Research as a Service

Armour Energy

Scoping Paper

Setting the scene for growth

Energy

4 September 2020

Armour Energy Limited (AJQ.ASX) is a junior energy producer and explorer with assets across northern, southern and eastern Australia. The company has been listed on the ASX since April 2012. The opportunity set for Armour through FY21 has the capacity to materially reshape the company financially by delivering cash flow growth, reducing debt and progressing a range of exploration options. Although significant exploration drilling may not occur until the end of CY21 and into 2022, the company is likely to be in a stronger position to work its assets at its own pace and to its own plan. We will be looking for delivery of the Kincora production growth plan which aims to more than double production, to 20TJd and growing over the next 18-24 months.

Scope

This report has been commissioned by Armour Energy to present investors with an analysis of the opportunities emerging for the company over the next 12 months. The company needs to deliver on its growth plans which should significantly improve its commercial positioning, but the oil and gas business is high-risk by definition. High risk investments should be a small part of a balanced portfolio.

Business model

Armour Energy is a junior oil and gas company holding a production base with expansion options; and an extensive exploration portfolio across three Australian states, dominantly focussed on exploring for gas. The portfolio consists of exploration plays, reflecting a mix of moderate risk and early exploration stage with transformational potential. The company is looking to leverage its production growth plan at Kincora to repair its balance sheet and service a more aggressive exploration strategy, without recourse to equity markets. Financing is always a concern at the small end and the company's high working interests provide options through partnering.

Scenario analysis

We have evaluated the AJQ portfolio against a range of risk factors based on our assessment of the operating environment accounting for commodity prices, location, phase of exploration, timing and scale of work programmes, potential timeline to the delivery of growth targets and financing. We exclude considerations based on factors such as comparative analogues and peer group benchmarking as we view AJQ as a somewhat unique offering in the small-microcap part of the sector. However, we note our current assumptions are subject to potentially significant adjustment as definitive drilling results come to hand.

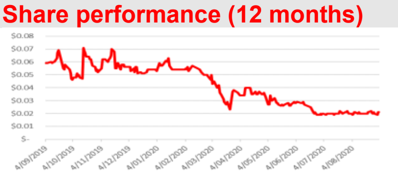
Valuation of $114m (13cps)

Valuing early phase exploration and even production growth assets is a subjective exercise, particularly when work programmes and financing are uncertain. We base our indicative valuation on risk-weighted development scenarios and typical unit NPV values across a range of prices and resource outcomes. Where appropriate we apply discretionary probability weightings to pricing, volume and success factors, which we believe are reasonable given the commercial operating environment and available data. We assign a risked valuation of $113m (13cps) to AJQ. **The reference share price (2.1cps) would suggest the market is heavily discounting the production growth and transformational gas opportunities, likely on financing and corporate risks.** We note the company has a number of deliverable outcomes, particularly pertaining to Kincora production expansion that have the potential to re-rate market sentiment and crystallise asset values closer to our ascribed NAV.

Share details

ASX Code	AJQ
Share price (2 Sept)	$0.021
Market Capitalisation	$17.5M
Shares on issue	832M
Net cash at 30 June 2020	$3.2M
Free float	~69%

Share performance (12 months)



Upside Case

- Above expectation results from Kincora gas growth programme…more gas, higher price, lower capex
- Northern Australia success…progress at Egilabria and securing a farm-in partner for the NT assets. Referred success from regional exploration would crystallise value.
- Success opens alternate financing options, improves the balance sheet and restricts dilution

Downside Case

- Growth gas is not delivered to expectation
- Current operating environment persists and all projects slow down
- Issues Senior Secure Amortising Notes covenants require additional equity capital or asset divestment

Board of Directors

Brad Lingo	CEO
Nick Mather	Executive Chairman
Stephen Bizzell	Non-Executive Director

Company contacts

Brad Lingo (CEO) +61 7 3303 0620

blingo@armourenergy.com.au

RaaS Advisory contacts

Andrew Williams +61 417 880 680
andrew.williams@raasgroup.com

Finola Burke +61 414 354 712
finola.burke@raasgroup.com

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Armour Energy Limited – Kincora sets up the growth phase

Armour Energy limited (AJQ.AX) has been listed on the ASX since April 2012 and holds a mix of production and early stage exploration assets with earnings upside and transformational gas potential across three Australian states, in proven and frontier basins. Near-term growth will be driven by the production expansion strategy at the Kincora Gas project, where plans are in place to increase output to 30TJd (from 8TJd), providing cashflow and earnings upside. This is the primary focus of the company's activity through FY21. Exploration activity will be slower to evolve but comprises a mix of moderate to high risk plays the NT/NWQ portfolio and across the western/northern flanks of the Cooper Basin. A return to drilling is likely to be towards the end of 2021. We like the asset mix, particularly the options and scale embedded in the NT/NWQ plays, but as per many small cap energy plays, financing constraints limit the pace with which AJQ can works its assets and debt overhangs the balance sheet.

Exhibit 1: AJQ NAV – the share price reflects an overly risked outlook

			Pr	A$mn	A$/share	
Queensland						
Kincora	Various	100%	50%	$73	$0.09	RaaS development scenario on 2P volumes
Newstead storage		100%	50%	$13	$0.01	With 'risked' expansion
Exploration	Various	100%		$10	$0.01	Includes conventional and unconventional opportunities…nominal only
Northern Australia						
Isa Super Basin	Various	30%	25%	$16	$0.02	Using the lower of risked weighted Prospective Resources or carry of STO farm-in deal
MacArthur Basin	Various	100%	1%	$35	$0.04	Using risk weighted 2C and Low Case Prospective Resources
Cooper Basin						
Exploration	Various	100%		$10	$0.01	Nominal only
Victoria						
Wombat-Trifon	PRL 2	15%	25%	$10	$0.01	Based on a risk weighted development model and ascribed 2C volumes
Otway-1	PEP 169	51%	6%	$3	<$0.01	Drill-ready opportunity with low economic threshold…likely to be small (but potentially profitable)
Other				$3	<$0.01	Includes a 6.12% LKO shareholding
				$174	**$0.20**	
Net debt (as at 30-Jun)				($55)	($0.06)	
Corporate				($5)	($0.01)	
TOTAL				**$114**	**$0.13**	
Shares issued (mn)*		832				

Source: RaaS analysis; Risked values based on look through Probabilities of Success (POS) for drilling and weighted by a RaaS risk overlay. Weightings at RaaS discretion.

Risk adjusted asset valuation at $114m

We value AJQ using estimated unit values on reserves and; contingent and prospective resources adjusted for our discretionary probability weighting (1-risk %), to derive a gross portfolio worth. Probability weightings are subject to change as the company delivers the next phase of exploration results and operating conditions.

Where possible we model development outcomes based on broad guidance and historical outcomes but note these are adjusted and overlain by RaaS risk outlook reflecting our views of the technical and commercial uncertainties associated with delivering the projects as modelled.

We note that beyond Kincora, most of the remaining portfolio is early stage exploration and ascribed values are subject to potentially significant change related to drilling results – both direct and indirect.

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A quick SWOT – Drilling success changes the outlook

As typical for small resources companies – offsetting strengths and weaknesses, opportunities and threats although we suggest the macro opportunities more than outweigh the commercial risks.

Exhibit 2: SWOT Analysis and Comments

Strengths	Comments
An asset in production (Kincora) with growth	Liquids rich gas reserves to support a 30TJd project could deliver $80-90mn pa (RaaS estimate) on a low decline basis
Diversified exploration portfolio across different basins and plays	NT-NW Queensland and Surat Deeps provide transformational upside on success
Strong farm-out deal with Santos in northern gas assets (NT and NW Queensland) provides for cash-carried activity in a frontier basin, whilst defraying high exploration costs	Santos underwriting up to $65mn of exploration costs delivers activity beyond the capacity of AJQ on a sole -risk basis
High equity (working) interests across the portfolio	High working interests offer capital offsets through the early stages
Assets located in close proximity to infrastructure-hubs.	Access to plants and pipelines with ullage enhances success case economics
Weaknesses	**Comments**
Exploration portfolio provides a range of opportunities across the risk spectrum but can come with a hefty price tag through to first gas on success	Northern Australia and Surat Deeps are expensive opportunities. The explore-evaluate-develop process could be longer and more complicated than other parts of the portfolio.
In the absence of equity capital, the company is cash flow constrained	Not unusual for small-cap energy stocks. Exploration activities will be limited with significant drilling activity likely to occur in 2022.
Almost 'early-stage' exploration nature of the portfolio	Early stage equals high risk and potentially high capital cost. The extensive nature of the holdings in areal terms means high-grading targets can have a long gestation period. Exploration is a capital-intensive game. Potentially long lead times to development on drilling success.
High equity (working) interests across the portfolio	A strength can be a weakness. High initial interests need to be solely funded until assets are sufficiently evaluated to be of interest to third parties or at a pre-development stage.
Debt structure constrains the balance sheet and reinvestment cash flow, with significant principle repayments in the next 2-4 years unless restructured.	Debt impacts the capacity to drive growth.
Opportunities	**Comments**
Supportive macro investment theme – East Coast gas supply	The macro environment continues to be strong despite the weakness in the short-term gas price. Supply is forecast to tighten significantly in 2022 (or earlier) and scenarios suggest there is significant opportunity for new suppliers to enter the market. We expect gas prices to remain high in the medium term and beyond.
Relatively easy and inexpensive growth at Kincora	Workovers and new wells required to produce out the 2P volumes (150PJ) but the risk should be low.
Expected increases in gas prices across the east coast over the medium to long-term	Stronger prices make gas in pre-development and uncontracted, very valuable
Threats	**Comments**
Persisting weak commodity prices	Weak export gas markets divert gas to the domestic market. The current spot rate in Queensland is low which could impact the terms and conditions of new gas contracts
Persisting CoVid-19 restrictions	Restrictions on travel and the supply chain can flow through to project delivery
Acceleration of the development of renewables	Renewables work better with gas…but this is not a company specific issue
Rush to market - there's other parties looking to enter the gas game	There is competition, from new basins (Narrabri) and within basins (other NT operators) with the very strong likelihood of LNG imports. The addition of significant, new gas volumes could negatively impact the pricing and supply dynamic for smaller operators.

Source: RaaS analysis

The first step – looking at the assets

Armour Energy has a geographically diversified set of assets lying across the risk spectrum, with the potential to provide a mix of short-term and long-term opportunities.

The anchor asset of the portfolio is the Kincora Gas Field, already in production with sufficient reserves to support a growth target of 30TJd (~11PJ pa) with accompanying gas liquids and crude oil. Delivery of the growth target could generate sales revenue of $80-90mn pa on a low decline basis (RaaS estimate), as a quasi-annuity.

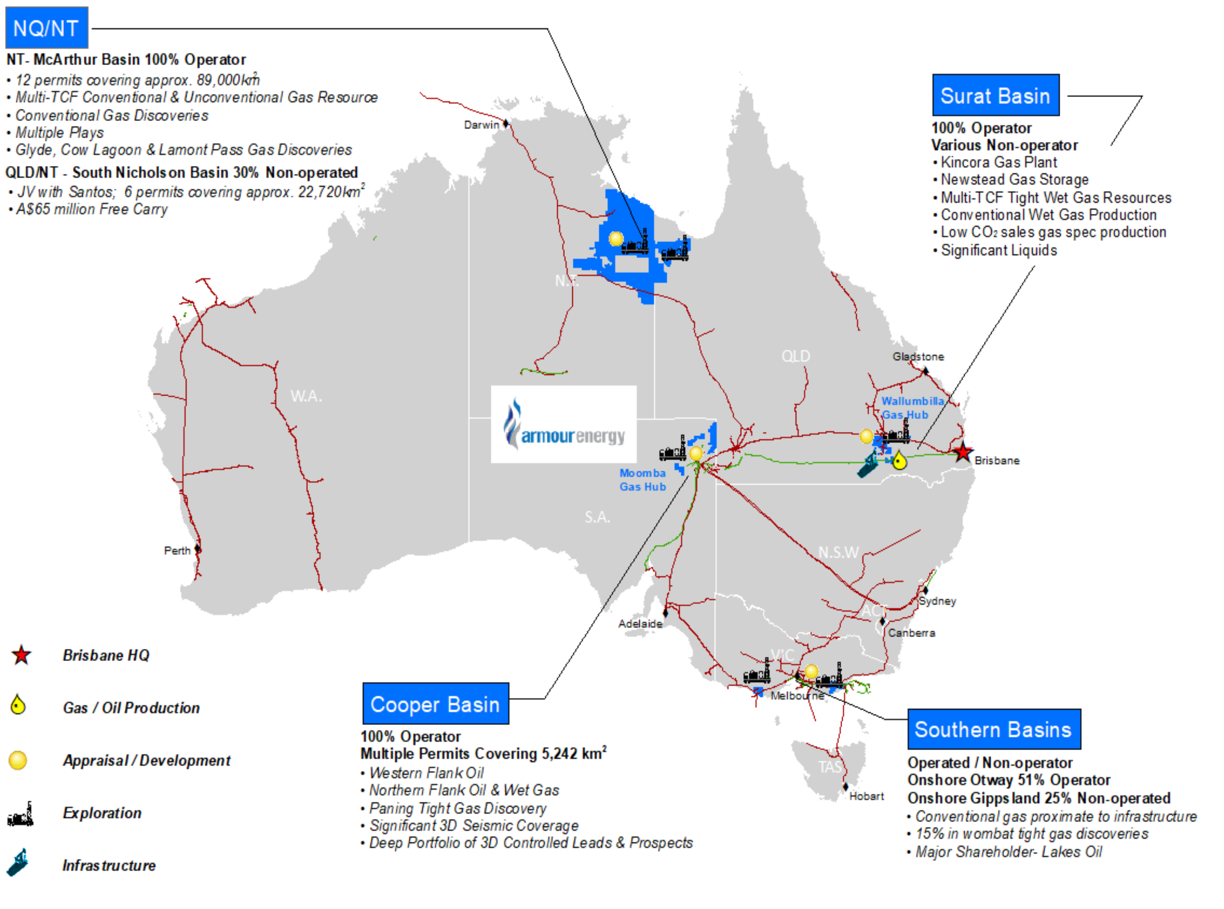
The exploration portfolio contains transformational opportunities, particularly in the NT-NWQ acreage, with gross best estimate prospective gas resource within shale formations estimated at 57Tcf.

We highlight the high-grade potential of ATP 1087P as the most advanced of the projects the company has in this region. Based on the success of the Egilabria-2 well, which flowed on test, the discovery has been ascribed 2C gross volumes of ~149PJ.

Importantly AJQ is free-carried for up to ~A$65mn of scheduled expenditure across a number of permits in this portfolio (refer Exhibit 28. Appendix 1).

As part of the acquisition/merger with Oilex, the company has secured a large set of Cooper Basin permits umbrellaing the northern wet gas and Western Flank oil plays. 3D seismic is the key and drilling could commence in 2022.

Exhibit 3: Australian portfolio offering production & exploration opportunities – incremental & transformational



Source: Company data

Kincora can be the cash driver…there's growth and transformational opportunity

The Kincora assets offer a major point of differentiation for Armour in the small-cap energy sector. Production and cashflow are always concerns for investors…quality assets need capital and recourse solely to equity markets is not a sustainable financing option.

The expansion potential of Kincora can underpin the company as a significant producer of gas and gas liquids. The Newstead storage facility adds an annuity-like development option. Armour is looking to expand these operations beyond the current capacity of 7.5PJ and 15TJd. Storage optimises Kincora financial returns, expansion sets up an important additional revenue stream.

The Kincora production assets were purchased from Origin Energy (ORG.AX) in Sep-2015 for around $13mn and included:

- 15 production licences;
- 4 exploration licenses;
- 4 pipeline licences and;
- associated infrastructure connecting directly into the Wallumbilla gas hub, including the Newstead gas storage facility with a capacity of 7.5PJ.

Access to the Roma Brisbane Pipeline through Wallumbilla is via a Connection Agreement with APA Group (APA.ASX), which allows supply to APLNG and access the broader east coast gas market.

The sales contract with APLNG is for up to 10TJd (3.65PJ pa) for five years to 2023. The facilities are currently producing at~ 8TJd with plans in train to increase plant capacity and gas throughput to 30TJd (11PJ pa) by 2023. Currently gas produced above the contract rate is sold into the Queensland spot market.

Exhibit 4: Reserves enough to underpin an expansion and drive growth

Kincora Gas Project		1P	2P	3P	
Gas	Bcf	59.3	132.2	282.4	
	PJ	67.4	150.3	321.1	Sufficient reserves to support expansion plans
LPG	kt	139	310	663	
Condensate	kb	670	1,493	3,191	
Crude Oil	kb	246	1,221	2,640	
	kboe	11,937	27,285	58,326	

Source: Company data

The plant has a nominal nameplate capacity of 30TJd but given the well head gas stream is strongly liquids rich, throughput is constrained by the operational limit of the Dew Point Control (DPC) unit at the front end of the plant (liquids recovery) to 20TJd.

The current gas production rate of <10TJd is itself constrained by well deliverability which is the first bottle neck to be addressed under the expansion/upgrade plans.

The end game is in sight with Stage 4 of the gas expansion strategy seeing AJQ conducting a three well work-over campaign to commence early Oct and run through to end 2020, which will consist of fracking and the installation of downhole pumps, with an additional three well campaign scheduled for 2021, to address the gas supply situation (refer Ex 5).

The initial three well frack programme is budgeted at around $5mn, with modelling simulations suggesting production rates of up to 8TJ on a single well could be achieved…**sales gas production to 20TJd could be delivered relatively quickly and at low capex.**

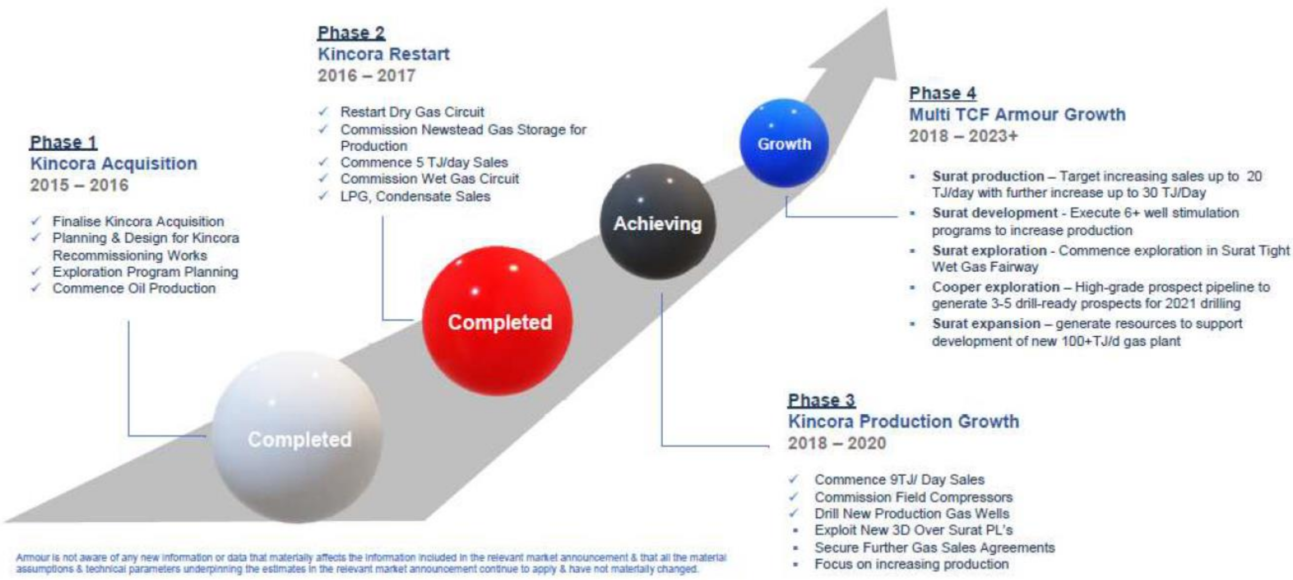
Expanding the facilities capacity to 30TJd, will likely require significantly more capex for compression and additional DPC units. The refurbishment of the Rolleston Gas Plant is likely to be the indicative analogue for Kincora.

Denison Gas is refurbishing and upgrading the Rolleston Gas Plant (RGP). This plant has been offline since 2011. After completion, the RGP will be restored to its nameplate capacity of ~30TJd. The project includes:

- – Installing a Dew Point Control Unit to bring the natural gas onto specification
- – Moving 2 compressors into the plant to improve reliability
- – Building a new evaporation Concept tank and water handling facilities
- – Upgrading the condensate loadout system
- – Testing and repairing existing pipelines, equipment and instrumentation.

Source: www.denisongas.com.au/rolleston-gas-plant-refurbishment

Exhibit 5: Kincora strategy –being delivered with Phase 3 set to commence



Source: Company data

Indicatively the cost of expanding the DPC capacity at Rolleston is likely to be in the order of $8mn, but this ultimately will be dependent on the volume of liquids being removed and Kincora is a liquids rich gas stream. Liquids ratios from FY20 production data are indicatively, Oil/Cond 19b per TJ and LPG 1.75t per TJ.

Broad guidance suggests that producing out the current 2P reserves will require 45 wells, which we anticipate will be a mix of new wells and workovers of current producers.

Exhibit 6: Current well stimulation candidates with targeted reservoirs

Frack portfolio	Rewan	Basal Rewan	Black Alley Shale	Intra Wallabella	Showgrounds	Tinowon A	Tinowon B	Tinowon C	Bandanna Upper	Bandanna Lower
Horseshoe-4		●								
Horseshoe-2		●	●	●						
Waroon-1	●				●					
Parknook-2	●								●	
Riverside-1							●	●		●
Ogilvie Creek-1			●			●				●
Myall Creek East-1			●			●				
Parknook-4	●				●					
Myall Creek-2			●							
Myall Creek-6			●						●	
Myall Creek-3			●							
Ungabilla-1						●				
Rednook-1			●							

Source: Company data; shaded wells scheduled for the initial 3+3 campaign (FY21)

Infield opportunities – some low hanging fruit

The firm FY21 work programme will consist of 6 well (3+3) frack campaign. The company has indicated there are an additional seven wells screened for future fracking operations, targeting by passed or untapped gas zones previously deemed as too tight or unproductive…this is the relatively easy 'low hanging fruit' (refer Exhibit 6).

The frack stimulation campaign uses the Myall Creek 5A (MC-5A) well as an analogue.

The MC-5A well was spudded on 01.11.18 to a depth of ~2,245m, reporting a 290m of gross gas column across Triassic and Permian formations from 1,875m.

Conventional perforation and completion of the Triassic Basal Rewan Formation failed to sustain a commercial gas flow and the well was subsequently and successfully fracture stimulated in Nov-2019 across the Permian Lower Bandana and Upper Tinowon formations, achieving an IP(30) rate of 3.2TJd.

The company has commented that the well continues to exceed expectations. The success of both the MC-5A and Horseshoe-4 underpinned the most recent reserves upgrade of 22% to 150PJ (2P).

The MC-5A well also confirmed the Black Alley Shale as having the potential to become a new regional gas play.

As noted in a recent company presentation, a critical focus of the frack stimulation programme is the Black Alley shale and sands, which have been deemed prospective in more than 10 wells in the field. Although the Black Alley Shale is recognised as an important seal and source rock in the Bowen Basin, it does contain intra-formational sands which could be quite attractive.

The key aspect to take away, is that the exploration and appraisal portfolio in support of the Kincora expansion strategy is deep and extensive and in relative terms, the production growth targets look deliverable within a moderate risk range.

Using the underlying assumptions as per Exhibits 7 and 8, we model Kincora delivering strong revenue growth, building through A$80mn in FY23 and in excess of $100mn by FY31, with corresponding net operating cash from A$53mn to nearly A$70mn. On that basis, **we assign an unrisked and ungeared NPV to the project of 18cps.**

- IP – 5TJd
- EUR – 3.4PJ
- Well abandonment rate 0.2TJd
- Aggregate capex to end field life - $136mn (wells (connected), plant and abandonment)
- Produced reserves – 143PJ

Exhibit 7: Commodity price assumptions based on the Forward Curves of 1-July

		FY21	FY22	FY23	FY24	FY25	FY26	FY27	...L/T
Gas (Contract – oil linked)	**A$/gj**	**5.28**	**5.57**	**5.82**	**6.04**	**6.24**	**6.26**	**6.13**	**8.69**
Gas (Spot)	A$/gj	4.00	5.00	5.50	5.61	5.72	5.84	5.95	6.70
LPG	**A$/t**	**443**	**468**	**489**	**508**	**524**	**526**	**516**	**730**
Crude Oil	A$/b	41.90	44.16	46.01	47.57	48.98	50.32	51.74	75.00
Currency		**0.6899**	**0.6886**	**0.6865**	**0.6840**	**0.6818**	**0.6981**	**0.7327**	**0.7500**

Source: RaaS estimates; investing.com; eia.gov

Note we do not model any conversion of the incremental 3P volumes into developable reserves although as a natural consequence of drilling new wells and workovers, the reserves attribution at Kincora will change and we see **the risk to ultimate recoveries as likely to be to the upside**.

Exhibit 8: Indicative Kincora cash flows

Production		FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Gas	**TJd**	**16**	**28**	**30**	**30**	**30**	**29**	**30**	**31**	**29**	**29**	**30**	**30**	**29**	**22**
Gas	PJ	6	10	11	11	11	11	11	11	11	11	11	11	11	8
LPG	kt	9	21	23	23	23	22	23	23	22	22	23	23	22	17
Condensate	kb	58	100	109	110	108	106	108	111	105	105	110	108	105	80
Oil	kb	60	57	54	51	49	46	44	42	40	38	36	34	32	31
	kboe	**1,148**	**1,975**	**2,152**	**2,166**	**2,126**	**2,072**	**2,112**	**2,173**	**2,063**	**2,061**	**2,138**	**2,103**	**2,051**	**1,575**
Revenue															
Gas		28,059	52,401	61,725	63,808	64,249	63,594	65,265	68,862	68,182	70,929	76,384	78,119	78,223	62,159
LPG		3,892	9,833	11,233	11,745	11,918	11,665	11,666	12,417	12,761	13,728	15,273	16,030	16,119	12,335
Oil/Condensate		7,172	10,061	10,948	11,241	11,277	10,949	10,717	11,158	11,460	12,161	13,224	13,760	13,750	11,120
TOTAL	**A$mn**	**39,123**	**72,295**	**83,905**	**86,794**	**87,445**	**86,208**	**87,649**	**92,437**	**92,404**	**96,819**	**104,881**	**107,909**	**108,091**	**85,614**
Average received commodity price	A$/boe	34.09	36.60	38.98	40.08	41.13	41.60	41.49	42.54	44.79	46.99	49.07	51.31	52.71	54.35
Operating Costs		18,871	22,312	23,521	24,159	24,609	25,013	25,801	26,698	26,897	27,558	28,592	29,149	29,629	28,077
Royalty		3,325	6,145	7,132	7,377	7,433	7,328	7,450	7,857	7,854	8,230	8,915	9,172	9,188	7,277
TOTAL Costs	**A$mn**	**22,196**	**28,458**	**30,653**	**31,537**	**32,042**	**32,341**	**33,251**	**34,555**	**34,751**	**35,787**	**37,507**	**38,321**	**38,817**	**35,354**
EBITDA	A$mn	16,927	43,838	53,252	55,257	55,403	53,867	54,398	57,882	57,653	61,031	67,375	69,588	69,274	50,260
Capex	A$mn	10,200	22,500	10,000	5,000	5,000	7,500	21,250	7,500	5,000	7,500	10,000	7,500	7,500	10,000
Implied cash tax	A$mn	3,666	9,899	14,389	15,690	15,898	15,571	15,463	16,167	16,444	17,072	18,635	19,669	19,794	15,948
Net Cash Flow	A$mn	3,061	11,439	28,864	34,567	34,505	30,796	17,685	34,215	36,209	36,459	38,739	42,418	41,980	34,312
NPV @	15%	144	162												
Issued capital (shares)	mn	779	857												
NPV (unrisked, ungeared)	$ps	$0.18	$0.19												
Unit NPV Margins		11%	14%												

Source: RaaS estimates

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Surat deeps…higher risk but basin centred gas plays can be transformational

Basin-centred gas plays (BCG) are typically regionally pervasive accumulations of gas saturated reservoirs, abnormally pressured (can be over or under-pressured), commonly lack a downdip water contact and have low-permeability. The targets are often 'ill-defined' structurally and can range from single, isolated, thin zones to multiple, stacked reservoirs hundreds of metres thick. Tight gas plays can be considered to be 'multi-Tcf' opportunities.

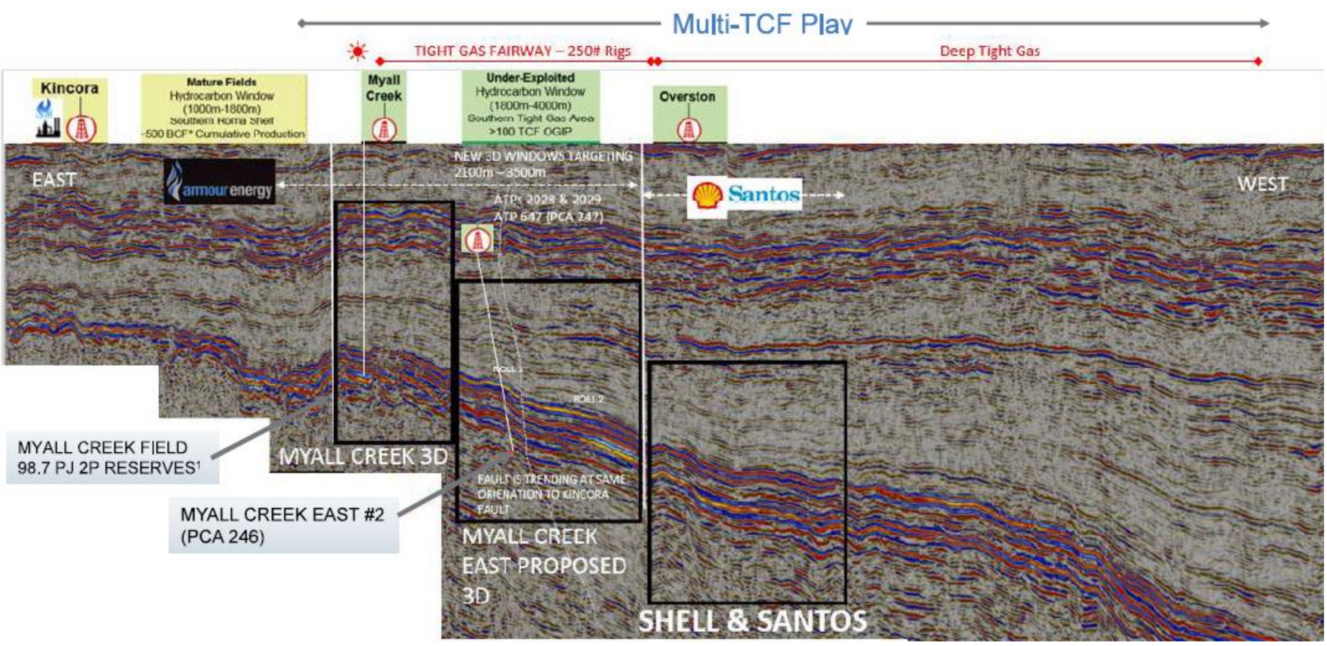
The nature of the play, means by definition they require multiple wells to define and fracture stimulation. Wells can be expensive

Armour is investigating the wet gas potential of the eastern part of its Surat Basin portfolio, recognizing a basin centred gas play, which has already been investigated by Santos and Shell (QGC) for gas additions to their LNG supply portfolios.

Whilst results to date have not delivered definitive commercial results, indications have been positive and the play has been identified across the AJQ holdings, which will be the subject of FY21 3D seismic surveys designated Myall Creek East and Parknook West (refer Exhibit 11).

The 3D surveys will high grade the potential, by defining gas prone anomalies across the permits.

Exhibit 9: Off the shelf into the trough is where the deep, tight gas opportunities lie



Source: Company data

Historically, the play has been hard to 'pin' down and in the Australian context has been mostly explored in the deep Nappamerri Trough region of the SA-Qld Cooper Basin and more recently in the Surat deeps.

In 2015, Shell (QGC) conducted exploration for a deeper tight gas play in the central to southern Taroom Trough, targeting tight sandstones in the lower Rewan Group and Kianga Formation (a Tinowon Formation equivalent), at a cost of some $40mn.

The results of the campaign were broadly positive, highlighting the potential for the deeper formations within the Bowen Basin to contain a tight gas resource, though no resource numbers were booked. The play is likely to occur within the Permo-Triassic units, below 2500m and drilling log data suggests it is likely that this play could contain wet gas. Where the target formations shallow onto the flanks of the basin, the play is likely to transition through to tight gas reservoirs, which provide additional exploration opportunity.

With no defined Prospective Resources volumes, it's difficult to put a value on this exploration play to which we ascribe only a nominal asset value at this stage.

Accelerated activity will likely require AJQ securing a farmout with a significant party.

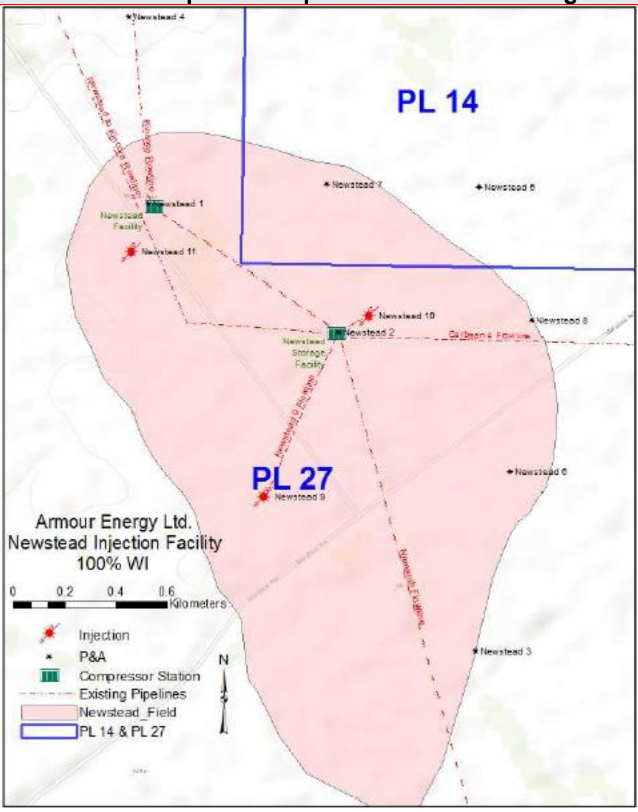
Newstead Gas Storage provides an annuity opportunity

The industry mid-stream (plants, pipelines and storage) are typically the domain of infrastructure companies. It's rare that storage assets find their way into the portfolio of dominantly upstream companies. Santos does have this capacity within its Cooper Basin gas hubs, but it's only a small incremental part of the total asset value.

Armour is quite unique in this regard with ownership of the Kincora plant and Newstead storage facilities.

Gas storage is valuable and we suggest will become increasingly so, as a mechanism to smooth supply, optimise field production and arbitrage gas prices.

Exhibit 10: A simple development – the Newstead gas storage play has very few moving parts



Newstead is ideally located, feeding directly into the Wallumbilla Hub which makes it suitable for redirection into the existing pipeline network, into domestic or export markets.

The facility has been operating as dry gas storage since 1997 with storage capacity of up to 7.5PJ and a daily drawdown rate limited to 15TJd.

The company is undertaking studies to expand the project capacity by adding additional depleted reservoirs into the network.

In a recent presentation the company indicated it was targeting an upgrade of throughput capacity of up to 4x…that would be equivalent to around 60TJd (~22-24PJpa). Naturally the capacity of the operations will be constrained by the level of cushion gas that must remain in the fields.

The business case for AJQ at Newstead is enhanced with expansion, particularly as an adjunct for export operators.

At this stage, Newstead can be an earnings contributor at the margin and the upside will be directly related to the company securing storage agreements of significant volume.

Source: Company data

At low levels of throughput, the ascribed value is subjective and on a risked basis, nominal.

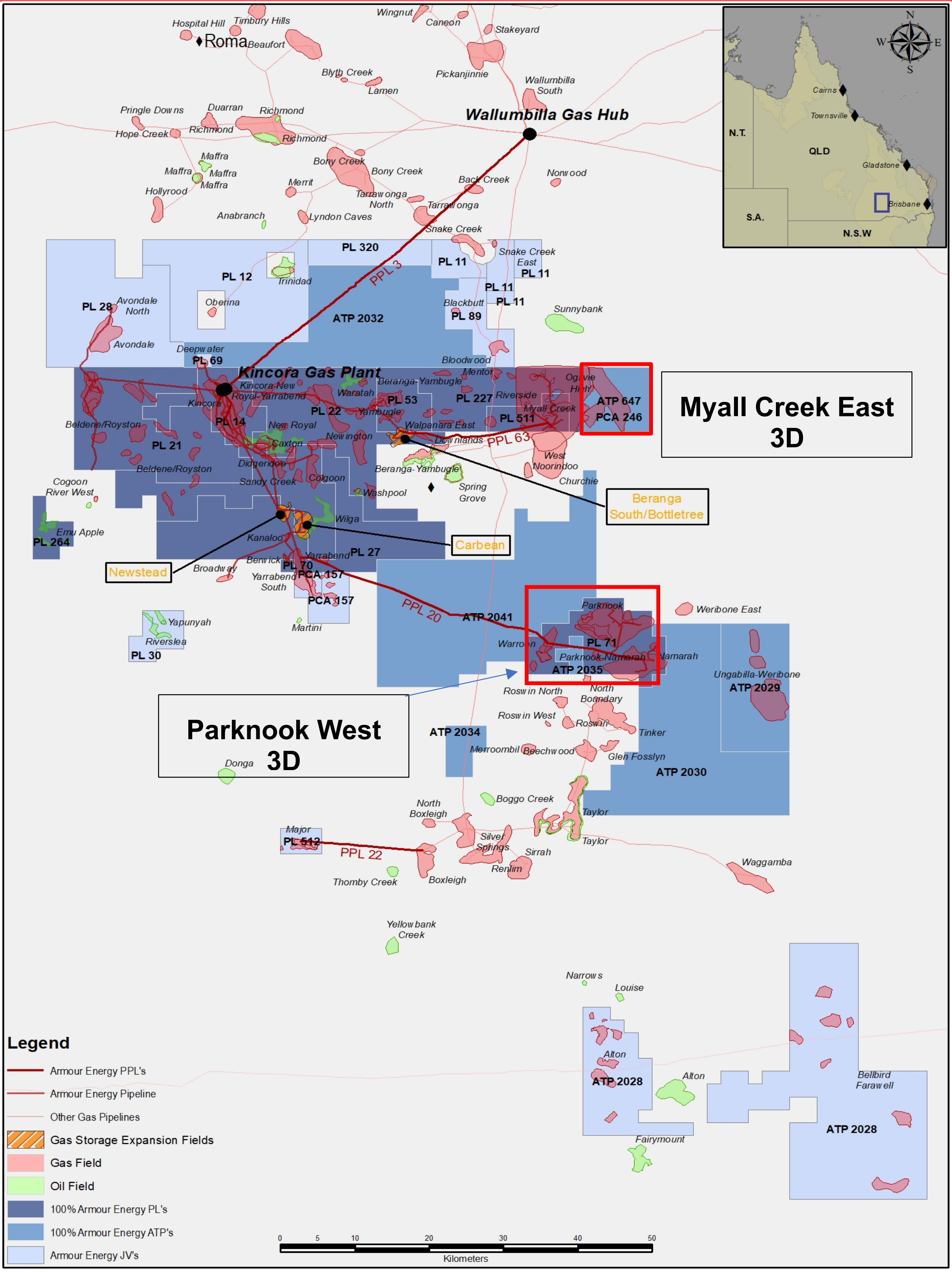
Early capital estimates suggest capacity could be upgraded to around 24PJ for as little $24mn (AJQ estimates), which is inexpensive in absolute terms and relatively low risk. The project is yet to achieve FID at this stage so costs and timing are fluid.

Indicatively we suggest EBITDA returns of up to $1.00/gj for injection/production may not be unreasonable, depending on the volume and contract terms, based on equivalent new storage financial estimates in Bass Strait.

However, we do not suggest Newstead as an operation will deliver this outcome and only highlight this as achievable in the southern gas market.

Gas storage provides an annuity style return option within the AJQ portfolio, but also provides the company with a financing alternative, particularly on an upgraded basis. The company is not necessarily a natural holder of this asset. In combination with the Kincora plant, this could also provide the company with an infrastructure restructure opportunity at some future point.

Exhibit 11: An extensive footprint with a direct tie to Wallumbilla and new 3D seismic to come



Source: DEDJTR (Jun-2015) [top]; Company data [bottom]

Northern Australia (NT and NW Queensland) - opportunities with transformational potential

Armour holds a dominant acreage position in contiguous permits straddling the Queensland and Northern Territory border providing unfettered exploration opportunities of transformational potential. The acreage holdings encompass some 89,000km^2 in the McArthur Basin over 12 permits and ~40,800km^2 in the Isa Superbasin over 6 permits (refer Exhibit 12).

Whilst the plays embrace both the conventional and unconventional, it's the unconventional options that provide multi-Tcf upside with a combined net Prospective Resource potential of ~36.6Tcf (P_{50}). It's worth noting AJQ also holds a net Prospective Resource estimate of 4.9Tcf (P_{50}) in the NT conventional plays.

It's simply the size of the prize!

The large assignation of Prospective Resource volumes is a direct function of the underexplored nature of the plays. Extrapolation of resource potential to commercial outcomes is subject to revision as more geophysical and geological (drilling) work is completed to define prospects and support hydrocarbon models.

In all aspects, in ground work is at an early stage so the assets are at the high end of the risk spectrum.

The acreage covers a vast areal extent so high grading of prospects takes time and capital… the securing of the farmout deal to Santos for an initial suite of permits, mostly in Queensland has been an excellent outcome, providing significant capital carry through the earlier, higher risk phase of exploration. The company requires and is actively seeking another partner(s) for the remainder of its NT portfolio.

The holdings do lie within reasonable access distance to existing pipeline infrastructure, which is currently underutilised, so offers an opportunity for developments that can be fast tracked. We'd note the significant activity already conducted and due to recommence on the NT side of the border and the potential for developments of scale to utilise pipeline ullage, but there are expansion plans on the table.

Network constraints are not an important issue right now given the early nature of the company's operations.

The Santos farm-in is by any measure a very good deal in absolute terms and we can see the attractiveness to Santos as being complimentary to its own northern Australia strategy, expanding its geological and geographical footprint. The Queensland acreage offers an early commercialisation option directly into the east coast market, albeit small at this stage but potentially significant for Armour.

Santos is looking for scale and we should take that as a positive read through…the A$85mn (total cost) investment may end up looking like a cheap entry.

Details of the farm-in agreement are included in Appendix 1 and we would note that $20mn of the contributions are for previous sunk-costs and for additional application works.

As a cautionary comment, the A$65mn of in-ground expenditure covers only **two significant wells**, with no specific timing on their drilling. We should read this as being indicative of the scale of the background work still to be undertaken and reflection of the early stage nature of the exploration process.

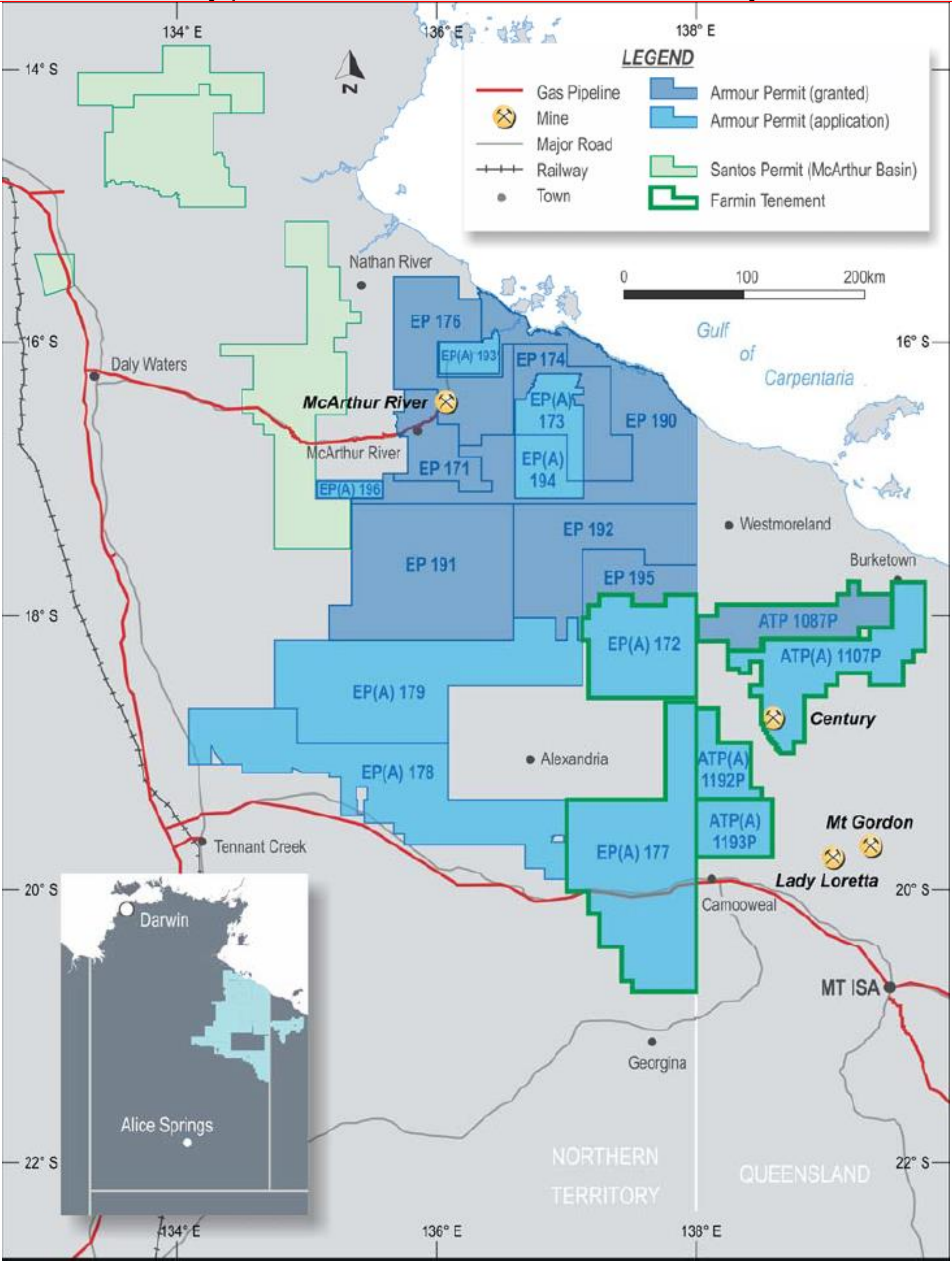
There is an advantage to be had for smaller companies. With few operators and participants there is a first mover advantage to be chased. At some point, given the resource potential, success…even early success, will attract interest from companies with balance sheet and capital capacity.

Although it may be too early and we don't imply any impending M&A activity, resource evaluation and commercial definition will highlight the leverage of the smaller operators/partners in the plays…and it easier to buy de-risked assets, particularly if success is not reflected in a share price re-rating.

Santos is coming to play – Queensland is the place to be (AJQ 30%)

The majority of work completed in these permits to date has been in the Queensland tenements with seven wells drilled for six 'discoveries'. The particular focus is on ATP 1087, which is the most advanced of the opportunities in this portfolio, the others being in various stages of pending applications.

Exhibit 12: Armour acreage position is vast with the Santos farm-in tenements outlined in green



Source: Company data]

There have been six wells in the permit with the critical results coming from the Egilabria drilling, which flowed gas from a fracked horizontal shale section in the Lawn Hill Formation.

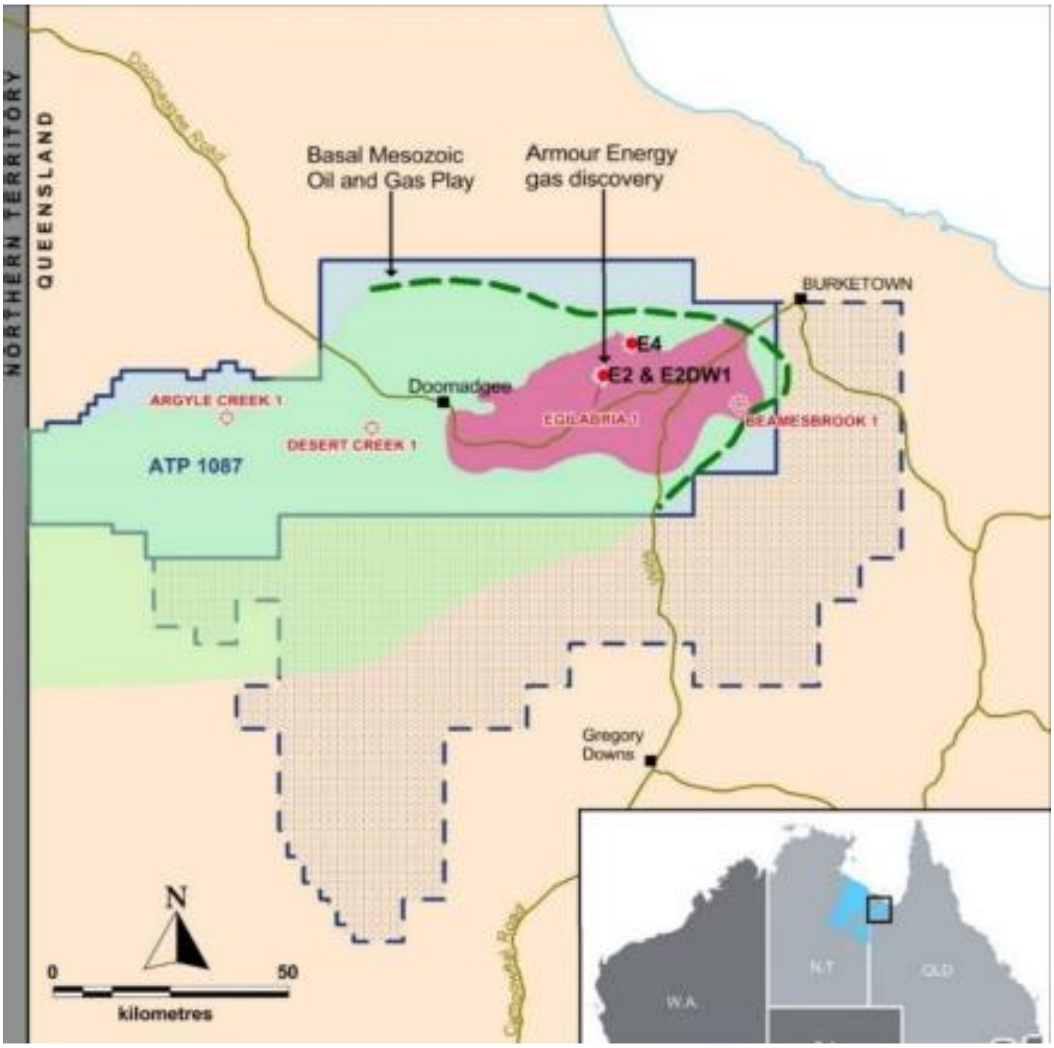
The Egilabria results were used to ringfence a 2C (Contingent Resource) booking of c.154PJ (gross). Further appraisal work is required to establish commercial flow rates. This ATP 1087 permit has been designated for one of the two 'significant wells' as scheduled under the Santos Farm-in agreement.

The Egilabria-2 well was drilled in mid-2013 to evaluate the Lawn Hill Formation shale play. Numerous gas shows and flares were encountered in the formation during the drilling with the target Lawn Shale noted as being 137m thick with 8% TOC.

The Egilabria-2 DW-1 well completed a horizontal section in the shale which was fracked and began flowing gas after recovery of 45% of the frack fluid. The gas composition was determined as 88.5% C_1, 0.6% C_2, 0.9% He, 0.4% CO_2 and 9.6% other inerts.

Egilabria-4 was completed in 2013, intersecting 110m of net shale in a gross interval of 265m

Exhibit 13: Strong Egilabria results but significantly under-explored



Source: Company data

Activity has largely been suspended over the last five years but is set to accelerate over the next four years under the terms of the farm-in agreement.

We are awaiting confirmation of a return to work in this area but suggest the first phase will be the acquisition of more geophysical data. Drilling may be sometime in FY22 by our estimate.

We assign a value to these assets based on a risked commercial look through from Contingent and Prospective resources; benchmarked against the value of the Santos farm-in.

Exhibit 14: A little bit of Egilabria gas in a portfolio of transformational potential

	Contingent Resources			Prospective Resources		
Volumes in Bcf	1C	2C	3C	Low (1U)	Best (2U)	High (3U)
Lawn Shale	9.9	46.3	109.2	800	2,433	5,900
Riversleigh Shale				1,200	4,195	11,800
	9.9	46.3	109.2	2,000	6,628	17,700

Source: Company data (net to AJQ 30%)

Greater McArthur Basin (Beetaloo sub-basin) - a shale play in a frontier area (AJQ 100%)

The sedimentary basins of the Northern Territory are underexplored. Activity has been spasmodic with less than 60 exploration wells drilled across all the basins and since 2007 only around 30 wells specifically targeting the unconventional opportunities.

The gas potential of the shale sequences has been subject to a number of studies, most notably by Geoscience Australia and the US Energy information Administration (2015), highlighting Prospective Resource estimates of around 250-260Tcf. With only a limited number of data points (wells) these estimates and extrapolations must be interpreted with some caution, but the premise of strong prospectivity has been supported by the drilling results to date.

The company has drilled a number of successful wells within EP-171 and -176 which forms the basis of the company's early development strategy (refer Appendix 2).

A notable conventional discovery at Glyde

Glyde-1 (conventional well) was drilled in mid-2012 to a total depth of 698m, with a lateral section of ~200m (at280m) in the Barney Creek Shale. The well flowed up to 3.3mmcfd at 600m, on a short duration test and recorded 132m of gas-charged, naturally fractured Barney Creek Shale

The gas specification was noted as 77% C_1, 11% C_2, 11% C_3 and negligible CO_2. This is clean gas with a significant LPG fraction.

Source: Glyde-1 flare (2013 Annual Report)

Based on analyses of the geological and flow test data flow test, DeGolyer and MacNaughton estimated a 3C Contingent Resource volume of 10.3Bcf (12.5PJ) attributable to the Coxco Formation.

Importantly the Glyde discovery ('Coxco') was shallow and through the northern tenements is expected to range from 300-1800m. Development should be relatively inexpensive particularly with potentially strong flow from shallow accumulations of clean gas.

At a minimum, more appraisal needs to be conducted to better define the extent of the development volumes and establish a stabilised flow rate.

The company has outlined a FY21 field work programme that includes additional geophysical acquisition (2D seismic and airborne gravimetrics) and an extended production test of the Glyde-1 well.

Exhibit 15: Net Contingent Resources (AJQ 100%) – small but important

	Contingent Resources			Prospective Resources		
Volumes in Bcf	1C	2C	3C	Low (1U)	Best (2U)	High (3U)
Coxco-Cooley	2.4	6.0	10.3	1,300	4,800	29,900

Source: Company data; Contingent resources are restricted to the Glyde Proposed Production Licence Area

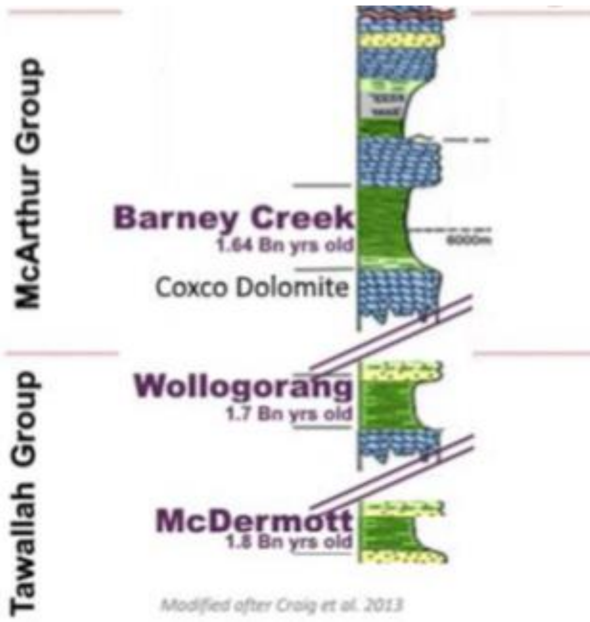
Production and retention Licence applications are pending and AJQ indicates gas sales could commence as early as 2022, with gas for power generation into local mining operations as the logical and natural buyers we suggest.

The assignment of a 'Best Case' Prospective Resource estimate for the conventional Coxco play of 4.8Tcf points to the opportunity set inherent in the acreage.

The unconventional

There are numerous prospective targets of a regional nature throughout the sedimentary sequence, extending north and west from the AJQ tenements.

Exhibit 16: Stacked targets…multiple plays



As specifically identified by the company in recent presentations:

The **Barney Creek** shale formation is a thick, sulphur-rich black shale unit overlying the brecciated Coxco Dolomite which flowed gas on test at the Glyde-1 well. It is present across AJQ's tenements and regional drilling data suggests it can be considered as a good candidate for fracture stimulation.

The **Wollogorang-McDermott** shale formations are pervasive, likely thinner, with recorded TOCs up to 7%. It has not been a primary exploration target in contiguous permit areas.

Source: Company data

In keeping with the prevailing assessment of the unconventional plays of the MacArthur Basin, AJQ holds an ascribed Prospective Resource of some 30Tcf on a 'Best Case' basis.

Exhibit 17: Prospective Resources…it's easier to focus on the Low case

Volumes in Tcf (AJQ 100%)	Low (1U)	Best (2U)	High (3U)
Barney Creek Shale	3.8	12.9	39.0
Wollogorang Shale (Tawallah Group)		6.9	141.4
McDermott Shale (Tawallah Group		10.1	152.1
	3.8	30.0	332.5

Source: Company data

The estimates are somewhat like lottery numbers but material de-risking can be achieved through a modest amount of seismic and drilling activity; and particularly the look-through results from drilling in adjacent tenements and on similar plays.

We would expect to see a significant amount of data and results from the field programmes of Santos, Origin Energy (ORG.AX) and Empire Energy (EEG.AX) at least through FY21.

Ascribing a value to this portfolio is subjective and somewhat arbitrary. We like the plays…not many small companies have the leverage and exposure to transformative opportunities. There is inherent value as evidenced by the declaration of Contingent Resource volumes and drilling data supports the views on prospectivity. However, the asset portfolio is dominantly early stage exploration, with no clearly defined pathway to commercialisation, uncertainties as to the speed and scope of work programmes; financing and de-risking events more likely to be driven by look-through results in other parts of basin.

Whilst there aren't many operators across the regions, there will be competition for opportunities and progress at scale could overwhelm the market. A more detailed discussion of pathways to market, infrastructure plans and what the gas business in the NT could look like is beyond scope of this report but there is an early mover advantage to be had and smaller companies, being more nimble can brings gas to buyers more rapidly…provided their assets are worked.

The most visible indication of value is the through asset transactions, in the case the cash carry of the Santos farm-in at least providing a starting point.

Additionally, we apply a risk-weighting process against Prospective Resources as booked. Using a 'unit NPV' against the Low Case volumes determines an unrisked estimate of potential value to which we apply an adjustment to reflect the perceived level of risk.

The early the exploration stage, the higher the commercial uncertainty and the greater the discount.

We assign a valuation to the northern Australia portfolio of $51mn (6cps).

Cooper Basin – an umbrella of opportunity

AJQ has accumulated a significant Cooper Basin position after completing a Share Purchase Agreement with Oilex Ltd (OEX.AX).

The tenements consist of:

- two exploration licences (PELs -112 and -444, both 100%),
- a portfolio of northern Cooper Basin assets ('Northern Fairway', 100%), comprising 27 PRLs considered to be prospective for oil and wet gas; and
- a newly awarded Block designated PELA 677 ('Block C') immediately adjacent and complimentary to the Northern Fairway PRLs

The strategy is to chase proven oil and wet gas plays along the western flank and northern margins of the basin

Exhibit 18: Embracing the basins margins. Chasing analogues discoveries

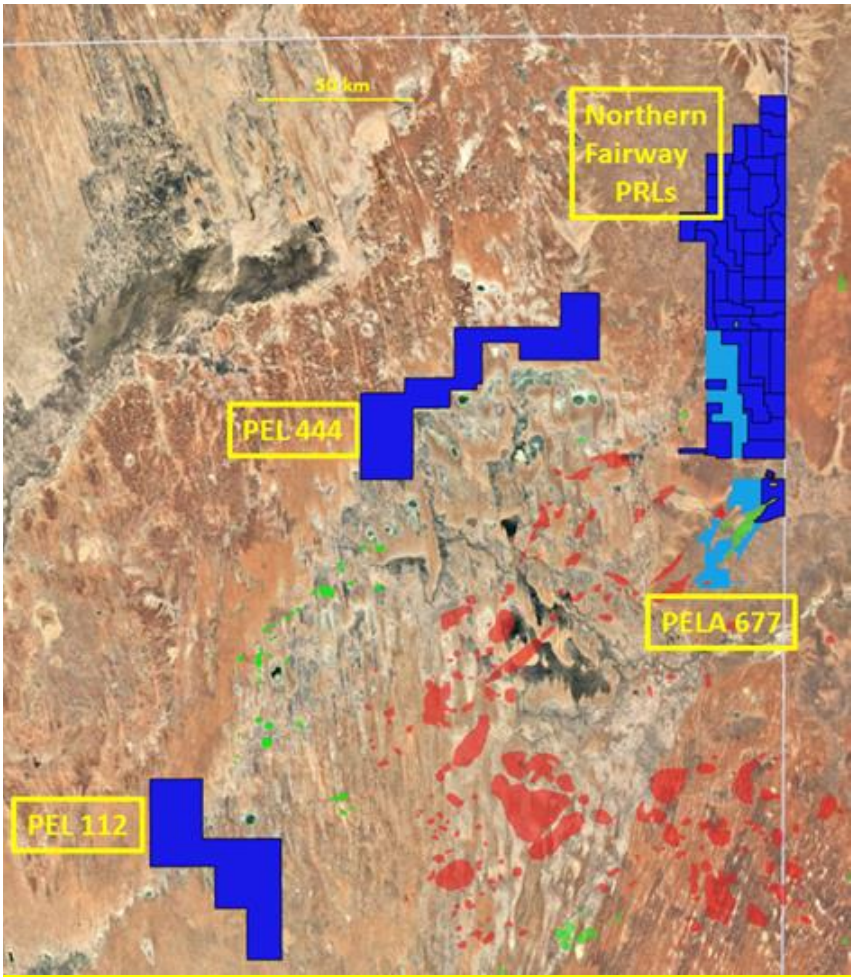
Northern Flank (AJQ 100%) PRLs provide long tenure with multiple (stacked) target horizons.

Contains the undeveloped Panning tight gas discovery.

PEL 444 is chasing the proven Birkhead Formation channel sands play using the Snatcher/Charo fields as analogues.

There is also considered to be the potential for high productivity Namur sands oil plays.

PEL 112 on the SW Western Flank (AJQ 100%) is targeting Birkhead channel plays with a number of prospects identified.



Source: Company data

Of recent interest is the new award, PELA 677 (Block C) being adjacent to a number of discoveries (Acrasia, Reg Sprigg, Flax and Juniper oil fields; and the Yarrow, Pondrinie and Packsaddle gas fields).

The best place to look for oil and gas is next door to where it has already been found.

The key unlocking the Cooper Basin has been 3D seismic. Many features in the Cooper-Eromanga basins sequence are subtle and too small to resolve on 2D seismic. The advent of 3D data has underpinned a boom in discovery rates, being able to resolve smaller prospects and providing direct hydrocarbon indications (DHIs), especially for gas.

Armour will look to high grade its existing leads and prospects inventory to *"…develop 3-5 drill-ready prospects for potential end-2021 (…) with a combination of oil and wet gas targets".*

We would comment that the Cooper-Eromanga portfolio is a mix of more frontier acreage, particularly along the Western Flank where drilling density is significantly lower and moderate-risk opportunities (near field exploration) in the Northern Fairway permits.

SXY has had success chasing Birkhead channels and while 3D seismic is critical risk mitigator we remain somewhat cautious. Channel features can be strongly evident on seismic, but the 'channel fill' can be hit or miss and generally can only be confirmed by drilling. Sand filled channels can be quite productive, however, seismic cannot distinguish between sand and shale.

15 June 2020 - Execution of Agreement with Oilex Ltd for Acquisition of Cooper Eromanga Basin Assets

The share sale agreement with Oilex Ltd ("Oilex") for the acquisition of all the issued capital in CoEra Ltd has been executed by the parties.

CoEra's assets comprise a substantial footprint of exploration and production licences on the oil rich Western and Northern Flanks of the Cooper Basin. The basin historically has a high exploration success rate, low cost development pathways, and remains under-explored and under-developed. Proven oil fairways transect and lie adjacent to the licence areas subject of the proposed acquisition and the many nearby discoveries and fields provide analogues for future discoveries.

The acquisition consideration includes the issue to Oilex (or its nominees) of **a minimum of 24.5m shares and a maximum of 34.5m shares in Armour**, subject to the VWAP of the Armour share price for a period of 90 days from the execution of the Term Sheet. The variance is designed to deliver a closing consideration of $906,500 in Armour shares to Oilex, subject to the aforementioned maximum and minimum parameters. Completion of the sale agreement is subject to a number of conditions. The conditions include that the issue of the shares to Oilex will be subject to any necessary Armour shareholder or regulatory approvals, and the shares issued will also be subject to a twelve-month voluntary escrow.

Senex retains a right to 'back-in'

Under the agreement with Oilex (and now with AJQ) Senex has retained a back-in right across the PRLs in the portfolio that can be exercised for a 20% working interest under the following terms:

- within six months of completion of the first well in a PRL;
- where an applicable well in a PRL has not been drilled within three years of the effective date of transfer of the permit.

The back-in right is PRL specific and effectively gives SXY a free look and catalyses drilling…a very strategic option for the company to hold.

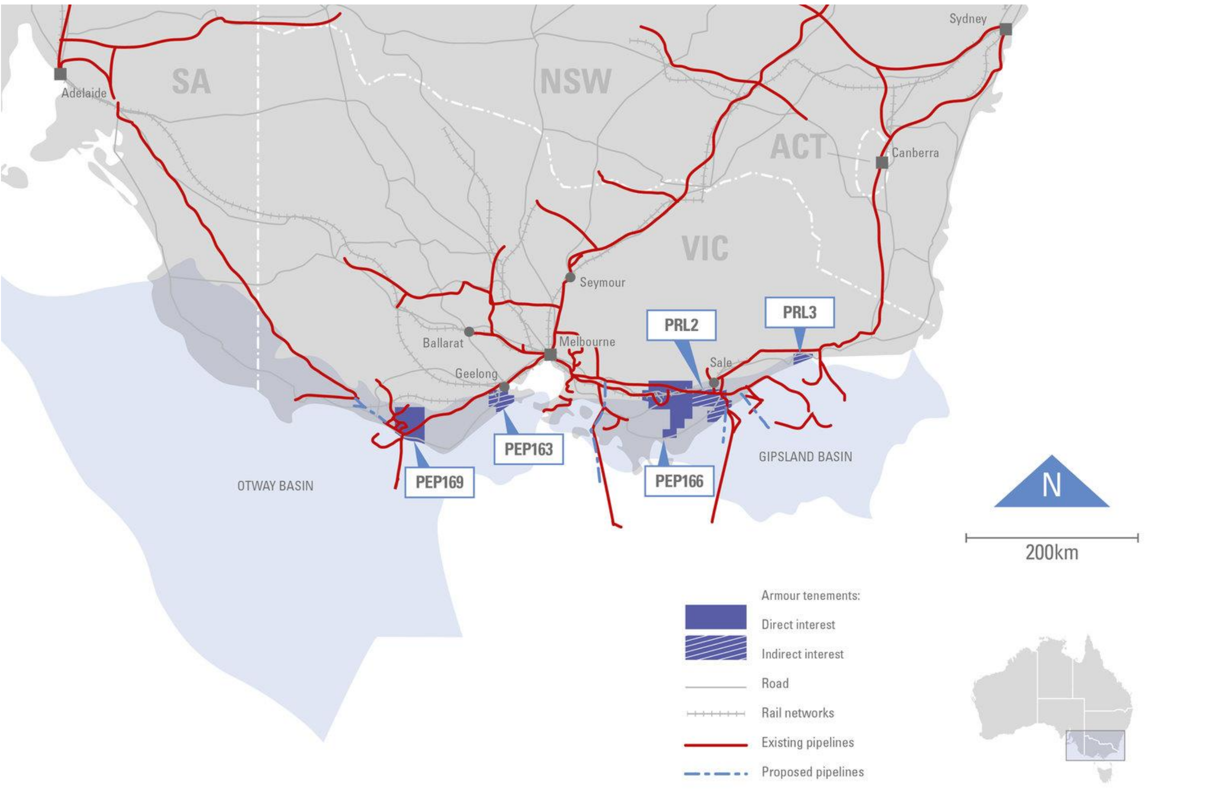
The cost to back-in is for 20% of the well capex with no uplift or promote.

Onshore Victoria – coming back into the light

With the expiry of the Victorian Government onshore drilling moratorium, asset holders can return evaluating their tenements and drilling from 1-Jul. Although a fracking ban adds a layer of uncertainty to commercial outcomes, there are two 'drill ready' opportunities that can be fast-tracked pending financing.

Armour hold direct interests in a number of tenements and a complimentary investment in Lakes Oil NL (LKO.AX) of 6.37%.

Exhibit 19: Across the southern basins – important assets, well situated



Source: Company data

A quick look – down the Wombat Hole (PRL 2, AQJ 15%)

PRL 2 holds a defined gas resource based on previous drilling success and measured gas flows. The resource sizes as indicated represent a significant gas opportunity, ascribing 719Bcf at 2C in aggregate.

Exhibit 20: PRL 2 Contingent Resources – a significant gas play sits here

				Bcf		POS
			Low	Mid	High	
PRL 2	Wombat Field	Gas	258	329	628	50%
	Trifon Field	Gas	126	390	526	25%
			384	719		

Source: Company data; assignment of POS (Probability of Success) weightings from LKO

The Wombat and Trifon fields are located in tight sands and whilst the discoveries are structurally controlled on seismically defined highs, the distribution of reservoir units is expected to be somewhat consistent across the permit. The upper section is weathered but is expected to be able to produce gas conventionally without the need for reservoir stimulation. This is not to suggest the development options are simple.

The Wombat Field has been defined by four wells, flowing 3TJd from Wombat-3, prior to mechanical failure of the well. Gas has been intersected throughout the Strzelecki Group sands with some zones indicating 'sweet spots' with more favourable reservoir characteristics that could be selectively targeted.

Tight sands suggest well productivity will likely need to be enhanced – in this case by lateral drilling to access a greater surface area (fracking is banned) and; it should be noted that reservoir performance and production rates can be more problematic, particularly with no analogue fields.

LKO as the operator has indicated it plans to drill the Wombat-5 appraisal well as soon as practicable, in this case subject to financing we suggest. A previous application will need to be refreshed but should be able to be completed in a timely manner pending agreement of the JV.

We understand Wombat-5 will be designed to be a directionally drilled well looking to determine what commercial flows could be achieved from the Strzelecki Formation without requiring stimulation. The well is being designed as a 1500m open hole lateral with an engineering estimate of flow rate potential up to 5-6mmcfd.

Otway-1, PEP 169 (AJQ 51%)

The PEP-169 permit contains the drill-ready Otway-1 prospect, which is a conventional target in close proximity to the Iona Gas Field. Being only 400m from existing facilities, a success could be commercialised rapidly. An economic discovery size could be as low as 5PJ but more likely around 10PJ

The well will target both the Waarre Sandstone (primary) and Eumeralla Formation (secondary) with a prognosed total depth of 1,500m which will make the well cost relatively inexpensive.

The Waarre Sandstone is a productive regional reservoir and hosts adjacent discoveries in the immediate region while the Eumeralla Formation is known to contain gas and has flowed on test, but is considered a higher risk, secondary target

We note the prospect has been ascribed a P_{50} Prospective Resource of 60Bcf (gross), which would make a discovery of this size, the largest in this region...the success case is likely to be significantly smaller on the balance of probabilities.

We suggest these assets hold significant intrinsic value from an exploration perspective – the plays are highly prospective and technically valid – but exploration/appraisal plays can be quite binary in their outcomes.

Financials – deliver the gas and the earnings will follow

The financials reflect a gas production growth scenario, which must be delivered to support our earnings and value estimates. Given the company is still in a pre-drill phase, we caution that our estimates are subject to significant change depending on the results of the upcoming frack phases and plant modifications.

Delays or deferments of activity cannot be discounted in the present CoVid-19 operating environment so our forecasts should be seen to represent a success case at this stage.

We refer to Appendix-3 and commentary on the Senior Secure Amortising Notes, highlighting the impacts the current operating environment has had on delivery of FY20 work programmes and production targets.

We model a building NPAT outcome through the forecast period, in line with production growth targets. We assume increasing commodity prices across the forecast period in line with our Forward Curve based price deck and netback gas contract price outcomes.

Exhibit 21: Summary profit/loss results (reporting currency AUD, balance date 30-June)

P&L	FY20e	FY21e	FY22e	In A$000's
Production (kboe pa)	**527**	**1,148**	**1,975**	**Growth forecast of ~275% over FY20 volumes**
Average received gas price (A$/gj)	5.76	4.79	5.21	A changing mix of gas prices – spot and contract
Revenue	**23,208**	**39,123**	**72,295**	**Higher volumes, means more revenue**
Cost of Sales	(16,931)	(23,978)	(30,507)	
Other income/expenses	(10,534)	(5,220)	(7691)	
Proforma EBIT	**(4,257)**	**9,925**	**34,098**	
EBIT Margin		*20%*	*47%*	*We model increasing EBIT margins driven by higher revenue against a dominantly fixed plant operating cost base*
Tax	(403)	(386)	(9,191)	
NPAT	**(9,812)**	**3,903**	**21,445**	**Strong profit margins underpinned by liquids-rich nature of the gas stream**
EPS (cps)	(1.5)	0.7	2.5	

Source: RaaS analysis

A key element of the company's financial strategy over the forecast period is to restructure the balance sheet, primarily by addressing the $55mn debt liability. Naturally the capacity to be able to achieve this will be strongly dependent on delivering the production expansion plan, which will minimise the potential for highly dilutive equity issues.

Exhibit 22: Summary Balance Sheet – debt reduction a major component of strengthening equity base

FINANCIAL POSITION	FY20a	FY21e	FY22e	In A$000's
Cash & Equivalents	3,245	1,945	3,478	Cash build flows from production growth
PP&E & Production assets	69,067	77,846	83,936	Largely related to Kincora gas growth capital
Exploration	33,824	36,824	38,664	Exploration expenditure expected to be relatively low and Surat/Cooper basins focussed, noting STO carry and uncertainty across Victorian assets
Total Assets	**124,446**	**119,062**	**130,018**	
Debt	61,975	49,753	33,381	We model debt reduction as per Amortisation schedule and terms of Tribeca facility
Total Liabilities	**78,308**	**68,258**	**57,005**	
Total Net Assets/Equity	**46,138**	**50,804**	**73,013**	**More cash, less debt…higher net assets**
Net Cash/(Debt)	**(58,730)**	**(47,808)**	**(29,903)**	

Source: RaaS analysis

Historically, financing has been secured through equity issues and most recently, debt and Senior Secure Amortising Note options. Success can support other funding options

The company is in a pretty unique position for a small energy company, holding a production asset with impactful growth upside, ostensibly achievable against a relatively modest capex outlay. Deliver on the production targets and in many respects the company is self-funding with the capacity to drive its own exploration agenda.

The debt/Note burden is constraining in the short-medium terms and is the biggest pull on the operating cash flow.

We model the company holding a nominally level cash balance through FY22 largely as a consequence of scheduled debt servicing requirements and capital expenditure on Kincora. Given the margin for error in estimates (production volumes and commodity prices) we cannot discount the potential of an equity raising through this period.

Exhibit 23: Summary cashflow statement

CASHFLOW	FY20e	FY21e	FY22e	In A$000's
Operational Cash Flow	**11,223**	**24,629**	**69,870**	
Net Interest	(5,153)	(3,896)	(2.520)	Falling on lower debt levels
Net Operating Cashflow	**(7,999)**	**4,580**	**34,128**	**Increasing against a fixed cost base**
O&G assets/Exploration	(17,214)	(10,200)	(10,000)	Largely related to Kincora drilling and plant modifications
Net Investing Cashflow	**628**	**3,800**	**(19,500)**	
Equity Issues (after costs)	7,457	1,670		We
Debt repayments	(6,066)	(11,350)	(15,559)	
Net Financing Cashflow	**1,391**	**(9,680)**	**(15,559)**	
Net Change in Cash	**(5,980)**	**(1,300)**	**1,533**	
Closing Cash	3,245	1,945	3,478	Closing cash through FY22 is forecast to be tight with little to no working capital buffer…we cannot discount the potential of an equity raise through this period

Source: RaaS analysis;

On our modelling, allowing for the uncertainty margins with respect to production, gas prices, operating and capital costs. we suggest AJQ will keep within its Senior Secure Amortising Note financial covenants at this stage **(refer to Appendix-3)**.

A risk assessment

The most critical factor in determining and delivering any resources project is, in our view the prevailing commodity price outlook. We remain very bullish on the east coast gas, supply-squeeze thematic and see AJQ as well placed, with production expansion and transformational portfolio opportunities.

The political risk issues are now beginning to abate with the realisation that gas prices can only come down sustainably if there is more supply (of scale). The ongoing Queensland Government exploration initiative is a proving to be of benefit and the lifting of the Victorian Government drilling moratorium should remove the constraints that impact the operational and commercial considerations of the company's assets located in that region.

Rather than a comprehensive assessment of all operating risks, we highlight a few key areas that we consider the most critical for the company and investors over the next 12-24 months.

Gas Prices and market commentary

It is beyond the scope of this report to enter into a detailed discussion of the east coast gas price dynamics, which continue to be assessed on a minute and specific basis by the ACCC gas enquiry. The most recent update (July-2020) indicates that as a result of the fall in LNG prices through late 2019 and early 2020, new contract gas prices were being set in a marginally lower range of $8-11/gj.

The compounding effects of the CoVid-19 economic slow-down and (further) 'collapse' in crude oil prices has seen more gas diverted into the domestic market, resulting in greater volume availability on a spot basis and weak spot-short gas prices. But translation of a lower gas prices into new contracts is not expected to persist.

The ACCC highlighted that despite weaker of LNG markets, domgas prices in Queensland were continuing to trade at a premium to export netback and that since Sep-2019, some 18 'spot' cargoes were sold at *"…prices substantially below the domestic gas price"*.

Whilst we agree with the premise that a better understanding of the pricing dynamics on the east coast is required, we see the potential for linking of the current market circumstances to the need for more regulation as premature and perhaps too simplistic.

The ACCC does recognise the impact of weaker commodity prices on the speed of development of new gas supply sources, particularly against the back-drop of CoVid-19 related travel restrictions, impacts on the supply chain and availability of capital. Gas is a finite resource and battling the decline curve has become more difficult.

The ACCC analysis supports our contention that the east coast gas supply thematic still holds, with perhaps a few new moving parts. Supply tightness remains with the potential a of significant supply shortfall to impact earlier rather than later in our view, which should support a relatively high base gas price. The current financial reporting season indicates the industry remains somewhat capital constrained and cautious. The consequence could be that field decline curves could be steeper and with drilling activity (exploration in particular) continuing to falling away, the supply side issue is getting quite serious.

It is interesting that the March AEMO Gas Statement of Opportunities suggests that *"…supply from existing and committed gas developments will be sufficient to meet forecast gas demand across eastern and south-eastern Australia until at least 2023,* ***provided that*** *liquefied natural gas (LNG) export* ***spot*** *cargoes are redirected to meet domestic demand, if required."*

The ACCC Report notes that while *"…supply is currently expected to be sufficient to meet demand in 2021"* the *<u>"uncertainty is higher because a greater proportion of production is forecast to come from undeveloped 2P reserves</u>. This is particularly an issue in the southern states, with 21% forecast to come from currently undeveloped reserves. If for any reason these reserves are not developed, or development is delayed, more gas from Queensland and, in particular, from LNG producers, may need to flow south."* As examples, we have seen the timing for both the Sole and Mahalo gas projects pushed back and other gas opportunities slow.

We would also highlight the potential production issues of the large Queensland CSG fields, particularly Fairview which is exhibiting steady decline in aggregate deliverability although we should interpret current data cautiously.

What we can say with a high degree of confidence, is that many (all) of the gas producing hubs are well past the production peak. Whilst increased activity may be able to deliver some growth at the margin, the industry will need to spend increasing amounts of capital to just mitigate the decline curve.

Our view is that the underlying tightness of the market may be higher than alluded to in the ACCC analysis and the only tangible way of providing downward pricing pressure in east coast markets is to increase supply in scale, which is going to require significant capital investment in field facilities and infrastructure. It may be that pipeline infrastructure and tariffing becomes the new bottleneck.

The business case for LNG imports is growing, supported by AEMO and ACCC analyses.

Increasingly, LNG import terminals are becoming accepted as a necessary mechanism and part of the gas supply model, but that in and of itself will/can add a significant new pricing dynamic into east coast gas pricing – import pricing rather than export netback could set the wholesale price for gas supply at the margin, particularly if as indicated by AGL in a gas conference presentation (April-2019) that east coast gas supply could see (LNG) imports of up to 300PJpa by 2030.

Given the time lag between new making new discoveries (or fully appraising opportunities) and production of first gas, the development of LNG terminals appears to be a faster option for new supply into the east coast. However, as noted by the ACCC *"…there remain material regulatory approvals still to be obtained and the case for each specific business model will need to be established in order to reach FID".* In effect, this supply option can only move as fast the regulatory process allows.

The NSW Government has identified the Port Kembla and Port of Newcastle LNG import terminals (with the Narrabri gas development), as priority projects under the NSW Energy Package MOU.

The most recent update on the Port Kembla terminal (May-2020) the project was still in the process of securing offtake agreements as a precursor of an anticipated FID sometime before end-2020.

Geology

On a generic basis, exploration plays come with a high inherent risk is high, even allowing for adjacent discoveries and developments. Whilst the target zones and parameters of any prospect can be outlined with confidence, especially when defined by 3D seismic, pre-drill analysis is a probabilistic exercise and drilling even within an existing field cannot be predicted with certainty – geology just doesn't work that way.

Even the production growth opportunities at Kincora should not be deemed riskless.

There are also higher risks associated with chasing new plays – for example the tight gas in the Kincora Deeps prospects and particularly in the NT/NWQ assets where initial drilling results are strongly encouraging but work can only be described as early stage.

In a similar fashion both the Cooper Basin and Victorian portfolios are higher along the risk spectrum, unlikely to be defined by one well or perhaps even 5 or 6 wells. Commercial outcomes may take some time to cystallise.

It should be noted that geology can surprise on the upside – reservoir parameters and flow results can exceed expectations with positive implications for reserves and capital costs but all of this needs to be determined through exploration and appraisal success.

Government Regulations and Legislation

By definition, all upstream companies operate within the constraints of government regulations and changes to legislation can act positively and negatively.

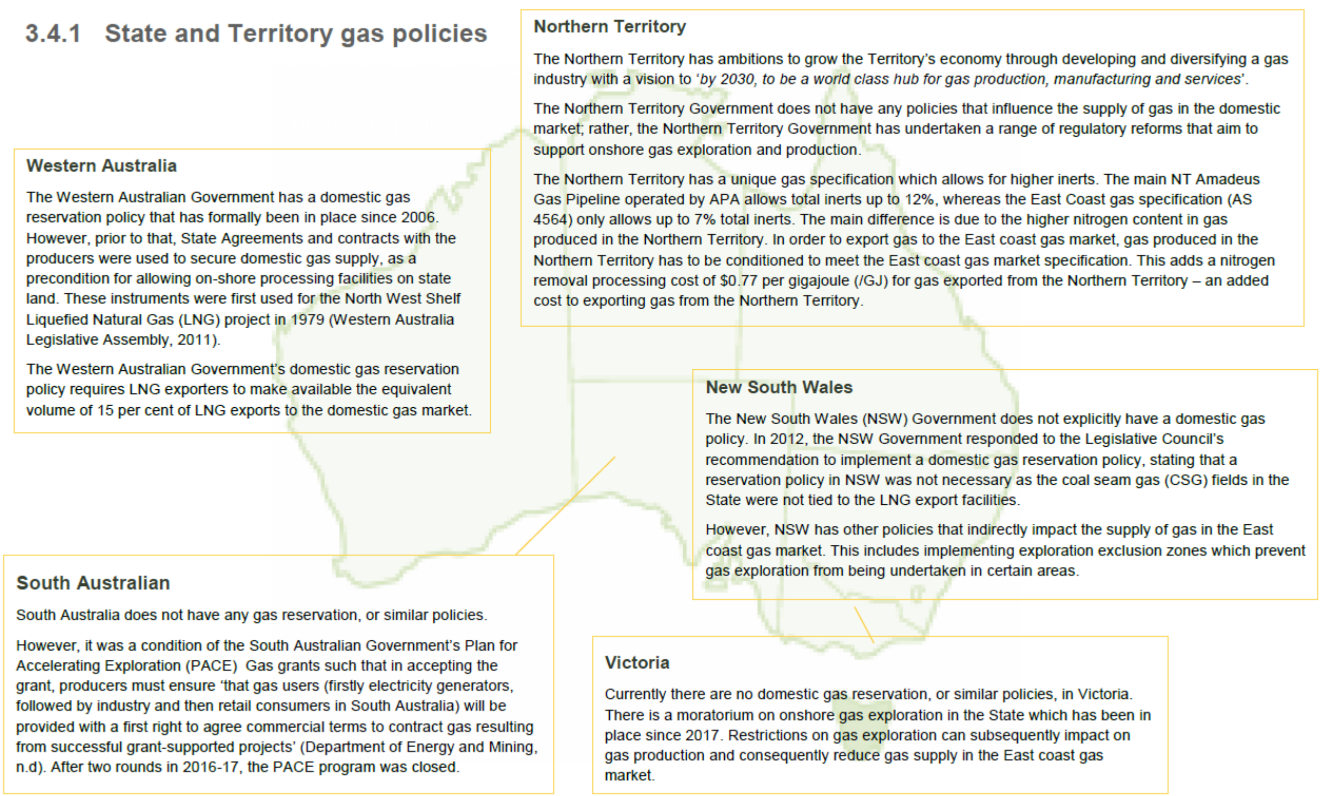
In Queensland, the government is actively supporting the gas industry through continuing releases of previously relinquished acreage that are available for tender. The acreage does come with a domestic gas supply mandate (“Australian Market **Supply Condition**”) and includes waivers on ‘rent and fees’. Armour, with other small operators has been the recipient of acreage awards.

A recent study conducted for the Department of Natural Resources, Mines and Energy (DNRME) concluded that the **Supply Condition** has improved the competitiveness of small/medium sized explorers/producers in the land release, tender process.

Source: ‘Review of the Australian Market Supply Condition”, Aurecon Australasia Pty Ltd (28.02.20)

With the majority of new acreage releases being within an extensive infrastructure network, the nominal economics for any discoveries are quite favourable. The government is actively ‘biased’ (in our view) towards smaller companies, seeking diversification of potential suppliers and the elimination of resource banking…these are positive aspects for the industry.

Exhibit 24: A Summary of regional gas policies noting constraints and opportunities



Source: DNRME “Review of the Australian Market Supply Condition”, Aurecon Australasia Pty Ltd (28.02.20)]

On the 17.03.20, the Victorian State Government lifted its moratorium on onshore oil and gas exploration, effective as of Jul-21. The legislation though continues to ban hydraulic fracturing and excludes the exploration for and mining of coal seam gas.

Although this outcome is positive for AJQ in terms of being able to return to in ground activity, it still comes with significant operational and administrative restrictions. Depending on the approval requirements and financial capacity, drilling could recommence though 2H21, however, the time line to first gas (assuming success) is somewhat long-dated and lies outside of the investment window.

There is no guarantee that time-lines won’t be significantly impacted by the legislation process at some stage in the future.

It is beyond the scope of this report to debate the merits or otherwise of the continuing fracking ban and we should note that whilst there are alternatives to frack stimulation such as closer spaced wells or horizontal completions, this can add time and significant cost to exploration and evaluation activities.

Although the lifting of the moratorium is a significant positive, we'd suggest the operating parameters for the industry in Victoria remain uncertain and realisation of value on the company's gas assets is strongly tied to a return to drilling.

The NT regulatory regime is still in the process of implementing all 135 of the recommendations as suggested in its Scientific Inquiry into Fracking (https://hydraulicfracturing.nt.gov.au) some of which we suggest are quite onerous particularly with respect to seismic levels associated with the fracking process.

Under the new regulatory conditions, companies will be required to undertake pre-exploration monitoring of methane emissions, weed surveys, groundwater quality benchmarking and; well and environmental management plans (numerous recommendations). These activities are required to establish an environmental baseline and should be conducted over a six-month period prior to any activity.

We would draw specific attention to Recommendation 5.7 that *"…to minimise the risk of occurrence of seismic events during hydraulic fracturing operations, a traffic light system for measured seismic intensity, similar to that in the UK, be implemented."*

All petroleum assets in the Territory reside with the government and transition through a usual Exploration Permit (EP), Retention Licence (RL) and Production Licence (PL) process, common to all states and territories. In some respects, the tenement tenure terms are more generous than in other states. For instance, EP's are granted for up to nine years as an initial five-year term, with two-x-two-year renewals. There is a relinquishment requirement of 50% at each renewal, to prevent land-banking. Ostensibly these terms are quite generous.

We would note that the granting of permits seems to be a more stringent process up front particularly with respect to the Native Title aspects with the need for an Access Authority that must be negotiated with the traditional landowners. Traditional owners have a 5-year right of veto, with limited right of appeal and activities at any time need landowner approval.

Field activity has recommenced, which suggests these are workable conditions and the Territory government is supportive and aims to build a gas industry to supply not only the local and east coast markets, but to underpin a proposed LNG hub at Darwin.

Financing

The expansion of the Kincora Project puts AJQ in a stronger position than many of the small cap energy stocks. Increasing gas production to 15TJd and beyond is expected to put the company in a positive net operating cash flow position and certainly support fin ground commitments in the remainder of the portfolio. The company has also secured an advantageous far-out deal with Santos (STO.ASX) which covers the next phase of evaluation across its Northern Queensland assets, up to $65mn of aggregate expenditure.

The company is constrained somewhat by its current debt commitments – the Tribeca $6.8mn facility is repayable on 27.07.21 and $55mn Corporate Bond Facility issue is repayable on 29.03.24. In this regard there are still balance sheet and financing issues to be dealt with. Further recourse to equity markets for working capital can't be ruled out at this stage. The company has indicated it is pursuing a range of options to reduce the debt and restore the balance sheet including:

- Using cashflow from the Kincora production expansion;
- Securing a JV partner for the remainder of the NT exploration assets on similar terms to the STO farm-out and using those proceeds to retire debt; and
- Better exploit currently under-utilised assets such as the Newstead gas storage project, with the notional potential to become a c.$100mn pa revenue opportunity (RaaS estimate).

Acreage assets come with work and expenditure permit commitments and given the extensive asset holdings of the company these commitments can be onerous. We note (as outlined in the FY19 Final Report for the period ending 31-Jun-2019), excluding the one year estimate in that report, the forward exploration commitments for the next four years (to end FY24) are estimated to be $37mn against a market capitalisation of ~$16mn (reference share price of 2.1cps).

Board and management

The composition of small company boards and management teams are perhaps more critical than for larger companies as the impact of seemingly incremental decisions can have a magnified impact on the growth and valuation of the company. There is less margin for error and often the Board is a critical source of working capital. Notably the two lead Directors have been strong supporters of company funding through direct investing and substantial underwriting positions since the IPO of the company in 2012.

Armour Energy has an experienced four-person board, providing we think the appropriate skills sets and balance for a company in transition and leveraged to potentially transformational change through referred and direct exploration. There is strong blend of corporate governance, finance and technical experience to set up and guide the company through what could be game changing activity over the next two to three years, which will require important strategic and operational decisions to position the company to fund and develop opportunities that could emerge.

Nicholas (Nick) Mather - Executive Chairman (Qualifications: BSc (Hons. Geology), MAusIMM)

Nick has been a Director of the company from February 2012. He has an extensive background in the junior resource sector at all levels for more than 30 years and particularly so in the energy sector as a:

- co-founder and Executive Director of Arrow Energy Ltd until 2004 (acquired by Royal Dutch Shell Plc and the PetroChina Group, for ~$3.5bn in 2010)
- co-founder and a Non-Executive Director of Bow Energy Ltd (acquired by Arrow Energy Ltd for $550mn in 2011)

He currently holds board positions at Lakes Oil NL (LKO.ASX; Executive Chairman and founder), Managing Director and founder of DGR Global Limited (DGR.ASX), Director (and co-founder) of SolGold Plc (SOLG.LSE [AIM listed]) and; Aus Tin Mining Ltd (ANW.ASX), Dark Horse Resources (DHR.ASX) and Iron Ridge Resources (a Brisbane based, AIM listed minerals exploration company).

Stephen Bizzell – Non-Executive Director (Qualifications: BComm, MAICD, SA FIN

Stephen is the Chairman of boutique corporate advisory and funds management group Bizzell Capital Partners Pty Ltd. He is currently also a director of Strike Energy Ltd (STX.ASX), Renascor Resources Ltd and Laneway Resources Ltd. In conjunction with Nick Mather, Stephen was:

- co-founder and Executive Director of Arrow Energy Ltd until its takeover in 2010 (acquired by Royal Dutch Shell Plc and the PetroChina Group, for ~$3.5bn)

- co-founder and a Non-Executive Director of Bow Energy Ltd (acquired by Arrow Energy Pty Ltd for $550mn in 2011)

He is also a former non-executive director of Queensland Treasury Corporation, Stanmore Coal Ltd, Diversa Ltd, Apollo Gas Ltd, UIL Energy Ltd and Dart Energy Ltd.

He qualified as a Chartered Accountant early in his career was employed in the Corporate Finance division of Ernst & Young and the Corporate Tax division of Coopers & Lybrand. He has had considerable experience and success in the fields of corporate restructuring, debt and equity financing, and mergers and acquisitions.

Roland Sleeman – Non-Executive Director (Qualifications: BEng (Mech), MBA)

Roland has some 34 years' experience in oil and gas, utilities and infrastructure, serving in various senior management roles with Eastern Star Gas Limited as Chief Commercial Officer and AGL as General Manager of the Goldfields Gas Pipeline. He has extensive commercial experience including negotiation of gas sales agreements, commercialisation of new gas and power station opportunities and management of major gas transmission pipeline infrastructure.

Roland is currently the CEO of Lakes Oil NL.

Other current directorships: Lakes Oil NL (LKO.ASX).

Eytan Uliel – Non-Executive Director (Qualifications: BA, LLB)

Eytan is a finance executive with extensive oil and gas industry experience, having served as the Commercial Director of Bahamas Petroleum plc (a UK-listed company) since 2015 and as the Chief Financial Officer/Chief Commercial Officer of Dart Energy Limited from 2009 – 2014.

Additionally, Eytan was the Asian Regional Head of the Corporate & Structured Finance Group at Babcock & Brown (2006-2008) and with Carnegie, Wylie & Company, with responsibility for that firm's Asian activities (1999-2006).

Eytan has extensive experience in mergers and acquisitions, capital raisings and general corporate advisory work, with oil and gas industry-specific experience in public market takeovers and transactions, private treaty acquisitions, and partnering transactions.

He has significant experience at a Director level on the ASX and SGX, previously serving on the Boards of Easycall International Ltd, Strike Energy Limited, Jasper Investments Ltd, CH4 Gas Ltd (until merging with Arrow Energy Ltd), and as an alternate director of Neverfail Springwater Ltd.

Exhibit 25: Summary shareholdings - Board and Executives

		Fully Paid Ordinary Shares	Options	Unlisted Options	
Nick Mather	Executive Chair	4,830,364	591,197		As of 29-June
Stephen Bizzell*	NED	9,787,066	4,064,005	6,000,000	As of 29-August
Roland Sleeman	NED	58,333			
Eytan Uliel	NED	Nil			

Source: Company data; * Stephen Bizzell also holds 100 Amortizing debt notes
It should be noted that both Messrs Mather and Bizzell shareholdings are before the allotment of the Rights Issue shortfall and before the allotment of the underwriting options (subject to EGM approval)

Brad Lingo – Chief Executive Officer (Qualifications: BA (Hons), JD)

Brad has recently been appointed the CEO of Armour Energy (ASX release – 15-June, 2020), bringing to the position over 30 years of experience across a wide range of industry roles, including business development, new ventures, mergers and acquisitions and corporate finance.

Mr Lingo has been in the oil and gas industry, particularly the Cooper-Eromanga basins since 1993, commencing as VP and Head of Business Development for Tenneco Energy but most notably as Managing Director and CEO of Drillsearch Energy Ltd for 6 years, where the company played a lead role in the technical unlocking of the now prolific Western Flank plays. During his time at Drillsearch, the market capitalisation of the company increased from ~ $40m to ~ $800m.

Exhibit 26: Brad Lingo Performance Rights

Performance criteria	No. of Performance Shares
On the first Commercial Discovery in the Co-Era Assets being determined in accordance with recognised standards in the oil and gas industry and announced by the company	900,000
The VWAP for Shares trading on the ASX for 20 consecutive days is not less than 500% over the last trading day before the Commencement Date	1,800,000
The Board approving the entering into of a farm-out or other commercial agreement in respect of the NT assets	1,350,000
The Board approving a refinancing of the FIIG Notes (Corporate Bond Facility)	1,350,000
The company achieving a stabilised flow rate of in excess of 14TJd from the Kincora Gas Project	900.000
On the first Commercial Discovery on any licences other than; a) the Kincora Gas Project; and b) The CoEra Assets	900,000

Source: Company data

Prior to Drillsearch, Brad was Head of Oil & Gas for the Commonwealth Bank of Australia. He was also a co-founder of Epic Energy which became one of Australia's leading developer, owner and operator of natural gas infrastructure.

At this stage Brad Lingo holds no shares in the company but has a schedule of Performance Rights awarded against specific criteria aligned with key outcomes related to the corporate strategy plan and shareholder interests (Exhibit 26).

In our view, it's always critical for executive remuneration (certainly shares based incentives) to be specifically aligned with measurable deliverables that benefit the shareholders.

Top 20

We note the retail investor nature of the share register and at some point, the need to transition the register towards long-term, institutional investors with stronger financing capacity, particularly to support appraisal (and development outcomes?) assuming drilling success cases.

Exhibit 27: Top 20 Shareholders holding >59% of the issued capital (ordinary shares) – As of 13-July, 2020

			%
1. DGR GLOBAL LIMITED		149,999,615	19.25
2. ROOKHARP CAPITAL PTY LIMITED		80,445,934	10.32
3. TENSTAR TRADING LIMITED		42,275,072	5.43
4. MR PAUL COZZI		41,815,487	5.37
5. TENSTAR TRADING LIMITED		23,284,383	2.99
6. CITICORP NOMINEES PTY LIMITED		16,056,528	2.06
7. BNP PARIBAS NOMINEES PTY LTD HUB24 CUSTODIAL SERV LTD DRP		11,361,476	1.46
8. HSBS CUSTODY NOMINEES (AUSTRALIA) LIMITED		9,560,144	1.23
9. HAYES INVESTMENTS CO PTY LTD		9,000,000	1.15
10. JETAN PTY LIMITED		8,695,652	1.12
11. BAM OPPORTUNITIES FUND PTY LTD		7,440,000	0.95
12. CF2 PTY LTD	<THE CF A/C>	6,238,301	0.80
13. J P MORGAN NOMINEES AUSTRALIA PTY LTD		5,637,203	0.72
14. NO BULL HEALTH PTY LTD		5,521,739	0.71
15. MR SIMON WILLIAM TRITTON	<INVESTMENT A/C>	5,434,782	0.70
16. CPS CONTROL SYSTEMS PTY LIMITED	<THE IAN CAMPBELL S/FUND A/C>	5,094,773	0.65
17. HAYES PASTORAL CORPORATION PTY LTD		5,000,000	0.64
18. MR RONALD GEOFFREY PHILLIPS		4,605,000	0.59
19. MR PAUL AINSWORTH		4,500,000	0.58
20. JSR CORPORATION PTY LTD	<JOHN MURRAY SUPER FUND>	4,347,826	0.56
		446,313,915	**57.27**

Source: Company data

We note the discrepancy between the Top 20 and the Directors Interests as per Exhibit 25 pending a rebalance post the upcoming EGM

Research as a Service

Appendix 1 – Santos farm-in deal in NT/NWQ

Armour announced it had secured a farm-out deal with Santos for certain Queensland and NT permits in an ASX release dated 21.09.15 as outlined.

Santos will farm-in to certain tenements, being a granted tenement and applications in North Queensland (ATP1087: granted, and ATP1107, ATP1192 and ATP1193: applications) and the Northern Territory permit applications (EP172 and EP177)

Armour will retain 100% ownership of its other tenements in Northern Australia covering approximately 774mn acres, including the McArthur Basin in the Northern Territory

Santos will pay Armour $A15mn in cash and further cash payments of up to $A15mn *(amended as per below)*

Santos will carry 100% of Armour's costs for the work programs within the Farm-in Tenements up to a combined total expenditure of $A65mn. Armour will transfer a 70% working interest and operatorship of the Farm-in Tenements to Santos on a phased approach, commencing with ATP 1087 as the immediate exploration target.

As per an amendment dated 27.07.20:

Under the original terms of the Farm-in Agreement, the Total Capped Amount was required to be allocated to defined farm-in programme activities and expenditure amounts across each of the Farm-in Permits including the Application Areas.

Santos and the Company have agreed to amend the Carried Work Programme (refer Exhibit 28). Santos' commitment to free carry Armour for the amended Carried Work Programme expenditure across the tenements up to a capped amount of A$64.9mn remains unchanged.

Exhibit 28: Santos farm-in details on a permit wide basis…committing to two significant wells underscores the expensive and early nature of exploration in the region.

Permit	Expenditure Cap	Firm Programme May be varied across permits by agreement	Flexible Programme across permits To maintain permit compliance while supporting optimal explorations programmes	Contingent
ATP 1087	A$12.5mn	Drill one **significant well**	Acquire and process up to 600 line km of new 2D seismic and/or magneto-telluric data or equivalent potential field surveying (eg airborne gravity/gradiometry).	If a **significant well** encounters an interval that Santos considers capable of passing a PRMS discovery test, sidetrack as a horizontal well and undertake fracture stimulation and flow testing.
ATP 1107	A$3.2mn		Drill up to 10 shallow aquifer wells to a total depth of 100-150m (or shallower if sufficient water is encountered).	
ATP 1192	A$20.7mn	Drill one **significant well*** *	Drill up to four core holes to enable seismic ties and undertake laboratory analysis of core samples.	
ATP 1193	A$9.5mn		Geological and geophysical studies.	
EP 172	A$9.5mn			
EP 177	A$9.5mn			
	A$64.9mn		GG&A	

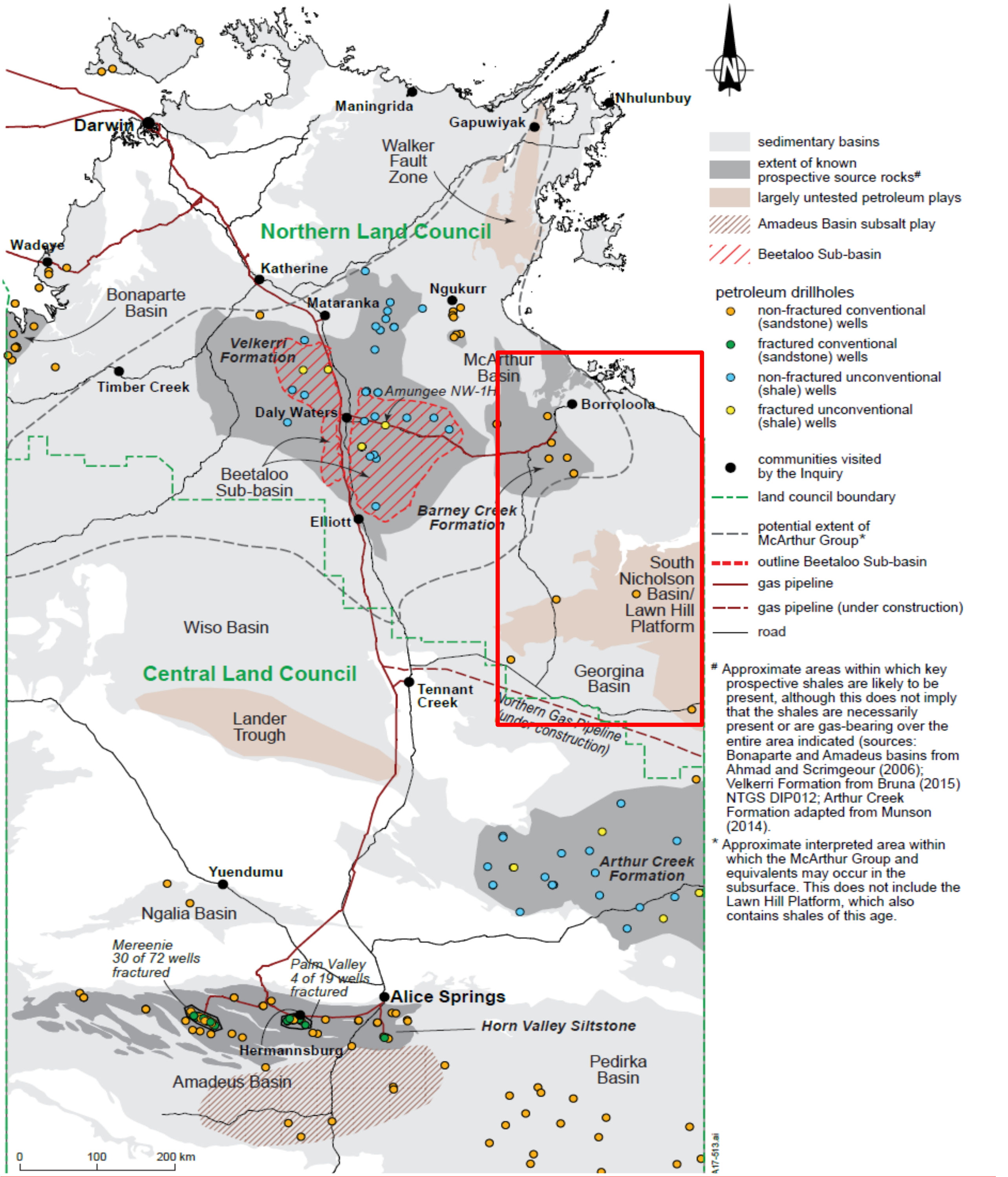
Source: Company data; * subject to clause 6.3 of the Agreement

Pursuant to the Farm-in Agreement Amendment, Santos will make a one-off, unconditional accelerated cash payment of $A6mn in total in full consideration of all future contingent permit transfer payments covering the Application Areas *(previously the commitment was for up to A$15mn).*

In conjunction with this unconditional payment, Santos will lead all activities and negotiations (including Native Title negotiations) and assume the responsibility and expense for pursuing the award of the outstanding Application Areas. This accelerated payment is no longer subject to the previous refund conditions (ie if the transfer of an interest in any of the Application Areas is not approved, or if the permit conditions on award are not acceptable to Santos).

Appendix 2 – NT zones of prospective source rocks

Exhibit 29: Armour acreage extends from Borroloola through to the Georgina Basin annotations…considered to contain identified prospective source rocks



Source: NT Fracking Inquiry (Final Report). The grey areas show the extent of the known shale gas source rocks. The taupe areas are those that are considered to have the potential prerequisites for shale gas to occur but have not yet been tested by drilling.

Red bordered overlay indicates broad zone of AJQ acreage.

Appendix 3 – Debt details

The company has a total of ~$55mn of debt on its balance sheet (estimated as at 30-June) via two facilities – as a Corporate Bond Facility and through a loan facility issued by Tribeca (Tribeca Global Natural Resources Credit Fund).

Corporate Bond Facility – Key terms

A new Corporate Bond facility was established in March 2019, in the order of $55mn, replacing and refinancing all of the outstanding Senior Secure Amortising Notes. The original financial covenants concerning leverage, debt servicing and gearing were amended [March-2020]. We highlight some of the key terms and conditions associated with the facility:

Debt Service Cover ratio

This is the ratio of EBIT/(aggregate interest and scheduled principal repayments)

Period	Ratio
1-July, 2020 to (and including) 30-September, 2020	1:50:1.00
1-October, 2020 to (and including), 30-June, 2021	1.75:1.00
1-July, 2021 to (and including) the Maturity Date	2.00:1.00

Gearing ratio calculated on a net debt/(net debt + equity) basis

Calculation Date	Ratio
30-June, 2020	60%
31-December, 2020	55%
30-June, 2021	50%
31-December, 2021	40%
Each 30-June and 31-December thereafter until the maturity date	35%

Leverage ratio

This is the ratio of debt/EBITDA for the periods as noted. For the periods up to 30-June, 2021 the EBITDA will be annualised estimate.

Calculation Date	Ratio
From 1-July, 2020 to (and including) 31-December, 2020	3.50:1.00
From 1-January, 2021 to (and including) 30-June, 2021	3.00:1.00
From 1-July, 2021 to (and including) 30-June, 2022	2.50:1.00
From 1-July, 2022 to (and including) the maturity date	2.00:1.00

Minimum cash balance

The company must hold a minimum cash balance of $2.0mn, not falling below $4.0mn for longer than 90 consecutive days.

Call on cash asset proceeds (disposal by sale and fam-outs)

With respect to the servicing and repayment of the Notes, the issuer is constrained by conditions related to asset sales and the cash consideration of farm-out deals as follows:

"Notwithstanding any other Condition, the Net Proceeds of any Disposal shall be allocated by the Issuer as follows:

(a) not less than 50% of such Net Proceeds being applied as an unscheduled amortisation payment on the Notes"…and;

"(b) the remaining balance (not applied to an unscheduled amortisation payment) *is to be retained and used and applied by the Group"* as working capital

And;

"Notwithstanding any other Condition, each Farm-In Payment shall be allocated by the Issuer as follows:

(a) not less than A$1,650,000 of each Farm-In Payment being applied as an unscheduled amortisation payment on the Notes"; and

"(b) the remaining balance (not applied to an unscheduled amortisation payment) *is to be retained and used and applied by the Group for general corporate purposes.'*

Amortisation (repayment) schedule

Payments of interest and amortisation of the principal will be according to the following schedule.

Exhibit 30: Amortisation schedule – remaining Corporate Facility repayments

Scheduled Amortisation Payment date	Payment (A$ per Note)	Aggregate Amortisation (A$) A	Aggregate Amortised Face Amount of the Notes (A$)	Interest (A$) B	A+B (A$)
29-Sep-20	20	1,100,000	50,050,000	1,118,906	2,218,906
29-Sep-20	96.37	5,300,350	44,749,650	0	5,300,350
29-Dec-20	20	1,100,000	43,649,650	978,899	2,078,899
29-Mar-21	35	1,925,000	41,724,650	954,836	2,879,836
29-Jun-21	35	1,925,000	39,799,650	912,727	2,837,727
29-Sep-21	40	2,200,000	37,599,650	870,617	3,070,617
29-Dec-21	40	2,200,000	35,399,650	822,492	3,022,492
29-Mar-22	40	2,200,000	33,199,650	774,367	2,974,367
29-Jun-22	40	2,200,000	30,999,650	726,242	2,926,242
29-Sep-22	45	2,475,000	28,524,650	678,117	3,153,117
29-Dec-22	45	2,475,000	26,049,650	623,977	3,098,977
29-Mar-23	50	2,750,000	23,299,650	569,836	3,319,836
29-Jun-23	50	2,750,000	20,549,650	509,680	3,259,680
29-Sep-23	50	2,750,000	17,799,650	449,524	3,199,524
29-Dec-23	50	2,750,000	15,049,650	389,367	3,139,367
29-Mar-24	273.63	15,049,650	0	329,211	15,378,861

Source: Company data; * Stephen Bizzell also holds 100 Amortizing debt notes
Note the 29-Sep payment of $5.3mn is a non-scheduled payment in accord with the conditions as outlined previously

It's worthwhile highlighting that the amendments to the Note covenants were the consequence of:

"…delays in the execution of the (work) *programme and; gas production and realised prices being lower than was anticipated at the time that the Notes were issued.*

The lower than expected production results were the result of a number of factors including the tight market for the procurement of drilling and workover rigs, and a 26-day outage of production from the Kincora Gas Plant, caused by the failure of a critical compressor associated with LPG production. The lower than expected output of the gas processing facility led to lower levels of working capital which would have ordinarily been used to further increase or accelerate new production."

We would add that the collapse of crude oil and LNG prices are causing a diversion of production into the Eastern Australian Gas Market, with a resultant fall in the spot domestic gas price. The spot gas price is expected (forecast) to remain weak through 2021, with supply tightness returning in 2022.

The probability of continuing oil price and CoVid impacts through FY21 should not be discounted.

Tribeca loan facility

AJQ ha a more vanilla debt facility (credit facility) with Tribeca which was secured on 26 July 2018.

As described:

"The Tribeca Facility is secured by:

- *a guarantee from the Company,*
- *a second ranking specific security over two bank accounts controlled by Westpac Banking Corporation (the Credit Accounts) in the name of Armour Surat, and*
- *a second ranking featherweight security interest over all the present and after-acquired property of Armour Surat."*

The debt has a 9% pa coupon rate payable quarterly in arrears on amounts drawn, Tribeca also holds 41,000,000 unlisted options to subscribe for ordinary shares with an exercise price of A$0.161.

The Options are currently well out of the money and are set to expire on 31.06.21.

Exhibit 31: Financial Summary

ARMOUR ENERGY LTD		AJQ
YEAR END		June
NAV	A$cps	$0.13
SHARE PRICE	Acps	$0.021
MARKET CAP	A$mn	17.5
ORDINARY SHARES	M	832
OPTIONS	M	

nm = not meaningful
na = not applicable

As per ASX data 4-Sep

COMMODITY ASSUMPTIONS		FY19A	FY20E	FY21E	FY22E
Realised liquids price	US$/b	96.03	66.26	60.73	64.13
Realised gas price	US$/mcf	6.06	5.76	5.28	5.57
Realised LPG Price	A$/t	581	484	443	468
Exchange Rate	A$:US$	0.7157	0.6822	0.6899	0.6886

RATIO ANALYSIS		FY19A	FY20E	FY21E	FY22E
Shares Outstanding	M	509	779	857	857
EPS (pre sig items)	Acps	(2.4)	(1.5)	0.7	2.5
EPS (post sig items)	Acps				
PER (pre sig items)	x	na	na	3.0x	0.8x
OCFPS	Acps	(1.9)	(10.3)	5.3	40.4
CFR	x	na	na	0.4x	0.1x
DPS	Acps				
Dividend Yield	%				
BVPS	Acps	87.9	59.2	59.3	85.2
Price/Book	x	nm	nm	nm	nm
ROE	%	(29%)	(21%)	12%	30%
ROA	%	(11%)	(8%)	5%	17%
(Trailing) Debt/Cash	x		18.1x	31.9x	14.3x
Interest Cover	x		nm	3.0x	11.2x
Gross Profit/share	Acps		8.1	17.7	48.8
EBITDAX	A$M	10.0	10.4	21.9	43.8
EBITDAX Ratio	%				

EARNINGS	A$000s	FY19A	FY20E	FY21E	FY22E
Revenue		27,819	23,208	39,123	72,295
Cost of sales		(19,018)	(16,931)	(23,978)	(30,507)
Gross Profit		**8,801**	**6,277**	**15,145**	**41,788**
Other revenue		78	2,879	5,000	0
Other income		193	123	69	44
Exploration written off		0	(520)	0	0
Finance costs		(13,656)	(5,276)	(3,357)	(3,042)
Impairment		(71)	0	0	0
Other expenses		(19,990)	(15,810)	(8,577)	(10,732)
EBIT		2,467	(4,257)	9,925	34,098
Profit before tax		**(10,996)**	**(9,410)**	**6,637**	**31,100**
Taxes		(688)	(403)	(597)	(9,330)
NPAT Reported		**(11,684)**	**(9,812)**	**6,040**	**21,770**
Underlying Adjustments					
NPAT Underlying					

CASHFLOW	A$000s	FY19A	FY20E	FY21E	FY22E
Operational Cash Flow		**1,436**	**11,223**	**24,629**	**62,073**
Net Interest		204	(5,153)	(3,896)	(3,150)
Taxes Paid		0	0	0	0
Other		(2,219)	(24,375)	(23,945)	(30,631)
Net Operating Cashflow		**(987)**	**(7,999)**	**4,580**	**34,592**
Exploration		(169)	(529)	0	0
PP&E		(22)	0	0	0
Petroleum Assets		(16,714)	(16,686)	(10,200)	(22,500)
Net Asset Sales/other		3,217	17,842	14,000	5,000
Net Investing Cashflow		**(13,688)**	**628**	**3,800**	**(17,500)**
Dividends Paid					
Net Debt Drawdown		11,612	(6,066)	(11,350)	(15,559)
Equity Issues/(Buyback)		7,184	7,457	1,670	0
Other					
Net Financing Cashflow		**18,796**	**1,391**	**(9,680)**	**(15,559)**
Net Change in Cash		**4,121**	**(5,980)**	**(1,300)**	**1,533**

BALANCE SHEET	A$000s	FY19A	FY20E	FY21E	FY22E
Cash & Equivalents		9,225	3,245	1,945	3,478
PP&E & Development		42,382	61,107	69,531	75,986
Exploration		49,277	33,824	33,824	33,824
Total Assets		**116,552**	**124,446**	**119,062**	**130,018**
Debt		58,618	61,975	49,753	33,381
Total Liabilities		**71,793**	**78,308**	**68,258**	**57,005**
Total Net Assets/Equity		**44,759**	**46,138**	**50,804**	**73,013**
Net Cash/(Debt)		(49,393)	(58,730)	(47,808)	(29,903)
Gearing dn/(dn+e)		52%	56%	48%	29%

PRODUCTION		FY19A	FY20E	FY21E	FY22E
Condensate/Crude Oil	kboe	56.2	55.2	118.1	156.9
Nat Gas	PJ	3.3	2.7	5.9	10.1
LPG	kt	4.5	4.2	8.8	21.0
TOTAL	**kboe**	**627**	**527**	**1,148**	**1,975**
Product Revenue	A$mn	27.8	23.2	39.1	72.3
Cash Costs	A$mn	17.9	15.7	22.2	28.5
Ave Price Realised	A$/boe	44.34	44.02	34.09	36.60
Cash Costs	A$/boe	28.53	29.73	19.34	14.41
Cash Margin		**36%**	**32%**	**43%**	**61%**

		Reserves			Contingent	
Net To AJQ		1P	2P	3P	1C	2C
Kincora Reserves						
Sales Gas	PJ	67.4	150.3	321.1		
LPG	kt	139	310	663		
Condensate	kb	670	1,493	3,191		
Oil	kb	246	1,221	2,640		
Isa Super Basin (STO farm-in area)						
Sales Gas	PJ				10.3	48.1
MacArthur Basin plays						
Conventional	PJ				2.5	6.2
Wombat-Triton						
Sales Gas	PJ				437	818
Otway-1						
Sales Gas	PJ					35

Prospective Resources		1U	2U	3U
Isa Super Basin (STO farm-in area)				
Sales Gas	PJ	2,079	6,881	18,399
MacArthur Basin plays				
Conventional	PJ	1,351	4,990	31,081
Unconventional	PJ	3,950	31,185	345,634
TOTAL	PJ	5,301	36,175	376,715

EQUITY VALUATION	Interest	Pr	A$mn	A$/share
Queensland				
Kincora	Various	50%	$74	$0.09
Exploration	Various		$10	$0.01
Newstead Gas Storage		50%	$13	$0.01
Northern Australia				
Isa Super basin	Various	25%	$16	$0.02
McArthur Basin	Various	1%	$35	$0.04
Cooper Basin				
Exploration	Various		$10	$0.01
Victoria				
Wombat - Trifon	PRL 2	25%	$10	$0.01
Otway-1	PEP 169	6%	$3	$0.00
Other			$3	$0.00
			$174	$0.20
Net cash/(debt)			($55)	($0.06)
Corporate costs			($5)	($0.01)
TOTAL			**$114**	**$0.13**

Source: RaaS Advisory (Priced close of trading 2-Sep at 2.1cps)

FINANCIAL SERVICES GUIDE

RaaS Advisory Pty Ltd

ABN 99 614 783 363

Corporate Authorised Representative, number 1248415

of

BR SECURITIES AUSTRALIA PTY LTD

ABN 92 168 734 530

AFSL 456663

Effective Date: 26th November 2018

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- who we are
- our services
- how we transact with you
- how we are paid, and
- complaint processes

Contact Details, BR and RaaS
BR Head Office: Level 14, 344 Queen Street, Brisbane, QLD, 4000
RaaS: 20 Halls Road Arcadia, NSW 2159
P: +61 414 354712
E: finola.burke@raasgroup.com

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