STATE ONE STOCKBROKING LTD
Participant of ASX Group
AFSL 247 100
ABN 95 092 989 083

Level 14
172 St George's Terrace
PERTH WA 6000
PO Box 7625
CLOISTERS SQUARE WA 6850
P: +61 8 9288 3388

Level 21
133 Castlereagh Street
SYDNEY NSW 2000
PO Box R1931
ROYAL EXCHANGE NSW 1225
P: +61 2 9024 9142

Leigh Creek Energy Limited

A new gas supplier for a new gas era

20 May 2016

LCK A$0.30 **(TP A$0.66)**

Recommendation
Speculative Buy

Risk Assessment
Higher

Leigh Creek (ASX:LCK) is targeting to produce up to 100PJpa of saleable gas via In-Situ Gasification (ISG) of a 377Mt coal Resource at the closed Leigh Creek coalmine in South Australia. While the technical capabilities of ISG have been established from three separately developed ISG pilot plants in Queensland, the legislative stance of the Queensland government towards ISG (in contrast to coal seam gas) has long acted as a headwind. In contrast, we believe the South Australian government is supportive of ISG and has developed a clear legal and regulatory framework to guide ISG development. The Leigh Creek Energy Project (LCEP) aims to monetise what is now a stranded asset, add to the state's energy (gas and electricity) supply, and critically, provide much needed regional employment opportunities.

LCK is actively engaging with potential gas and electricity buyers for long-term contracts. The group is also looking to secure farm-in partners to monetise its 2,964PJ Resource (2C) and reduce project equity and debt funding requirements; Heads of Agreements (HOAs) have already been signed with the APA Group (ASX:APA) and with Shanghai Electric Power Generation Group. We believe that large East Coast (EC) gas buyers are looking to broaden their sources of supply, and this could be an important driver for entering into offtake and/or JV agreements. Note: Coal Seam Gas (CSG) currently supplies 60% of EC domestic gas demand, and virtually 100% of LNG-feedstock.

Estimated NPV_{10} of gas and electricity sales: ~A$1.95bn

We calculate LCK's total NPV_{10} (pre-debt) at A$1.95bn (A$1.77bn gas sales, A$180m electricity JV). Adjusted for A$1.2bn in forecast project debt finance, we calculate LCK's equity value at A$747m or A$2.66 per share (on a fully diluted basis). Attaching a 75% discount for LCEP risk (execution, funding), we calculate a risk-adjusted NPV-derived target price of A$0.66ps.

We believe that LCK offers exciting capital upside for speculative investors as the LCEP is progressively de-risked. Potential near-term share price catalysts include customer offtake or farm-in agreements, firming up of existing HOAs, and a successful Stage 1 gas production demonstration (targeted for year-end).

Key Financials

Year-end June	FY15A	FY16E	FY17E	FY18E	FY19E
EC gas price (A$/GJ)	-	7.00	7.14	7.28	7.43
Annual % change	-	-	2.0%	2.0%	2.0%
Production (PJ)	-	0	0	0	50
ARP (A$/GJ)	-	na	na	na	6.60
Revenue (A$m)	0	0	0	0	330
EBITDA (A$m)	-18	-2.5	-2.5	-2.5	140
Costs excl.royalties (A$/GJ)	-	na	na	na	3.23
Costs incl. royalties (A$/GJ)	-	na	na	na	3.57
Normalised NPAT (A$m)	-18	-2.5	-2.3	-2.2	75
EPS Reported (A$)	-0.08	-0.01	0.01	-0.01	0.27
EPS Normalised (A$)	-0.08	-0.01	-0.01	-0.01	0.27
DPS (A$)	0.00	0.00	0.00	0.00	0.00
PER (x)	na	na	na	na	1.4
Net debt / (cash) (A$m)	-1	-12	285	887	1,116
Capex (A$m)	0	0	-300	-600	-302

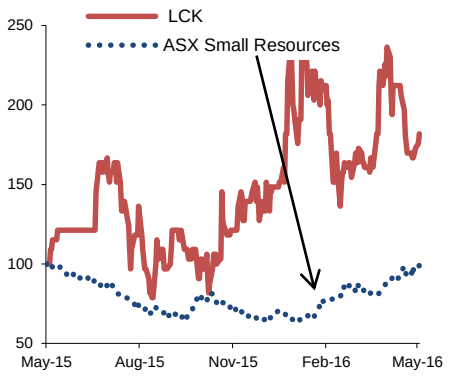
Source: IRESS, Company Data, State One Stockbroking. Share price: $ 0.300 May 18, 2016

Resources – Oil & Gas

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

Leigh Creek Energy Ltd	
ASX Code	LCK
52 week range	A$0.13-A$0.42
Market Cap (ASm)	93
Shares Outstanding (m)	266.4
Av Daily Turnover (shares)	129k
ASX All Ordinaries	5,458
FY16E BV per share (A$)	0.05
EPS FY16E (A$)	-0.01
Net Debt/(Cash) FY16E (A$m)	-12

Relative price performance



Source: IRESS

Financial Statements

Leigh Creek Energy Limited

Year ending June

Profit & Loss Statement (A$M)	FY15A	FY16E	FY17E	FY18E	FY19E
Revenue	0.0	0.0	0	0	330
Production/Pipeline	0.0	0.0	0	0	(149)
Corporate	0.0	(2.5)	(2.5)	(2.5)	(5.0)
PRRT	(17.6)	0.0	0	0	(36)
EBITDA	**(18)**	**(3)**	**(3)**	**(3)**	**140**
Depreciation & Amortisation	0.0	0.0	0	0	(24)
Operating profit	**(17.6)**	**(2.5)**	**(3)**	**(3)**	**116**
NOI	0.0	0.0	5	0	0
EBIT	**(17.6)**	**(2.5)**	**3**	**(3)**	**116**
Interest income	0.0	0.0	0	0	0
Interest expense	0.0	0.0	0	0	(42)
Tax expense	0.0	0.0	0	0	0
Reported NPAT	(17.6)	(2.5)	3	(2)	75
Normalised NPAT	**(18)**	**(2)**	**(2)**	**(2)**	**75**
EBITDA Margin (%)	na	na	na	na	42%
Operating profit margin (%)	na	na	na	na	35%
EPS Reported (A$)	(0.08)	(0.01)	0.01	(0.01)	0.27
EPS Normalised (A$)	(0.08)	(0.01)	(0.01)	(0.01)	0.27
EPS growth (%)	nm	nm	nm	nm	nm
DPS - Declared (A$)	0.00	0.00	0.00	0.00	0.00
Avg. no. of fully-diluted shares (m)	138	263	281	281	281
YE no. of fuly-diluted shares (m)	231	281	281	281	281

Cash Flow Statement (A$M)	FY15A	FY16E	FY17E	FY18E	FY19E
EBITDA	0	(2.5)	(2.5)	(2.5)	140
Investment in working capital	0	0.0	0.0	0.0	(25)
Tax expense	0	0.0	0.0	0.0	0
Operating Cash Flow	**0**	**(2.5)**	**(2.5)**	**(2.5)**	**115**
Capex	0	0	(300)	(600)	(302)
Other investments	0	0	0	0	0
Investing Cash Flow	**0**	**0**	**(300)**	**(600)**	**(302)**
Net interest received / (paid)	0	0	0	0	(42)
Debt drawdown / (repayment)	0	0	300	600	300
Dividends paid	0	0	0	0	0
Equity raised / (repaid)	0	13	0	0	0
Financing Cash Flow	**0**	**13**	**300**	**600**	**258**
Non-operating & Other	0	0	5	0	0
Inc/(Dec) in Cash	**0**	**10.8**	**2.7**	**(2.2)**	**71**

Balance Sheet (A$M)	FY15A	FY16E	FY17E	FY18E	FY19E
Cash & Equivalents	1.5	12	15	13	84
Receivables	0.1	0	0	0	33
Inventories	0.0	0	0	0	25
Other Current Assets	0.0	0	0	0	0
PPE and Exploration & Development	0.8	1	301	901	1,179
Deferred tax asset	0.0	0	0	0	0
Other Non Current Assets	0.0	0	0	0	0
Total Assets	**2.4**	**13**	**316**	**914**	**1,321**
Payables and other current Liabilities	0.4	0	0	0	33
Short Term Debt	0.1	0	0	0	0
Long Term Debt	0.0	0	300	900	1,200
Other Non Current Liabilities	0.0	0	0	0	0
Total Liabilities	**0.5**	**1**	**301**	**901**	**1,233**
Total Equity	**1.9**	**13**	**15**	**13**	**88**
Net Debt (Cash)	(1.4)	(12)	285	887	1,116

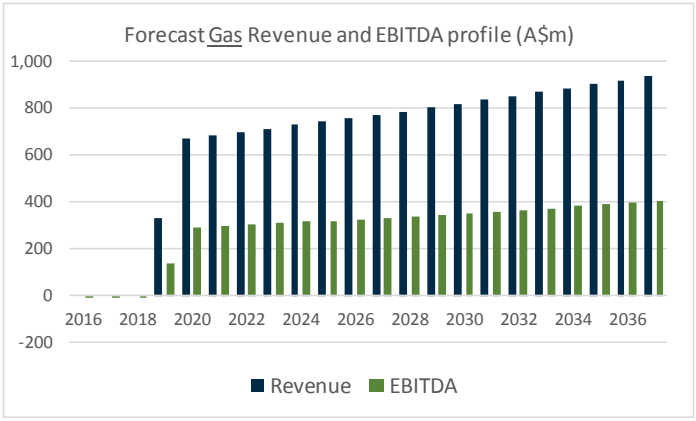
Top 3 Shareholders	%	Date
Allied Resource Partners Pty Ltd	45.5	
Former ARP TriEnergy shareholders	14.6	Mar-16
CITIC	7.5	

Source: Company, IRESS, State One Stockbroking forecasts

Assumptions	FY15A	FY16E	FY17E	FY18E	FY19E
Production (PJ)	-	0.0	0.0	0.0	50.0
Market gas price (A$/GJ)	-	7.00	7.14	7.28	7.43
Extraction/processing costs (A$/GJ	-	*na*	*na*	*na*	*2.33*
Pipeline tariff costs (A$/GJ)	-	*na*	*na*	*na*	*0.80*
Corporate/Admin costs (A$/GJ)	-	*na*	*na*	*na*	*0.10*
Royalties (A$/GJ)	-	*na*	*na*	*na*	*0.73*
Total costs (A$/GJ)	-	na	na	na	3.57
EBITDA (A$/GJ)	-	na	na	na	3.86
EBITDA margin (%)	-	na	na	na	52%

Resources (PRMS)	Category	Est. Recoverable Energy (PJ)
PEL 650:LCEP	1P Reserves	0.0
	2P Reserves	0.0
	3P Reserves	0.0
	1C Contingent Resource	2,748
	2C Contingent Resource	**2,964**
	3C Contingent Resource	3,303

Note: PRMS = Petroleum Resources Management System



Leverage	FY15A	FY16E	FY17E	FY18E	FY19E
Net Debt/Equity	cash	cash	1847%	6705%	1272%
Gearing (ND/ND+E)	cash	cash	95%	99%	93%
Interest Cover (x)	na	na	na	na	2.8

Valuation Ratios (x)	FY15A	FY16E	FY17E	FY18E	FY19E
Normalised P/E	na	na	na	na	1.4
Price/OP Cash Flow	na	na	na	na	0.7
Book value per share (A$)	0.01	0.05	0.05	0.05	0.31
EV/EBITDA	na	na	na	na	8
ROE (%)	na	na	na	na	85%

$NPV_{10\%}$ Valuation	(A$m)	(A$/share)	A$/ Resource PJ
NPV	1,947	6.94	0.66
…less Project Debt	(1,200)	(4.28)	(0.40)
Equity value - unrisked	747	2.66	0.25
Risk weighting	*75%*		
Equity value - risked	**187**	**0.66**	**0.06**

Note: Per share valuation based on fully diluted number of shares

Company Overview:

Leigh Creek Energy (LCK) is an emerging unconventional gas producer. The company's key asset is 2,964PJ of 2C recoverable gas Resources associated with 377Mt of coal (Inferred Resource, 2012 JORC compliant) at its flagship Leigh Creek Energy Project located at the shuttered Leigh Creek coal mine in Central South Australia (550km north of Adelaide). LCK has an oil and gas exploration licence (PEL 650) -which overlays the Leigh Creek coal mining licence, and is targeting to produce ~ 100PJ per annum of gas from underground coal gasification (UCG) from early 2019. Near term objectives include successfully completing gas flaring in late 2016 to prove up the commercial potential of the project.

Valuation

NPV (un-risked)

Underpinned by an estimated NPV_{10} of A$1,767m for gas sales (2,450PJ over a 25-year LOM), and an NPV_{10} of A$180m for a forecast 25% interest in a 350MW capacity on-site gas-fired power station, we calculate LCK's total NPV (pre-debt) at A$1.95bn. Adjusted for A$1.2bn in forecast project debt finance, we calculate LCK's equity value at A$747m or A$2.66 per share (on a fully diluted basis).

NPV valuation:

A$2.66 per diluted share

Figure 1: Leigh Creek Energy Project NPV Valuation

	Year FY	2016	2017	2018	1 2019	2 2020	3 2021	4 2022	5 2023	6 2024	Year 7-25	LOM
2C Resources	PJ	2,964										
Resource to Reserve conversion	*%*	*100%*										
Syngas conversion factor	*%*	*84%*	*(i.e., % of syngas converted to saleable product)*									
Inventory - opening	PJ	2,500	2,500	2,500	2,500	2,450	2,350	2,250	2,150	2,050		
Inventory - closing	PJ	2,500	2,500	2,500	2,450	2,350	2,250	2,150	2,050	1,950		
Saleable gas production	PJ	-	-	-	50	100	100	100	100	100	1,900	2,450
ARP	A$/GJ	6.2	6.4	6.5	6.6	6.7	6.9	7.0	7.1	7.3		-
Revenue	**A$m**	-	-	-	**330**	**673**	**686**	**700**	**714**	**728**	**16,907**	**20,739**
Production costs	A$m	-	-	-	(117)	(238)	(243)	(248)	(253)	(258)	(6,005)	(7,361)
Pipeline tariffs	A$m	-	-	-	(32)	(65)	(66)	(68)	(69)	(70)	(1,638)	(2,008)
Admin/ Corporate	A$m	(2.5)	(2.5)	(2.5)	(5)	(5)	(5)	(5)	(5)	(6)	(129)	(168)
State and Vendor Royalties	A$m	-	-	-	(36)	(74)	(76)	(77)	(79)	(80)	(1,860)	(2,281)
Total costs	A$m	(2.5)	(2.5)	(2.5)	(190)	(382)	(390)	(398)	(406)	(414)	(9,631)	(11,818)
EBITDA	A$m	(2.5)	(2.5)	(2.5)	140	291	297	302	308	314	7,276	8,921
PAT	A$m	(2.5)	(2.5)	(2.5)	140	240	244	248	252	256	5,777	7,148
Equity funding	A$m	11	-	-	-	-	-	-	-	-	-	11
Debt funding	A$m	-	300	600	300	-	-	-	-	-	-	1,200
Project capex	A$m	-	(300)	(600)	(300)	-	-	-	-	-	(20)	(1,220)
Sustaining capex	A$m	-	-	-	(2)	(2)	(2)	(2)	(2)	(2)	(50)	(63)
Cash flow from gas sales	**A$m**	**8**	**(3)**	**(3)**	**140**	**240**	**244**	**248**	**252**	**256**	**5,757**	**7,139**
NPV$_{10}$: Gas	**A$m**	**1,767**										
Cash flow from JV electricity	**A$m**	-	-	-	**5**	**24**	**24**	**25**	**26**	**26**	**637**	**768**
NPV$_{10}$: Electricity	**A$m**	**180**										

NPV$_{10}$: Gas & Electricity	**A$m**	**1,947**
....less Debt (A$m)		(1,200)
= Equity value (A$m)		**747**
Equity value per diluted share (A$)		**2.66**

Current no. of shares (m)	*280.5*
Options (m)	*14.3*
Equity-funded capex (m)	*35.9*
Diluted no. of shares (m)	*280.7*

Equity value and share price sensitivity to Gas Price

	Market Gas Price (A$/GJ)	Equity value (A$m)	Share price value (A$)
Base case -10%	6.30	152	0.54
Base case gas price (real)	7.00	747	2.66
Base case +10%	7.70	1,404	5.00

Price and cost assumptions		2016	2017	2018	2019	2020	2021	2022	2023	2024
Market gas sales	%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Power Station JV sales	%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Market gas price	**A$/GJ**	**7.00**	7.14	7.28	7.43	7.58	7.73	7.88	8.04	8.20
JV Power Station gas price	A$/GJ	3.1	3.2	3.2	3.3	3.4	3.4	3.5	3.5	3.6
Production costs	A$/GJ	2.20	2.24	2.29	2.33	2.38	2.43	2.48	2.53	2.58
Pipeline tariff costs - LCK to Moomba	A$/GJ	0.75	0.77	0.78	0.80	0.81	0.83	0.84	0.86	0.88
Pipeline tariff costs - Moomba to EC	A$/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Admin/ Corporate/Other	A$m	2.50	2.50	2.50	5.00	5.10	5.20	5.31	5.41	5.52
Price/cost inflation	%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Effective State Royalty	%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
TriE Royalty (Founders)	%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Tax rate	%	0%	0%	0%	0%	30%	30%	30%	30%	30%
AUD:USD exchange rate	unit	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Gas unit data										
Revenue	A$/PJ	na	na	na	6.60	6.73	6.86	7.00	7.14	7.28
Costs excluding royalty	A$/PJ	na	na	na	(3.07)	(3.08)	(3.14)	(3.21)	(3.27)	(3.34)
Total costs including royalty	A$/PJ	na	na	na	(3.80)	(3.82)	(3.90)	(3.98)	(4.06)	(4.14)
EBITDA	A$/PJ	na	na	na	2.81	2.91	2.97	3.02	3.08	3.14
EBITDA margin (%)	%	na	na	na	42%	43%	43%	43%	43%	43%

Source: Company, State One Stockbroking forecasts

Target price and Sensitivity

Risk-adjusted target price: A$0.66ps

Our NPV_{10} of A$747m, (A$2.66ps on a fully-diluted basis) indicates significant upside potential relative to current share price levels. However, the valuation is predicated on a number of key timing, operational, technical, and funding assumptions. Attaching a 75% discount for these risks, we calculate a risk-adjusted NPV-derived target price of A$0.66 per share.

Figure 2: Risk-weighted target price

Valuation	(A$m)	Per share (A$)	A$/ Resource GJ
NPV	1,947	6.94	0.66
...less Project Debt	(1,200)	(4.28)	(0.40)
Equity value - unrisked	747	2.66	0.25
Risk weighting	*75%*		
Equity value - risked	**187**	**0.66**	**0.06**

Source: State One Stockbroking forecasts

….equivalent to A$0.06/GJ

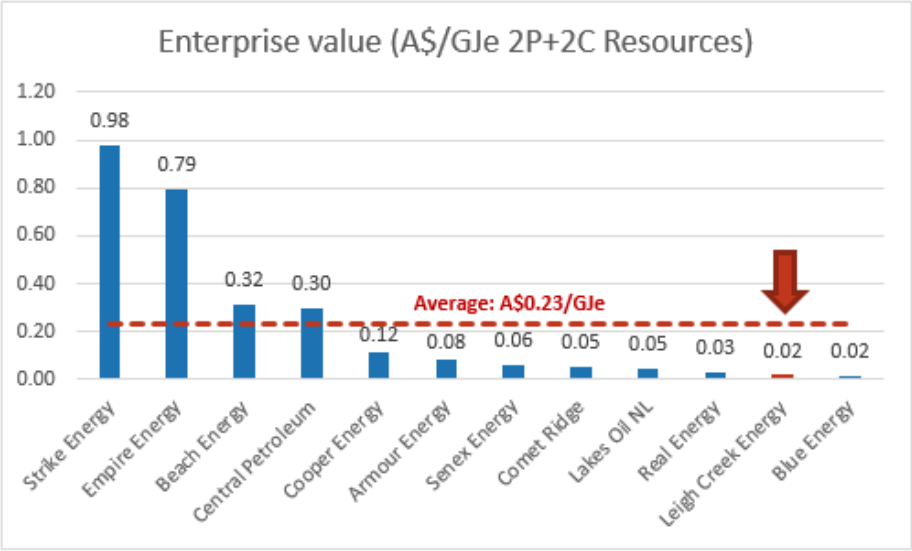
Our risk-adjusted target price equates to A$0.06/GJ Resource (i.e., A$187m / 2,964PJ). This is slightly above the A$0.05/GJe average for ASX-listed CSG/unconventional juniors, but well below the A$0.20/GJe enjoyed by Cooper Basin oil and gas plays. Large m'cap, established oil and gas producers typically with large resource bases (AGL Energy excepted), appear to be valued at a significantly higher average of ~A$1.00/GJe.

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

Company	Ticker	Share price (A$)	Total shares (million)	Mkt Cap (A$m)	Cash (A$m)	Debt (A$m)	EV (A$m)	1P PJe	2P PJe	2C PJe	EV/1P A$/PJe	EV/2P A$/PJe	EV/(2P+2C) A$/GJe	Gearing D/(D+E) %
								price equivalent basis						
Large cap				**60,416**	**2,740**	**31,266**	**88,942**	**18,905**	**32,375**	**55,594**	**4.70**	**2.75**	**1.01**	**34%**
AGL	AGK	18	675	12,255	106	3,018	15,167	211	1,817	0	71.88	8.35	8.35	20%
Oil Search	OSH	7	1,523	10,212	1200	5,571	14,583	2,502	3,783	5,476	5.83	3.85	1.57	35%
Origin Energy	ORG	5	1,750	8,698	158	9,506	18,046	3,368	7,626	1,270	5.36	2.37	2.03	52%
Santos	STO	4	1,766	6,905	1154	7,421	13,172	3,661	7,125	13,994	3.60	1.85	0.62	52%
Woodside Petroleum	WPL	27	824	22,347	122	5,750	27,975	9,163	12,024	34,854	3.05	2.33	0.60	20%
Cooper Basin				**2,140**	**494**	**329**	**1,975**	**378**	**1,190**	**8,619**	**5.22**	**1.66**	**0.20**	**13%**
Beach Energy	BPT	0.67	2,419	1,621	329	321	1,613	320	680	4,439	5.04	2.37	0.32	17%
Cooper Energy	COE	0.25	334	84	29	0	55	18	28	436	3.03	1.95	0.12	0%
Senex Energy	SXY	0.26	1,153	294	100	0	194	39	482	2,740	4.97	0.40	0.06	0%
Icon Energy	ICN	0.04	601	21	19	0	2	0	0	600	-	-	0.00	0%
Real Energy	RLE	0.10	204	20	11	0	9	0	0	300	-	-	0.03	0%
Strike Energy	STX	0.12	833	100	6	8	102	1	0	104	102.0	-	0.98	7%
CSG/Unconventional Juniors				**201**	**78**	**157**	**280**	**105**	**365**	**5,260**	**2.67**	**0.77**	**0.05**	**44%**
Armour Energy	AJQ	0.08	323	27	1	15	41	0	0	490	-	-	0.08	36%
Baraka Petroleum	BKP	0.001	2,225	2	0	0	2	0	0	0	-	-	-	0%
Blue Energy	BUL	0.02	1,141	25	6	0	19	0	71	984	-	0.27	0.02	0%
Carbon Minerals	CRM	0.18	19	3	5	0	-2	0	0	64	-	-	-0.02	0%
Central Petroleum	CTP	0.10	433	42	16	89	115	70	192	197	1.65	0.60	0.30	68%
Comet Ridge	COI	0.07	526	34	3	0	31	0	30	540	-	1.04	0.05	0%
Empire Energy	EEG	0.02	344	6	1	52	57	35	72	0	1.63	0.79	0.79	89%
Galilee Energy	GLL	0.09	152	13	12	0	1	0	0	2,508	-	-	0.00	0%
Lakes Oil NL	LKO	0.002	11,658	23	2	1	22	0	0	477	-	-	0.05	4%
Metgaso	MEL	0.06	442	25	32	0	-7	0	0	0	-	-	-	0%
UCG				**102**	**3**	**10**	**109**	**7**	**1,129**	**11,474**	**15.54**	**0.10**	**0.01**	**9%**
Carbon Energy	CNX	0.01	1,496	21	2	10	29	7	1,129	8,510	4.13	0.03	0.003	32%
Leigh Creek Energy	LCK	0.35	231	81	1	0	80	0	0	2,964	-	-	0.03	0%

Source: Companies, IRESS, State One Stockbroking forecasts

Figure 4: Peer comparative: EV/PJe



Source: Companies, IRESS, State One Stockbroking

Peers are valued at a simple average of A$0.23/GJe

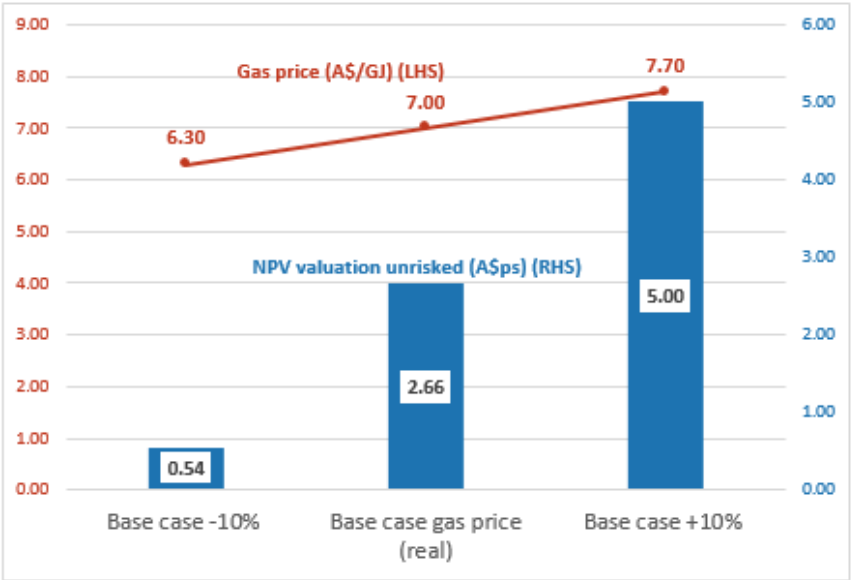
At a (simple) peer-average valuation of A$0.23/GJe, we estimate that LCK's value would be closer to A$682m (A$2.42 per fully-diluted share). This, we suggest, illustrates LCK's upside potential, as the LCEP is progressively de-risked.

With a forecast LOM gas output of some 2,450PJ (2.45 billion GJ), our estimated NPV valuation is particularly sensitive to the A$/GJ gas price. We calculate that in a 10% lower gas price environment (relative to our base-case of A$7/GJ real), our un-risked NPV falls from A$2.66ps to A$0.54ps. Conversely, in a 10% higher gas price environment (relative to our base-case of A$7/GJ real), our un-risked NPV increases from A$2.66ps to A$5.00ps.

LOM gas output estimated at 2.45bn GJ….

…..not surprisingly, a 10% variance relative to our base case A$/GJ gas price has a big NPV impact

Figure 5: NPV (un-risked) sensitivity to the gas price



Source: Companies, IRESS, State One Stockbroking

Recommendation

At current share price levels, we believe that LCK offers attractive upside potential to our risk-adjusted target price of A$0.66ps. As the LCEP is progressively de-risked, we believe that the share price has significantly higher upside potential to ~A$2.66. LCK offers investors exposure to an early-stage unconventional gas developer, and an ISG Resource of nearly 3,000PJ (2C) in South Australia, a state supportive of unconventional gas development. LCK has already entered into HOAs with two heavyweights in the energy sector, and is looking to sign in electricity and gas sales contracts before the end of 2016, at which time it aims to conduct a pre-commercial gas production demonstration. **We believe that LCK offers exciting capital upside for speculative investors as the LCEP is progressively de-risked. Recommendation: Speculative Buy. Risk: Higher**

Speculative Buy

Risks

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

- East coast gas and South Australian electricity prices. Domestic gas prices may be impacted by overseas LNG prices which in turn may be impacted by the US$ oil price and the USD:AUD exchange rate. SA electricity prices may be impacted by commercial and industrial demand and the increase in renewable energy (specifically wind and solar-generated electricity).
- Decline in east coast gas demand due to slower than expected demand for primary (gas) or secondary power (electricity), or an increase in renewable energy (wind, solar, battery).
- An increase in available gas to the domestic market: established east coast gas producers/developers may convert undeveloped 2P Reserves to Developed or convert Contingent Resources (2C) to 2P Reserves, or new gas explorers/developers appear.
- LCEP meeting all licensing and approvals as per the Petroleum and Geothermal Energy Act (PGE) in South Australia, i.e., state approval to develop the LCEP.
- Community buy-in, i.e., establishing and maintaining a "social licence" to operate with landowners (indigenous and pastoral), and regional communities.
- Progressing with initial signed HOAs with the APA Group and Shanghai Electric, and securing long-term gas and electricity offtake contracts.
- The start-date of production, production output and composition (State One forecast: 100PJpa (80% methane) from 2019) may alter.
- Technical risks associated with the ISG process, geology risks associated with the coal Resource, surface processing risks associating with cleaning the syngas to methane.
- Resource to Reserve conversion, and the conversion rate of syngas to synthetic natural gas.
- The final capex amount (State One forecast: A$2bn), securing funding, cost of funding, and the funding mix.
- Unit operating costs (State One forecast: A$3.80/GJ in 2019 estimated to fall as full production for a full year occurs).

Assumptions

Inventory: 2,500PJ

On 8 January 2016, LCK announced a maiden ISG Resource (2C) of 2,964PJ recoverable gas at its flagship Leigh Creek Energy Project (LCEP). The Resource was independently estimated by MHA Petroleum Consultants LLC USA (MHA), and certified under the Petroleum Resources Management System (PRMS). PRMS is the internationally recognised standard for reporting oil and gas Resources and Reserves.

The Resource is underpinned by a JORC 2012-compliant Inferred coal Resource of 377Mt, and gasification test work indicating an energy yield of 15.2GJ/t for a gross energy potential of some 5,730PJ of syngas. However, after adjusting for process recovery efficiencies and geologic factors (seam thickness, overburden thickness), the consultants derived a recoverable ISG Resource of 2,964PJ (equivalent to 52% of total energy, or 7.9GJ/t of coal Resource). Our understanding is that once field pre-commercial gas production demonstration has been successfully conducted, the Resource estimate may be upgraded to Reserves.

We have added an extra layer of conservatism, and reduced the estimated Recoverable Resource by a further 16% to our forecast inventory of 2,500PJ.

Most oil and gas companies suffer from what is known as "reservoir risk" whereby there is a need to test an individual oil or gas field for long lengths of time to better understand the flow rates and how these decline over time due to specific geological factors. The key factors are porosity (what proportion of voids between sand grains exists) and permeability (how readily a fluid can move through a rock).

The LCEP has no reservoir risk. ISG is simply a duplication across a known coal asset. This results in the need for only a short gas demonstration, rather than sometimes a multi-year demonstration for traditional oil and gas fields.

Production profile: 100PJpa, 25 year life-of-mine (LOM)

We assume saleable gas production/sales of 100PJpa, of which 80% (80PJpa) is methane suitable for pipeline distribution and sale to external buyers, and 20% (20PJpa) is lower-grade /lower-calorific syngas suitable for burning in an on-site gas-fired power station.

We assume gas production commencing at the end of 2018 (i.e., beginning 2H FY19), and a LOM of 25 years, for total LOM production/sales of 2,450PJ.

The present problems in South Australia regarding its dominant mix of renewable energy (wind and solar) has caused electricity prices to soar and power supply is expected to be frequently disrupted because of the dominance of intermittent wind.

The LCEP has the potential to offer reliable power to industrial customers in South Australia, and this is presently being investigated by LCK.

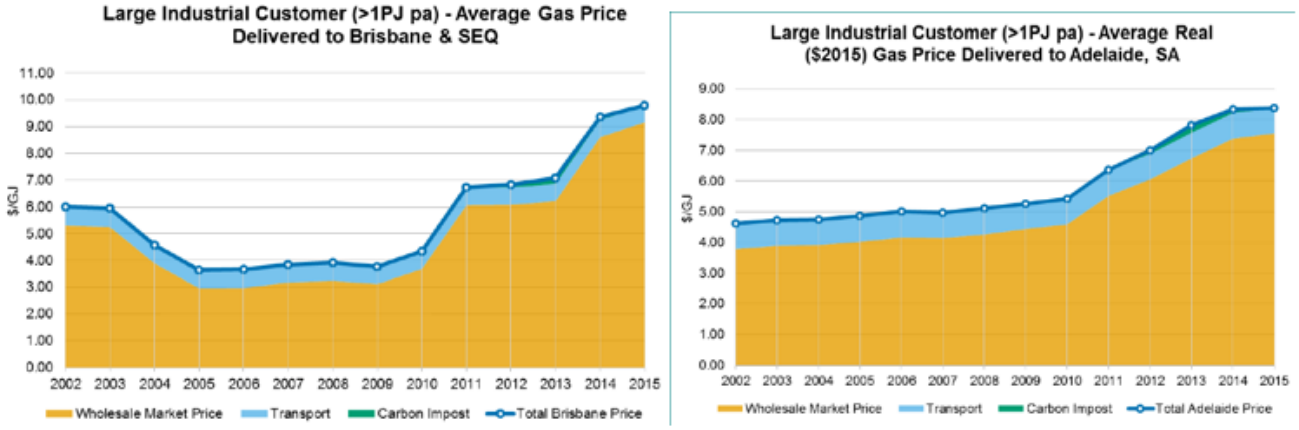
It is possible that there is a shift to produce greater quantities of electricity longer term and reduce export methane sales into the EC grid.

Average Realised Price (ARP): (~A$6.20/GJ)

We assume average received gas prices from third party /external clients at A$7.00/GJ (escalated at 2%pa). We believe this price is comparable to the

(pre-transport) wholesale prices currently paid by large industrial gas buyers in Queensland and South Australia. See graphs below.

Figure 6: Gas prices – Queensland (LHS) and South Australia (RHS)



Source: Oakley Greenwood Gas Price Trends Review, December 2015

We assume average internal gas prices (i.e., sales to a JV Power Station) at A$3.14/PJ, based on ~60% of sales at A$1.00/GJ (LCK's estimated production cost for partially cleaned gas) and ~40% of sales at A$6/GJ (more typical of commercial prices paid by gas powered electricity generators). The 60:40 split (rounded) is predicated on LCK and a Third Party developing a 350MW on-site gas-fired power station, with 200MW of capacity allocated for LCEP operations, and 150MW of capacity allocated for third party electricity sales.

Applying an 80% weighting to external gas prices of A$7.00/GJ (real) and a 20% weighting to internal (Power Station JV) gas prices of A$3.14/GJ, we calculate an average realised gas price for the LCEP of A$6.23/GJ. See table below.

Gas used for the LCEP's own energy needs is known as "fuel gas" and is likely to be excluded from South Australian government royalty calculations.

Figure 7: Estimated average realised gas price (2016)

	External Sales	Power Station JV	
Price (A$/GJ)		1.00	6.00
Weighting (%)		57%	43%
Price (A$/GJ)	**7.00**	**3.14**	
Weighting (%)	80%	20%	
Price (A$/GJ)	**6.23**		

Source: Company, State One Stockbroking forecasts

Unit costs (A$/GJ): ~A$3.80/GJ

Forecast average unit production (extraction and processing) costs of A$2.20/GJ are predicated on management guided production costs of A$2.50/GJ for pipeline specification gas (methane) and A$1.00/GJ for partially cleaned or raw syngas (note: costs are weighted 80:20 respectively). Costs are escalated by 2%pa.

We assume that pipeline tariffs from APA's distribution hub at Moomba to the east coast are borne by the end-user. However, our base-case view is that APA will build, own and operate a 150Km pipeline from Leigh Creek to the Moomba

distribution hub, and that the return on capex associated with this will be worn by LCK. Note: in a gas-constrained market, the cost could be equally shared between LCK, APA , and a third party (gas buyer), but this is subject to negotiations which we believe form part of the LCK/APA HOA signed in mid-December 2015. APA and LCK continue to work together on pipeline related matters and no ownership decisions regarding the new pipeline have been made.

Predicated on a pipeline capex of A$400m, we believe that a tariff charge of A$0.75/GJ will deliver an IRR of 10% We suggest this level of return would be acceptable for APA given the annuity nature of its business (selling pipeline capacity) and its ability to source low cost debt. Note: assuming a lower required IRR of 7%, we calculate that tariff costs could fall closer to A$0.57/GJ.

Figure 8: Estimated NPV of Leigh Creek to Moomba Pipeline

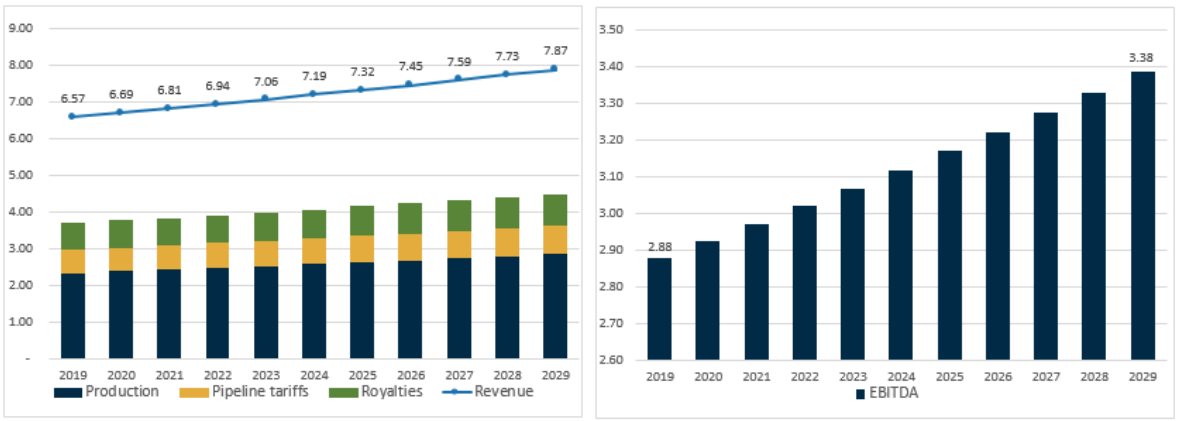
	Year FY	2016	2017	2018	1 2019	2 2020	3 2021	4 2022	5 2023	6 2024	Year 7 -25	LOM
Gas Volumes to Market	PJ	-	-	-	40	80	80	80	80	80	1,520	1,960
Tariff charge: LCK to Moomba	A$/GJ	0.75	0.77	0.78	0.80	0.81	0.83	0.84	0.86	0.88		
Tariff revenue (A$m)	A$m	-	-	-	32	65	66	68	69	70	1,638	2,008
Operating costs as % revenue	%	5%	5%	5%	5%	5%	5%	5%	5%	5%		
PBT	A$m	-	-	-	30	62	63	64	65	67	1,556	1,907
PAT	A$m	-	-	-	21	43	44	45	46	47	1,089	1,335
Project capex	A$m	-	-	(400)	-	-	-	-	-	-	-	(400)
Sustaining capex	A$m	-	-	-	(3)	(3)	(3)	(3)	(3)	(3)	(64)	(80)
Cash Flow	A$m	-	-	(400)	19	41	41	42	43	44	1,025	855
NPV_{10}:	A$m	3										

Source: State One Stockbroking forecasts

We assume effective government royalty expenses of 7% of revenue, based on government royalties (PRRT) of 10% of well-head revenues, and effective vendor royalties (to ARP TriEnergy Pty Ltd) of 4% of revenue (A$0.30/GJ in a A$6-A$10/GJ price environment). With Native Title having been extinguished over the Mining Lease, we believe that LCK is not liable to pay Native Title Royalties on revenues generated from the LCEP.

Our forecast gas revenue and cost assumptions imply a unit EBITDA margin in FY2019 (first year of production) of A$2.88/GJ, equivalent to an EBITDA margin of 44%. Note: our forecast EBITDA margin is maintained at ~44% over our forecast period, as both revenues and costs are escalated at a similar 2%pa.

Figure 9: Forecast unit revenue and cost profile (A$/GJ): 2019-2029



Source: Company, State One Stockbroking forecasts
Note: Costs exclude Admin/Corporate, years are LCK financial years (June year-end)

Electricity Joint Venture: we assume 75% third party:25% LCK

The Leigh Creek coal mine is currently linked to the electricity grid via a 20MW connection. The gas clean-up plant and oxygen plants (3) required to produce pipeline specification methane requires considerably more power – management estimates some 200MW.

With South Australia suffering from high electricity prices and recent power instability, one alternative is to build a captive 200MW gas-fired power plant on-site, fed by cheap (A$1/GJ) partially cleaned syngas. LCK's preferred alternative, however, is to enter into a joint venture with a third party to develop a larger capacity plant that could service both LCK and external customers. This would not only provide a (baseload) customer for LCK, but would also reduce/eliminate upfront capex requirements, while electricity sales would provide the group with a second revenue stream (similar to a mining co-product).

LCK's preferred option is to form a JV for a gas-fed electricity power with excess capacity for third party contracts

The reduced capital expenditure needs of electricity are derived by the ability to use air in the ISG process to produce lower quality syngas which can be readily cleaned for power generation.

Production of methane requires oxygen be used in the ISG process to produce a higher quality of syngas which then has a high level of gas clean up applied. Oxygen plants (essentially large fridges) are expensive to build and consume large quantities of electricity (albeit low-cost electricity from the LCEP).

As a result, we view the recent (6 April 2016) HOA with HK-listed Shanghai Electric Power Generation Group as a key development. We believe that LCK has a significant amount to offer to any potential Power Station JV. Assuming a commercial gas price to gas-fired power stations of A$6/GJ and our estimated average gas price to a LCK/third party JV of A$3.14/GJ, we calculate that the marginal benefit to the JV is A$2.86/GJ – a not inconsiderable saving.

The LCEP is now in a position to offer long term reliable electricity supply contracts to a range of large customers in South Australia including:

- Mines to the west of the LECP – being Olympic Dam (BHP) and Prominent Hill (OZL),
- Retail energy entities such as AGL and Origin, and
- Industrial users.

We calculate the NPV_{10} of this lower gas-feed cost to be some A$564m; this valuation is based on a 350MW-capacity plant requiring annual gas feed of 20PJ (40% thermal efficiency), and a 25-year operating life.

We estimate the NPV_{10} of a 350MW capacity power station at some A$364m; this assumes pre-production capex of A$450m, 95% uptime, gas-feed costs of A$3.14GJ (real), and an electricity price to both external and internal (i.e., LCK) customers of A$75/MWh (real).

Figure 10: Estimated NPV of 350MW gas-fed Power Station JV

	Year				1	2	3	4	5	6	Year 7-25	LOM
	FY	2016	2017	2018	2019	2020	2021	2022	2023	2024		
Electricity capacity	MW	350										
Electricity capacity	*GWh*	*3,066*										
Capacity utilisation	*%*	*0.0%*	*0.0%*	*0.0%*	*40.0%*	*95.0%*	*95.0%*	*95.0%*	*95.0%*	*95.0%*		
Electricity produced	GWh	-	-	-	1,226	2,913	2,913	2,913	2,913	2,913	55,341	71,131
SA market electricity price	A$/MWh	75	77	78	80	81	83	84	86	88		
LCK electricity price	A$/MWh	75	77	78	80	81	83	84	86	88	2,047	
Weighted average price	A$/MWh	75	77	78	80	81	83	84	86	88		
Electricity revenue	**A$m**	-	-	-	**98**	**236**	**241**	**246**	**251**	**256**	**5,963**	**7,291**
Gas feed	PJ	-	-	-	10	20	20	20	20	20	380	490
Gas cost	A$/PJ	3.14	3.19	3.25	3.30	3.35	3.41	3.47	3.53	3.58		
Gas cost	A$m	-	-	-	(33)	(67)	(68)	(69)	(71)	(72)	(1,621)	(2,001)
Other costs	A$m	-	-	-	(10)	(10)	(10)	(10)	(11)	(11)	(252)	(314)
PBT	A$m	-	-	-	55	159	163	166	170	173	4,090	4,976
PAT	A$m	-	-	-	24	98	100	102	105	107	2,597	3,133
Capex	A$m	-	(225)	(225)	(2.5)	(2.5)	(2.5)	(2.5)	(2.5)	(2.5)	(48)	(513)
Cash flow	**A$m**	-	**(225)**	**(225)**	**22**	**95**	**97**	**100**	**102**	**105**	**2,549**	**2,621**
NPV$_{10}$: Power Station JV (100)	**A$m**	**364**										
Cash flow attributable to LCK:		*25%*	*interest in JV (excluding pre-production capex)*									
Cash flow	**A$m**	-	-	-	**5**	**24**	**24**	**25**	**26**	**26**	**637**	**768**
NPV$_{10}$: LCK interest	**A$m**	**180**										

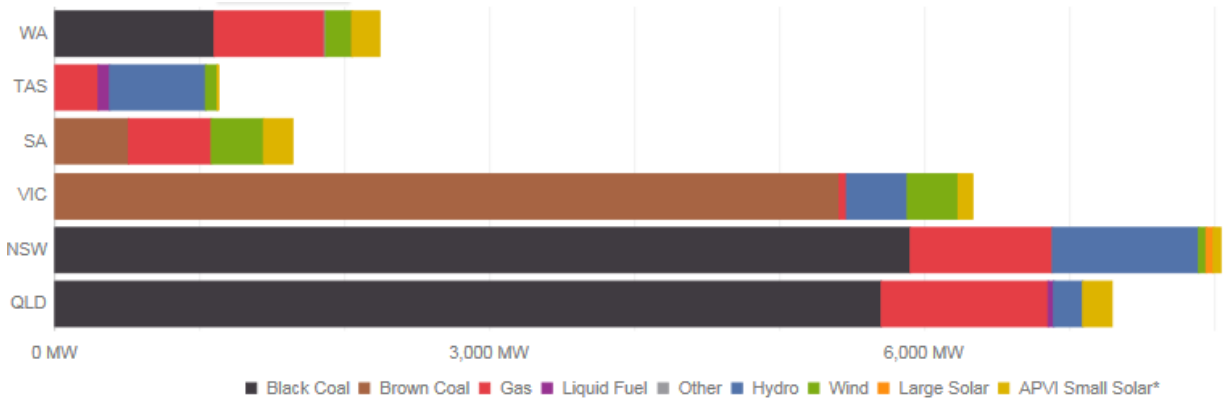
Source: State One Stockbroking forecasts
Note: 1GWh = 1,000MWh

Estimating the JV split between a third party and LCK is problematic. LCK brings the low-cost gas feed (without which a baseload gas-fired power station is uneconomic), while a JV partner brings the financial muscle and operational expertise. We calculate that splitting the JV 75:25 between a third party partner and LCK, will result in LCK sharing in ~50% of the JV NPV (backing out pre-production capex).

We believe that our forecast electricity price of A$75/MWh has the potential to surprise on the upside. South Australia has recently endured several episodes of sharply rising electricity prices and grid instability, largely due to the state's reliance on wind power electricity generation. The closure of the coal-fired Port Augusta Power Station (in early May 2016) has added further pressure on baseload power. Certainly, we suggest that large regional electricity users like BHP Billiton and Oz Minerals might be interested in securing long-term reliable power for their respective Olympic Dam, and Prominent Hill and Carrapatenna operations (existing, planned, and expanded).

Estimating the ownership split in a JV between LCK and a third party power station operator is problematic

Figure 11: Electricity generation by state by power source



Source: Renew Economy, data as at Friday 22 April 2016

Figure 12: Mine locations relative to the Leigh Creek area

Source: Company

We believe that BHP and Oz Minerals will need to secure long-term reliable electricity supply before expanding their operations in South Australia

Capex and Funding: A$2bn total capex

Our base-case assumes that a 80PJpa-capacity pipeline linking LCEP to the east coast gas pipeline network, and a 350MW on-site power station, are fully paid for by separate build-own-operate (BOO) agreements with third parties – specifically APA and the Shanghai Electric Power. Note, no formal agreement has been signed regarding ownership with either of these entities. Also, we suggest, the profitability of these infrastructure projects is such that it would be logical for LCK to derive some form of payment for them if LCK is not the 100% owner. We have not included such a payment to LCK in our calculations. We believe that these BOO agreements could reduce the Project capex requirements by some A$800m. For the purposes of estimating an initial project valuation, we assume that the A$1.2bn balance of project capex is 100% debt-funded. In reality, it is unlikely that LCK will be able to obtain this level of debt financing. LCK is currently pursuing a range of alternative funding options including project sell-down (farm-in) at an asset level to provide equity funding, government-supported debt funding, infrastructure debt, R&D factoring, gas streaming with potential end-customers, and other funding options.

Tax: no tax in Year 1 of production, 30% corporate tax thereafter

We assume that the current corporate tax losses of ~A$40m will be fully utilised in Year 1 of production (i.e., in FY19E). From FY20E, we assume profits are taxed at a corporate tax rate of 30% (with an effective tax rate closer to 20% after non-cash and interest expenses).

Fully diluted number of shares: 288 million

We assume 288 million fully diluted number of shares for calculating NPV (and earnings) per share. This is based on 266.4m shares in issue plus 14.3m options including the new shares issued in the April 2016 capital raise (A$10.7m at an issue price of A$0.30ps). We have not included any of the options associated with the capital raise (option exercise price A$0.50ps, expiry two years from issue).

Leigh Creek Energy Project (LCEP)

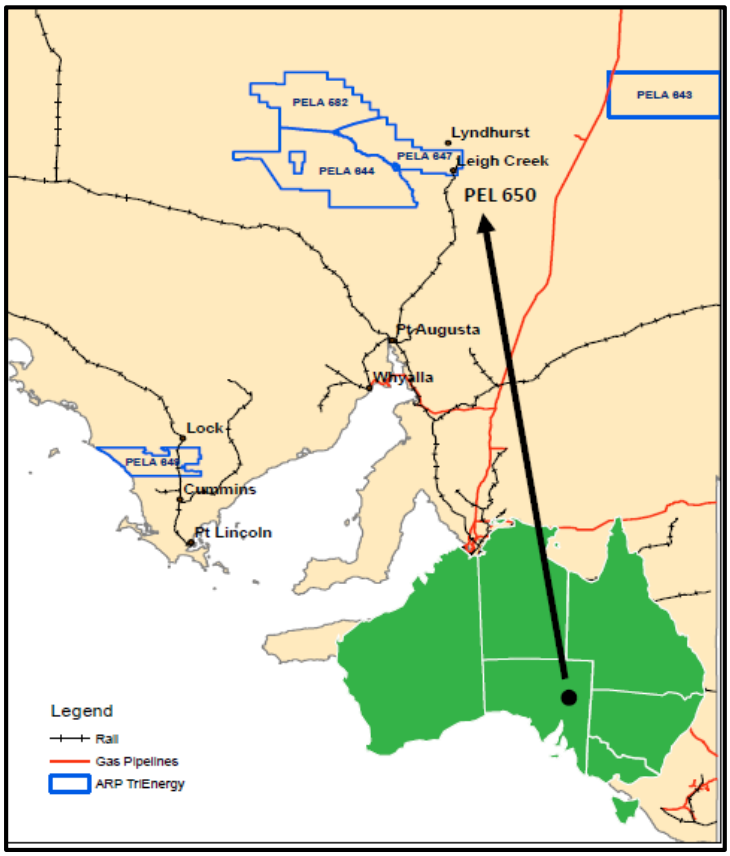
Background

Leigh Creek Energy Limited (ASX:LCK) is an emerging gas company focused on developing its 100% owned Leigh Creek Energy Project (LCEP), located at Leigh Creek, 550km north of Adelaide in South Australia. LCK - previously ASX-listed Marathon Resources Ltd - acquired the Project through the scrip acquisition of project owners, ARP TriEnergy Pty Ltd, in June 2015 (consideration: 138.3m LCK shares with a deemed value of A$27.6m, plus a royalty stream on production). The company changed its name to Leigh Creek Energy Limited after a shareholder vote in August 2015.

The Project's key asset is some 2,964PJ of recoverable in-situ synthetic gas (syngas) Resources (2C) contained within 377Mt of JORC 2012-compliant Inferred coal Resources. The gas Resource (Petroleum Resource Management System [PRMS]-compliant) is located within the 93.4km^2 Petroleum Exploration Licence PEL 650, which overlays Alinta Energy's Leigh Creek open-cut coal mine. Large-scale coal mining at Leigh Creek stopped in November 2015, and operations are currently limited to minor surface mining relating to rehabilitation. The captive Port Augusta coal-fired power stations fed by the Leigh Creek Coal Mine were shut in early May 2016.

LCK also holds (through 100% subsidiary ARP TriEnergy) extensive PEL application (PELA) tenements surrounding, and to the north and west of the Leigh Creek mine (PEL 650) as well as some EL's north of Leigh Creek (EL 5596 and EL 5597).

Figure 13: Location of LCEP and other licences



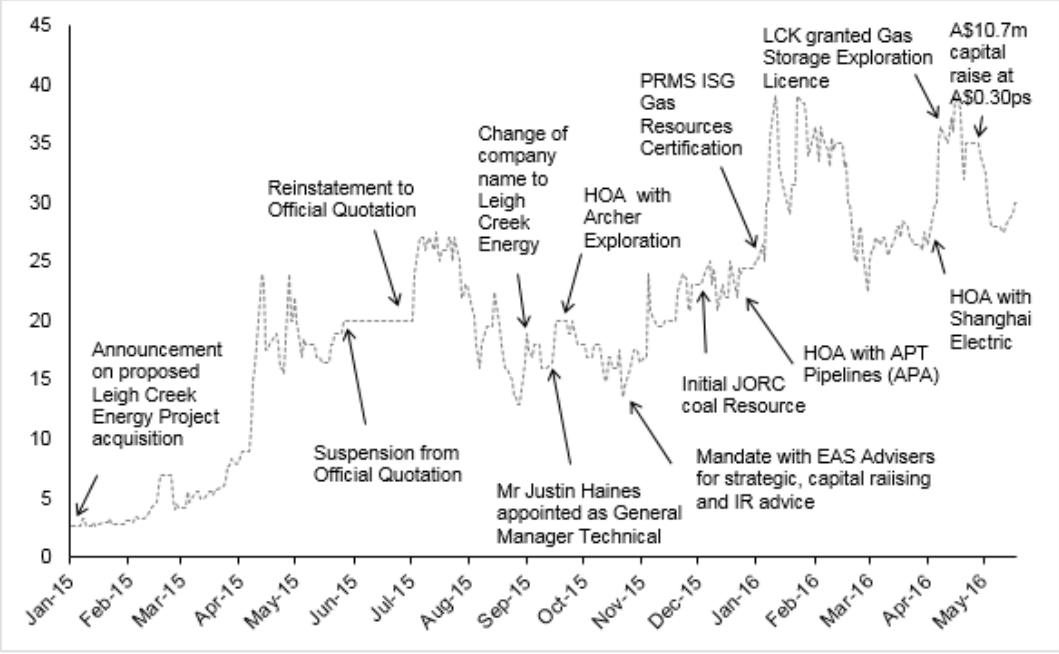
Source: Company

LCK has extensive PELA tenements in addition to the Leigh Creek PEL (PEL 650)

Since acquiring the Leigh Creek Energy Project in mid-2015, LCK has progressed on a number of key commercial, geological, and managerial /technical developments; this pro-active stance has seen LCK's share price double from ~A$0.20 to (a high of) ~A$0.40ps over the past six months.

- The appointment in September 2015 of Justin Haines as General Manager Technical; Mr Haines worked as Technical Manager for Carbon Energy (ASX:CNX), an ISG-technology company which operated one of only three UCG pilot plants in Australia.
- A mandate signed in October 2015 with EAS Advisors LLC (New York, USA) for strategic, capital raising and IR advice.
- The announcement in December 2015 of a JORC 2012-compliant maiden Inferred Resource of 377Mt of coal, followed by gasification test work on coal samples, and a subsequent PRMS-compliant estimated gas Resource (2C) of 2,964PJ in January 2016.
- A non-binding Heads of Agreement (HOA) signed with APT Pipelines, a subsidiary of APA Group (ASX:APA), which will allow the development of conceptual plans for the interconnection of the LCEP via a new pipeline with the east coast (EC) gas markets.
- A HOA signed with Shanghai Electric Power Generation Group, to establish a joint venture company in South Australia, with the intent to build, own and operate a gas-fired power station.
- An initial five-year Gas Storage Exploration Licence (overlaying the Leigh Creek PEL 650), obtained from the Government of South Australia, Department of State Development; this gives LCK optionality between storing gas, or delivering gas to EC customers or a local power station (as per HOAs with APA and Shanghai Electric). It also allows sequestration of CO_2.

Figure 14: Share price history (A$c): January 2015-Present



Source: IRESS, Company, compiled by State One Stockbroking
Note: Events prior to 3 September 2015, refer to Marathon Resources Ltd (ASX: MTN)

Near-term objective: Gas Demonstration

LCK is targeting to produce syngas at the end of the fourth quarter of (calendar year) 2016 via a two to three month-long pre-commercial gas production demonstration. LCK is currently carrying out a base line environmental assessment (specifically water quality) at the proposed test-site, preparing engineering, scope of works, and tender documents to contractors, and engaging with relevant state government departments for approval. The objectives of the gas demonstration are:

- To demonstrate the ability to produce syngas; successful production should allow for the current Resource (2C) classification to be upgraded to Reserves,
- To get data on the minor constituents within gas composition , process control fundamentals, shutdown capabilities, and costs; all this data will ultimately feed into the process plant design,
- To demonstrate to stakeholders (government, community, investors) that ISG can be completed at the Leigh Creek site, safely and with minimal impact on the environment.

LCK is targeting Stage 1 gas production by the end of 2016…a test run for Stage 2 ISG commercial production

LCK estimates that total expenditure associated with the gas demonstration will be some A$18m (A$5m for site assessment, environmental base line studies, water monitoring wells, A$10m for plant and equipment, skids, thermal oxidiser, diesel storage, A$3m for admin and staffing).

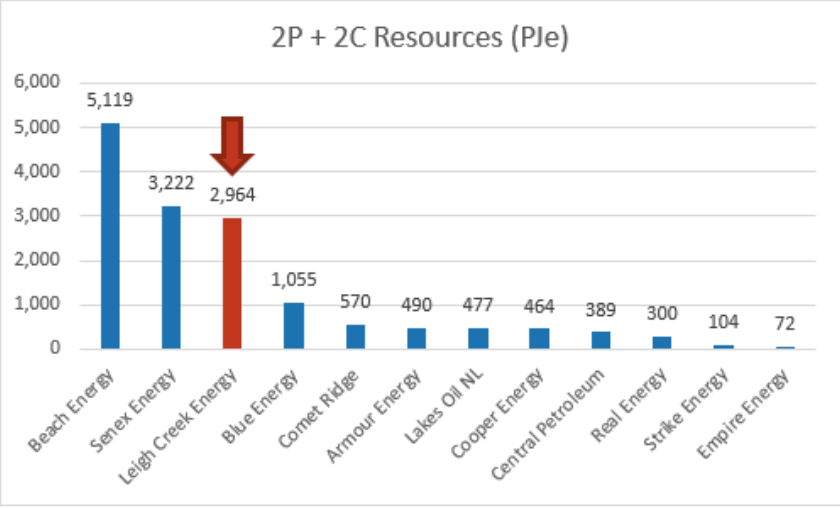
LCK carried out additional 2D seismic surveys in February 2016 to identify a suitable demonstration site; the surveys will also assist with new drill locations for Resource extensions. Management has stated that relatively few in-fill holes will be required to significantly increase the current coal Resource size (and a subsequent increase in gas Resource certification).

Medium-term objectives: Commercial Gas Production

LCK is in the fortunate position of having established a significant gas Resource at a time when 1) gas demand has tripled in the east coast market (see report section "Australia's gas market") and, 2) electricity supply interruptions in South Australia and rising electricity prices have prompted a relook of the state's energy mix for power generation.

LCK aims to monetise a significant gas Resource

Figure 15: Gas Resources PJ (2P+2C): small-mid cap gas developers



Source: Companies, State One Stockbroking

As a result, and concurrent with developing the Resource base and preparing for a pre-commercial gas production demonstration, LCK is actively pursuing a number of gas monetisation options including: asset sale / purchase of gas Resources in ground, purchase of equity in the LCEP, or some combination of the above. In addition, LCK is engaged in east coast market/customer studies and following-up on gas sales discussions with a number of EC gas buyers (industrial end-users, gas wholesalers/retailers, gas-fired electricity generators). The end-goal is to obtain binding long-term gas supply contracts. We suggest that separate HOAs recently signed with industry heavyweights, the APA Group and Shanghai Electric Power, indicate that there is significant (local and overseas) interest in LCK's energy offering.

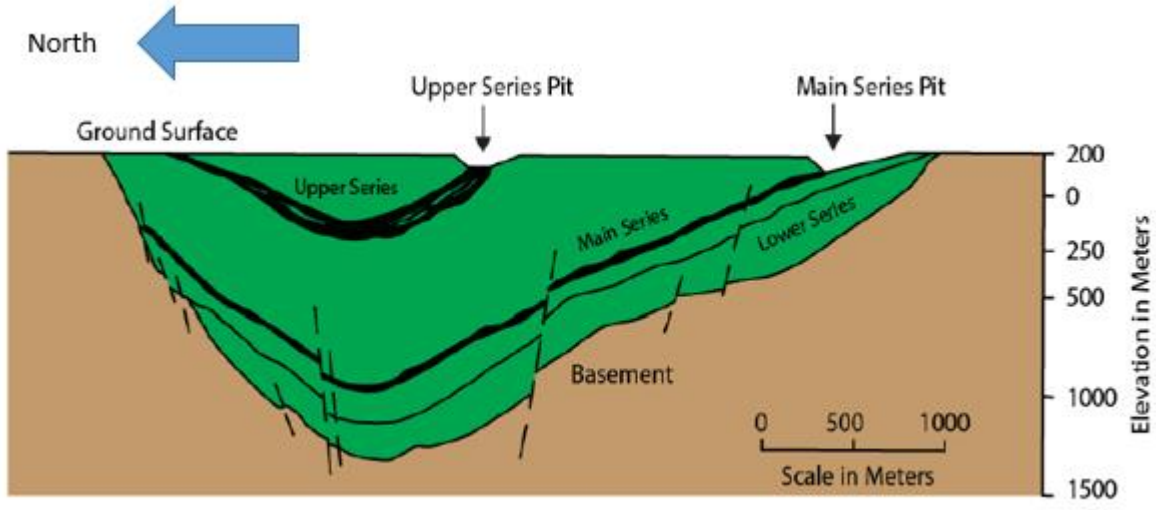
Management currently is investigating funding options and opportunities to enter into offtake agreements with gas buyers

Leigh Creek Mine

The Leigh Creek coal mine, closed November 2015, operated as a "captive mine", railing up to 2.5Mtpa of low-grade, sub-bituminous black coal 260km south to Alinta Energy's Port Augusta Power Stations (closed in early May 2016). The power stations, mining rights at Leigh Creek coal mine, and Leigh Creek town (population 500) are owned by the South Australian government but operated by Alinta Energy.

The coal occurs in several nested bowl-shaped seams, each several metres thick (the Main Series coal seam is up to 18m thick in the open cut mine).

Figure 16: Leigh Creek coal mine: schematic cross-section



Source: Company, State One Stockbroking

In December 2015, LCK announced a JORC 2012-compliant maiden Inferred Resource of 377Mt for the Leigh Creek coal mine. The Resource estimate was largely based on an extensive database of geological and drill-hole data provided by Alinta Energy. LCK management believe that significant Resource extensions can be achieved with a relatively small infill drilling and seismic survey programme.

LCK will be focusing its ISG activities on the deeper parts of the Upper seam, Main seam and Lower Series seam (with the upcoming pre-commercial gas production demonstration likely to be located at a depth of ~500m south of the Main Series Pit). At these levels, gasification rates should benefit from coal seam thickness and increased hydrostatic pressure.

Note: A prior study of Leigh Creek coal by Golder Associates in 1985 confirmed the suitability of the deposit (seam thickness, seam continuity, roof rock competence, ground water movement etc) for ISG

Mining at the Leigh Creek Coalfield has been going on for over 100 years intermittently and permanently since the 1940's till the recent mine closure. However, except for some limited grading of waste heaps, the 7.5km x 4.5km mine site (Telford Basin) is largely un-rehabilitated. The site is excluded from the Mining Act of 1971, and neither past or current licence holders are liable for having to carry out more extensive rehabilitation activities, i.e., drainage control (surface water and groundwater), return of overburden and/or topsoil preservation, contour ripping, seeding with native vegetation, grading, sediment control, mine subsidence evaluation, dust control, solid waste control, infrastructure reclamation, etc.

Leigh Creek Coalfield, which closed in November 2015, operated for over 100 years

See photographs below of the Leigh Creek mine taken on a 16 March 2016 site visit; the photos show the (largely) un-rehabilitated nature of the site.

Figure 17: Main Pit (looking south)

Photo: State One Stockbroking

Figure 18: The end of mining operations at Leigh Creek coal mine

Photo: State One Stockbroking

Figure 19: Sealed road approach to mine showing graded waste heaps

Photo: State One Stockbroking

Below is a photograph of the countryside – barren, scrubby, sparsely populated, no arable farming, limited grazing potential; typical of the area surrounding the mine site.

Figure 20: A long way from the Darling Downs!

Photo: State One Stockbroking

Government and Social

At present, there are a number of moratoriums and/or restrictions impeding or preventing coal seam gas (CSG) development in NSW, Victoria, and Tasmania. In the Northern Territory, the Labor opposition is threatening its own moratorium on unconventional gas extraction if it wins the upcoming state election (on 27 August 2016). On April 18 2016, the Queensland government issued a total ban on ISG development stating its incompatibility with the state's environmental and economic needs.

The Queensland government's negative stance towards ISG also stems, we suggest, from the state's unwillingness to have competing gas-extraction technologies competing over, and looking to exploit, the same coalfields. In effect, the Queensland government, not surprisingly in our view, favours more established CSG developers to supply Gladstone's massive (1,500PJpa) CSG-based LNG sector.

In comparison to Queensland, South Australia, has a far smaller coal resource to exploit. The Leigh Creek coalfield is self-contained, is remote from major centres, in a largely un-rehabilitated pre-existing mine site with little surrounding agriculture, and critically, lies outside (to the south) of the State and Federal "legislatively sensitive" Great Artesian Basin. In addition, the Leigh Creek coal is not associated with CSG (the coal does not contain methane which can be readily released). We believe that with the recent closure of the Port Augusta coal-fired power station, ISG will represent the only opportunity to monetise the Leigh Creek coal resources.

The South Australian government is, we believe, committed to the responsible development of state natural resources, including ISG (note: ISG is specifically contemplated and supported by the state's Petroleum & Geothermal Energy Act). SA's 2012 Unconventional Gas Policy states that "(environmental issues) can be mitigated through careful project design, site selection and monitoring" and "ISG has enormous potential for harnessing the energy of coal resources that would otherwise be too expensive or difficult to reach".

The PGE Act allows for incremental approvals and progress, while the SA Department of State Development (DSD) has a clear process - comprising 1) licencing, 2) environmental assessment, and 3) activity notification and approval – that should, in our view, facilitate project development.

Outside of offering the potential to contribute to the state's primary (gas) and secondary (electricity) energy supply, the development of the LCEP would contribute to the state's revenue base (State One estimated LOM tax receipts of ~A$1.8bn), and create much-needed jobs. The unemployment rate in SA is some 7.2 per cent, up 1.7 per cent over the last five years, whereas Australia's (in total) has risen to some 5.8 per cent, up by 0.9 per cent. The closure of the Leigh Creek coal mine and Port Augusta power stations, and the uncertainty surrounding the Whyalla steel mill, add to the pressing need to find new regional employment opportunities.

Most importantly, it is now likely that South Australia will suffer unreliable electricity supply on high power demand days when wind is not blowing.

The future of the Leigh Creek town is, we suspect, of particular concern to the SA government. The town (20km south of the coal mine) is operated by Alinta, and forms a key service hub, particularly for education & health, for the north-central region of the state. While Alinta is required to fund town services (water, sanitation, lights, maintenance) and provide subsidised accommodation for ex-employees for two years after the mine closure (at an

South Australia – a supportive environment for unconventional gas development

SA Department of State Development

- Well organised administration
- One-Stop-Shop
- Inter-departmental agreements
- Designated response times

Increasing need to find long-term quality employment opportunities in regional SA, and for the residents of the Leigh Creek town in particular

estimated cost of A$15mpa), the town's longer-term future is uncertain. We believe that the government would be supportive of a company which could provide employment opportunities to the town's population, and help maintain the town's key regional position.

Fraser Institute: Global Petroleum Survey 2015

The Fraser Institute (Canada) carries out an annual survey of petroleum industry executives and managers regarding barriers to investment in oil and gas exploration and production facilities in various jurisdictions around the globe. These barriers, as identified by the survey respondents, include high tax rates, costly regulatory obligations, and uncertainty over environmental regulations, interpretation and administration of regulations governing the upstream petroleum industry, and concerns with regard to political stability and security of personnel and equipment. Results from the 2015 survey are summarised below.

Of 14 jurisdictions with **large petroleum Reserves**, the five that rank as most attractive/least deterrent to investment are Texas, United Arab Emirates, Alberta, Qatar, and Kuwait. The five least attractive of the large-Reserve jurisdictions for investment on the basis of their Policy Perception Index scores (Libya, Venezuela, Russia-Other, Iran, and Iraq) account for over half of the proved oil and gas reserves all the jurisdictions included in the survey.

In the group of 38 jurisdictions with **medium-sized Reserves**, the 10 most attractive jurisdictions are: Oklahoma, North Dakota, Norway-North Sea, West Virginia, Louisiana, Norway-Other, Wyoming, US Offshore-Gulf of Mexico, United Kingdom-North Sea, and Pennsylvania. Syria, Ecuador, Ukraine, Indonesia, and Yemen, appear to pose the greatest barriers to upstream investment among medium Reserve-size holders

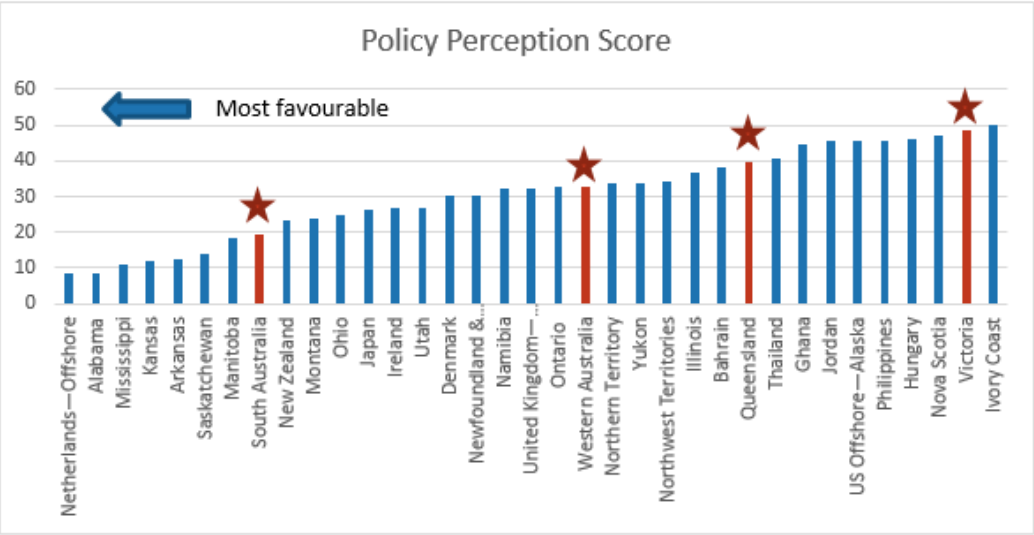
Of **66 jurisdictions with relatively small proved oil and gas Reserves**, the top 10 performers are Netherlands—Offshore, Alabama, Mississippi, Kansas, Arkansas, Saskatchewan, Manitoba, **South Australia**, New Zealand, and Montana. Those in this group deemed the least attractive for investment on the basis of poor Policy Perception Index scores are: US Offshore—Pacific, Bangladesh, Timor Gap (JPDA), Myanmar, and Argentina—Mendoza.

South Australia:

In the top -10 global jurisdictions with relatively small oil & gas Reserves….

…significantly ahead of Western Australia, Queensland, and Victoria

Figure 21: Fraser Institute 2015 Survey results (top-35 in small Reserve jurisdictions)



Source: Fraser Institute, compiled by State One Stockbroking

Board and share register

We note that Justyn Peters (Executive Chairman) and Justin Haines (GM Technical) have wide experience in the ISG sector through their previous roles at Linc Energy and Carbon Energy respectively.

Managing Director David Shearwood has extensive experience in finance, fund management, and investment. Mr Shearwood is a significant shareholder (10.3%) in LCK through 186,000 shares held directly in this name, and a 22.47% interest in the 104.8m shares belonging to ARP.

Of the 266.4m shares currently on issue (post-April 2016 capital raise), some 52% or 138.3m shares in total are held in escrow (33.5m until 4 July 2016, 104.8m until 4 July 2017). As a result, only 126.5m are currently available for trade.

Board and management have significant ISG experience

LCK shares – low liquidity

Figure 22: Board and management

Name	Title	Profile
Justyn Peters	**Executive Chairman**	Lawyer, former experienced Senior Manager with Linc Energy and Queensland Government and Federal agencies. Representative of ARP
David Shearwood	**Managing Director**	Mining engineer, post graduate qualifications in finance and HR. 30 years experience in funds management and investment banking. Representative of ARP
Greg English	**Non-Exec Director**	Mining Engineer and lawyer, with experience at Leigh Creek coal mine and with oil and gas contracts
Phil Staveley	**CEO and CFO**	CPA. 30 years experience in energy and resources, 15 years experience in CFO / CEO positions in Australia and Overseas. Formerly with Schlumberger, Normandy Mining and Centrex Metals.
Justin Haines	**GM Technical**	Mining engineer, Geologist, Project engineer. Formally head of technical with Carbon Energy Limited (CNX), who successfully demonstrated ISG in Australia
TBA	**Non-Exec Director**	*Pending*
TBA	**Non-Exec Director**	*Search underway – energy construction experience*

Source: Company

Figure 23: Share register

Shareholder	#	%	Escrow	Details
Allied Resource Partners Pty Ltd ("**ARP**")	104,767,190	45.45	**Yes**	2 years till 4 Jul 2017 [15 months away]
Former ARP TriEnergy shareholders ("**TriE**")	33,544,493	14.55	**Yes**	1 year till 4 Jul 2016 [3 months away]
CITIC	17,242,855	7.48	No	
Other	73,964,934	28.62	No	~25m (1/3rd) held by TriE shareholders after buying post re-listing
Total	**230,519,472**	**100.00**		

Source: Company Presentation (mid-April 2016)
Note: Share register details pre April 2016 capital raise and pre treasury share buy buck

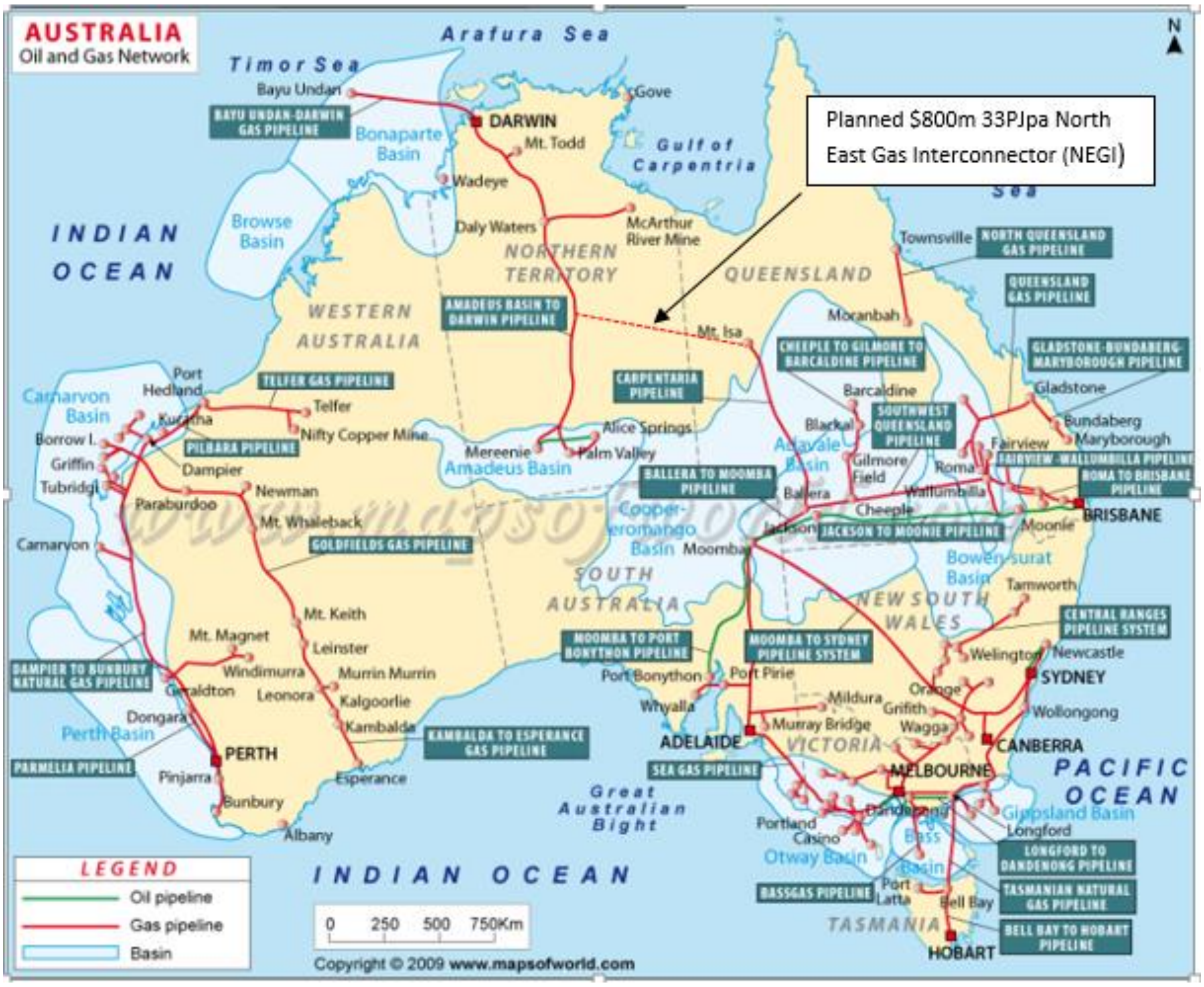
Australia’s gas market

Domestic market

Due to lack of interconnectivity, Australia’s domestic gas market is divided into a western market (Western Australia), the Northern territory, and an east coast (EC) market - often referred to as the national gas grid - comprising the eastern states of Queensland, NSW, Victoria, South Australia, and Tasmania. After completion of the 30PJpa North East Gas Interconnector (NEGI) in 2018, the Northern Territory will be connected to Mt Isa in Queensland, effectively integrating the NT into the EC gas market.

East Coast (EC) market is entirely separate from Western Australia

Figure 24: Australia – Oil and Gas pipeline network



Source: www.mapsofworld, State One Stockbroking

Total Australian domestic gas consumption in 2014 was some 1,270 petajoules (PJ) with the EC gas market accounting for some 685PJ (54%) and Western Australia accounting for 530 PJ (42%).

Looking specifically at the domestic EC market, Queensland accounts for some 36% of demand (250PJ), followed by Victoria 31% (210PJ), NSW 20% (140PJ), SA 11% (75PJ) and Tasmania 1% (10PJ).

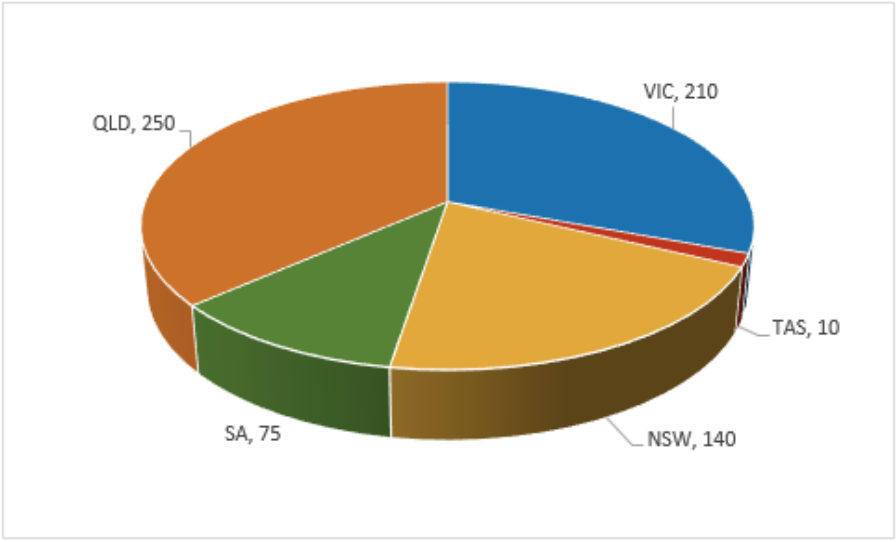
The industrial sector accounts for 44% of EC domestic gas use, the gas-powered generation (GPG) sector 30%, with the residential & commercial

(R&C) sector accounting for some 26% of gas consumption. There is, however, a wide variation in the consumption of gas in these sectors between each state, reflecting both the overall size of the sectors in each state, and the level of competition between gas and alternative fuels.

Forecasts from the Australian Energy Market Operator (AEMO) - incorporated into the Australian Government, Gas Market Report 2015 - indicate that EC 2014-2024 domestic gas demand is expected to fall in response to 1) a decline in demand from energy-intensive manufacturing sectors on rising wholesale gas prices and, 2) an overall decline in NEM electricity demand with gas-powered electricity generation (GPG) falling the most, squeezed between lower cost coal-powered electricity generation and a higher contribution from government-mandated renewable energy (wind, solar).

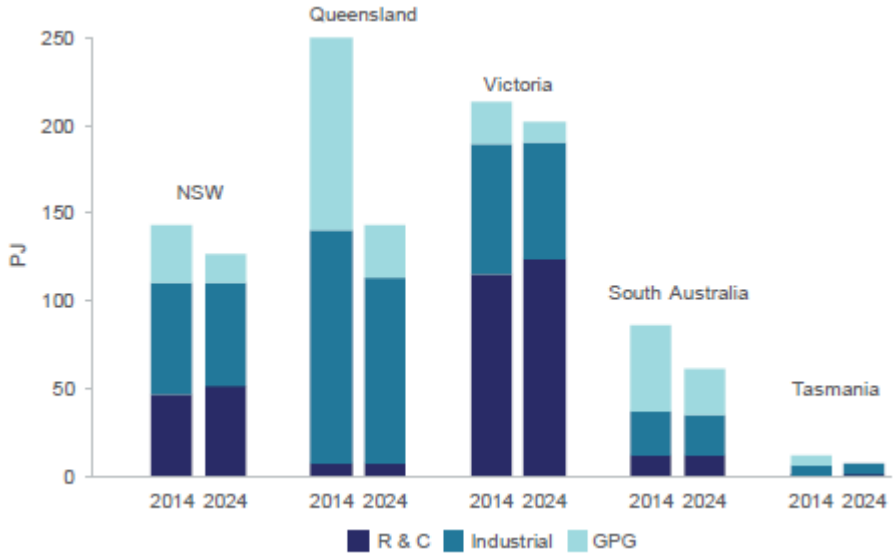
Domestic east coast (EC) market: ~ 700PJpa, but forecast to fall by ~150PJ by 2024

Figure 25: 2014 East Coast (EC) domestic gas consumption by state (PJ)



Source: Australian Government, Gas Market Report 2015, State One Stockbroking

Figure 26: EC gas demand by sector (PJ)



Source: Australian Government, Gas Market Report 2015, State One Stockbroking

Impact of LNG production on EC gas demand

We calculate that the three Queensland LNG plants (GLNG, QCLNG, and APLNG), will require some 1,600PJ of gas per annum when operating at their combined full annual production of 25.3Mt of LNG which occurs from late 2016.

Figure 27: Queensland LNG capacity and gas feedstock requirement

Plant (Owners)	LNG Capacity (Mtpa)	Required gas feed (PJpa)	Status
Gladstone LNG (Santos, Petronas, Total,Kogas)	7.8	493	1 train operating, 2nd train to start
Queensland Curtis (BG, CNOOC)	8.5	538	2 trains operating
Australia Pacific LNG (Origin,Conoco Phillips,Sinopec)	9.0	569	1 train operating, 2nd train to start
Total	**25.3**	**1,600**	

Source: Companies, State One Stockbroking

Note: 1Mt LNG = 55PJ gas. We assume gas requirement will be closer to 63PJ per 1Mt of LNG (+15%) after accounting for extraction, transmission and liquefaction gas losses.

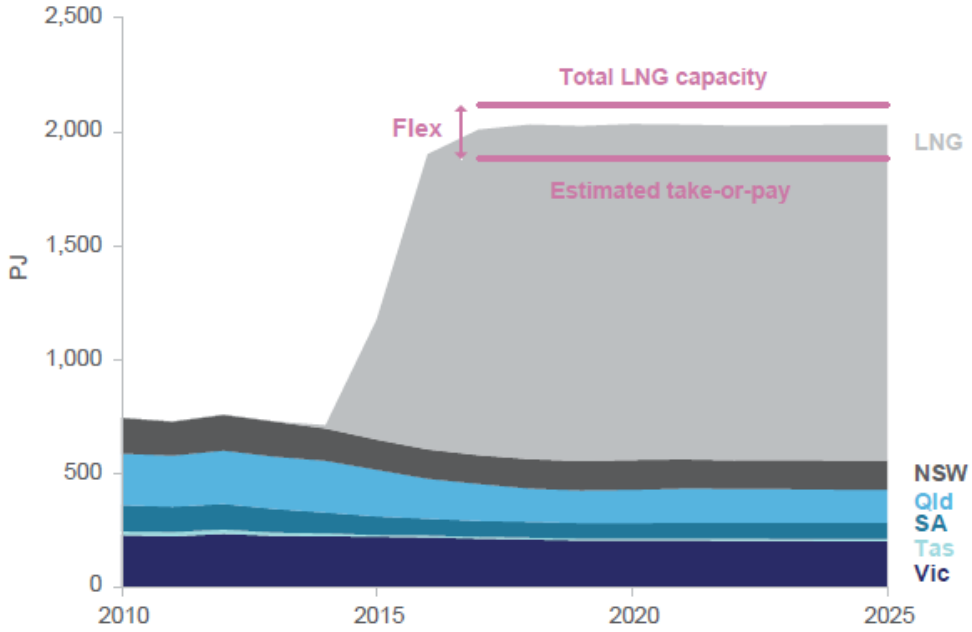
Note: In January 2015, Shell announced that - due to the oil/gas price slump - it had formally abandoned plans to build a US$20bn 8Mtpa LNG plant at Gladstone. Shell/PetroChina is currently deciding on what to do with its coal seam gas (CSG) Resource, but one option could be to supply gas initially earmarked for its Arrow LNG plant, to one or more of the other three LNG plants already up and running.

As a result, and despite an anticipated decline in domestic gas demand out to 2025, total EC gas demand is forecast to rise significantly to ~2,100PJ from 2016/2017.

Because of the lack of interconnectivity to the natural gas-fields off-shore Western Australia and the Northern Territory, this increase in gas demand will have to be sourced from EC gas supplies, and particularly from the Resources of coal seam gas (CSG) belonging to the LNG JV partners.

Ramp up of LNG plants will increase total east coast gas demand to ~2,100PJpa

Figure 28: Forecast EC gas demand (LNG versus domestic)



Source: Australian Government, Gas Market Report 2015 (Original Source: AEMO (2014))

Gas prices: EC market

The EC gas market for large industrial customers is dominated by volume/quantity contracts, usually with take-or-pay provisions. This provides the certainty for producers and pipeline operators to undertake the large capital investment that is needed to bring on supply. The model also ensures certainty of supply for users to underpin their own investment decisions. Historically, price direction has been driven by a cost-plus formula, adjusted for domestic inflation (specifically energy inflation).

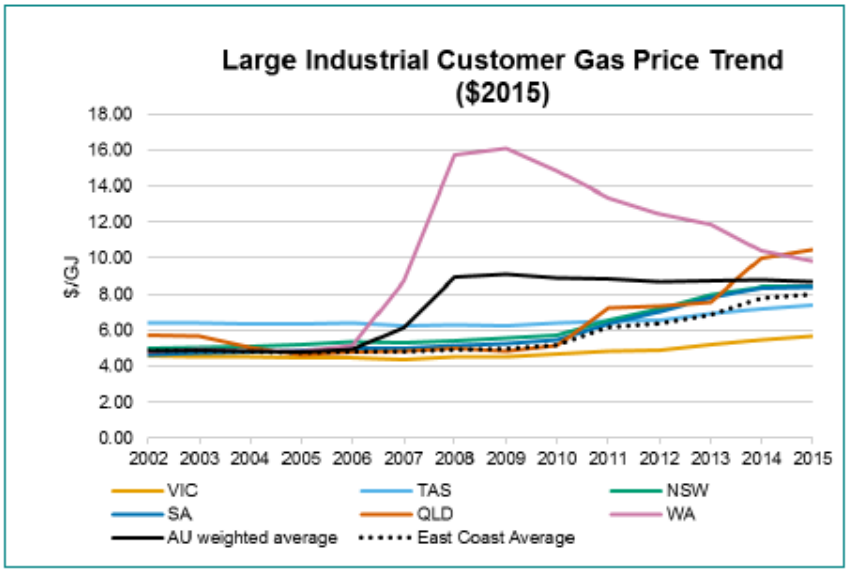
After a period of (inflation-linked) price stability between 2000 and 2010, average prices increased significantly (+70%) from ~A$5/GJ in 2010 to ~A$7/GJ in 2015. Some of the more important inter-related drivers behind the sudden acceleration in the price environment are listed below:

- supply/demand imbalances - particularly in late 2015 - with LNG producers augmenting ramp-up CSG with conventional gas,
- the unwinding of long-term (and low-priced) legacy contracts,
- an increasing cost-base with higher-cost coal seam gas (CSG) from the Surat/Bowen supplying a greater percentage of the overall gas mix,
- a long-term decline in supply from traditional sources of (cheaper-cost) conventional gas, i.e., the Cooper Basin,
- the "quarantining" of CSG Reserves (particularly from 2010) in preparation for LNG production in 2015, and a concomitant move towards shorter, less flexible contracts,
- Increased buyer concern over gas supply.

The ramp-up of LNG exports in 2015/2016, and the substitutability between gas destined for export and gas for domestic is adding an additional complication - the "LNG netback price" - into the pricing dynamic. We believe that the introduction of what is effectively export parity pricing into the EC market is likely to put additional upward pressure on domestic gas prices.

Note: LNG netback price is calculated by subtracting downstream costs (gas transportation, liquefaction and shipment) from the LNG delivered price

Figure 29: Gas price trends (2002-2015)

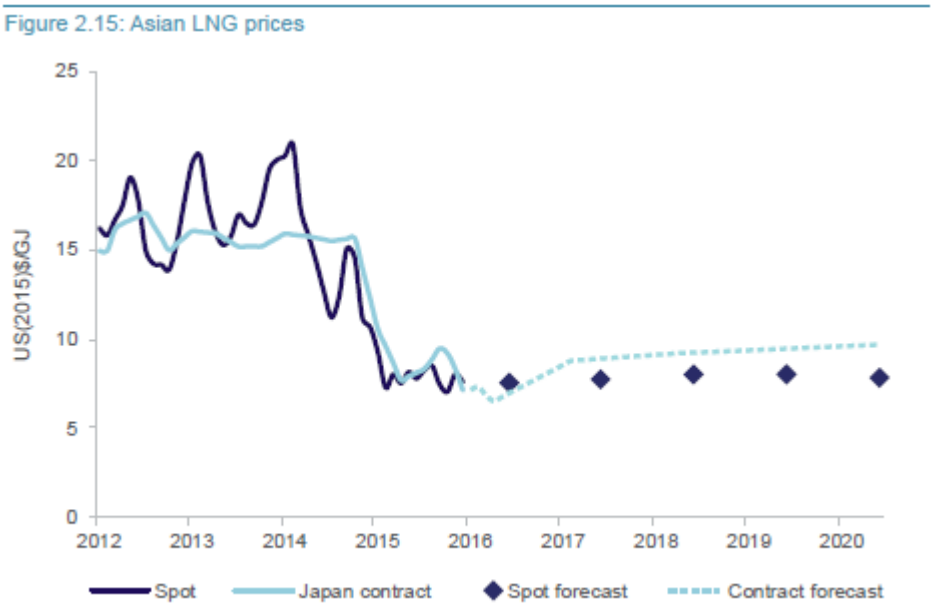


Source: Oakley Greenwood – Gas Price Trends Review, December 2015

LNG prices – potential to put pressure on domestic gas prices

Australia's LNG projects are substantially underwritten by long-term contracts with Asian customers at oil-linked prices. These contracts were largely signed between 2010 and 2012 when the oil (and hence LNG) price environment was significantly higher than present. In addition, a stagnant global economy and a surge in global LNG capacity has resulted in excess LNG supply capacity. As a result, there is additional price pressure on uncontracted volumes, and spot LNG prices are forecast to trade at a discount to contract prices for at least the next five years.

Figure 30: Forecast Asian LNG price profile (US$/GJ)



Source: Australian Government, Gas Market Report 2015 (Original Source: Various)

With one barrel of oil containing the calorific equivalent of around 6GJ of gas (6MMBtu), a ready reckoner - ignoring oil/gas slope factors - is to divide the oil price by six to get the equivalent calorific value of gas. For example, at a forecast long-term oil price of US$60/bbl, the long-term Asian-contract LNG price could approximate US$10/GJ (A$13/GJ at the current AUD:USD exchange rate). In this price environment, and relative to forecast domestic wholesale prices of A$7/GJ, one can see that gas sellers may prefer to target buyers in the LNG-producing sector. This could potentially put upward pressure on the domestic gas price environment. Even in the current depressed oil price environment of US$45/bbl, we believe that an LNG price of ~A$10/GJ could be attractive to gas suppliers (even after LNG netback deductions).

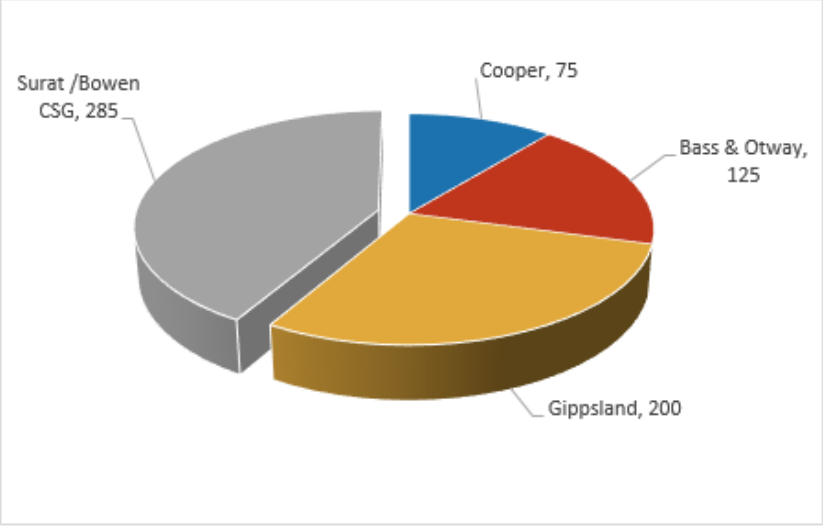
We note recent comments from EC manufacturers warning of the potential impact of oil-linked LNG prices on domestic gas prices. Andrew Liveris, the chief executive of Dow Chemicals, called for new controls on natural gas exports and policies to encourage more domestic consumption via investments in down-stream value-adding chemical manufacturing. Economists, as a whole, however appear to dismiss gas reservation for domestic use as a "protectionist" policy which will deny gas producers the highest value use of their gas, and undermine the economic wellbeing of the nation as a whole.

Note: The Gorgon and Wheatstone LNG Projects are obliged to supply gas into local markets under WA's gas reservation policy……east coast states have not adopted this stance

Supply/demand balance

Some 60% of the 685PJpa EC domestic gas market is met from conventional gas from the Cooper Basin (QLD, SA,) and the Gippsland, Otway and Bass Basins (offshore Victoria), with 40% of demand met from CSG ex the Surat/Bowen Basins in Queensland.

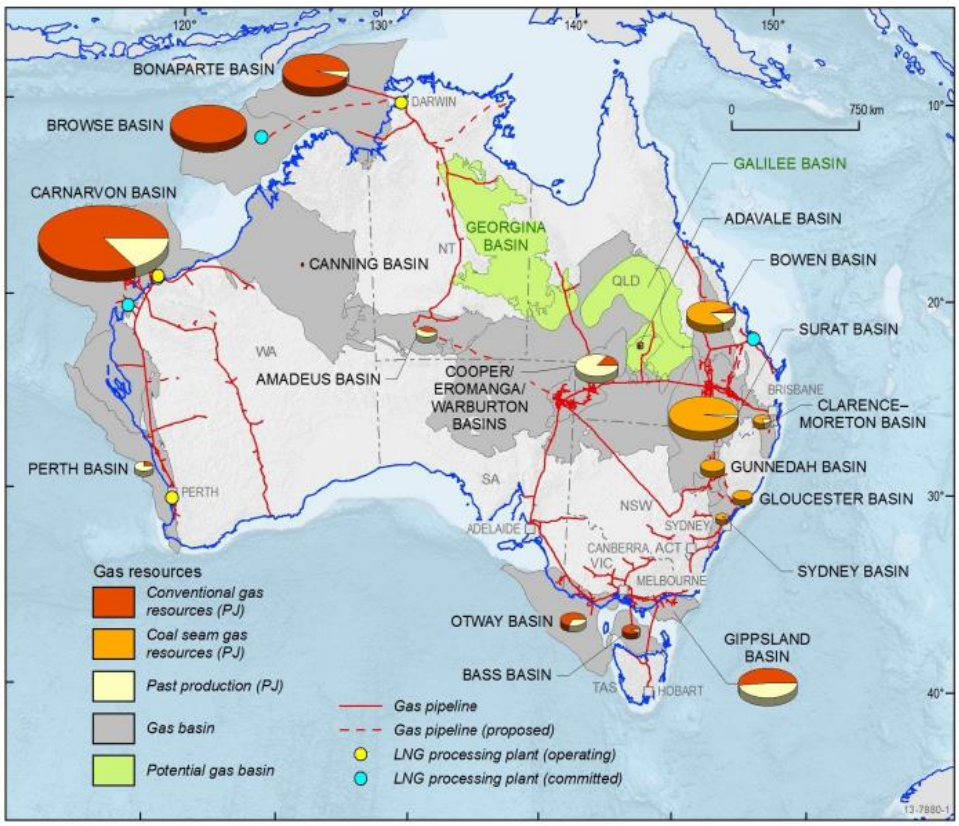
Figure 31: EC sources of gas supply (PJ)



Gas supply for the EC domestic market is split roughly 60:40 between conventional natural gas and CSG

Source: Australian Government, Gas Market Report 2015 (Original Source: Various), State One Stockbroking

Figure 32: Location of Australia's gas resources



Source: Australian Government, Eastern Australian Domestic Gas Market Study, 2013

Predicated on forecast total (domestic and LNG) EC gas demand of 2,100PJpa from 2016/2017, we calculate that proved and probable (2P) Reserves of some 42,000PJ are required to meet domestic requirements and effectively underwrite 20 years of LNG production (at current capacity). The 20-year time frame is important as the LNG JVs have all entered into long-term (~20 year) contractual obligations with overseas LNG buyers.

Estimates from AGRA (Australian Gas Resource Assessment, 2012) and RLMS (Resource and Land Management Services, 2013) contained in the Australian Government, Eastern Australian Domestic Gas Market Study 2013, indicate total EC 2P Reserves of ~45,000PJ with some 31,000PJ of additional contingent (2C) Resources.

Thus, on the face of it, the East Coast market looks to have sufficient Resources to meet domestic and export needs.

Figure 33: EC gas Reserves and Resources (PJ)

	2P	2C	2P+2C	%	%	%
Conventional gas - Offshore Victoria	5,785	3,247	9,031	13%	10%	12%
Conventional gas - Onshore SA/QLD	1,803	2,550	4,353	4%	8%	6%
CSG - QLD	37,311	25,340	62,651	83%	81%	82%
Total	**44,898**	**31,136**	**76,034**	**100%**	**100%**	**100%**

Source: Australian Government, Eastern Australian Domestic Gas Market Study, 2013 (Original Source: Various), State One Stockbroking

Note: Excludes CSG Resources from New South Wales (~2,850PJ 2P in 2012/2013) due to a State ban on fracking

Note: Offshore Victoria conventional gas Resources comprises the Gippsland Basin (80%), Otway Basin (16%), Bass Basin (4%). Onshore South Australia/Queensland comprises the Cooper/Eromanga/Warbuton Basins (80%), and the Surat/Bowen/Adavale Basins (20%)

However, we believe it important to note that some 83% of the EC gas Reserves are CSG Reserves in Queensland's Surat and Bowen Basins. While the technology underpinning CSG production is well established, Australia's east coast LNG projects are a world-first. No other country has developed unconventional gas-dependent LNG capacity (25Mtpa) to this scale. We believe there could be operational/production/output risks associated with the ability of CSG fields to provide gas feedstock to the LNG plants, at a consistent and predictable pressure, over a long (+20-year) time-frame. To mitigate this risk, we believe that each LNG producer will look to diversify their feedstock sources.

Development of Arrow's 10,000PJ of gas is key to meeting EC gas demand…..this will require agreement between joint owners Shell and PetroChina

Feedstock to augment LNG producers own "captive" Reserves include:

- CSG Reserves belonging to peer LNG producers (note: this will require a lot more co-operation than currently exists between the LNG producers),
- Queensland CSG Reserves belonging to non-LNG producers (note: this is effectively Shell/Sinopec's 10,000PJ via Arrow Energy, with other (much-smaller) Reserves owned by Senex, Blue Energy etc),
- Conventional gas Reserves and,
- New sources of third party gas (i.e. from LCK).

While, the East Coast market appears to have sufficient gas to meet domestic and export needs, there are a number of caveats.

Adequate supply assumes that undeveloped gas Reserves and contingent and prospective Resources are brought into play. There is, as usual, technical (geology, recovery) risks associated with this process. In addition, the low oil price environment is impacting revenue streams and capital budgets, leading to a heightened risk that some conventional gas resource development (in combined oil/gas fields) may not be commercially viable, or postponed.

A significant portion of the total east coast 2P Reserves is controlled by Arrow Energy. If oil prices recover (we estimate to US$80/bbl), JV partners Shell and PetroChina may elect to revive plans for the 8Mtpa Arrow LNG Project (abandoned in January 2015). This would effectively remove 10,000PJ of 2P Reserves from the market and significantly tighten the supply/demand balance.

Although we estimate that aggregate 2P Reserves of ~45,000PJ is enough to meet aggregate 20-year EC gas demand, we believe that there are individual companies which are particularly keen to resolve medium-to-longer term supply issues.

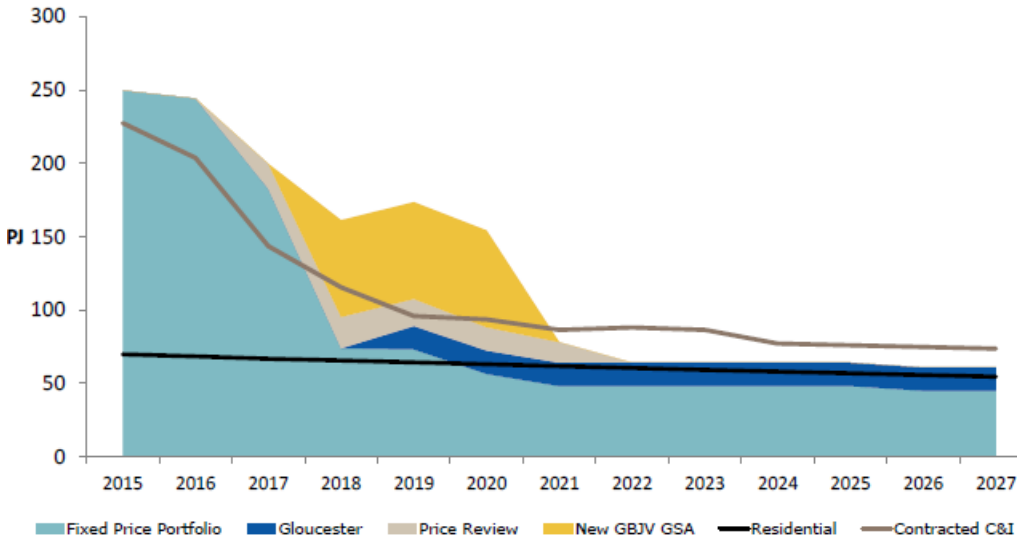
Santos's (ASX:STO) current CSG Reserves (2P) of some 5,700PJ is significantly lower than the estimated 9,800PJ of gas required to supply the 7.8Mtpa Gladstone LNG Plant over a 20-year time horizon. While, the GLNG Project (like any other LNG Project) does not require all the gas at once, to meet 20-years of gas requirements, we imagine that a development such as Shell/PetroChina restarting plans for ALNG could be of particular concern to STO.

Santos needs to prove up Resources to meet its LOM gas demand

AGL Energy's (ASX:AGK) decision in 2015 to abandon gas exploration and development in NSW, largely due to political headwinds against CSG exploration, means that one of Australia's largest gas buyers (FY2015: 237PJ) is heavily exposed to third party gas supplies. As illustrated in the chart below, some 130PJ of Consumer and Industrial (C&I) customer gas contracts are up for renewal from 2019, with current contracted gas supply short by some 50PJ.

AGL now almost wholly dependent on third party gas supply

Figure 34: AGL Contracted Supply – maximum annual quantity



Source: AGL Energy (2015 Annual Results Presentation)

In-Situ Gasification (ISG)

Underground Coal Gasification (UCG) or In-Situ Gasification (ISG) is the process by which coal is converted to gases in-situ (i.e., while the coal is still underground) via controlled partial combustion. ISG can be used to monetise coal resources that are either uneconomic to mine by conventional open cut or underground coal mining methods, or are inaccessible due to depth, geology or other mining and safety considerations.

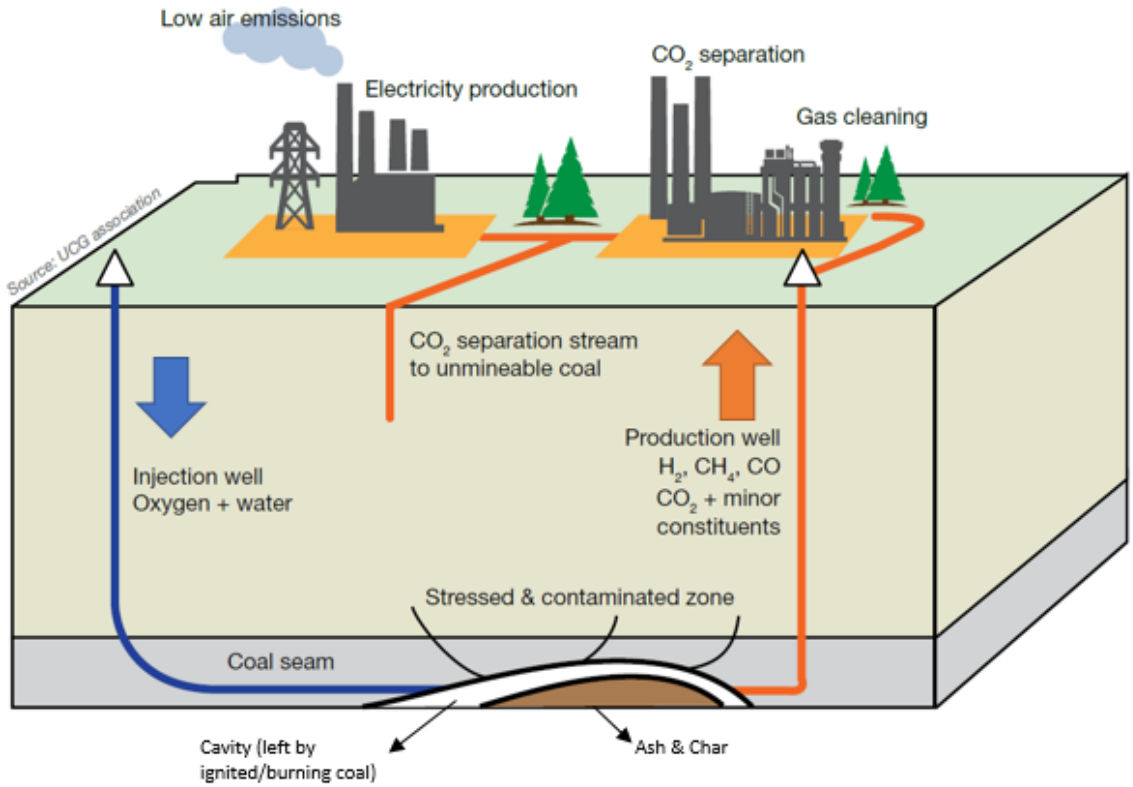
Underground Coal Gasification (UCG) and In-Situ Gasification (ISG)……different terms for converting underground coal to gas

ISG is a very different process from that used to extract coal seam gas (CSG). ISG involves converting coal to a synthesised gas (syngas) - a mixture of hydrogen, carbon monoxide, carbon dioxide, methane, water vapour - via enforced partial combustion. This syngas is then brought to surface, where it can be fully cleaned and processed to a synthetic natural gas (methane) or partially cleaned to feed modified gas-powered electricity generators. In comparison, the CSG process involves dewatering coal seams to release coal seam gas (which is primarily a naturally occurring methane gas).

Process

ISG typically employs a minimum of two wells (an injection well and a production well) partly drilled into coal seam, often with a separate ignition well. A gasifying agent (air, oxygen enriched air, possibly with added steam) is supplied via the injection well to the underground gasification chamber (section of partially ignited coal bed), and the resultant syngas is extracted via the production well to the surface for treatment and use.

Figure 35: Schematic diagram of traditional vertical well UCG process



Source: UCG Association, State One Stockbroking

Although ISG is conceptually very simple, the development of a working system has proved more difficult in practice. The main problems are accurate in-seam drilling, controlling the reaction within the seam, producing a consistent gas quality, and environmental concerns (particularly underground water/aquifer contamination and geotechnical stability). Meaningful experiments cannot be carried out in the laboratory, resulting in the need for expensive and time consuming gas (flare) demonstration trials. Comprehensive site and safety/environmental studies and economic evaluations are also required to convince financial investors, and permitting authorities to support commercial projects. Pleasingly for ISG the science of coal gasification is well understood and all surface equipment for gas clean-up is standard and readily available.

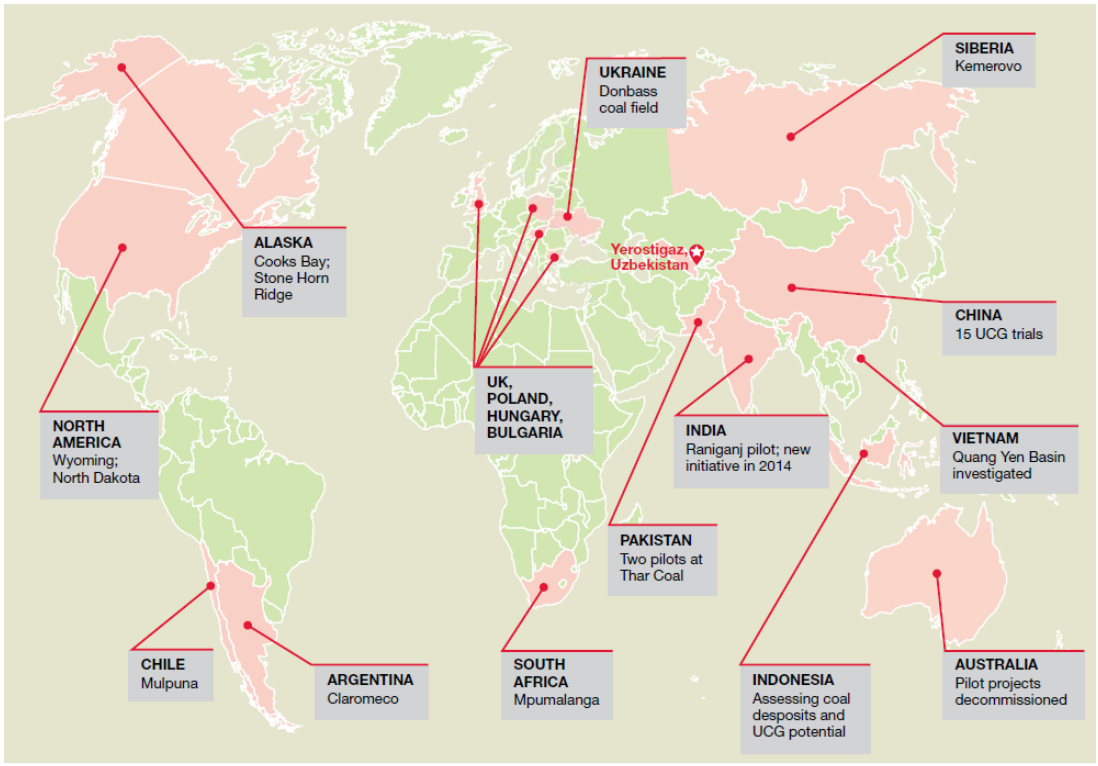
Projects: limited number of operations globally

Few operational ISG plants in the world….but numerous developments

The only commercial UCG facility currently operating in the world is in **Uzbekistan** where the Yerostigaz gasification plant (which uses Linc Energy's UCG technology) produces some 14PJpa of syngas (1 million m^3/d). After successfully completing a demonstration project, Swan Hills Synfuels is looking to develop a deep (1,400m) UCG project in Alberta, **Canada**, tied to a proposed 300MW combined-cycle power station. This project is on hold due to low gas prices in North America. A decision on commercialising a 100MW UCG-fired pilot plant at the 4,110MW Majuba power station in **South Africa** has been pushed out to 2017/2018 on permitting and operational concerns.

Nevertheless, development work on UCG Projects is taking place around the world as part of a broader global initiative to find clean-energy solutions and monetise stranded coal resources.

Figure 36: Worldwide ISG projects; a snapshot



Source: the chemical engineer (Feb 2014)

UCG in Australia

Over the past eight years, three separate UCG technology pilot plants were developed in Queensland: Cougar Energy's (now Moreton Resources ASX: MRV) Kingaroy Project, Singapore listed Linc Energy's Chinchilla Project, and Carbon Energy's (ASX:CNX) Bloodwood Creek Project.

- The Kingaroy Project was closed down by the QLD government in mid-2010 on the back of water tests which showed a single low benzene contamination result.
- Despite operational success, Linc Energy's Chinchilla Project was abandoned in November 2013 on the back of rising opposition from regional environmental and farming activist groups, and - according to Linc's Peter Bond - an apparent lack of support from a State government which seemed to favour the rival CSG industry. Linc Energy is currently being sued by the QLD government for causing environmental damage to a 175km^2 swathe of southern Queensland farmland. In a Magistrates hearing during early 2016 the Chief Scientist representing the Qld government agreed that chemicals recovered from soil were naturally occurring across the region and could not be attributed directly to Linc Energy.
- Carbon Energy's pilot plant at Bloodswood Creek has been dismantled and the area is currently being rehabilitated. Approval of the Decommissioning Report and Rehabilitation Plan for Bloodswood Creek was seen as a key step for the company to proceed with commercialisation of its Blue Gum Project in the Surat Basin (2P Reserves of 1,128PJ, 3P + 2C Resources of 13,810PJ). However, **in mid-April 2016, the Ministers for Natural Resources and Mining (DNRM) and Environment and Heritage Protection (DEHP), elected to place a complete ban on UCG in Queensland**. We suggest that CNX's Blue Gum Project is unlikely to be successfully developed anytime soon. Currently, CNX's primary focus is to commercialise its keyseam® USG technology via licencing agreements and JVs in China.

ISG pilot plants in Australia:

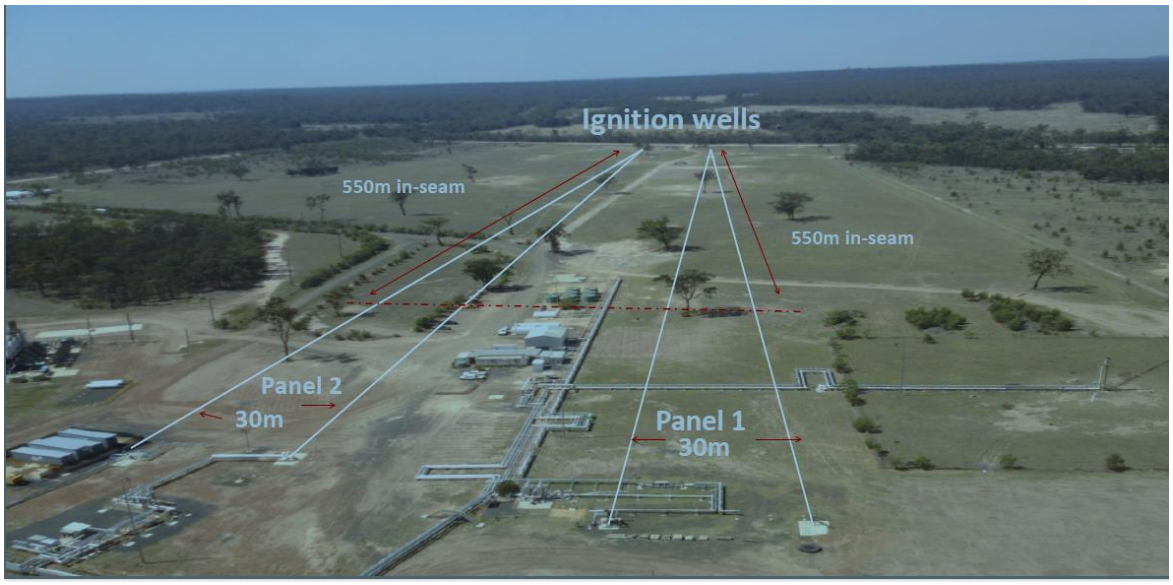
Cougar Energy

Linc Energy

Carbon Energy

…all in Queensland

Figure 37: Carbon Energy's Bloodwood Creek Pilot Site (as in 2012)



Source: Carbon Energy

General Advice Warning

The contents of this document have been prepared without taking account of your objectives, financial situation or needs. You should, before taking any action to acquire or deal in, or follow a recommendation (if any) in respect of any of the financial products or information mentioned in this document, consult your own investment advisor to consider whether that is appropriate having regard to your own objectives, financial situation and needs. Whilst State One Stockbroking Ltd believes information contained in this document is based on information which is believed to be reliable, its accuracy and completeness are not guaranteed and no warranty of accuracy or reliability is given or implied and no responsibility for any loss or damage arising in any way for any representation, act or omission is accepted by State One Stockbroking Ltd or any officer, agent or employee of State One Stockbroking Ltd. If applicable, you should obtain the Product Disclosure Statement relating to the relevant financial product mentioned in this document (which contains full details of the terms and conditions of the financial product) and consider it before making any decision about whether to acquire the financial product.

Disclosure

The directors and associated persons of State One Stockbroking Ltd may have an interest in the financial products discussed in this document and they may earn brokerage, commissions, fees and advantages, pecuniary or otherwise, in connection with the making of a recommendation or dealing by a client in such financial products. The Research Analyst who prepared this report hereby certifies that the views expressed in this research document accurately reflect the analyst's personal views about the company and its financial products. The research analyst has not been and will not be receiving direct or indirect compensation for expressing the specific recommendations or views in this report. This research at all times remains the property of State One Stockbroking Ltd. And as such cannot be reprinted, distributed, copied, posted on the internet, in part or whole, without written prior approval from the Executive Director of State One Stockbroking Ltd.

State One Stockbroking Ltd was Lead Manager (Australia) for LCK's April 2016 capital raise.

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

Peter Curtis
Head of Institutional Sales
Phone: +61 2 9024 9106
pcurtis@stateone.com.au

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

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

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

Peter Wong
Equities Advisor
Phone: +61 8 9288 3330
pwong@stateone.com.au

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

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

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

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

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

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

Robert Chen
Equities Advisor
Phone: +61 2 9024 9132
rchen@stateone.com.au