Central Petroleum Limited

Multiple routes to share price upside

19 November 2019

Share Price: A$0.17

Target Price: A$0.26

Target upside: 53%

Recommendation
Buy

Risk Assessment
Higher

Resources – Oil & Gas

David Brennan, CFA
Senior Investment Analyst
dbrennan@stateone.com.au
+61 (0)2 9024 9142

FY19 was a key year for Central Petroleum (ASX:CTP). The Northern Gas Pipeline (NGP), which started operations in January 2019, opened the gas-hungry east coast market to the group's Northern Territory conventional gas fields - Mereenie (50% CTP, 50% Macquarie), Palm Valley (100% CTP) and Dingo (100% CTP). As a result, group sales increased by 97% to 10.8PJe in FY19 from 5.5PJe in FY18. We are forecasting a further 30% increase in production to 14.1PJe in the current year (FY20E).

Predicated on unchanged annual production of 14.1PJ, a received gas price of A$5.00/GJ (real) and COGS of A$2.80/GJe (real), we calculate that CTP's 30 June 2019 2P Reserve of 150PJe has an NPV_{10} value of A$115m. This equates to A$0.15 per diluted share (774 million). Thus, **at current share price levels, we suggest that the market is effectively valuing CTP on its Reserves only** and is attaching little value to the group's 2C Resource base, or to exploration upside, or to potential NPV uplift in a higher gas price environment.

NPV sensitivity to gas prices: Predicated on 13.5PJpa of gas production, each additional A$1.00/GJ in the received gas price increases revenues by A$13.5m. We calculate that a A$6.00/GJ (real) ARP increases our estimated NPV_{10} of CPT's 2P Reserve by 70% to A$195m (A$0.25ps) from A$115m (A$0.15ps). We note that gas prices remain buoyant in east coast markets and that CTP is currently negotiating gas sales agreements for uncontracted gas post the expiry in January 2020 of a Gas Sales Agreement with Incitec Pivot (ASX:IPL). As a result, we believe our forecast A$5.00/GJ (real) gas price may be conservative and has the potential to surprise on the upside.

Potential corporate activity – Range Project (50% CTP, 50% IPL): In August 2019, CTP booked a maiden 2C contingent coal seam gas (CSG) Resource of 135PJ (CTP share) at its Range Project in the Surat Basin, Queensland. An appraisal pilot well planned for 2020 will look to convert this Resource to a 2P Reserve. The Range Project is surrounded by several large CSG developers and producers; we note that in February 2019, Australia Pacific LNG acquired Origin's Energy's 129PJ 2P Reserve Ironbark Gas Project – located some 100km south-east of Project Range - for US$165m of A$1.79/GJ. A similar acquisition metric would value CTP's interest in Project Range at A$242m. In our SOTP valuation for CTP, we value the Project at (only) A$60m.

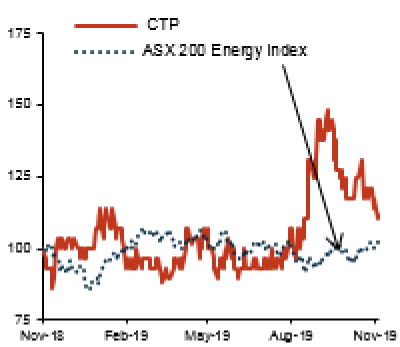
CY2020 exploration program: CTP is targeting an aggregated best estimate (P50) prospective resource of up to 465PJe; this is above the group's current Resource of 390PJe. Although CTP's ultimate equity interest in this Resource after a proposed sell-down/farmout to fund the A$51m program is not known, it points to the potential for significant value uplift.

Valuation and Recommendation. A$0.26ps, Buy

Underpinned by NPV valuation for CTP's 2P Reserves, we forecast CTP's SOTP enterprise value at A$252m. Adjusted for forecast net debt of A$52m in FY20E, we calculate CTP's equity value at A$200m (equivalent to A$0.26 per diluted share). Recommendation: Buy (Higher Risk). **We believe that CTP offers exciting capital upside for investors on the back of an expected uplift in financial performance from the group's producing assets, with significant upside potential on the back of a re-rating in Project Range as the CSG Resource is converted to Reserves. In addition, CTP's CY2020 exploration programme has the potential to significantly increase the group's Resource base.**

Central Petroleum Ltd	
ASX Code	CTP
52- week range	A$0.13-A$0.22
Market Cap (diluted) (ASm)	132
Shares (diluted) (m)	774
Av Daily Turnover (shares)	1.23 million
ASX All Ordinaries	6,857
2020E BV per share (A$c)	0.8
2020E EPS (A$c)	1.54
2020E Net Cash/(Debt) (A$m)	-50

Relative price performance



Financial Statements

Central Petroleum Ltd

Year ending June

Profit & Loss Statement (A$M)	FY19A	FY20E	FY21E	FY22E	FY23E
Revenue	59.4	73.6	73.8	75.3	76.8
COGS	(30.4)	(39.5)	(39.5)	(39.5)	(39.5)
Corporate costs	(6.8)	(6.2)	(6.3)	(6.5)	(6.6)
Exploration expenses	(15.8)	(3.0)	(3.1)	(3.1)	(3.2)
EBITDA	**6.4**	**24.9**	**24.9**	**26.2**	**27.5**
Depreciation & Amortisation	(12.7)	(18.0)	(18.0)	(18.0)	(18.0)
Operating profit	**(6.3)**	**6.9**	**6.9**	**8.2**	**9.5**
NOI	0.0	0.0	0.0	0.0	0.0
EBIT	**(6.3)**	**6.9**	**6.9**	**8.2**	**9.5**
Interest income	0.4	0.4	0.3	0.5	0.7
Interest expense	(8.6)	(6.1)	(5.4)	(5.1)	(4.8)
Tax expense	0.0	0.0	0.0	0.0	0.0
Reported NPAT	(14.5)	1.2	1.9	3.7	5.5
Normalised NPAT	**(14.5)**	**1.2**	**1.9**	**3.7**	**5.5**
EBITDA Margin (%)	11%	34%	34%	35%	36%
Operating profit margin (%)	-11%	9%	9%	11%	12%
EPS Reported (A$c)	(1.88)	0.16	0.24	0.47	0.70
EPS Normalised (A$c)	(1.88)	0.16	0.24	0.47	0.70
EPS growth (%)	n/a	n/a	53%	95%	50%
DPS - Declared (A$)	0.00	0.00	0.00	0.00	0.00
Avg. no. of fully-diluted shares (m)	770	778	783	783	783
YE no. of fuly-diluted shares (m)	774	783	783	783	783

Cash Flow Statement (A$M)	FY19A	FY20E	FY21E	FY22E	FY23E
EBITDA	6.4	24.9	24.9	26.2	27.5
Investment in working capital	2.1	(0.7)	(0.0)	(0.1)	(0.1)
Tax expense	0.0	0.0	0.0	0.0	0.0
Operating Cash Flow	**8.5**	**24.3**	**24.9**	**26.2**	**27.5**
Capex	(15.4)	(7.0)	(7.1)	(7.3)	(7.4)
Other investments	0.0	0.0	0.0	0.0	0.0
Investing Cash Flow	**(15.4)**	**(7.0)**	**(7.1)**	**(7.3)**	**(7.4)**
Net interest received / (paid)	(8.2)	(5.7)	(5.1)	(4.6)	(4.0)
Debt draw down / (repayment)	3.4	(12.0)	(4.0)	(4.0)	(4.0)
Dividends paid	0.0	0.0	0.0	0.0	0.0
Equity raised / (repaid)	1.9	0.0	0.0	0.0	0.0
Financing Cash Flow	**(2.9)**	**(17.7)**	**(9.1)**	**(8.6)**	**(8.0)**
Non-operating & Other (R&D rebate)	0.5	0.0	0.0	0.0	0.0
Inc/(Dec) in Cash	**(9.4)**	**(0.4)**	**8.7**	**10.3**	**12.0**

Balance Sheet (A$M)	FY19A	FY20E	FY21E	FY22E	FY23E
Cash & Equivalents	17.8	17.4	26.2	36.5	48.5
Receivables	9.1	9.1	9.1	9.1	9.1
Inventories	2.7	3.4	3.4	3.4	3.5
Other Current Assets	0.0	0.0	0.0	0.0	0.0
PPE and Exploration & Development	132.4	121.4	110.5	99.8	89.2
Deferred tax asset	0.0	0.0	0.0	0.0	0.0
Other Non Current Assets	6.8	6.8	6.8	6.8	6.8
Total Assets	**168.7**	**158.0**	**155.9**	**155.6**	**157.1**
Payables and other current Liabilities	20.2	20.2	20.2	20.2	20.2
Short Term Debt	11.0	11.0	11.0	11.0	11.0
Long Term Debt	70.8	58.8	54.8	50.8	46.8
Other Non Current Liabilities	72.5	72.5	72.5	72.5	72.5
Total Liabilities	**174.4**	**162.4**	**158.4**	**154.4**	**150.4**
Total Equity	**(5.6)**	**(4.3)**	**(2.5)**	**1.2**	**6.7**
Net Cash / (Debt)	(63.9)	(52.3)	(39.6)	(25.3)	(9.3)

Top 3 Registered Shareholders	%	Date
UBS Nominees	4.4	
Citicorp Nominees	2.7	Sep-19
Chris Wallin Super Fund	2.4	

Source: Company, IRESS, State One Stockbroking forecasts

Revenue Forecast (A$m)	FY19A	FY20E	FY21E	FY22E	FY23E
Gas sales (PJ)	10.2	13.0	12.8	12.8	12.8
ARP (A$/GJ)	4.9	5.0	5.1	5.2	5.3
Revenue -Gas	49.7	65.0	65.0	66.3	67.7
Oil sales (MMbbl)	0.10	0.10	0.10	0.10	0.10
ARP (A$/bbl)	99.6	86.1	87.8	89.6	91.4
Revenue -Oil	9.7	8.6	8.8	9.0	9.1
Revenue - Gas & Oil	**59.4**	**73.6**	**73.8**	**75.3**	**76.8**
Annual % change in revenue	70%	24%	0%	2%	2%
Total sales volume (PJe)	10.8	13.6	13.4	13.4	13.4
Annual % change sales volume	97%	26%	-2%	0%	0%
Gas contributon to sales volume	95%	96%	96%	96%	96%
Oil contribution to sales volume	5%	4%	4%	4%	4%
Gas contributon to revenue	84%	88%	88%	88%	88%
Oil contribution to revenue	16%	12%	12%	12%	12%

Crude oil price forecast	FY19A	FY20E	FY21E	FY22E	FY23E
Brent crude oil price (US$/bbl)	69.1	61.5	62.7	64.0	65.3
AUD/USD exchange rate	0.72	0.70	0.70	0.70	0.70
Brent crude oil (A$/bbl)	96.0	87.9	89.6	91.4	93.2
ARP oil as % A$ Brent	3.8%	-2.0%	-2.0%	-2.0%	-2.0%

Reserves & Resources	*2P Reserve*	*2C*	*2P + 2C*
Mereenie, Gas (PJ)	81.6	91.2	172.8
Mereenie, Oil (MMbbl)	0.87	0.1	0.97
Palm Valley, Gas (PJ)	25.8	13.6	39.4
Palm Valley, Oil (MMbbl)	0.0	0.0	0.0
Dingo, Gas (PJ)	37.3	0.0	37.3
Dingo, Oil (MMbbl)	0.0	0.0	0.0
Range Project, Gas (PJ)	0.0	135.0	135.0
Range Project, Oil (MMbbl)	0.0	0.0	0.0
Gas - total (PJ)	144.7	239.8	384.5
Oil - total (MMbbl)	0.87	0.10	0.97
Gas & Oil (PJe)	149.9	240.4	390.3
Gas as % Group Resource	96.5%	99.8%	98.5%

Note: Oil converted to gas using rate of 1bbl oil = 6 GJ gas

Mereenie as % Group Resource	*2P Reserve*	*2C*	*2P + 2C*
	58%	38%	46%

Leverage	FY19A	FY20E	FY21E	FY22E	FY23E
Net Debt/Equity	cash	cash	cash	-2116%	-138%
Gearing (ND/ND+E)	92%	92%	94%	105%	360%
Interest Cover (x)	-0.8	1.2	1.4	1.8	2.4

Valuation Ratios (x)	FY19A	FY20E	FY21E	FY22E	FY23E
Normalised P/E	-9.0	108.4	71.0	36.4	24.2
Price/OP Cash Flow	15.5	5.4	5.3	5.0	4.8
Book value per share (A$c)	-0.7	-0.6	-0.3	0.2	0.9
EV (A$m)	195	184	171	157	141
EV/EBITDA	30.7	7.4	6.9	6.0	5.1
ROE (%)	n/a	n/a	-ve	306%	82%

SOTP Valuation	(A$m)	(A$/share)	Resource (PJe)
NPV-derived 2P Reserve valuation	115	0.15	150
2C Resource (including Project Range)	101	0.13	240
Current Resource (total)	**215**	**0.28**	**390**
Exploration upside - Gas: CY2020 program	21	0.03	205
Exploration upside - Oil: CY2020 program	11	0.01	57
Exploration upside: Dukas-1 /Other	5	0.01	
Enterprise value	**252**	**0.33**	
Net Debt (FY20E)	(52)	(0.07)	
Equity value	**200**	**0.26**	

Note: Per share data based on diluted number of shares

Valuation

NPV of 2P reserves: A$115m

We calculate the NPV_{10} of CTP's 2P Reserves (145PJ gas, 0.87MMbbl Oil as at 30 June 2019) at A$115m. See table below.

Figure 1: NPV of 2P Reserves

	FY	2020	2021	2022	2023	2024	2025	2026	2027	2028	Balance	Total
2P Gas Reserve - opening	PJ	145	131	118	104	91	77	64	50	37		
2P Gas Reserve - closing	PJ	131	118	104	91	77	64	50	37	23		
Saleable gas production	PJ	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	23	145
Payback of overlift to Macquarie	PJ	(0.5)	(0.75)	(0.75)	(0.75)	(0.75)	(0.75)	(0.75)	-	-	-	(5)
Net sales	PJ	13.0	12.8	12.8	12.8	12.8	12.8	12.8	13.5	13.5	23	140
Gas ARP	A$/GJ	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.9		-
Revenue : Gas	A$m	65	65	66	68	69	70	72	78	79	140	772
2P Oil Reserve - opening	MMbbl	0.87	0.77	0.67	0.57	0.47	0.37	0.27	0.17	0.07	-	-
2P Oil Reserve - closing	MMbbl	0.77	0.67	0.57	0.47	0.37	0.27	0.17	0.07	-	-	-
Saleable oil production	MMbbl	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.07	-	0.87
Oil ARP (2% discount to Brent)	A$/bbl	86	88	90	91	93	95	97	99	101	2,350	-
Revenue : Oil	A$m	9	9	9	9	9	10	10	10	7	-	81
Revenue Total	**A$m**	**74**	**74**	**75**	**77**	**78**	**80**	**81**	**87**	**86**	**140**	**853**
COGS	*A$m*	*(39)*	*(39)*	*(39)*	*(39)*	*(39)*	*(39)*	*(39)*	*(39)*	*(39*	*(65*	*(420*
Admin/Corporate	*A$m*	*(6)*	*(6)*	*(6)*	*(7)*	*(7)*	*(7)*	*(7)*	*(7)*	*(7*	*(15*	*(75*
Exploration expenses	*A$m*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(4*	*(7*	*(37*
Total costs	A$m	(49)	(49)	(49)	(49)	(49)	(50)	(50)	(50)	(50)	(87)	(532)
EBITDA	A$m	25	25	26	28	29	30	32	37	36	53	321
PAT	**A$m**	**25**	**25**	**26**	**28**	**29**	**23**	**24**	**28**	**27**	**39**	**274**
Equity funding	A$m	-	-	-	-	-	-	-	-	-	-	-
Debt funding	A$m	-	-	-	-	-	-	-	-	-	-	-
Development capex	A$m	-	-	-	-	-	-	-	-	-	-	-
Sustaining capex	A$m	(7)	(7)	(7)	(7)	(8)	(8)	(8)	(8)	(8)	(17)	(85)
Cash flow	**A$m**	**18**	**18**	**19**	**20**	**21**	**15**	**16**	**20**	**19**	**23**	**189**
Discount rate		*10%*										
NPV of 2P Gas & Oil Reserves	**A$m**	**115**										

Price and cost assumptions		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ARP: Gas	A$/GJ	5.00	5.1	5.20	5.31	5.41	5.52	5.63	5.74	5.86
Brent crude oil	US$/bbl	61.5	62.7	64.0	65.3	66.6	67.9	69.3	70.6	72.1
AUD:USD exchange rate	unit	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Cost of Sales	A$/GJe	2.80	2.86	2.91	2.97	3.03	3.09	3.15	3.22	3.28
Price/cost inflation	%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Effective tax rate	%	0%	0%	0%	0%	0%	25%	25%	25%	25%
Gas unit data										
Revenue	A$/GJe	5.22	5.23	5.34	5.45	5.55	5.67	5.78	6.20	6.19
Costs pre exploration	A$/GJe	(3.24)	(3.25)	(3.26)	(3.27)	(3.28)	(3.29)	(3.30)	(3.31)	(3.32)
EBITDAX	A$/GJe	1.98	1.99	2.08	2.18	2.28	2.38	2.48	2.90	2.87
Exploration costs	A$/GJe	(0.21)	(0.22)	(0.22)	(0.23)	(0.23)	(0.23)	(0.24)	(0.24)	(0.25)
EBITDA	A$/GJe	1.77	1.77	1.86	1.95	2.05	2.15	2.24	2.65	2.61
EBITDAX margin	%	38%	38%	39%	40%	41%	42%	43%	47%	46%
EBITDA margin	%	34%	34%	35%	36%	37%	38%	39%	43%	42%

Source: State One Stockbroking forecasts

Assumptions:

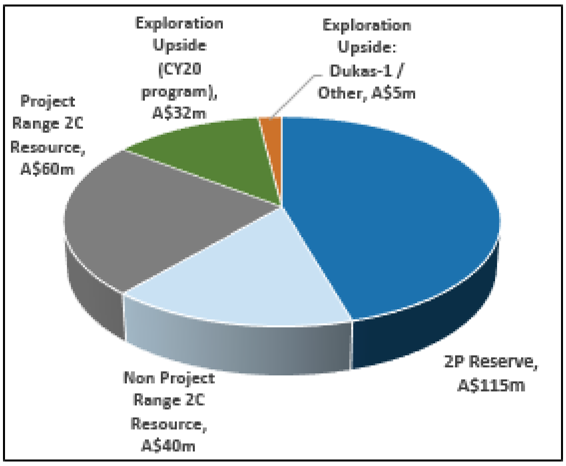
- Annual production sales of 14.1PJe per annum, and 11-year 2P Reserve life. 5PJ gas over lift returned to Macquarie Mereenie.
- Average Received Price (ARP) for gas of A$5.00/GJ (real); ARP for oil based on 2% discount to forecast Brent crude oil price of US$61.50/bbl and US$0.70 exchange rate.
- Cost of goods sold (COGS) of A$2.80/GJe escalated at 2%pa.
- Annual sustaining capital of A$10m (including exploration capex) to maintain annual production at ~14PJe. Note: capex guidance from CTP March 2019 presentation.
- Zero corporate tax rate until 2025 (on back of A$38m potential tax benefit).

Sum-Of-The-Parts (SOTP) valuation

Underpinned by NPV valuation for CTP's 2P Reserves, we forecast CTP's SOTP enterprise value at A$252m. Adjusted for forecast net debt of A$52m in FY20E, we calculate an equity value for the group of A$200m (equivalent to A$0.26 per diluted share).

Figure 2: SOTP valuation

	(A$m)	(A$/share)	(A$/GJe)	Resource (PJe)
NPV-derived 2P Reserve valuation	**115**	**0.15**	**0.76**	**150**
2C Contingent Resource excl Range Project	40	0.05	0.38	105
Resource (exl Range Project)	155	0.20	0.61	255
2C Contingent Resource: Range Project	60	0.08	0.45	135
Exploration upside - Gas: CY2020 program	21	0.03	0.10	205
Exploration upside - Oil: CY2020 program	11	0.01	0.20	57
Exploration upside: CY2020 program	32	0.04	0.12	262
Exploration upside: Dukas-1/Other	5	0.01		
Enterprise value	252	0.33	0.39	652
Net Debt (FY20E)	-52	-0.07		
Equity value	**200**	**0.26**		



Contribution to forecast enterprise value:

1) 2P Reserve: 45%
2) 2C Resource – excluding Project Range: 16%
3) 2C Resource – Project Range (coal seam gas, QLD): 24%
4) CY2020 exploration programme: 13%
5) Other exploration i.e. Dukas-1: 2%

Source: State One Stockbroking forecasts

Assumptions:

- **2P Reserve** valuation based on NPV_{10}.
- **2C Resource <u>excluding</u> Project Range** valuation assumes GJe unit value at 50% discount to calculated unit value of 2P Reserve.
- **Project Range 2C Resource** valuation equates to A$0.45/GJ and assumes a 75% discount to the A$1.79/GJ paid by Australian Pacific LNG for Origin Energy's Ironbark Gas Project (129PJ 2P) in February 2019.
- The forecast Resource for the **CY2020 exploration program** is based on management's guided risked prospective Resource (in October 2019) of 205PJ gas and 9.5MMbbl oil. We have attached appropriately conservative unit values of A$0.10/GJ and A$0.20/GJe respectively to account for uncertainty over program funding, and of course, the outcome of the program.
- We attach **a nominal A$5m to the Dukas-1 exploration well**. At this juncture, we do not attach any value to CTP's other, **longer-term exploration strategies** (Ooraminna field (NT), early stage prospects in the Amadeus Basin (NT), ATPs in the Southern Georgina Basin (QLD)).

Sanity check: EV/GJe peer comparative

At CTP's current enterprise value (EV) of A$192m and combined 2P Reserves and 2C Resources of 393PJe, we calculate that CTP's resource base is currently valued at A$0.49/GJe (rounded).

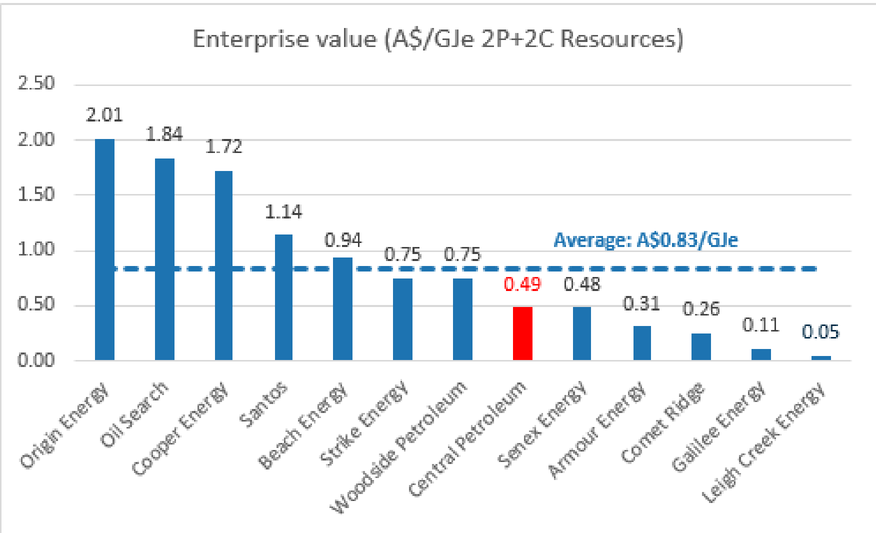
This is below the (simple) average of A$0.83/GJe calculated for our peer sample of ASX-listed oil and gas plays and indicates that CTP offer value on a relative basis.

Figure 3: Selected ASX-listed oil and gas stocks: enterprise value per GJe

Company	Ticker	Share price (A$)	Total shares (million)	Mkt Cap (A$m)	Cash (A$m)	Debt (A$m)	EV (A$m)	1P PJe	2P *price equivalent basis* PJe	2C PJe	EV/1P A$/GJe	EV/2P A$/GJe	EV/ (2P+2C) A$/GJe	Gearing D/(D+E) %
Large Cap "Majors"				**78,744**	**6,508**	**20,802**	**93,038**	**17,305**	**26,057**	**59,595**	**5.38**	**3.57**	**1.09**	**21%**
Beach Energy	BPT	2.44	2,279	5,561	172	0	5,389	2,201	3,673	2,031	2.45	1.47	0.94	0%
Oil Search	OSH	7.32	1,525	11,163	538	3,531	14,156	2,486	2,887	4,807	5.69	4.90	1.84	24%
Origin Energy	ORG	7.99	1,761	14,070	1,546	7,496	20,020	2,880	4,799	5,166	6.95	4.17	2.01	35%
Santos	STO	8.21	2,100	17,241	1,215	4,251	20,277	3,651	6,376	11,383	5.55	3.18	1.14	20%
Woodside Petroleum	WPL	32.60	942	30,709	3,037	5,524	33,196	6,087	8,322	36,208	5.45	3.99	0.75	15%
Junior Producers				**1,653**	**254**	**394**	**1,793**	**884**	**1,458**	**827**	**2.03**	**1.23**	**0.78**	**19%**
Armour Energy	AJQ	0.06	589	35	9	59	85	40	124	149	2.14	0.69	0.31	62%
Central Petroleum	CTP	0.17	774	128	18	82	192	125	152	241	1.53	1.26	0.49	39%
Cooper Energy	COE	0.57	1,700	969	164	214	1,019	256	354	238	3.98	2.88	1.72	18%
Senex Energy	SXY	0.35	1,487	520	63	40	498	463	828	199	1.07	0.60	0.48	7%
CSG/Shale explorers/developers				**864**	**36**	**3**	**830**	**18**	**172**	**3,587**	**46.13**	**4.83**	**0.22**	**0%**
Comet Ridge	COI	0.28	751	207	12.9	0	194	18	172	582	10.76	1.13	0.26	0%
Galilee Energy	GLL	0.98	282	276	11.5	0	265	0	0	2,508	-	-	0.11	0%
Strike Energy	STX	0.24	1,620	381	11	3	372	0	0	497	-	-	0.75	1%
UCG				**124**	**3.1**	**4.0**	**125**	**0**	**1,153**	**1,469**	**-**	**0.11**	**0.05**	**3%**
Leigh Creek Energy	LCK	0.21	605	124	3.1	4.0	125	0	1,153	1,469	-	0.11	0.05	3%

Source: Companies, IRESS, compiled by State One Stockbroking.
Note: for the purposes of peer comparison, we have converted oil to GJ on a price equivalent basis of 1bbl oil = 8GJe, rather than on the calorific or energy conversion rate of 1bbl oil = 6GJe.

Figure 4: Peer comparative: EV/GJe



Source: Companies, IRESS, compiled by State One Stockbroking

Recommendation & Risks

At current share price levels of A$0.17, CTP offers some 53% upside relative to our SOTP valuation of A$0.26. **Recommendation: Buy (Higher Risk).**

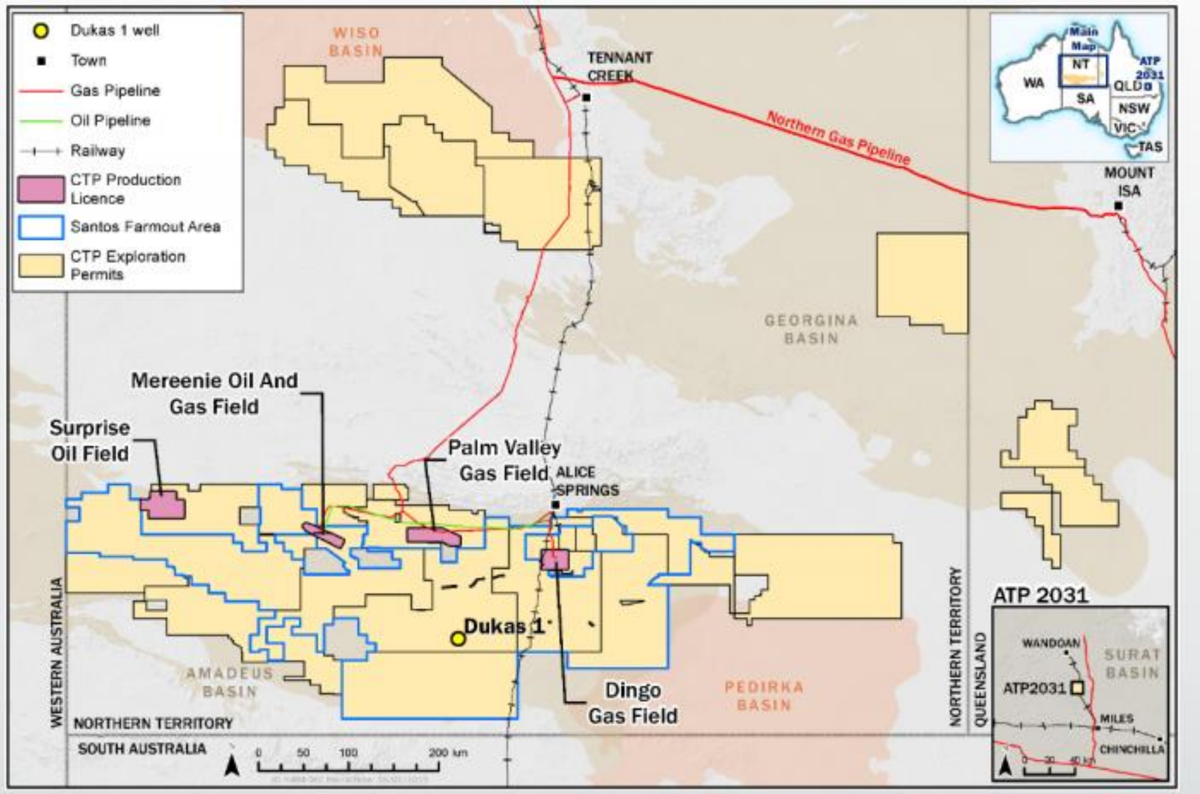
Risks to our estimated target price and forecast earnings profile include, but are not limited to:

- **Commodity prices – specifically the domestic (east coast) gas price** and the international crude oil price (translated into Australian dollars). With gas accounting for some 96% of PJe sales volume and 90% of revenue, CTP's earnings profile is particularly sensitive to the domestic gas price environment. At forecast average annual gas production/sales of 13.5PJ, we calculate that a A$1/GJ increase in the average received gas price (relative to our base-case ARP forecast of A$5/GJ) will increase gas revenues by A$13.5m and boost gas revenues by 19%. With a tight market in the east coast supporting elevated city gate prices, and with several of CTP's gas contracts up for renewal at year-end, we believe that our base-case ARP forecast is conservative and could surprise on the upside.
- **Production profile**. Our base case forecast assumes (1) steady-state annual production of 14.1PJe - based on annualised September 2019 quarter output of 3.5PJe – and (2) A$10m in annual sustaining capex to support this level of output. Reservoir/field performance is subject to operating and subsurface uncertainty; lower than forecast production and sales and/or higher than forecast sustaining capex will reduce CTP's earnings profile and target price.
- **Access to pipeline infrastructure**. The increase in sales volume from 2H FY19 was due to CTP successfully securing capacity in the newly built 33PJpa NGP. Any increase in production levels above the current level of 14PJpa - from new NT discoveries or field developments - will most likely require CTP securing additional pipeline capacity. While the NGP has 20% (7PJpa) spare capacity at present, the pipeline owner – Jemena - is currently in negotiations to fill this. Thus, without securing additional pipeline capacity, future NT resource discoveries could be "stranded", reducing their value.
- **CY2020 exploration program**. Some 13% of our SOTP valuation is from forecast Resources stemming from a proposed CY2020 exploration program. The exploration program may not result in a favourable result relative to expectations. In addition, CTP intends to fund the A$51m program through a formal farmout process with a target completion in mid-2020. There is no guarantee that the farmout/sell-down process will be successful or will be completed in the targeted timeframe.
- **Financial / Debt.** CPT's had A$81.7m in outstanding Macquarie Bank debt as at 30 June 2019. CTP is targeting to reduce this to A$72.7m by 31 December 2019 and to just under A$70m by September 2020 – when it is due in full. A refinancing process is currently underway; CTP has received indicative term sheets from three (3) major Australian banks and is looking to have a preferred bank selected by 1Q CY2020. Successfully refinancing the debt facility is not guaranteed, or the conditions could be onerous.
- **Other**. Regulatory or compliance change, environmental and social licence to operate, key personnel risk, change in tax or royalty environment.

Assets

Over the past five years Central Petroleum (ASX: CTP) has built up equity interests in a significant portfolio of conventional oil and gas production licenses and exploration permits, largely located in the Northern Territory, plus a 50% interest in a coal seam gas (CSG) Authority to Prospect (ATP) license (ATP 2031, the Range Gas Project) in the Surat Basin, Queensland.

Figure 5: Geographic location of assets



Source: Company

Reserves and Resources

Figure 6: CTP Reserves and Resources (CTP interest)

Reserves & Resources	2P Reserve	2C	2P + 2C
Mereenie, Gas (PJ)	81.6	91.2	172.8
Mereenie, Oil (MMbbl)	0.87	0.1	0.97
Palm Valley, Gas (PJ)	25.8	13.6	39.4
Palm Valley, Oil (MMbbl)	0.0	0.0	0.0
Dingo, Gas (PJ)	37.3	0.0	37.3
Dingo, Oil (MMbbl)	0.0	0.0	0.0
Range Project, Gas (PJ)	0.0	135.0	135.0
Range Project, Oil (MMbbl)	0.0	0.0	0.0
Gas - total (PJ)	144.7	239.8	384.5
Oil - total (MMbbl)	0.87	0.10	0.97
Gas & Oil (PJe)	149.9	240.4	390.3
Gas as % Group Resource	96.5%	99.8%	98.5%

Resource summary

	2P PJe	2P + 2C PJe
Mereenie	87	179
Palm Valley	26	39
Dingo	37	37
Range Project	0	135
Total	150	390
	%	%
Mereenie	58%	46%
Palm Valley	17%	10%
Dingo	25%	10%
Range Project	0%	35%
Total	100%	100%

Source: Company, compiled by State One Stockbroking. Note: PJe = Petajoule equivalent, with oil converted at 1bbl = 6GJ gas

Following the August 2019 announcement of a NSAI certified maiden 2C Resource of 270PJ (135PJ net to CTP) at the Range CSG Project in Queensland, we calculate CTP's total Resource (2P+2C) at 390PJe.

CTP's Resource is very much gas-based; we calculate that some 97% of the group Reserve is gas, with gas accounting for a higher 99% of the total Resource (2P+2C).

Producing

Mereenie Oil & Gas Field – Northern Territory

(CTP – 50% interest (and Operator), Macquarie Mereenie Pty Ltd – 50% interest)

The Mereenie oil and gas field was discovered in 1963 and commenced production in 1984, delivering hydrocarbon liquids for sale in South Australia and gas to Northern Territory markets. CTP's 50% interest was acquired from Santos (ASX:STO) in September 2015. In 2019 the Northern Gas Pipeline (NGP) commenced operations, enabling Mereenie gas to access the east coast market for the first time. As a result, sales volumes increased to 7.68PJe (CTP share) in FY19 from 4.6PJe in FY18. September 2019 quarter (1Q FY20) production declined to 40.1TJ/d (100% JV) from 48.3TJ/d in the June 2019 quarter (4Q FY19). To mitigate ongoing field decline, a campaign of targeted recompletions (targeting new potential hydrocarbon formations) is being planned. Timing for conversion of injector wells to production wells, and new development wells, to optimize field production capacity is also under consideration.

Palm Valley Gas Field – Northern Territory

(CTP – 100% interest)

Acquired from Magellan in April 2014. Production ceased in FY16; in FY19 the field was successfully restarted to deliver gas into the broader gas market available via the NGP connection. Production in FY19 (1.9PJ) was however less than anticipated and resulted in a downward adjustment to reserves (to 2C from 2P). The focus is now on increasing field production capacity through the installation of either additional compressors or via reconfiguring the existing compressors. September 2019 quarter (1Q FY20) production increased to 9.4TJ/d (100% JV) from 8.7TJ/d in the June 2019 quarter (4Q FY19).

Dingo Gas Field – Northern Territory

(CTP – 100% interest)

Acquired from Magellan in April 2014 with development completed in April 2015. The field was developed to supply 1.55PJpa (31PJ over 20 years) to the Owen Springs Power Station. While offtake is running below this (0.8PJ in FY18, 0.9PJ in FY19) CTP is entitled to payment for the difference via a "Take or Pay" provision in the supply agreement. Owen Spring Power Station gas consumption is increasing as commissioning progresses and in the September 2019 quarter, Dingo gas field production/sales increased to 3.3TJ/d (or 1.2PJ annualised).

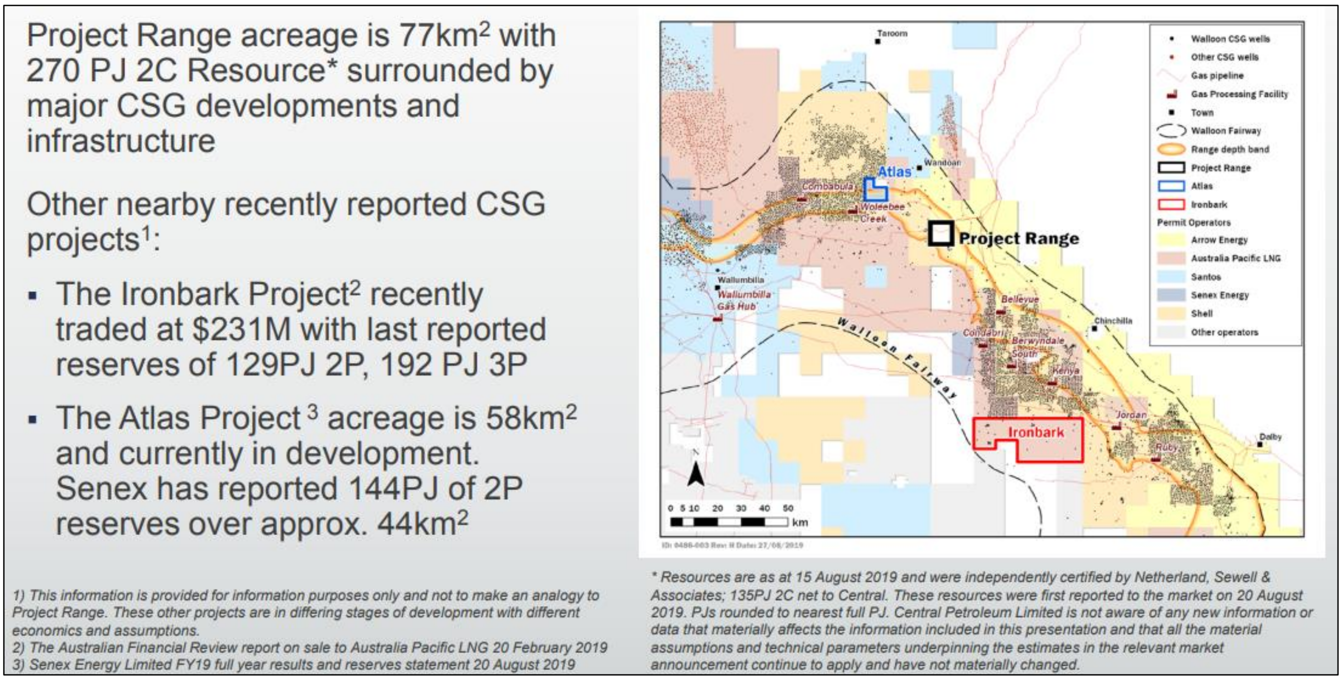
Development

Range Gas Project (ATP 2031) – Queensland

(CTP – 50% interest, Incitec Pivot Queensland Gas Pty Ltd ("Incitec") – 50% interest)

In August 2019, CTP booked a maiden 2C contingent gas resource of 270PJ (100% basis). Completion of pre-FID activities, including an appraisal pilot commencing in 1Q CY2020, will look to upgrade the 2C Resources to 2P certified reserves. The permit area covers 77km^2 in Queensland Surat Basin and is adjacent to a number of producing and developed CSG wells. We note that in February 2019, Australia Pacific LNG acquired Origin's Energy's 129PJ 2P Reserve Ironbark Gas Project – located some 100km south-east of Project Range - for US$165m of A$1.79/GJ. A similar acquisition metric would value CTP's interest in Project Range at A$242m.

Figure 7: Range Gas Project (Surat Basin, QLD)



Source: Company

Exploration

Dukas-1 (EP112) – Northern Territory

(CTP – 30% interest, Santos (and Operator) currently 40%, earning up to 70%)

The Dukas-1 well was spudded in April 2019 and suspended in September 2019 due to high formation pressures (>10,000psi) at a depth of ~3,700m - some 100m short of its target, the sub-salt section of the Amadeus Basin. Further technical work, including finalizing well design and data interpretation is required to formulate a definitive forward plan but CPT indicate that, at this point, a return to Dukas-1 (operated and fully funded by Santos) is unlikely before 2021.

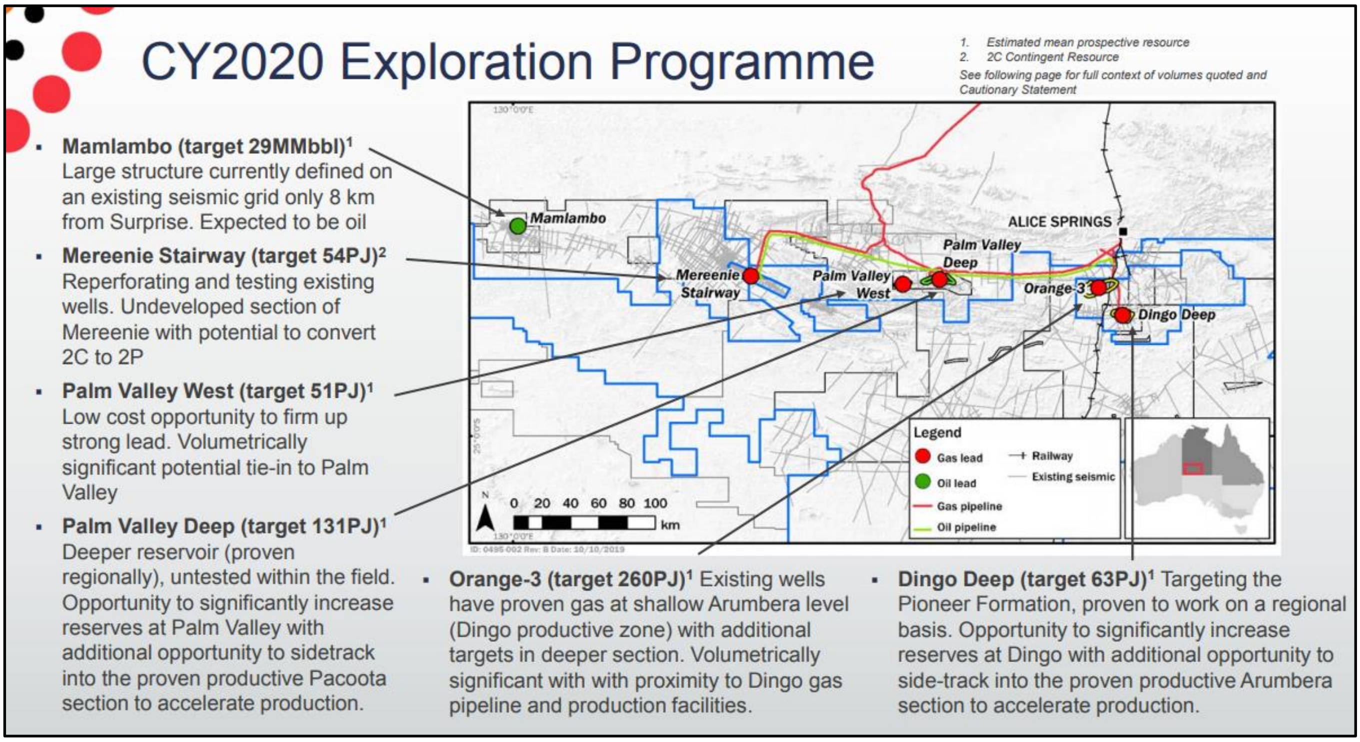
2020 exploration plan

Following connection to the east coast gas market via the NGP in January 2019, CTP's Northern Territory exploration assets now have a pathway to a new market. Recognising this new market dynamic, CTP has significantly augmented its exploration capabilities, including a new GM exploration (April 2019) and a new experienced Reservoir Engineer (March 2019). While the Dukas-1 2019 drilling program was disappointing – in terms of technical difficulties encountered - the Amadeus Basin remains largely unexplored, is a large structure with multi-TCF gas potential, and will be the target of a significant (A$51m) exploration program in 2020.

The CY2020 exploration program (announced in October 2019) consists of five (5) drill-ready low to moderate-risk brownfield targets, close to existing CPT production facilities and infrastructure, in 100%-owned CPT tenements.

Management estimates the P50 aggregate prospective Resource contained within the prospects at 465PJe (321PJ gas and 24MMbbl oil). This is more than CTP's current 2P+2C Resource base of 390PJe. On a risked-basis, CTP estimates an aggregate prospective Resource of 262PJe (205PJ gas and 9.5MMbbl oil). In addition, the program aims to provide a potential pathway to convert 54PJ of 2C Resources (CTP interest) to Reserves with a targeted Mereenie Stairway appraisal program.

Figure 8: CY20 exploration program – Amadeus Basin



Prospective Resources (net to Central)

Lead / Prospect	Target formation	Depth (mMD)	Licenses / Permits	License / Permit Interest	Low Estimate P90 Recoverable (PJ)	Best Estimate P50 Recoverable (PJ)	High Estimate P10 Recoverable (PJ)	Mean Recoverable (PJ)
Dingo Deep	Pioneer	3600	L7	100%	13	41	135	63
Orange-3	Arumbera	2800	EP82(DSA)	100%	17	81	296	131
	Pioneer	3500	EP82(DSA)	100%	23	84	275	129
Palm Valley Deep	Arumbera	3600	OL3	100%	17	80	299	131
Palm Valley West	Pacoota	1900	OL3	100%	7	35	114	51
Aggregate gas						321		505
Oil prospects					(mmbbl)	(mmbbl)	(mmbbl)	(mmbbl)
Mamlambo	Pacoota	1500	L6	100%	7	24	60	29

Contingent Resources (net to Central)*

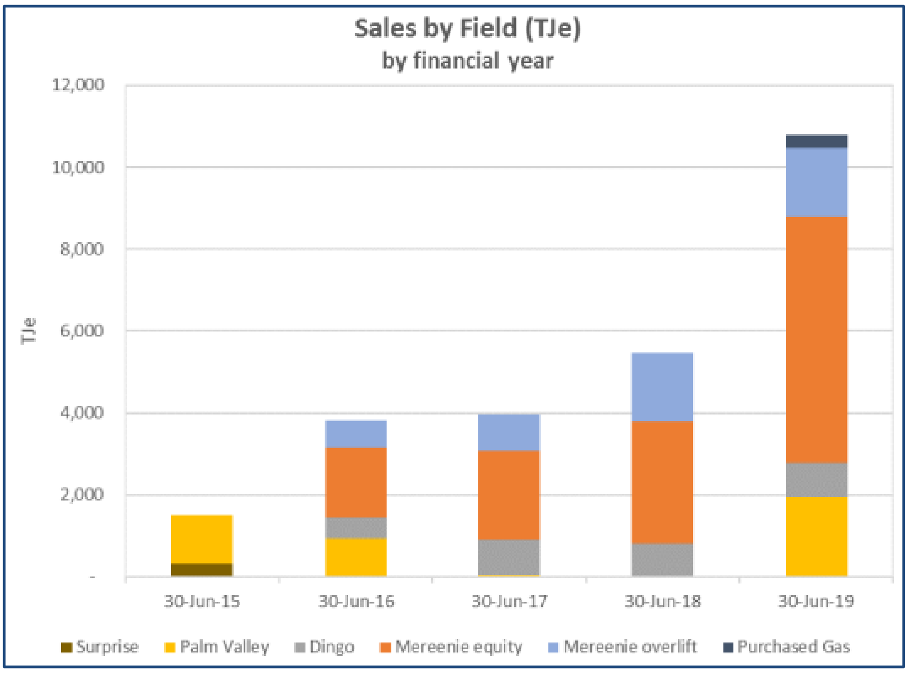
Appraisal target	Target formation	License	License Interest	2C Contingent (PJ)
Mereenie Stairway	Stairway	OL4/5	50%	54

Source: Company

Historical production

In January 2019, the Northern Gas Pipeline (NGP) - linking Tennant Creek in the Northern Territory to Mt Isa in Queensland - started first deliveries of commercial gas. The A$800m, 622km pipeline, built and operated by Asian conglomerate Jemena, has enabled previously stranded gas fields in the Northern Territory to find new gas-hungry customers in the east coast (Brisbane, Sydney, Adelaide) market. From the east coast customers' perspective, the pipeline's capacity of 90TJ/day facilitates some 33PJpa of much-needed new supply into the market. The pipeline is currently operating at 80% of capacity (~26PJpa) and is looking to expand capacity.

Figure 9: Sales by field (FY15-FY19)



Source: Company,
Note: 1 terajoule (TJ) = 1,000 gigajoules (GJ) = .001 petajoule (PJ). Conversely, 1PJ = 1,000TJ

During 2017/2018, CTP expanded its gas production facilities at Mereenie (50% interest, Operator) and Palm Valley (100% interest) - the Gas Acceleration Programme (GAP) - to meet increased firm gas supply commitments that were tied to the commencement of the NGP in early 2019.

The GAP was completed on time (and budget); as a result, FY19 quarterly sales ramped up from 1.3PJe in 1QFY19, to 1.8PJe in 2QFY19, to 3.7PJe in 3QFY19, and to 4.0PJe in 4QFY19. This translated to annual sales increasing by 97% to 10.8PJe in FY19 from 5.5PJe in FY18.

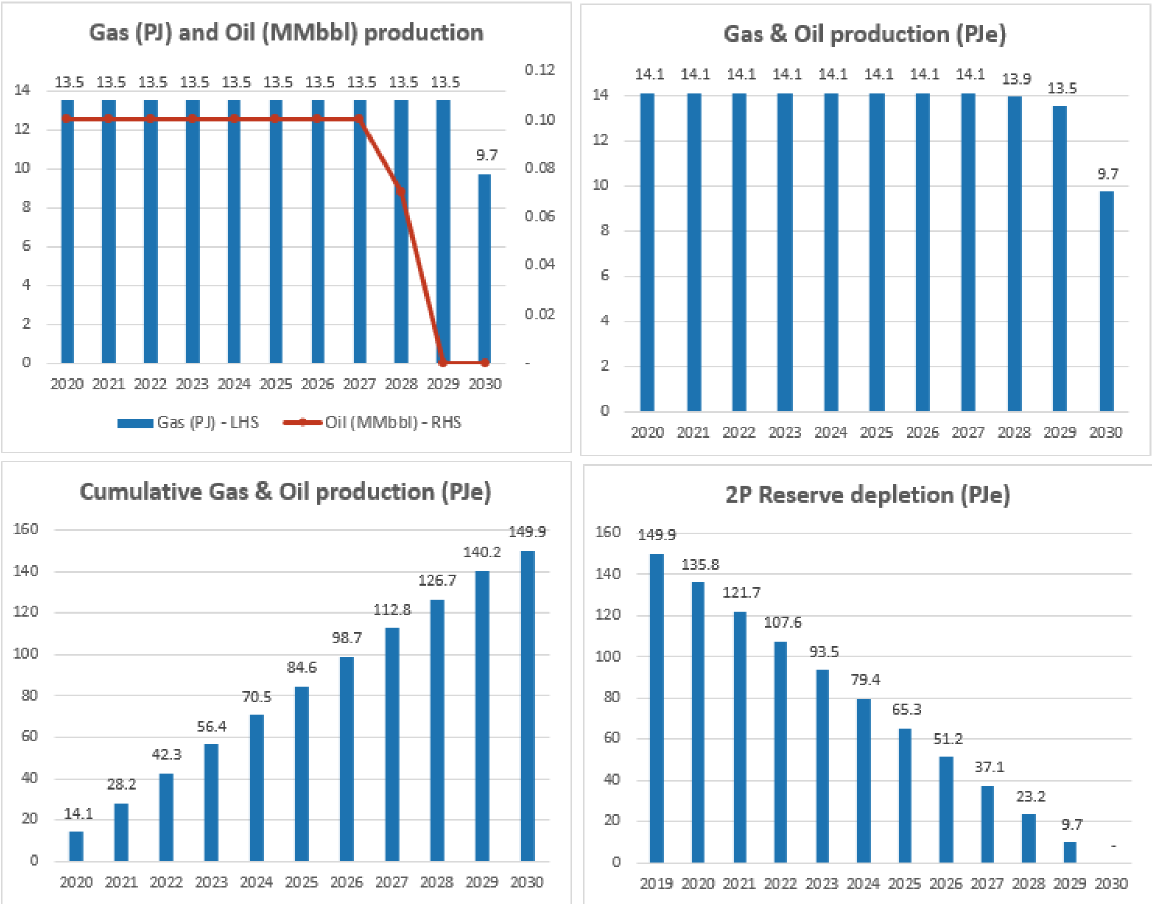
The bulk of production comes from the Mereenie Oil & Gas Field (CTP 50% interest). Mereenie production averaged 40.1TJ/d (14.6PJpa 100% basis) in the most recent September 2019 quarter (1Q FY20).

Forecast revenue and gross margin

Production

September 2019 quarter (1QFY20) sales volumes of 3.5PJe equate to annualised sales volumes of ~14PJe (+30% on FY19A). Maintaining sales volumes at this level, we calculate an 11-year life of mine (LOM) i.e., until FY30E, for CTP's currently stated 2P Reserves of 150PJe (144.7PJ gas and 0.87MMbbl oil). Note: management have indicated a sustaining capex (including exploration) requirement of A$10Mpa to maintain group production at this level.

Figure 10: Forecast production profile (based on 2P Reserves)



Source: Sate One Stockbroking forecasts

Product Price

Gas

CPT received an average gas price of A$5.30/GJ in FY18 (A$25.5m/4.84PJ) and A$4.90GJ in FY19 (A$49.7m/10.2PJ). In the September 2019 quarter activities report, management stated that the group was in advanced stages of completing a new gas sales agreement (GSA) to replace existing contracts (Incitec Pivot (ASX: IPL) expiring at the end of 2019, and that east coast markets remain buoyant, with strong demand and pricing. Our base case assumes flat (real) average received gas prices of A$5.00/GJ over our forecast period i.e, we escalate gas prices by 2%pa to maintain a flat (real) price environment.

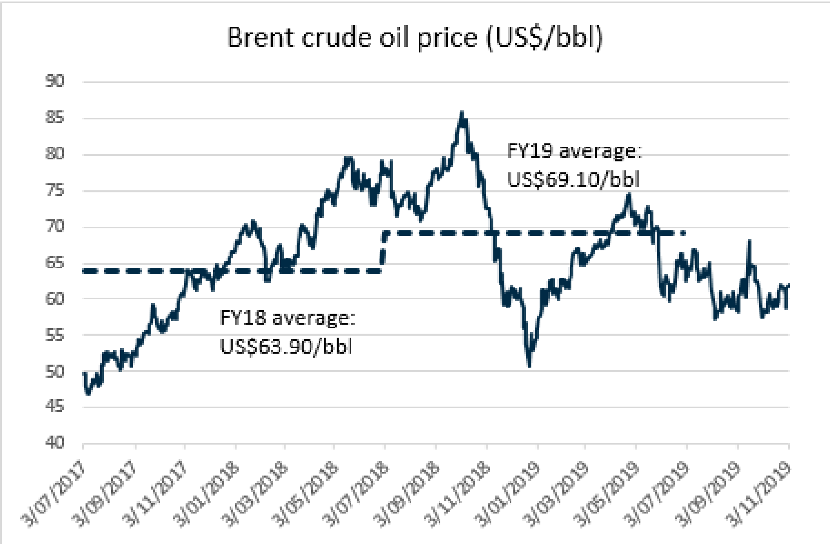
Product Price

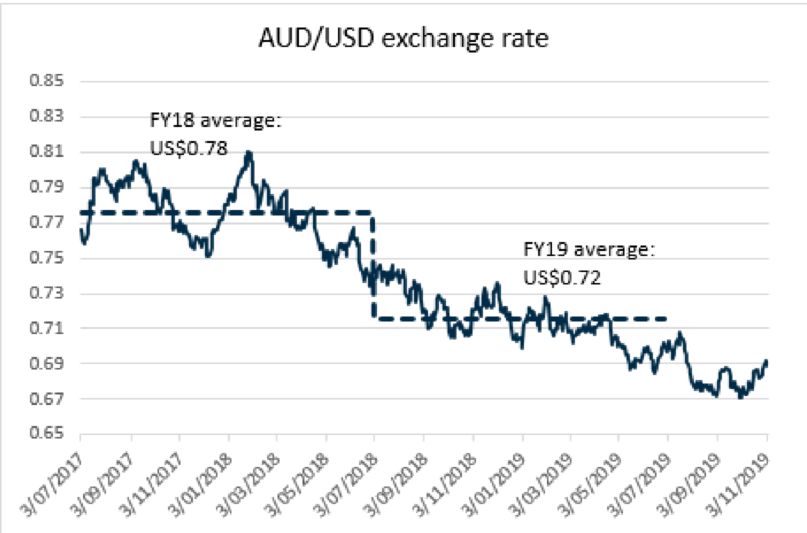
Oil

CPT received an average oil price of A$89.80/bbl in FY18 (A$9.5m/105,619bbl); this represents a 9.6% premium to the average FY18 Brent crude oil price of A$81.90/bbl (US$63.90/bbl @ US$0.78). CPT received an average oil price of A$99.600/bbl in FY19 (A$9.7m/97,292bbl); this represents a 3.8% premium to the average FY19 Brent crude oil price of A$96/bbl (US$69.10/bbl @ US$0.72). However, with the commencement in the September 2019 quarter of a new crude oil sale and purchase agreement for deliveries to Port Bonython (SA), we believe that going ahead, the ARP is likely to be at a discount (we forecast 2%) rather than at a premium to the prevailing Australian dollar Brent crude oil price.

Our base case assumes a flat (real) Brent crude oil price of US$61.50/bbl (effectively spot Brent) and a constant US$0.70 exchange rate (effectively spot exchange rate).

Figure 11: Brent crude oil price and AUD:USD (July 2017-Present)



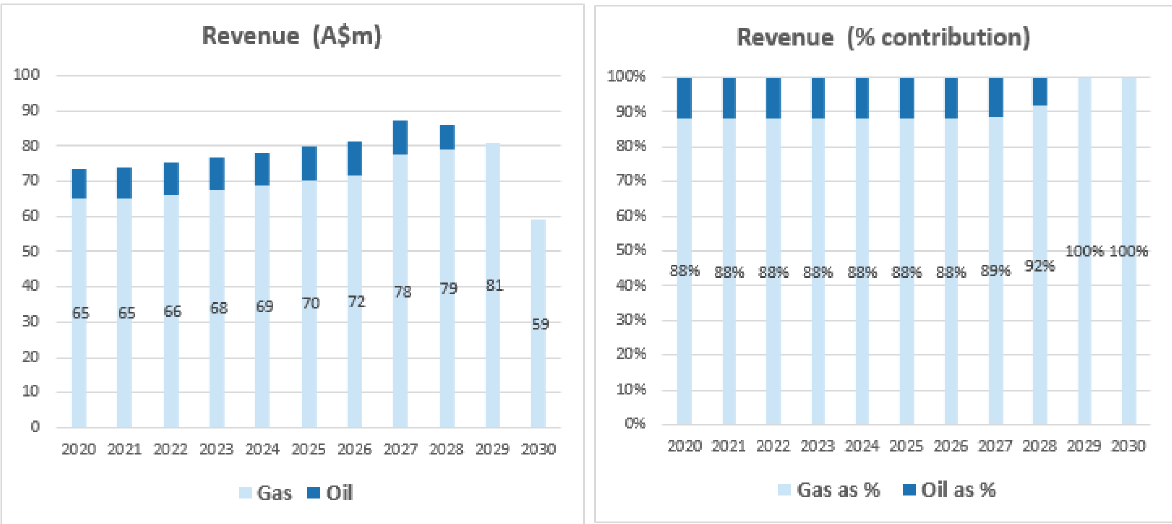


Source: IRESS, Sate One Stockbroking

Revenue profile

Predicated on our production and price profiles, we forecast FY20E revenue of A$74m; (+25% on FY19A's A$59m due to forecast increase in production/sales). Our forecast revenue profile thereafter is effectively flat (in real terms) on the back of a forecast flat production profile and 2%pa escalation in ARPs. We note that while we forecast oil accounting for (only) 4% of PJe production/sales, we calculate that the higher value oil (in terms of A$/calorific unit) accounts for a significantly larger 12% of revenue.

Figure 12: Forecast revenue profile and revenue composition



Source: State One Stockbroking forecasts

COGS and gross margin

Unit cost of goods sold (COGS) amounted to A$3.40/GJe (A$18.7m /5.48PJe) in FY18 and A$2.80/GJe (A$30.4m /10.8PJe) in FY19. Maintaining unit costs at A$2.80/PJe (real), we calculate an average gross profit margin of A$2.60/GJe and a gross profit margin of 46% over our forecast period.

Figure 13: Forecast COGS and gross margin

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenue (A$/GJe)	5.22	5.23	5.34	5.45	5.55	5.67	5.78	6.20	6.19	5.98	6.09
COGS (A$/GJe)	(2.80)	(2.86)	(2.91)	(2.97)	(3.03)	(3.09)	(3.15)	(3.22)	(3.28)	(3.35)	(3.41)
Gross margin (A$/GJe)	2.42	2.38	2.43	2.47	2.52	2.57	2.63	2.98	2.91	2.63	2.68
Gross margin (%)	*46%*	*45%*	*45%*	*45%*	*45%*	*45%*	*45%*	*48%*	*47%*	*44%*	*44%*
Production (PJe)	*14.1*	*14.1*	*14.1*	*14.1*	*14.1*	*14.1*	*14.1*	*14.1*	*13.9*	*13.5*	*9.7*

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenue (A$m)	74	74	75	77	78	80	81	87	86	81	59
COGS (A$m)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(38)	(27)
Gross margin (A$m)	34	34	36	37	39	40	42	48	47	43	32

Source: State One Stockbroking forecasts

Note: unit revenue, COGS and gross margin calculated using saleable gas production as the denominator (i.e., not net sales after payback to Macquarie Mereenie of historical gas overlift).

Selected Management Profiles (Source: Company)

Leon Devaney | Managing Director & Chief Executive Officer | BSc MBA

- Finance
- Commercial
- Strategy

Background

- 19 years of experience within the Australian oil and gas sector
- Strategic, finance and commercial consulting to junior CSG companies, including QGC, Deloitte (2000-2005)
- Pivotal role in QGC's growth from a small cap gas exploration company into a multi-billion dollar takeover target in 2008.
- Continued with BG(QGC) as Commercial Manager for domestic gas and electricity portfolio.
- Central from 2012 - commercial, finance and BD responsibilities, including: acquisition of Mereenie, Palm Valley and Dingo Gas fields and securing and progressing Project Range.

Ross Evans | Chief Operations Officer | GAICD MBA BE(Hons 1)

- Operations
- Projects & Engineering
- Subsurface Engineering

Background

- 20+ years upstream experience in technical and commercial roles
- Executive GM for Exploration & Development at Lattice Energy (acquired by Beach for $1.6bn)
- Instrumental in the acquisition, conception and delivery of the $25bn APLNG CSG to LNG Project
- Deep experience operating in QLD (APLNG project) and the NT (Beetaloo drill / frack)
- Prior experience with Origin & BHP

Robin Polson | Chief Commercial Officer | BCom GDipAppFinInv MAICD

- M&A
- Strategy
- Commercial

Background

- 30+ years experience in audit, advisory, independent expert valuation, M&A and strategy – 13 years as partner of Deloitte and three years as a director of and investment banking business
- Independent expert or strategic advisor in respect of most of the significant Australia east coast on-market and other corporate oil & gas transactions since 2003
- Most recently lead financial and commercial adviser to CNOOC, as participant in QCLNG, with respect to an AUD35 billion long term gas purchase from Arrow Energy

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Alan Hill
Executive Chairman
Phone: +61 8 9288 3388
ahill@stateone.com.au

Ric Heydon
Equities & Derivatives Advisor
Phone: +61 8 9288 3307
rheydon@stateone.com.au

Mark Sullivan
Institutional Dealer
Phone: +61 2 9024 9134
msullivan@stateone.com.au

Thomas Tan
Equities Advisor
Phone: +61 2 9024 9131
ttan@stateone.com.au

Morris Levitzke
Equities Advisor
Phone: +61 8 9288 3315
mlevitzke@stateone.com.au

Graeme Johnson
Equities & Derivatives Advisor
Phone: +61 8 9288 3316
gjohnson@stateone.com.au

Yitz Barber
Equities Advisor
Phone: +61 2 9024 9107
ybarber@stateone.com.au

Tammie Wong
Equities Advisor
Phone: +61 2 9024 9133
twong@stateone.com.au

Dawn Chia
Business Development Manager
Phone: +61 8 9288 3336
dawn.chia@amscot.com.au

David Zhang
Equities Advisor
Phone: +61 2 9024 9130
dzhang@stateone.com.au

David Brennan
Senior Investment Analyst
Phone: +61 2 9024 9142
dbrennan@stateone.com.au