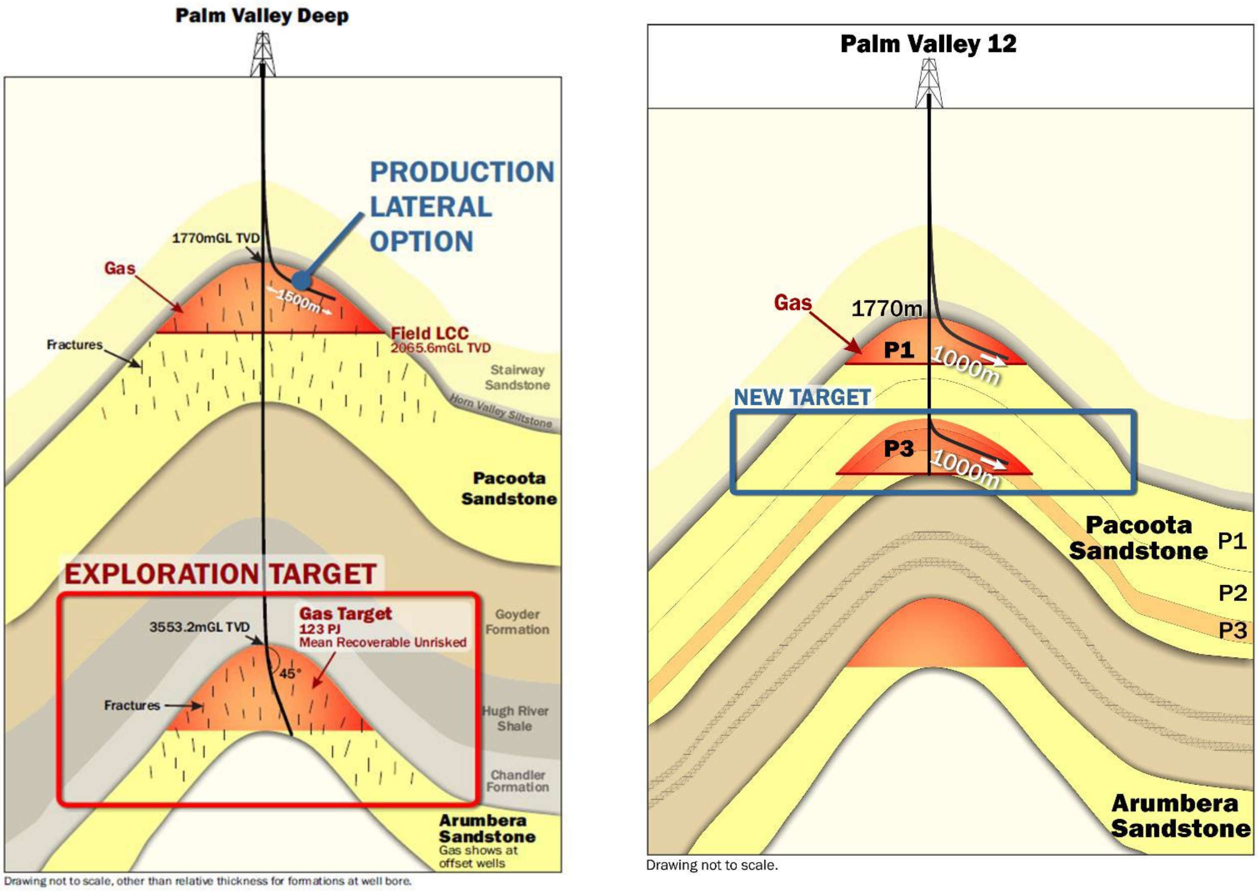
Exhibit 2 – PV12: Original plan (LHS), PV12: Revised program (RHS)




(1) Mean prospective resource.
Source: CTP.

## What's the Potential Outcome of the New PV12 Program? Fast Commercialisation

Appraisal success at P2/P3 at Palm Valley could be more rapidly and cheaply commercialised than the deep target, with the well being able to be tied into the Palm Valley processing facility within months. This gas could be delivered into the high-priced spot market as it would be uncontracted.

From a longer-term perspective, a significant increase to the Palm Valley reserves from P2/P3 may lead to investment into an increased number of wells and increased long-term production. This would also require an increase in production capacity at the Palm Valley facility.

If the P2/P3 exploration objective is unsuccessful, the well will be plugged back and a second lateral well side-tracked to test the shallower Pacoota (P1) Sandstone (approximately 1,770m depth), which is the current producing zone for the Palm Valley gas field. The lateral design is similar to the successful PV13 appraisal well drilled in 2019, which had a lateral extension of only 300m and has already produced approximately 5.7 PJs in its first three years.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## What Does the New Plan Mean for the Remainder of the Amadeus Free-Carry Program? – Deferral of Dingo Deep Exploration Well

### Original plan for Dingo Deep exploration well

Had the PV12 well not encountered the significant drilling issues requiring a major change of plans, a second deep exploration well at Dingo Deeps was planned. The plan for that well was:

- a deep exploration well with option to access existing production formation
- targeting a mean recoverable volume of 69 PJ (34.5 PJ net to CTP)
- a successful exploration test would have opened up a new play fairway in the basin

### Exploration well deferred

The planned Dingo Deep exploration well has been deferred to prioritise capital for near-term production-enhancement activities at Mereenie or Palm Valley. The current ECGM provides clear incentive for development at Palm Valley or recompletions and development at Mereenie.

In contrast, the Dingo field is not currently connected to the ECGM as it supplies gas directly to a single customer. Commercialisation options for success at Dingo Deep would have required construction of new surface infrastructure and modifications to the Amadeus Gas Pipeline and Alice Springs Pipeline to transport gas to the ECGM.

### What's left of the free carry

Under the free-carry arrangements relating to the partial asset sale, the new joint ventures at Mereenie, Palm Valley and Dingo agreed to pay $40m of CTP's share of certain future exploration and development costs in those fields. At the end of June, $21.1m remained available for future use.



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# Other Key Appraisal and Exploration Projects – An Update

## Range CSG Project – Production Testing Underway

CTP's 50%-owned Range CSG Project aims to bring production into the ECGM. The Range CSG Project contains 135 PJ of 2C contingent gas resource (net to CTP). Gas production from the Range CSG Project is reserved for domestic use.

The initial pilot program encountered lower-than-expected initial water rates which led to an extended dewatering period. The four previous exploration wells had intersected circa 25% more net coal than the pilot wells (33m vs 26m). It is well understood with CSG in the Surat Basin that the coals show some variability and that selection of the position of the wells is important. Two new pilot wells were drilled in April 2022 and have been spaced at a greater distance (circa 2km) and averaged 29m of net coal.

Extended production test of the new pilot step-out wells (Range-9 and Range-10) commenced in early April, with water production controlled to allow for a gradual drawdown. One of the original pilot wells, Range-6, was returned to production and production testing of the three wells continues. Gas flows have been gradually increasing and the pilot wells are currently producing gas at an aggregate 40,000 scfd. Early gas flows indicate good gas saturation, although the relatively low water rates suggest that a longer dewatering period will be required.

The pilot wells are intended to provide key information regarding reservoir productivity (initially via water rates), gas desorption (when gas is first produced), zonal contribution (how much each coal seam is contributing) and the initial production profiles of gas and water ramp-up. Recent data swaps with a neighbouring permit could provide additional technical insights.

## Progress on Sub-Salt Drilling in 2023: Farm Out to Peak Helium; Helium and Hydrogen on the Radar

### Three wells to be drilled by Peak Helium, with costs carried for two

CTP has farmed out interests in a number of its sub-salt permits to Peak Helium[1]. Peak has committed to drilling at least three wells, carrying CTP's costs for two of these. Details are as follows:

- EP82 (includes Magee/Mahler): Peak will receive a 31% interest in EP82 from CTP, reducing CTP's interest in this tenement to 29% from 60%. In return, Peak will fund CTP's share of costs (up to a cap of $20m gross well cost) for a new exploration well at the Mahler prospect, targeting natural gas and helium.
- EP112 (includes Dukas): Peak will receive a 10% interest in EP112 from CTP, reducing CTP's interest in this tenement to 35% from 45%. There is no funding/carry of CTP's costs in this permit. Peak has, however, committed to the timely drilling of the highly prospective Dukas exploration well.
- EP125 (includes Mt Kitty): Peak will receive a 6% interest in EP125 from CTP, reducing CTP's interest in this tenement to 24% from 30%. In return, effective 1 October 2021, Peak will fund CTP's share of costs (up to a cap of $20m gross well cost) for a new exploration well, or a re-entry of the existing suspended exploration well, at Mt Kitty, which will target helium, hydrogen and natural gas.

Completion of CTP's farmouts to Peak is subject to the usual conditions precedent for a transaction of this nature including Joint Venture, Central Land Council, royalty holders and NT regulatory approvals. Progress towards completion has continued, with the satisfaction date extended to 31 August 2022 (from 31 July 2022).

Santos, as operator of these permits, has commenced detailed planning, approvals and procurement for the 2023 drilling program.

[1] Peak Helium (Amadeus Basin) Pty Ltd is a private company with a focus on exploring, developing and commercialising discoveries of helium to create an Asia Pacific and international market leader. Peak Helium currently holds a 100% interest in EP134, Northern Territory, Australia.


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# A Strong End to the Financial Year – Spot Sales Drive Higher Cash

## Entry into the ECGM Spot Market – A Game Changer for CTP

In early May, CTP began delivering uncontracted gas into the spot East Coast Gas Market (ECGM). Through May and June, it supplied gas into spot markets at an average delivered price of $34/GJ, generating over $2m revenue net to CTP.

The ECGM spot sales make up a small portion of the total sales portfolio (some 15% of gas production), but they have helped boost overall revenues by 19% from the last quarter and contributed to the $21.6m cash balance at 30 June.

## A Quick Look at the Volumes, Prices and Financials

### Volumes – maintenance on the pipeline softens production in the last quarter

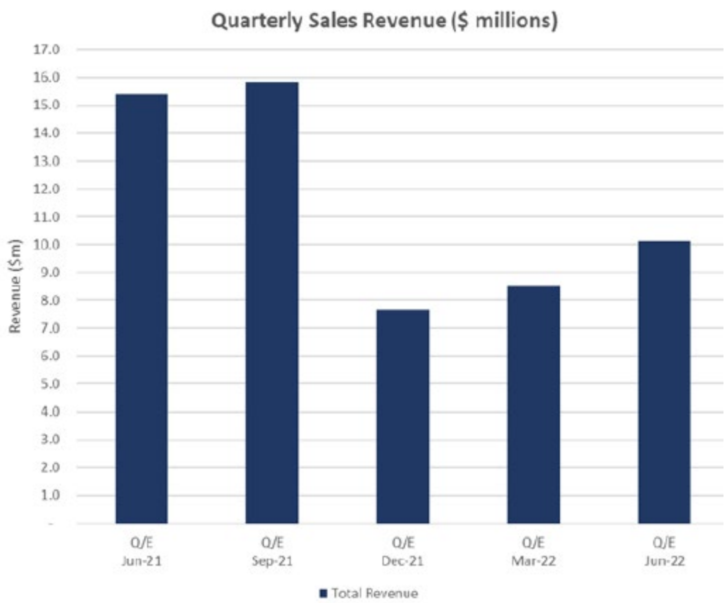
Scheduled maintenance on the Northern Gas Pipeline restricted gas sales during the quarter, which resulted in sales volumes being 6.5% lower than the previous quarter. Firm long-term gas supply contracts in the Northern Territory accounted for 85% of June-quarter volumes, with the balance being supplied into the high-demand spot ECGM.

### Prices and revenue – spot prices turbo charge the last quarter

Sales revenue for the June quarter was $10.1m, up 18.7% from the March quarter. Unit sales prices across the portfolio increased by 26.9% from the March quarter to an average of $8.49/GJ, reflecting CTP's new access to high-priced spot ECGM and higher oil prices.

CTP's $42.2m full-year revenue was lower than FY2021 due to the lower ownership interests from 1 October 2021, but after adjusting for that impact, **revenues were 12.7% higher than FY2021 on a like-for-like basis**. This was achieved on lower like-for-like volumes (down 2% on FY2021), with the realised oil price 76% higher in FY2022 and the average gas portfolio price up 9% on FY2021.

Exhibit 3 – Quarterly sales for FY2022 ($m)




Source: CTP.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## Financial position – balance sheet strengthening

### Cash and debt

Cash balances were $21.6m at the end of the quarter, up from $18.9m at the end of March. The net cash inflow from operations for the quarter was $5.5m after exploration costs and finance costs. Cash receipts from customers during the quarter were $10.8m, benefitting from strong oil prices and spot gas sales into the higher-priced ECGM.

Net debt was $10.2m at 30 June, down from $15.0m at the end of March due to higher cash balances.

CTP's strong quarter of cash flow generation allowed further pay down of debt.

Exhibit 4 – Debt balance ($m) – CTP's forecast paydown


Source: CTP.

### Extension of debt facility

In April, CTP extended its $32.8m loan facility by three years, with the partially-amortising facility now expiring on 30 September 2025. The terms remain substantially the same as the existing facility.

## Forecasts for FY2022 – Upgrade Off Higher Gas Volumes and Prices

We have reviewed our forecasts for FY2022 (summarised in Exhibit 5). The key changes are:

- revised production for gas
- upgrading forecast for higher prices for gas and oil, driven by strong oil prices in the Q4FY22 and delivery of gas into high priced spot contracts in Q4FY22.

Exhibit 5 – Review of FY2022 forecasts

| Profit & Loss (A$m) | FY2022 Previous | FY2022 New | Difference | Notes |
|---|---|---|---|---|
| Oil / Condensate Revenue | 4 | 6 | 2 | Higher oil pricing in Q4 |
| LPG Revenue | – | – | – | |
| Gas Revenue | 31 | 36 | 5 | High priced spot sales in Q4 plus higher received gas prices than previously forcast |
| **Total Sales** | **35** | **42** | **7** | |
| Operating Costs | (8) | (8) | (1) | |
| Government Resource Taxes | (3) | (3) | (1) | |
| Exploration & Development Expenses | (10) | (10) | – | |
| Other Net Income / Expense | 25 | 25 | 0 | |
| **EBITDA** | **40** | **47** | **5** | |
| **EBITDAX** | **49** | **56** | **7** | |
| Depreciation & Amortisation | (8) | (7) | 1 | |
| EBIT | 32 | 40 | 8 | |
| Net Interest Expense | (4) | (4) | (0) | |
| **Pretax Profit** | 28 | 36 | 8 | |
| Tax Expense / Benefit | – | – | – | |
| **Net Attributable Profit** | **28** | **36** | **8** | Higher prices directly through to profit |

Source: MST estimates.


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# East Coast Gas Market Update – The Current Conditions

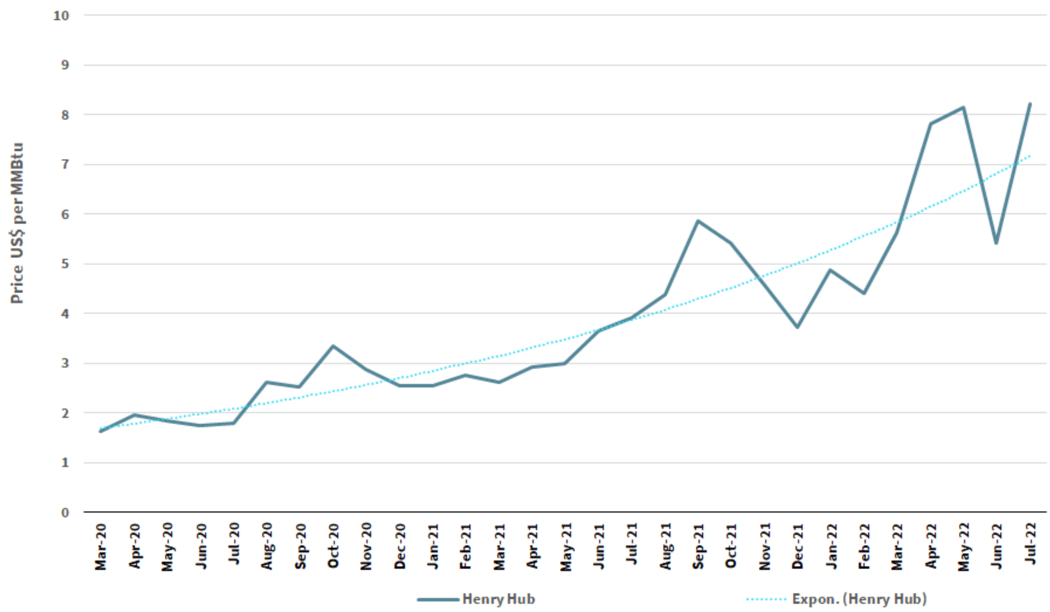
As discussed earlier, CTP has sold gas into the high-priced ECGM spot markets achieving an average price of A$34/GJ. The gas markets continue to be challenged with high demand meeting tightening supply.

## Global Gas Market Continues to Be Challenged

The focus of the global gas market remains on supply to Europe. Russia's Ukraine invasion and the subsequent sanctions enforced upon Russia, as well as Russia's political movements with regards to cutting off supply, have exacerbated an already tight situation in Europe. The US continues to work to shore up gas supply for Europe through LNG imports from the US and allied nations, including Australia.

The US gas market has also increased substantially, sitting some 165% above the price a year ago (see Exhibit 6). The tight global supply situation, coupled with the US being viewed as a supplier of choice to Europe and with a relatively inelastic demand picture in the US, have combined to see a 'fear premium' being priced into the US gas price.

Exhibit 6 – US Henry Hub gas price, 2 years




Source: Factset.

## East Coast Gas Market – Australian LNG Seen as Part of the Global Solution; Pressure Building on Local Supply

Spot prices have strengthened over the past 12 months, with LNG pricing increasing as Northern Hemisphere demand coincided with tightening supply. Local demand has increased from Queensland LNG projects looking to supply into a global market. Domestic East Coast demand has also increased markedly this winter as gas-fired electricity generation was called upon to replace coal-fired generation shortfalls, and government policy has been put in place looking at gas as a key energy component for domestic manufacturing and as a transition fuel into renewable energy sources.

From a supply point of view, the ACCC has forecast a potential domestic gas supply shortfall of 30 PJ pa as early as 2024 before a much greater potential shortfall of 358 PJ pa in 2032.

### Spot pricing will influence future contract pricing

Large contracts in the Australian gas market are typically at negotiated prices and over terms of 3–5 years. The prevailing spot market price inevitably influences contract pricing arrangements. Continued high spot prices may lead to higher contract prices.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## Domestic Gas Pricing – LNG Netback – Export Parity

### What is the LNG netback price?

The LNG netback price is a measure of an export parity price that a gas supplier can expect to receive for exporting its gas. It is calculated by taking the price that could be received for LNG and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port. When adjusted for these factors, an LNG netback price represents the price that a gas supplier would expect to receive from a domestic gas buyer so as to be indifferent to a choice between selling the gas to the domestic buyer and exporting it as LNG. LNG netback prices based on Asian LNG spot prices currently play an important role in influencing ECGM gas prices.

### LNG netback price recently hit highest level since records began in 2016

Tightening global gas conditions, particularly in Europe, have put upward pressure on LNG prices, leading to a strong upward movement in the LNG netback price. The LNG netback price per the Australian Competition & Consumer Commission (ACCC) for July 2022 is A$29/GJ. August forward prices indicate a higher price of A$49.16/GJ.

### What does this mean for the spot price of East Coast gas?

The confluence of global supply side issues and increasing demand, coupled with a tight domestic supply demand scenario, has naturally put upward pressure on domestic pricing. An added recent local dynamic is the emergence of shortfalls in the dispatchable electricity generation capacity and demand brought on by downtime in key base load electricity plants, a gap that is projected to widen with scheduled retirement of coal-fired plants.

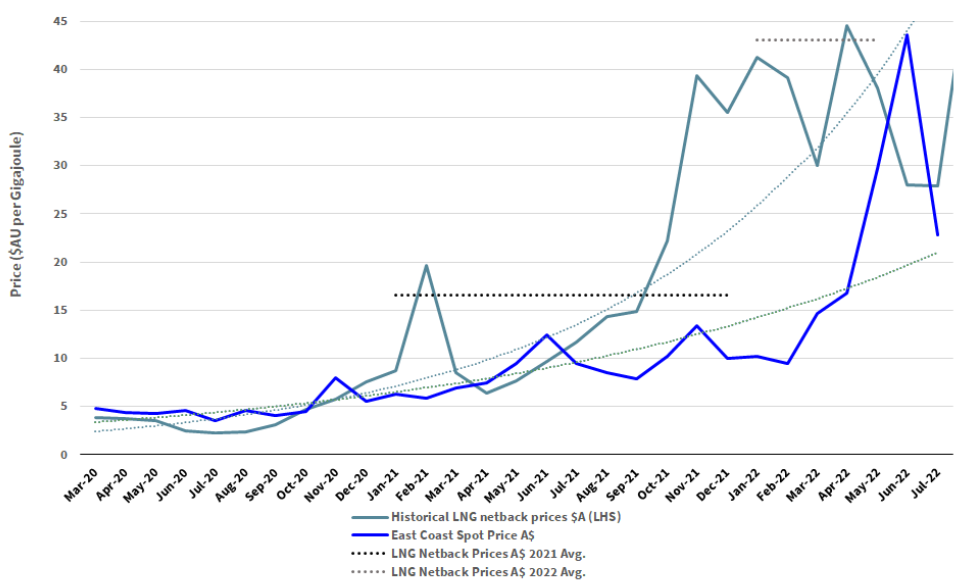
The spot (Wallumbilla netback) ECGM has seen significant pricing moves in CY2022, having begun the year around A$10/GJ, with pricing at the end of July at over $22/GJ. Prices peaked at over A$40/GJ in June.

The Australian government has proposed an extension of the Australian Domestic Gas Security Mechanism (ADGSM) until 2030 and may also review the policy aimed at boosting domestic gas supply. The review of the ADGSM, created by the previous government to ensure domestic gas supply, comes amid growing criticism about the fact that Australia exports the majority of its gas production, along with the recent electricity shortages in the eastern states.

The spot gas price over the last few days has corrected back to levels around the A$12/GJ mark off the back of this announcement and the return of coal-fired electricity generation capacity to the market.

Exhibit 7 shows the current ECGM spot vs LNG netback prices. It shows a distinct breakout of LNG netback prices from late 2021 and spot price movement from February 2022.

Exhibit 7 – LNG netback prices vs prevailing spot ECGM prices




Source: ACCC, AEMO STTM.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# Valuation: Current Operations Generate Value, Exploration Program Presents Significant Upside

## Base-Case Valuation of A$0.31 (Unchanged) – Further Upside from Exploration

The Amadeus Basin assets provide underlying production, earnings and cash flow from which CTP can unlock substantial upside potential. We believe this upside is being potentially mis-priced by the equity market. In addition, the Range CSG Project has a significant contingent resource in a basin that has been proven to be able to be brought to production rapidly.

Our valuation is A$0.31/share (unchanged). Our valuation includes the strong ECGM fundamentals as the gas price received over time by CTP rolls contracts into higher prices as well as delivering uncontracted gas into higher priced spot markets. We have not included any volumes from any success at the P2/P3 lateral drilling at Palm Valley, which would be delivered into the spot market.

### Valuation methodology: accounting for uncertainty by applying a risk factor to each asset

Valuing oil and gas assets, particularly in the exploration and appraisal stage, is quite a subjective process. A number of uncertainties are at play, as significant test and appraisal works are still to be completed.

We include a risk factor in our valuation of each of the individual assets. We use an individual risk weighting for each asset, allowing us to account for these developments as well as the less certain opportunities for some of the other assets. Production assets are risk weighted at 100% (see Exhibit 8).

Exhibit 8 – Base-case valuation summary – fully diluted (A$ per share)

| NPV Valuation | A$m | Risking | A$m | A$ps |
|---|---|---|---|---|
| Mereenie - OL4 & OL5 (25%) | 48 | 100% | 48 | 0.07 |
| Palm Valley - OL3 (50%) | 22 | 100% | 22 | 0.03 |
| Dingo - L7 & PL30 (50%) | 35 | 100% | 35 | 0.05 |
| Project Range - ATP 2031 (50%) | 102 | 75% | 76 | 0.11 |
| **Total Operations** | **207** | | **181** | **0.25** |
| Net Cash / (Debt) | (1) | 100% | (1) | (0.00) |
| Admin / Corporate / Other | (22) | 100% | (22) | (0.03) |
| Exploration (risk-adjusted) | 26 | 50% | 13 | 0.02 |
| Mereenie & Palm Valley 2C gas (risked) | 40 | 70% | 28 | 0.04 |
| Dingo & Palm Valley (Prospective) | 47 | 60% | 28 | 0.04 |
| **TOTAL VALUATION** | **297** | | **228** | **0.31** |

Source: MST estimates.

## Significant Upside Potential, Driven by Multiple Sources

We see strong upside potential to our base-case valuation. CTP has multiple sources of potential upside valuation over time. Potential drivers of future upside include:

- exploration program – potential to substantially increase reserves and increase production and/or life of assets – short term success at P2/P3 which could be delivered rapidly into the spot market.
- construction of Amadeus to Moomba Gas Pipeline (AMGP) – significantly reducing gas transport costs and increasing net received gas price
- further increase in east coast gas price
- Range CSG Project development – rapid development potential, would add significant cash flow
- helium and hydrogen exploration success.



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## Key risks

- Exploration success would drive an increase in production and or asset life. However, any delay in exploration programmes or disappointing results would create a risk to that upside.
- Delays in the progress of the AMGP would delay the upside potential from increased volumes and lower costs.
- CTP's cash flow and valuation are sensitive to the gas price.
- Operational issues at existing assets would reflect poorly on management and decrease cash flow and valuation.
- The Range Gas Project in the Surat Basin has strong potential for development. Any lack of progress would be a risk to the valuation and share price.

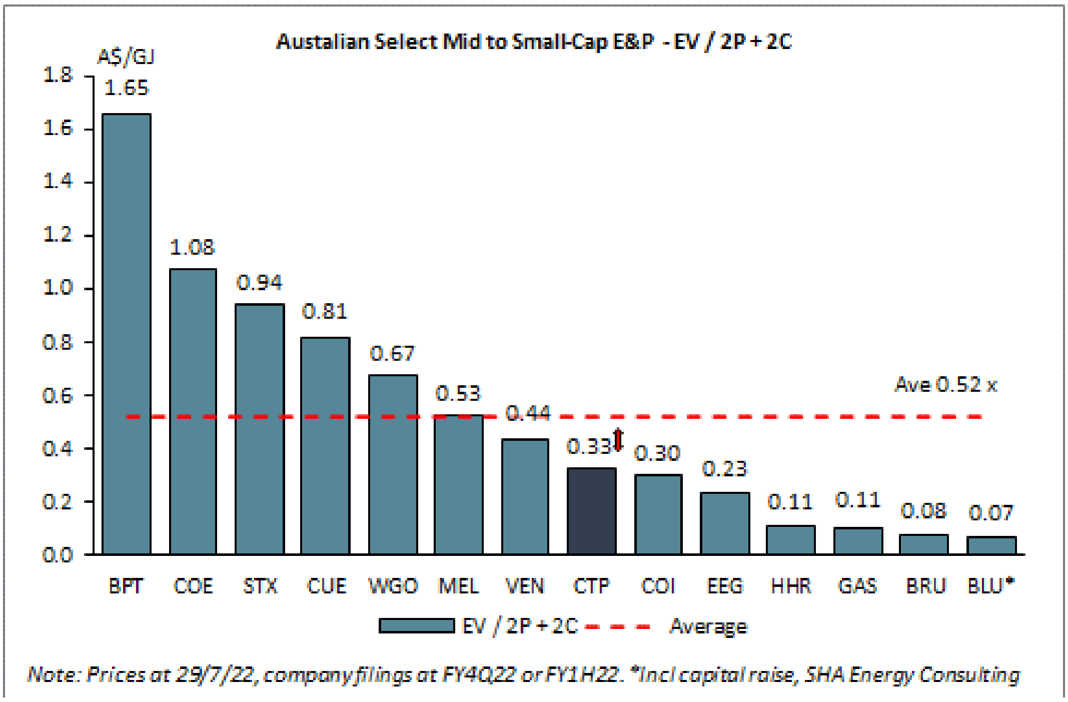
## Enterprise Valuation to Resources:
## A Cross Check on our Valuation Supports our View that CTP Is Undervalued

An additional check on our valuation is to observe how the market values the reserves and resources of CTP and its ASX-listed peers (see Exhibit 9), using EV/2P+2C. This yields a lower alternative valuation than our NPV-based method, but does reflect upside to the current share price, particularly if the 2P reserves base can be expanded.

This valuation metric shows the relative value the market attributes to the company's reserve and resource base. CTP is valued significantly below its peer average, with CTP's EV/2P+2C of 0.33 comparing to the average of 0.52. The peer average would see CTP valued at **A$0.17 vs. the current share price of A$0.11 and our valuation of A$0.31.**

The market has placed the highest value on the reserves and resources of Beach Petroleum, Cooper Energy and Strike Energy, both of which have a significantly larger 2P reserves base than both CTP and the peer group. The 2P reserves base is given a higher relative value by the market than 2C resources.

Exhibit 9 – Select Australian EV/Resources multiples




Source: MST estimates, company releases, SHA Energy.



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## Appendix 1: Resources and Reserves

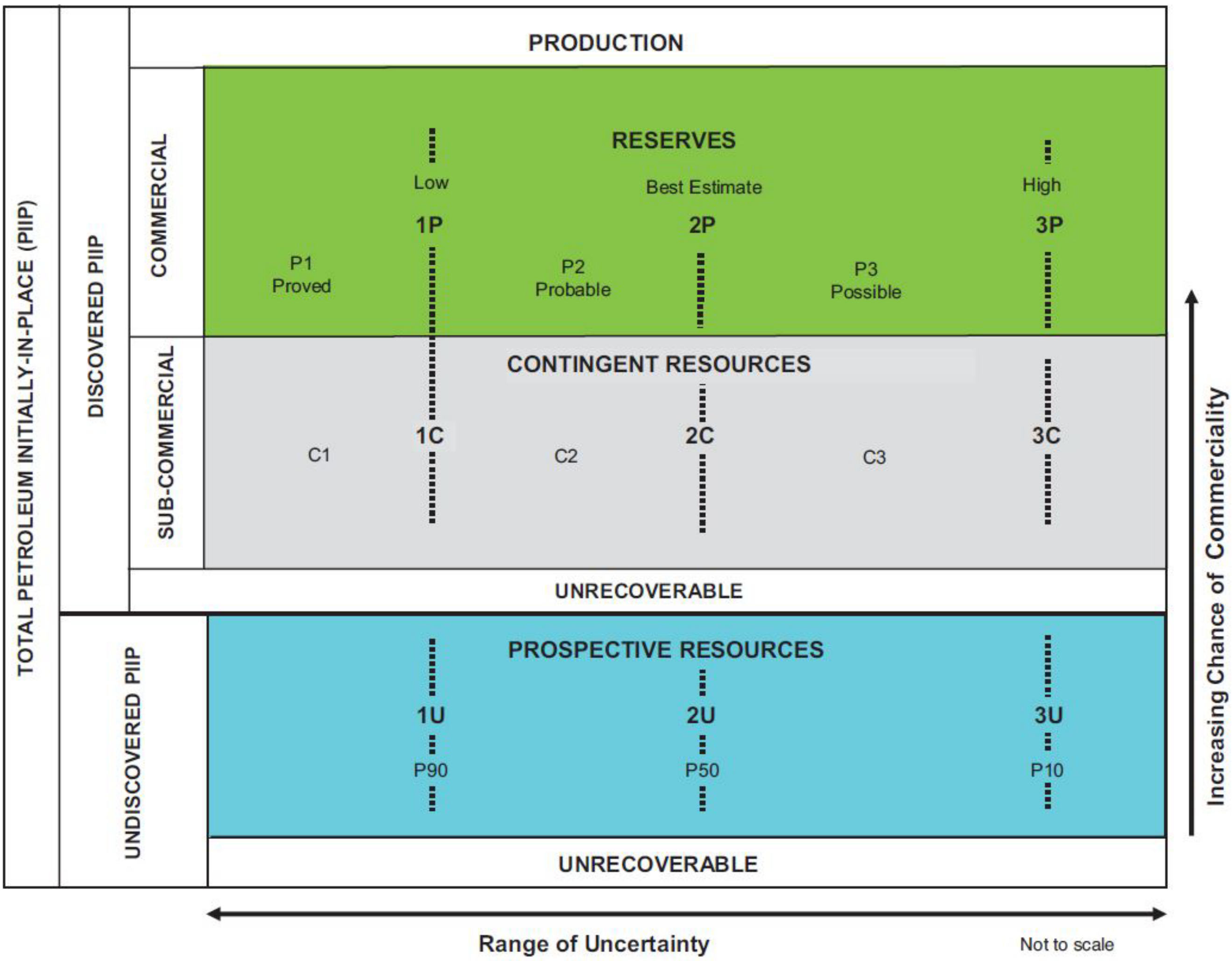
Exhibit 10 shows the three categories into which estimated quantities of potentially recoverable petroleum can be placed: Prospective Resources, Contingent Resources and Reserves. Within each category, three estimates are designated to describe the range, with greater certainty at the low end and less certainty at the high end.

**Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects.

**Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but where the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.

**Reserves** are 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. The categories within Reserves, in decreasing certainty, are Proved, Probable and Possible.

Exhibit 10 – Resources and Reserves




Source: CTP.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