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Lakes Blue Energy NL

Update Report

A partner for the Enterprise North dance

Energy

23 November 2023

Lakes Blue Energy NL (ASX:LKO) is a junior energy explorer with assets across southern and eastern Australia (and PNG). Having secured a farm-in deal, the company is set to return to exploration with the high-graded Enterprise North prospect set for drilling in H2 2024 subject to securing the requisite regulatory approvals. The success case of Enterprise North can also add material look-through upside to other Victorian opportunities. There are a number of potential high-grade re-rating points for the company in the short-medium term. The success case at Enterprise North has the capacity to significantly change the structure and value base of the company. We suggest a material gas discovery could be monetised relatively rapidly through a low capital cost development option or asset transaction. With more clarity in the operating environment, the path to commercialisation should be relatively simple as a domestic gas play. Crystallising the inherent value is dependent on successful drilling outcomes and the company's capacity to continue to secure financing beyond the drilling phase, but certainly the opportunity set looks attractive over the next 12-18 months.

Business model

Lakes Blue Energy is a junior energy company holding extensive acreage across three Australian states (and PNG), dominantly focussed on exploring for gas. The company holds a portfolio of exploration assets and a pre-development, commercial discovery (industrial CO_2) at Nangwarry. Recent evaluation works have high-graded the Enterprise North Prospect in the Otway Basin, with the nearby Beach Energy (ASX:BPT) operated Enterprise gas discovery pointing to the look-through potential as an analogue model. The company is working the requisite approvals applications through the regulatory process with drilling likely in H2 2024. The success case could be transformational and commercialised quite rapidly.

Financing adds to the Enterprise North technical promise

Securing a partnering deal with Cooper Energy (ASX:COE) underpins LKO's financing requirement for the drilling of Enterprise North (PEP 169) in the onshore Otway Basin (LKO 49%, reducing to 23.9% on completion). The prospect is supported by 3D seismic and tie backs to analogue gas discoveries. Comparative analyses suggests a high-quality and material gas opportunity, at up to 150PJ with a probability-of-success rating estimated at 72%. Discovery success rates based on 3D seismic are >90% and this prospect ticks the boxes. Drilling could commence in H2 2024. Confidence levels should be high given the success at the Beach Energy well (Enterprise-1) only 3km distant and the success case could be transformational - uncontracted gas with low capital and operating costs remains the most valuable asset in the sector.

Valuation of $278mn (0.5cps) at the mid-point

Valuing early-phase exploration assets is a subjective exercise. We assign values holistically, breaking out specific opportunities where sufficient detail is available. We value Enterprise North against transaction metrics at $54-158mn on a success case, but values assigned to specific plays are indicative only – success cases can deliver material upside versus the values assigned. We set a mid-point valuation of $278mn (0.5cps) to LKO, with an upside case to $460mn (0.8cps). Against a reference share price (0.1cps) would suggest the market is appropriately weighting the asset base for the current operational and corporate risks but note **a success outcome on Enterprise North could result in a material unwinding of risk weightings and reset the economic base cases, with potentially transformative upside, well in excess of our valuation range…**such is the nature and attraction of exploration plays.

Share Details

ASX code	LKO
Share price	$0.001
Market capitalisation	$58M
Shares on issue	58,430M
Net cash at 30-Sep	$0.2M
Free float	63.8%

Upside Case

- Drilling success at Enterprise North-1 crystallises a commercial outcome that may be well in excess of our current estimates
- The success case supports acceleration of other portfolio opportunities at Otway and Wombat
- The gas supply squeeze delivers commercial pricing in excess of our model

Downside Case

- Enterprise North-1 is unsuccessful with negative impact across the remainder of the high-risk exploration portfolio
- No material progress on other pre-development opportunities – Otway, Wombat, Nangwarry
- Continuing financing reliance through equity issues – dilutionary effects rendering capitalisation somewhat meaningless

Board of Directors

Roland Sleeman	CEO/Managing Director
Richard Ash	Non-Executive Chairman
Nick Mather	Non-Executive Director

Company Contact

Roland Sleeman +613 9629 1566

lakes@lakesoil.com.au

RaaS Contacts

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

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

Enterprise North – Arm's Length Validation

For small companies, working the asset base remains the key to garnering and retaining the attention of investment markets. Ultimately, value potential can only be realised through drilling holes.

The most prominent opportunity in the LKO portfolio is the Enterprise North prospect (PEP 169, LKO 49%*).

*subject to completion of the Cooper Energy farm-in

The company in JV with Armor Energy (ASX:AJQ) evaluated its Enterprise North prospect post the success of the Enterprise gas discovery [Beach Energy (ASX:BPT)].

The Enterprise North prospect is mapped as being on trend and highly correlated with the Enterprise and the Minerva gas fields [Cooper Energy (ASX:COE)].

The Enterprise gas discovery was made in Nov-2020 with the exploration well drilled from an onshore location, 3.5km from Port Campbell and 8km from the Otway Gas Plant.

Solely on the initial discovery Beach reported gross 2P undeveloped reserves of 161 PJ of sales gas, 352kt of LPG, and 4Mb of condensate, at an initial gas-condensate yield of around 25b/mmcf.

The company was quoted as indicating that the *"…liquids content in the field is more than double pre-drill expectation, significantly increasing the value of the discovery".*

Refer Beach Energy ASX releases for more details.

Enterprise North is considered to be a drill-ready prospect and <u>the best place to find gas is near to where it has already been found.</u>

Funded and waiting - there really is not much more to be done except drill

As announced on 23-Oct, LKO and COE have agreed to a partnering deal whereby COE will farm-in to the LKO/AJQ owned PEP 169 permit via the drilling of the Enterprise North-1 well.

COE has agreed binding terms as follows:

- Upfront payment of $1.2mn;
- Upon completion, Lakes will assign a 25.1% interest in PEP 169 to Cooper Energy, noting Armour* holds a pre-emptive right to match the deal;
- Cooper will fund LKO for its share of the drilling of Enterprise North-1 to a capped limit of $1.25mn …that implies a drilling cost of about $5.2mn; and
- Post-completion the JV will be AJQ* (51%), COE (25.1%), LKO (23.9%).

*Armour was placed into receivership on 10-Nov - refer commentary in Appendices for more details.

The timing of the well is subject to rig availability and navigating the Victorian approvals process but could be drilling in H2 2024.

We have previously reviewed the Enterprise North play (*refer RaaS Reinitiation Report: Nov-2022*) and we expand our analysis and commentary from that update.

We maintain our view that the technical work underpinning the play is very strong, notwithstanding that exploration drilling is by definition a risky and speculative undertaking, but draw a high level of confidence from the analogue gas discoveries and the underpinning 3D seismic data.

Nothing in exploration is riskless and we'd highlight that Enterprise North does have risks, particularly extrapolating 3D seismic into the onshore. Whilst the prospect is well worth drilling, it <u>must be considered as early-stage exploration with all the resultant risks associated with pre-drill analysis and modelling</u>. However, the COE farm-in represents an independent evaluation and validation of the play, particularly when the company is prepared to commit capital to the opportunity and we can see why COE is interested.

Importantly, having COE in the JV provides a clear path to market that was not there previously. At its recent AGM the company indicated it was *"…open to third-party gas processing opportunities"* through its Athena Gas Processing Plant (COE 50%) with a nameplate capacity of 150 TJd. Athena is currently processing around 25 TJd…accommodating an Enterprise North discovery will not be an issue.

We highlight the JV has assigned a probability of success of 72% to the prospect.

Upcoming Return To Exploration In Victoria

The Enterprise gas discovery resulted in the PEP 169 operator undertaking a reinterpretation of the 3D seismic across the permit. Enterprise provided an additional, high-quality calibration point allowing prospect interpretation and analysis to be extrapolated along a regional trend from Minerva back through Enterprise and into Enterprise North.

Exhibit 1: The best place to look for gas is next to where it's already been found

Source: Company data

Exhibit 2 demonstrates the strong and directly correlatable seismic amplitude features across the three data points (M-E-EN), which provides a high degree of technical, if not commercial, confidence on a pre-drill basis, particularly as the commercial success rate of prospects drilled on 3D seismic, displaying AVO anomalies, is >90% (and reported as 100% in Beach Energy operated acreage).

Whilst the proximity of the Enterprise gas discovery should provide a high-quality interpretation and conversion to pre-drill estimates on reservoir thickness and properties, geology does not always co-operate in this respect so any resource estimates should be considered speculative until confirmed by drilling and testing.

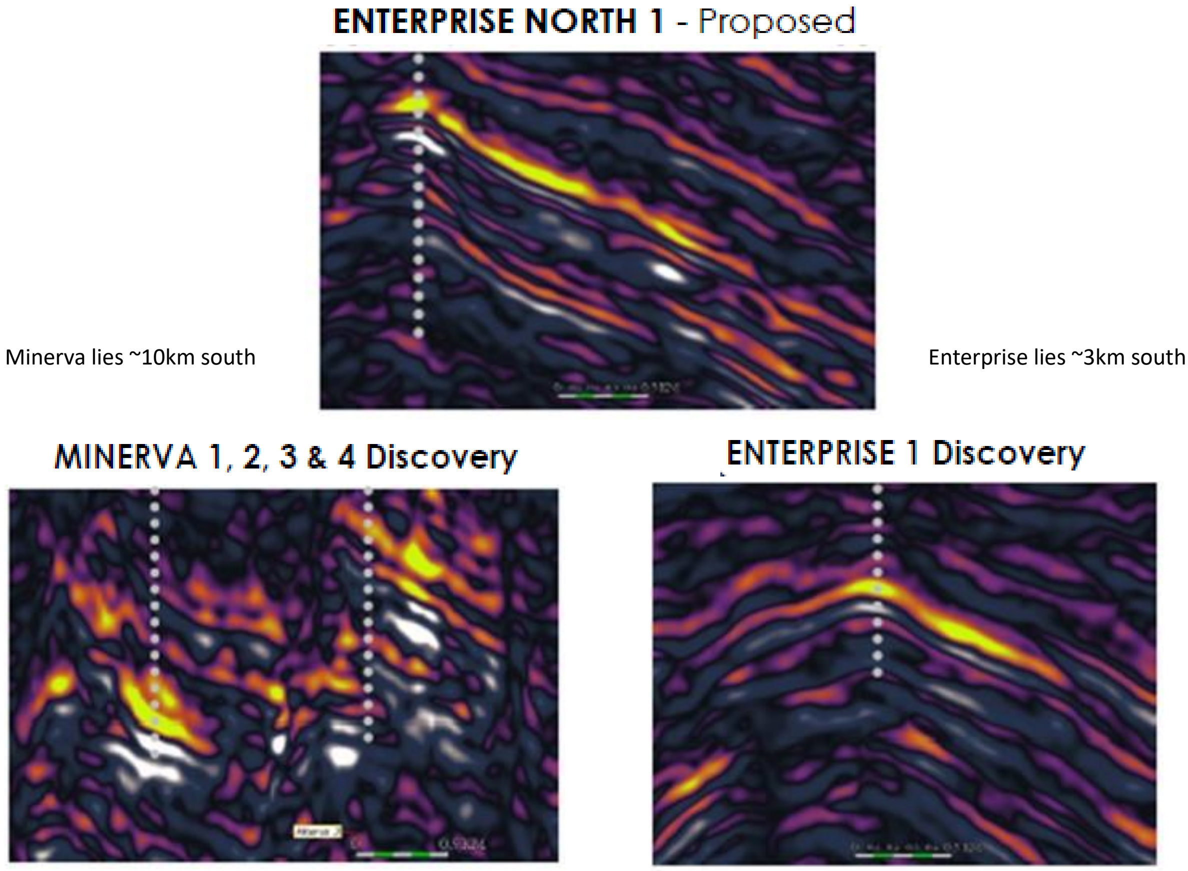
The Waarre sandstone as the primary target indicates that reservoir risk is unlikely to be a major consideration in determining the commercial case. The Waarre, on a regional basis, has demonstrated a high porosity-permeability relationship of 19-25% and 1-10darcies, with high storage capacity; and can deliver very strong production rates. If there is gas there, getting it out of the ground at commercial rates should not be a problem.

A success case is more likely to be infrastructure limited than reservoir constrained.

We note from an Armor Energy (ASX:AJQ) presentation, that at a modelled reservoir pressure of ~2,750psi, flow rates greater than 50mmcfd could theoretically be possible.

We caution that a success case at Enterprise North may not achieve these rates – porosity, permeability and total gas may be at the low end of the assumption ranges.

Exhibit 2: 'Bright spots' provide the confidence and what works for one generally works for others



Source: Company data

Extrapolation based on comparative data (**Exhibit 3**) suggests that a success case at Enterprise North could have the potential to hold recoverable reserves equivalent to Enterprise. Assuming recovery rates and CO_2 content assumptions are valid, a broad estimate of the gas opportunity for Enterprise North could be upwards of 150PJ at the top end of expectations.

For scenario valuation purposes we assume a range of 50-150PJ (gross recoverable gas), with 50PJ representing a minimum commercial outcome (RaaS estimate). We highlight that the comparative data also implies that a success case at Enterprise North has the strong potential to be liquids rich.

Exhibit 3: Extrapolating into Enterprise North from analogues supports a high degree of confidence

	Enterprise North	Enterprise	Minerva	
Discovery date		Nov-2020	1993	
Reserves				
Gas		161 PJ	318 PJ	Liquids content at **Enterprise** was double the pre-drill estimate
LPG		35 2kt	331 kt	
Condensate		4 Mb	0.7 Mb	
Prospective	~419 Bcf GIIP* ~10 Mb of condensate	~300 Bcf GIIP		Est. recovery rate of ~60% for **Minerva**
CO_2 content	~10-20%	10-15%	1.3%	For modelling purposes only on E-North
Main reservoir		Upper Waarre sandstone	Waarre sandstone	The Waarre sandstone was intersected 89m high to prognosis at **Enterprise**…generally considered to be a hydrocarbon effect
Depth to target		2,052m		
Net thickness (m)	Est. 115m	115m (146m gross)	40-118m across the field	
First gas		est. mid-2023		
Flow data	JV estimates flow rates may be up to 60mmcfd***		Minerva-1 28.8mmcfd Minerva-3 50mmcfd	**Minerva** flow rates reported as 'facilities restricted'
Development cost		$51mn	$145mn inc. gas plant	
Field life		~12 years	~15 years	

Source: Armour Energy presentation (28 Sep); * GIIP = Gas Initially In Place; ** We suggest 60mmcfd is an engineering extrapolation

Revisiting The 'Value' Of An Enterprise North Success Case

With the resolution of the Federal Government Gas Code of Conduct ('Code') and price control exemptions for small, domestic-only producers, there is more clarity and certainty around the commercial landscape for an Enterprise North success case.

We are aware of industry noises suggesting gas prices in the $15-18/gj range have been the starting point in recent supply discussions, however, we should consider that speculative with no indication of volumes or terms. What we do draw from this is that holistically, the supply squeeze is still in effect and 'market pricing' remains well in excess of the nominal $12/gj price cap previously proposed in the Code.

Our previous valuation scenario was based on a long-run gas price assumption of $12/gj, which although likely conservative, we consider to a reasonable base-case estimate given the associated uncertainties with this exercise.

Whilst the prospect is an exciting opportunity, it is still early-stage exploration with all the resultant risks associated with pre-drill analysis and modelling. The proof will be in the result and that remains a risk and by definition speculative until completed. However, the entry of Cooper Energy, via farm-in, does provide a reasonable arms-length validation of the play, particularly given that company's operating experience in the Otway Basin which included the Minerva Gas Field prior to abandonment.

We note two ways to consider the value potential of Enterprise North - as a producing asset or on an asset sale basis.

We had previously indicated that given the number of assumptions that need to be made with respect to assigning a value range based on an Enterprise North development model, any estimates would contain a high degree of associated uncertainty.

With the entry of Cooper Energy to the JV (assuming completion of the farm-in deal), a clear path to market is likely to be provided through the Athena Gas Processing Plant with two points of sale available to LKO – at the well head and ex-plant, which would probably attract a tolling/processing fee.

Whilst optionality is a good outcome for LKO, it ultimately makes a 'development matrix' more complex.

We caution that although the Victorian regulatory process is nominally more sympathetic to new gas projects than previously (**refer Appendix commentary**) we are concerned that the approvals process may still be slower and relatively onerous, with timing to first gas still somewhat of a 'regulatory black hole'.

On many levels it seems more likely that a gas discovery at Enterprise North could be more readily monetised by LKO through an asset sale rather than a development and that on a pre-drill basis the cleanest and easiest method to assign a success-case valuation range is to apply a transaction metric.

We make this assumption solely on assigning a pre-drill valuation range, with no specific indication of the company's future monetisation intentions in the event of a success case. **We'd add that given the strength in gas market pricing and a look-through development analogue (Minerva), there could be more commercial attraction in Enterprise North as a future cash-flow project.**

Any value derived from comparative transactions is by definition based on historical data and even if adjusted for the current macro-economic environment, should probably be considered as a minimum in the absence of testing and development capex information.

A transaction metric benchmark

There is a weak point in the methodology – there has been only one specific transaction in the Otway Basin recent enough to better reflect the intrinsic value of east coast gas, but even so the market has materially moved on in terms of gas pricing and supply constraints since 2018.

Exhibit 4: A benchmark data point sets the base case

Transaction	Announced/ Completed	A$mn	Metric 2P		Comments
Beach Energy sale Otway interest to OG Energy	5/10/2018	**$344.0**	$11.50 $2.01	per boe per gje	In production with infrastructure . At the time of the deal gas prices were perhaps around the $7-8/gj, so the deal was NPV based with upside from near-field appraisal and development Looked 'fully priced' at the time

Source: Company data

Although there have been some recent farm-in transactions in the Otway Basin, they have been on a pre-drill basis on exploration opportunities and the prices paid reflect the high-risk nature of the opportunities, however, the promoted premiums do indicate the quality of the prospects.

- LKO with CEO basically a 2:1 promote; and
- 3D Oil (ASX:TDO) with ConocoPhilips – paying sunk costs and covering the cost of two offshore wells up to a cap of US$65mn for an 80% permit interests – TDO is capitalised at A$16mn.

We suggest the thin portfolio of deals is a pretty accurate reflection of how tight the acreage position is in the Otway Basin, with few operators but holding dominant tenement portfolios and entry level premiums being paid at the pre-drill or success-case levels.

Exhibit 4 outlines the Beach Energy-OG Energy deal with a look-through metric of $2.01/gj for reserves in production.

At the time of the deal, industry was modelling long-term contract gas prices in the order of $8/gj, with the transaction metric of ~$2/gj representing a unit NPV ratio of 25% of the long-run commodity price.

Effectively, BPT was selling proven, developed reserves with expansion potential requiring a significant capital investment in drilling and infrastructure (plant) expansion. The transaction price likely reflected the cum-expansion nature of the asset.

Ostensibly, this may seem like 'unders' for producing reserves but given the future capital commitments and timing to full gas expansion (the Otway processing plant is not expected to be at peak utilisation until sometime in 2025), the purchase price could probably have been considered as 'full' at the time, particularly if we were to add back to the cash component, the net capital benefits to BPT.

Purchase Price	$344mn (for a 40% working interest)
(Capex – cash flow) benefit	$250mn (est. at time of transaction on guidance and gas price assumptions)
Total 'benefit' to BPT	$594mn

Scaling off **Exhibit 4** would infer an equivalent unit transaction cost of ~$3.50/gje or a NPV ratio against a (then) long run gas price assumption ($8.00/gj) of ~43%, which would be at the high end of the scale.

We can assume those NPV ratios (25-43%) as bookends for producing reserves. However, the Enterprise North success case should be, by definition, as an undiscovered resource, at the lower end of the range at this stage, in our view.

We calculate a nominal NAV for the prosect using a simple equation:

$$P\ (\$/gj) * \phi\ (\%) * V\ (PJ) * X = \text{gross NAV}$$

Where –

P = average realised gas price	Estimate of average realised project gas price = $12/gj. Gas pricing is the key sensitivity assuming all other risk factors stay the same.
ɸ = NPV ratio	25% as per above (or $3/gj on a $12/gj long run price) The lower end of the range should adequately capture the exploration, development and financing risks on a pre-drill, pre-development basis.
V = modelled reserves (100% basis)	50-150PJ We capture the commercial uncertainty in the reserves range, with 50PJ at the low end, potentially suggesting a unit capex of c.$1/gj and 150PJ at the top, broadly equivalent to the pre-drill, analogue modelling as outlined previously.
X = Probability of success	We apply the JV-assigned probability of success rating of **72%.**

On a 100% basis we estimate the potential value of a success case at Enterprise North as ~$108-324mn on a 'risked' reserves range of 50-150PJ, noting that perhaps an initial reserves certification may be limited on the basis of a one-well result.

We do highlight that BPT has booked gross reserves of 161PJ (plus liquids) at Enterprise on the basis of one well and testing; and the JV has pre-drill expectations that the success case has a high probability of being somewhat of an Enterprise 'twin'.

Net success case value to LKO on the basis of this analysis (@49%) equates to $54-$158mn.

We assign a value on assuming a success case to Enterprise North only, however, the JV has identified additional exploration upside with the Scimitar lead mapped as a potentially large closure with associated seismic anomalies, indicating the presence of gas charge. Additional seismic data is required to promote the lead to drillable status, but on success there's likely more gas to find.

In that case there may be a bigger deal to be negotiated on a holistic basis.

Sensitivity…what is the chance long-run gas prices will be higher than $12/gj?

Naturally, for every $1/gj the unit NPV value (P * ɸ) changes and the implied value moves in accordance with the magnitude of the change on a 1:1 basis.

At $4/gj unit NPV (applying a $16/gj average realised gas price or ɸ = 33%), the net success-case value range for LKO becomes $71–210mn.

+$1/gj unit NPV = +$17-52mn net to LKO

How high long-run gas prices can go is an interesting but speculative discussion.

On top down observations from industry news and discussions, we suggest the rollout of renewables is slowing and likely to take longer than expected, resulting in more pressure on gas as a transition energy source.

We see gas demand increasing whilst supply options are narrowing:

- Cooper and Gippsland basins are in irrevocable decline with accelerated timelines to abandonment;
- Progress on the next tranches of Victorian gas, in particular, is slow, with little activity in-train post the lifting of the exploration moratorium and navigating of the (more onerous?) regulatory environment.

…we note the impending offshore Otway Basin drilling campaign via a consortium of operators (Beach Energy, ConocoPhilips, and Cooper Energy) but exploration activity may not commence till mid-2025 with long(ish) lead times to first production.

- Little to no material progress on supply options at scale in the Eastern Australia network

…all of which is a strong recipe for rising prices.

We would also comment that a success-case development option to supply gas through the Athena Plant could be very low capex – with a <2km tie-into the Minerva Pipeline and potentially high flow rates driving unit operating costs commensurately low.

We wouldn't be surprised on a best-case scenario to see the 'ϕ factor' material higher than the 25-43% implied by the BPT-OG Energy transaction.

Our speculative success-case our valuation range should probably be considered as a base case at this stage.

On a cautionary note, **no company has ever found a risked PJ of gas, so in absolute terms, the well outcome will be binary** – it is exploration, so "success = 0" is always a possibility.

A likely buyer on an asset basis?

With COE farming-into PEP 169, it is more likely to be the obvious and natural buyer on an asset transaction basis in our opinion. We had previously postulated that BPT should not be discounted as a potential buyer, as a success case should have significant attraction to both companies as low-risk expansion or extension gas, readily connectable into either the Otway or Athena gas plants.

Both companies could make low capex cases with high operating margins.

Although a high-margin development/cash-flow option is attractive as a monetisation play, an acquisition option cannot be totally discounted, particularly with the third JV party (Armor Energy – 51%) having recently been placed into receivership.

There may be a greater aggregation play unfolding here.

BPT has already shown at Enterprise that volumes around 150PJ are sufficiently large enough to constitute critical mass. COE has also shown through the farm-in that it sees the quantum of potential, probably has a lower reserves threshold than BPT and perhaps, sees stronger optionality and lower risk in the gas on a shorter time frame than the next phase of offshore drilling in its OP3D campaign.

Either way, we suggest these companies should be interested in what an holistic success case could deliver…bankable, undeveloped, low-cost gas in proximity to their respective infrastructure networks.

It's unlikely in our view that either BPT or COE would bid a significant premium unless there was competition. With control of the local infrastructure networks, perhaps LKO (AJQ?) could be considered as price takers in any negotiation.

However, let's find the gas first.

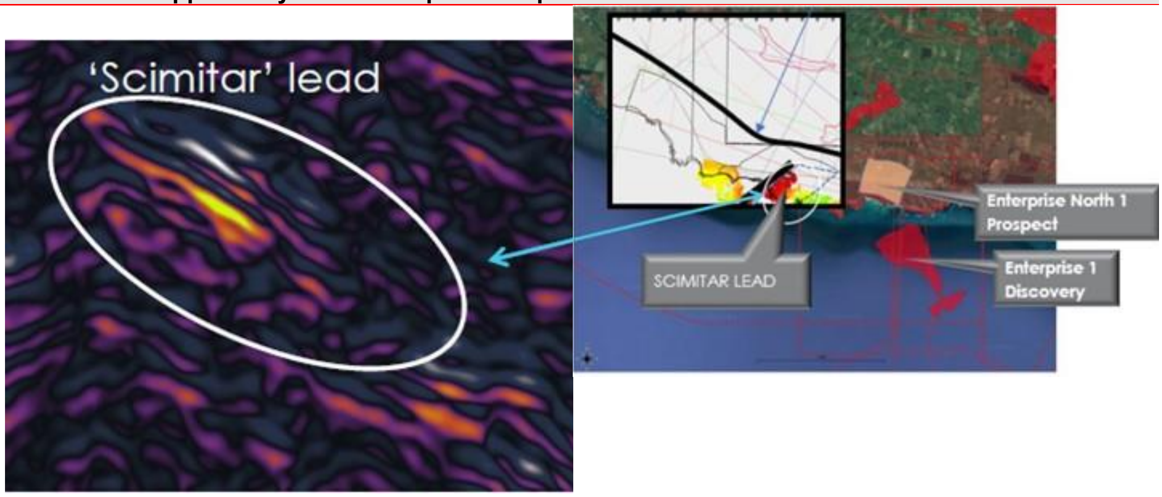
Beyond Enterprise North – There Is More To Find

The success case can be a greater de-risking event.

Gas at Enterprise North has positive implications for PEP 169 holistically and the Scimitar lead specifically (refer Exhibit 5). The lead is mapped as a potentially large closure with associated seismic anomalies, indicating the likely presence of gas charge.

Scimitar is not drill-ready and more seismic data would be required to better define the structure.

Exhibit 5: The opportunity doesn't stop at Enterprise North



Source: Company data

Otway-1 adds to the portfolio

The main regional, structural control of PEP 169 is a bounding fault that lies to the north of the Enterprise North prospect as mapped in Exhibit 4, which is typical of the Otway Basin. Gas discoveries on the northern side of this regional structural feature are typically small(er), ranging from 1-28 Bcf (Gas Initially In Place [GIIP]), whilst south into the offshore, field sizes are materially larger, at 200-558 Bcf (GIIP).

Exhibit 6: …and there is potential 'north' of the fault

Otway-1 is a conventional well ready to be drilled in close proximity to the Iona gas field but in a separate fault block.

Being only 400m from existing facilities a discovery could be commercialised rapidly.

Small gas volumes may likely mean gas sales on an interruptible basis only, with uncertainty on pricing.

We note LKO has ascribed a P_{50} Prospective Resource to Otway-1 of 60Bcf (gross) which is significant and highly valuable in the current gas price environment.

An economic threshold would likely be around 10PJ but would come with a commensurately short project life of perhaps three-four years.

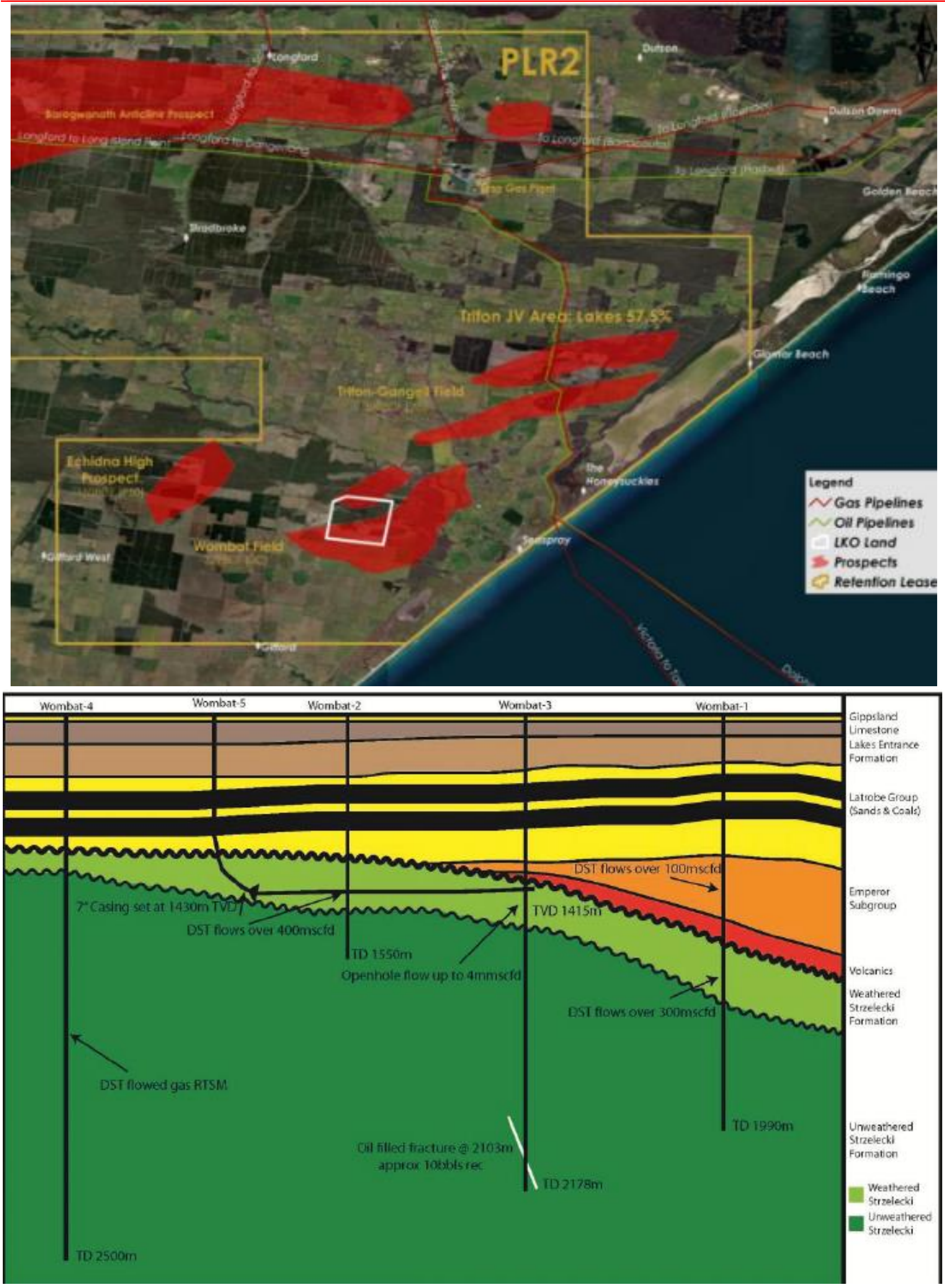
The JV carries a probability of success rating of 25%. An Enterprise North success could materially reduce the risk.

Source: Company data

Back Down The Wombat Hole (PRL 2, LKO 100%)

A success case at Enterprise North could also have positive implications for the company at its Wombat Project, which has been static for a number of years, because of the State Moratorium on exploration and recently due to issues navigating the new regulatory process on permit renewals and approvals.

Exhibit 7: Wombat is big gas – Enterprise North success can provide the capital



Source: Company data

At this stage, PRL 2 is the only asset where Lakes holds a defined gas resource (refer Exhibit 7). The working interests across the two fields vary but conceptually LKO could,negotiate to assume the remaining interest in the Trifon/Gangell fields. The resource sizes as indicated, particularly on the Wombat and Trifon fields, represent a material gas opportunity, ascribing 719Bcf at 2C.

Exhibit 8: Contingent [C] and Prospective [P] Resources – a significant gas play sits here

						Bcf		POS
					Low	Mid	High	
PRL 2	100%	Wombat Field	Gas	C	258	329	628	50%
	57.5%	Trifon Field	Gas	C	126	390	526	25%

Source: Company data

The Wombat Gas Field has been defined by four wells, flowing 3TJd from the Wombat-3 well.

Within the Wombat field gas has been intersected throughout the formation with some zones representing sweet spots with more favourable reservoir characteristics. This highlights the higher degree of complexity associated with potential development options.

LKO has indicated gas rates from Wombat-3 at ~4mmcfd (3TJd) whilst an extended production test of Wombat-2 produced average flows of ~0.8mmcfd from one zone in the well, in what is likely to be a multi-zone play.

The company plans to drill the Wombat-5 as expeditiously as regulatory approval and financing allow and it is here that the success case at Enterprise North could provide financing options via cash flow or cash to accelerate the appraisal and other pre-development activities.

Wombat-5 is designed to be a directionally drilled well as per the schematic noted in **Exhibit 7,** to test the commercial flow potential of long-reach Strzelecki Formation completions without fracking. We believe the well would likely be designed as a 1,500m open-hole lateral. Internal studies suggest gas flow rates could perhaps deliver around 5-6mmcfd.

The Wombat play was attractive enough to have warranted interest from Beach Energy, pre-moratorium, when a fracking solution was considered to be an optimal development process. The obvious attraction continues to remain the size of the potential resource.

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Our Valuation Demonstrates The Uplift On Success

Lakes Blue Energy is an exploration company, which by definition is a high-risk, speculative activity with largely binary outcomes – there will either be a commercial outcome or there won't.

Assigning values to an exploration portfolio should be viewed within that context and represents where indicated probabilistic, success-case outcomes. Drilling can deliver significantly different results to pre-drill expectations with material impacts to valuation estimates both up and down. Exploration is also capital intensive and the confirmation of prospect values is strongly dependent on the availability of capital at any point.

Risk-weighted asset valuation at $278mn (mid-point)

Our valuation is based risk-weighted unit gas values applied across resource estimates where applicable. Pure exploration plays are assigned nominal values and where appropriate, specific projects are valued against analogue transaction metrics as per the Enterprise North prospect. We have chosen to apply an asset transaction method to Enterprise North in the absence of more certainty around a success-case development option and note that there is no certainty that the same metrics can or will apply.

Intuitively, we suggest our ascribed value is not unreasonable given the location of the assets and position along the evaluation curve, particularly accounting for the subjective nature of risk weightings and commercial assumptions. **However, success cases can provide transformational upside**.

Exhibit 9: LKO NAV – Mid-point NAV represents a realistic success-case range

			Risked range (A$m)			
			Low	Mid	High	
Enterprise North	PEP 167	49%	$54	$108	$158	LKO ascribed POS = 72%
Wombat	PRL 2	100%	$20	$72	$120	Asset contains 2C volumes representing lower risk outcomes…the gas is there awaiting a defined development model
Trifon	PRL 2	57.5%	$10	$40	$60	2C volumes ascribed and valued as per Wombat, a lower weighting is applied based on Trifon as longer-dated production
Nangwarry	PRL 249	50%	$5	$10	$15	Risk weighted at 50% and subject to further project definition including guidance on pricing
Other Victoria	Various		$10	$24	$53	Nominal only and dependent on a success case at Enterprise North
Other SA	Various		$2	$3	$5	Nominal only
Other Queensland	Various	100%	$12	$21	$45	Nominal only
PNG	Various	100%	$5	$5	$5	After reviewing the technical data, TotalEnergies has declined to exercise its Phase B option, considering the Buna Prospect to be more likely oil prone rather than gas
			$117	**$280**	**$462**	
Net cash/(debt)				$1		
Corporate				($2)		
TOTAL			**$115**	**$278**	**$460**	
Shares issued (mn)		58,431	0.2cps	0.5cps	0.8cps	

Source: RaaS estimates; Risked ranges based on company ratings for drilling and where applicable a discretionary RaaS risk adjustment

We note as per the ASX release made on 30-Oct, LKO has proposed a share consolidation of one ordinary share per 1,000 ordinary shares currently issued.

The proposed consolidation is conditional on a final board decision to proceed dependent on market circumstances and shareholder approval.

Appendix – The Gas Markets

Exploration has returned to Victoria but is it business as usual?

In late 2022, the moratorium on all exploration activity (particularly drilling) in Victoria was lifted, although fracking and coal seam gas activity remains permanently banned.

The lifting of the moratorium has come with a revised regulatory process and some 12 months on, with no new drilling having been undertaken, it is probably fair to say the approvals process continues to be relatively onerous or at least uncertain.

The lifting of the moratorium was in response to the finding of the **Victorian Gas Program**, which concluded that *"…an onshore conventional gas industry would not compromise Victoria's environment or (our) vital agricultural sector"*.

Source: https://earthresources.vic.gov.au/projects/victorian-gas-program

One of the more interesting comments in the report was that an *"…onshore conventional gas industry could potentially start production from 2023–24 if industry makes a gas discovery quickly, considers it commercially feasible to develop, and secures the necessary regulatory approvals".*

As we are reviewing the past 12 months and approaching the end of 2023, the closest Victorian project to first gas is Beach Energy's Enterprise development, the status of which was addressed in the company's AGM commentary (14-Nov) as having *"…conclude*(d) *native title negotiations"* with *"…the outstanding work program, largely comprising wellsite hook-up and commissioning…now subject only to a final regulatory approval".*

First gas is targeted for the June quarter of 2024, noting that Beach managed to bypass the Victorian moratorium and new regulatory regime (as its well was "offshore"). The gas discovery was made in Nov-2020.

Ostensibly ~42 months from discovery to first gas is perhaps not an excess timeframe, but given the project is one well (already drilled) with a production well head and relatively short distance connection into the existing pipeline network, on balance that does appear long-dated.

However, being the first project to navigate the new regulatory regime perhaps provides a working template for future applications.

We would highlight the risk that success at Enterprise North may take a similar period to monetise, although we understand there may be less Native Title risk.

There is more clarity on federal gas policy overall

The release of the Federal Government's Safeguard Mechanism and Code of Conduct draft legislation in early 2023 has provided more certainty for the gas industry, particularly with respect to gas pricing for small operators selling gas into the domestic market.

Whilst the operating and development requirements for projects through to first 'new' gas are largely defined and on a headline basis the market looks like a reversion to 'pre-intervention' outcomes, there is a sting in the legislation that wasn't there previously with the potential for more restrictive covenants embedded within the framework.

The Federal Government has implemented its gas industry mandatory **Code of Conduct** ('Code") which commenced on 11 July 2023 and we suggest ostensibly clears the way forward for smaller gas operators.

https://www.legislation.gov.au/Details/F2023L00994

Industry body, AEP (Australian Energy Producers – formerly APPEA) had previously released preliminary observations suggesting that whilst the Code recognises the *"…critical need for investment in new gas supply to avoid future shortfalls in the east coast domestic market and to put downward pressure on gas prices"*, the process and practice of the operating regulations remained somewhat "uncertain" (at least in our interpretation of its commentary).

The Code imposes a nominal $12/gj price cap for new gas contracts and is subject to review and may be updated every two years, although the ACCC may review the price cap earlier if market conditions substantially change or notified by the requisite Ministers.

The cap does not apply to sales in the short-term gas markets as we have seen in the daily AEMO data.

There are deemed exceptions to the pricing rules which *"…automatically apply to small suppliers who produce less than 100 PJ of gas per year and who supply **all** of that gas to the domestic market. Eligibility is determined by the amount of 'counted gas' that has been produced in the most recent calendar year".*

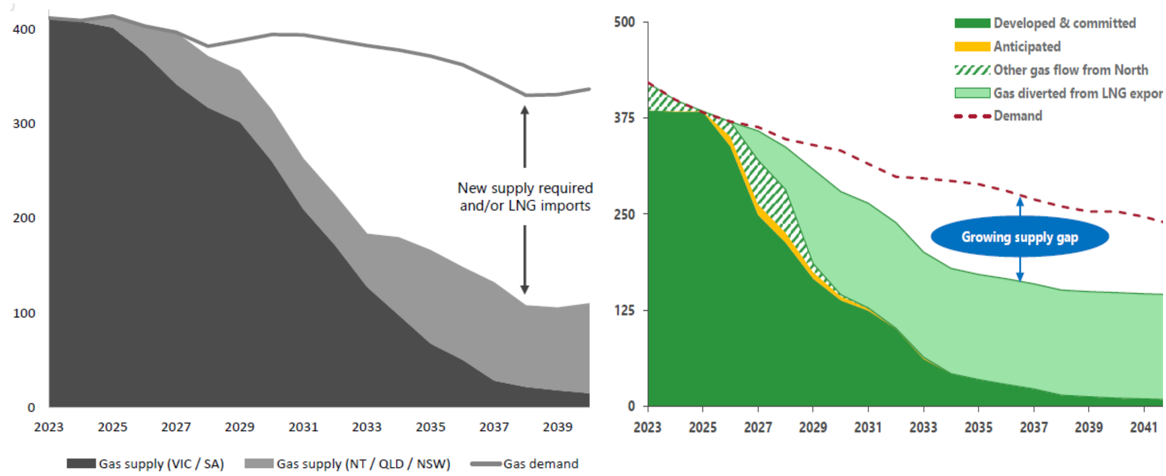
In this regard, any Enterprise North success case would be exempt from any price controls.

We remain somewhat at odds with the need for regulatory approvals to be at the joint discretion of the Climate Change and Energy Minister; and Resources Minister, which we suggest could lead to, perhaps, unnecessary delays, particularly in areas that may cross the mandates of both departments.

The gas supply squeeze continues

We feel little need to enter into specific detail on the state of east coast gas supply – this has become a staple inclusion of industry presentations and we refer readers to any of many released over the past couple of months.

Exhibit 10: A growing gas supply gap that all charts are showing



Source: Energy Quest (via Beach Energy 2023 AGM presentation) [LHS]; Cooper Energy (Nov-2023) [RHS]

Consensus points to a growing long-term supply gap and that has made sense intrinsically for quite some time, with the fall in supply (natural decline and end-field life) outpacing new development contributions.

In this regard, the gas price is meant to act as the balancing mechanism and in broad terms, the market has seen reported realised east coast domestic gas prices rise from around $5/gj in 2012 as per **Exhibit 11** notwithstanding adjustments for net third-party sales.

Exhibit 11: Average realised gas prices trending up across the gas producers

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
		FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23
STO	A$/gj	5.12	5.64	4.97	5.39	5.22	5.97	6.75	6.18	**5.91**	**7.48**	**10.75**	**11.97**
BPT		5.03	5.35	5.37	5.68	5.99	6.10	6.57	6.81	7.30	7.35	8.06	8.80
COE							5.08	6.26	7.71	7.65	6.86	8.27	8.59

Source: Company data (adj.); STO = Santos Limited; BPT = Beach Energy; COE = Cooper Energy

We would note that the Santos prices from 2022 may reflect gas sales into GLNG on oil-price linked terms and through 2022-2023 spot sales into local market at significant premiums to contract prices, especially through the winter periods.

Forecasting future gas prices is the unicorn, particularly given the political issues associated with energy prices through the transition period to renewables. There is the spectre of materially rising gas prices and increasingly shrill noises being made by commercial and industrial (C&I) gas users on economics, job losses and capacity closures.

As a long-term, arms-length observer we can point to history and suggest that upstream industry commentary has been highlighting/warning, with increasing volume, on rising gas prices for at least the past 15 years.

Anecdotally, we believe gas buyers continue to approach existing or emerging gas producers pre-emptively on east coast gas supply for 2024 and beyond and have been discussing prices well in excess of a nominal $12/gj benchmark.

There is somewhat of a disconnect between the headline noise and what is happening on the ground in a practical sense.

Given the supply constraints, we may have expected to see realised gas prices rise more sharply, but would highlight that certainly in the period up to the end 2020, the majority of domestic gas was still subject to CPI-linked pricing mechanisms in legacy supply contracts and the upside was being reflected in spot market pricing.

We'd highlight the systemic change in spot prices in the SYD market since the beginning of FY21 as an example of the 'balancing' pricing being on the rise, even through periods of off-peak and shoulder coming into and out of winter.

Note the spot market average pricing compared to company realised prices as per **Exhibit 11.**

Exhibit 12: SYD spot gas market showing the upwards 'permanent shift' in prices

$/gj	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
FY21	4.35	4.56	4.23	5.40	6.15	6.34	6.17	5.95	6.21	6.89	7.58	11.21
FY22	16.71	8.63	8.00	8.29	12.43	11.76	8.84	9.84	10.97	16.15	30.09	41.28
FY23	43.53	16.96	20.84	19.24	18.16	15.25	12.65	14.14	9.59	12.32	19.36	12.54
FY24	10.68	11.02	9.24	9.32	12.14							

Source: AEMO data; Nov-2023 prices reflect the daily average to 17-Nov

We draw on recent ACCC analyses and AEMO gas data and cite from the following ACCC publication where highlighted:

ACCC Gas inquiry 2017-2030 Interim update on east coast gas supply-demand outlook for quarter1 of 2024 (Sep-2023)

The ACCC in its analysis has forecast:

- *"…1.4PJ surplus in Q1 2024 even if LNG producers export all their gas, rising to 19.9PJ of surplus if exports only meet long-term contract commitments.*

  The commentary represents a swing away from the more bearish scenarios of previous updates. The range remains tight compared to daily consumption of around 5.3PJd (domestic and export), and should not be considered as a long-standing or material easing of the supply tightness in our view. The volumes of gas that will flow through to export will be, in part, dependent on the northern hemisphere demand over the winter period, which could still yet send the market into a nominal deficit.

  We would add that, anecdotally, we are aware of export operators still being (aggressively?) active in the market seeking third-party gas.

The ACCC report concurs with our view in that:

- *"While the overall outlook is positive there remains risk that the outlook could worsen, particularly from higher-than-expected gas demand.*

  If additional uncontracted gas is exported and there is an upswing in demand, then gas supply could be insufficient to meet demand. It is important to recognise that demand is dependent on prevailing weather and other uncertainties in the electricity market."

  …and yes, that sensitivity swings both ways.

We note that the ACCC cites supply-demand volumes for Q1 on the east coast of 485 v 484PJ.

We continue to highlight that the weakest data in any forecast is a company's estimate of supply at any given time. AEMO daily data often includes a seven-day forecast as provided by the companies and we would note that rarely does the daily actual out-perform the forecast, but rather under-performs.

The market continues to look supply tight in the absence of new supply – the spot market prices are telling you that.

We note commentary from Exxon-Mobil (reported 23-Mar-2023) warning that *"…the number of wells it operates in the Bass Strait could almost halve in the next eighteen months.",* confirming:

- *"…the company's wells in the Bass Strait (Gippsland) have* ***shrunk in number from 122 in 2010 to 68 today****, and would continue to rapidly decline";*
- *"…by next winter, it expects to have 36 wells producing to six gas platforms supplying two onshore gas plants;* ***a 70% reduction in the number of producing wells since 2010****"; and*
- *…the Gippsland Basin production plant "****will no longer have the capacity to step in to provide whole-of-market solutions*** *when additional gas is required to support the electricity market."*

https://www.abc.net.au/news/2023-03-23/exxonmobil-warns-gas-production-in-bass-strait-will-drop/102133966

The market will be fully supplied – by definition, the market is always fully supplied, with the balancing mechanism being the Short-Term Trading Markets (STTM) and prices set sufficiently high enough to attract gas back into domestic supply.

There is also a material disconnect between the supply tightness and rising prices; and small company share prices.

It seems paradoxical that industry and industry observers can all see the virtue of the upside in the east coast gas market on the basis that more gas will be **needed for decades to come** (industry consensus view) with supply tight and only going to get tighter. Yet tangible progress across the board on new gas opportunities has been 'glacial'.

We understand there has been recent regulatory (market pricing) and approvals uncertainty across most of 2023, but many companies have been holding significant gas volumes (reserves and resources) for sometimes years and we have yet to see a rush to market. Is it a timing issue, waiting for the supply squeeze to become more critical or pricing to firm, availability of capital, disfunctional JVs or a lack of government incentive?

In any respect, there has been a reluctance from companies to 'pre-invest' per se in accelerating first gas that may represent 'early expenditure' but would not necessarily be onerous in total capital costs and would provide a kick-start to production.

Under-priced assets in a rising commodity price environment normally catalyse aggregation (M&A) activity, but there has been little in the way of east coast M&A activity apart from the takeover of Senex as the analogue. We do highlight that in that specific case the company was (is) in production with a growth outlook…it had worked its assets even though that had not translated to share-price out-performance. Perhaps therein lies the key.

There is always an opportunity cost associated with not progressing development opportunities.

Whilst contract gas prices have crystallised at higher levels than 12-24-36 months ago, debt financing is now more difficult to secure, comes at higher interest rates, and the excess return opportunity through spot-market pricing has somewhat evaporated year-on-year.

Investors in general have limited bandwidth for stranded projects or assets with no defined and tangible pathway to market, no matter how attractive the macro-investment thematic may be.

The macro-environment is still largely favourable and in the transition to a lower-carbon world, the prevailing weight of opinion overwhelmingly supports a continuing role for gas as a required energy source.

The risks for smaller companies

In what has seemed like a rolling 18 months or so, we have been waiting for a number of companies to progress projects underpinning their transition from explorer to producer and/or building on existing supply platforms.

In what has often been the sea-anchor, the most critical constraint in the small-cap space has been and is likely to remain access to capital.

We mention the recent issues associated with Armor Energy (ASX:AJQ) as a JV partner in PEP 169, having been suspended from trading and having been placed into receivership [13-Nov], and would highlight the broadly common risks associated with smaller companies:

- Complicated corporate structures mixing ordinary shares with interest-bearing Convertible Notes with a priority call over cash flow and liens over the assets. In some ways CNs are aligned with the development strategy of the company – the need to move to a production phase to service the imposts, but in other ways CNs can make securing alternate financing sources more difficult.
- Operational risks residing with any JV partners can impact work programmes and progress of exploration projects particularly where that specific partner(s) hold material interests in the consortium.

Specifically in the case of AJQ and its potential impact on the PEP 169 JV and drilling of Enterprise North:

- The receivers have indicated they intend to run the company in a 'business as usual' mode while a buyer or alternate financing is sought. Critically then, the company will need to do whatever it can to maintain the assets in good standing. However, 'business as usual' in this case will require funding of pre-drill activities and non-payment could result in default.
- Under standard JV JOAs (Joint Operating Agreements), parties in default can be removed from the JV and permit title with the remaining partners assuming the default interests on a pro-rata basis.

For LKO, until the CEO farm-in conditions are met (drilling the well), it would become the sole entity on title assuming 100% of the tenement.

Ultimately, this could provide increased leverage to the project and/or further financing (partnering) opportunities.

The downside would be that in the absence of revised or additional financing through partnering, LKO would need to fund the 51% (defaulted) interest in all future activities.

Lakes is currently undertaking a capital raising seeking ~$1.73mn through an entitlement issue under the following terms –

- 3 new shares for every 100 shares held at 0.1cps with a;
- 2 new bonus shares for every 3 shares purchased under the entitlement

…this effectively subscribing for 5 shares at 0.06cps

As per guidance, should all of the entitlement be taken up it would result in the issue of 2,891,254,501 new (and bonus) shares bringing the issued capital to 60,716,355,528 ordinary shares.

As of 12-Oct only 605,799,698 new (and bonus) shares were settled and quoted on the market representing 21% of the offer, raising some $0.36mn.

The company is continuing to offer the shortfall for subscription.

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Exhibit 13: Financial Summary

LAKES BLUE ENERGY NL		LKO
YEAR END		June
NAV	A$mn	$278
SHARE PRICE	A$	$0.001
MARKET CAP	A$mn	$58
ORDINARY SHARES	M	58,431
OPTIONS	M	0
CONVERTIBLE NOTES	M	0

nm = not meaningful
na = not applicable

COMMODITY ASSUMPTIONS		FY22A	FY23E	FY24E	FY25E
Realised oil price	US$/b				
Realised gas price	US$/mcf				
Exchange Rate	A$:US$				

RATIO ANALYSIS		FY22A	FY23E	FY24E	FY25E
Shares Outstanding	M	45,296	57,825	60,959	63,459
EPS (pre sig items)	Acps	(0.04)	(0.01)	(0.00)	(0.00)
EPS (post sig items)	Acps				
PER (pre sig items)	x	na	na	na	na
OCFPS	Acps	(0.03)	(0.03)	(0.03)	(0.03)
CFR	x	na	na	na	na
DPS	Acps				
Dividend Yield	%				
BVPS	Acps	0.1	0.2	0.2	0.2
Price/Book	x	0.7x	0.4x	0.4x	0.4x
ROE	%	-220%	-22%	-10%	-10%
ROA	%	-84%	-19%	-9%	-9%
(Trailing) Debt/Cash	x				
Interest Cover	x				
Gross Profit/share	Acps				
EBITDAX	A$M	(14.2)	(3.0)	(1.5)	(1.5)
EBITDAX Ratio	%				

EARNINGS	A$000s	FY22A	FY23E	FY24E	FY25E
Revenue		0	0	0	0
Cost of sales		0	0	0	0
Gross Profit		**0**	**0**	**0**	**0**
Other revenue					
Other income		30	29	50	100
Exploration written off		(77)	(6)	(50)	(100)
Finance costs		(1,308)	(1,468)	0	0
Impairment					
Other expenses		(14,275)	(3,057)	(1,561)	(1,614)
EBIT		(14,245)	(3,028)	(1,511)	(1,514)
Profit before tax		**(14,245)**	**(3,028)**	**(1,511)**	**(1,514)**
Taxes		0	0	0	0
NPAT Reported		**(14,245)**	**(3,028)**	**(1,511)**	**(1,514)**
Underlying Adjustments					
NPAT Underlying					

CASHFLOW	A$000s	FY22A	FY23E	FY24E	FY25E
Operational Cash Flow		**(1,466)**	**(1,729)**	**(1,650)**	**(1,650)**
Net Interest		17	18	15	12
Taxes Paid					
Other					
Net Operating Cashflow		**(1,419)**	**(1,602)**	**(2,085)**	**(2,038)**
Exploration		(1,998)	(699)	(250)	(500)
PP&E		0	0	50	150
Petroleum Assets		0	0	0	0
Net Asset Sales/other		0	0	0	0
Net Investing Cashflow		**(1,998)**	**(552)**	**(200)**	**(350)**
Dividends Paid					
Net Debt Drawdown		0	0	0	0
Net Equity Issues/(Buyback)		5,256	908	1,648	2,375
Other					
Net Financing Cashflow		**5,256**	**606**	**1,648**	**2,375**
Net Change in Cash		**1,839**	**(1,548)**	**(637)**	**(13)**

BALANCE SHEET	A$000s	FY22A	FY23E	FY24E	FY25E
Cash & Equivalents		2,308	760	123	110
PP&E & Development		684	681	688	688
Exploration		13,235	13,715	13,915	14,315
Total Assets		**16,970**	**15,843**	**16,124**	**17,030**
Debt		0	0	0	0
Total Liabilities		**10,508**	**2,122**	**1,500**	**1,500**
Total Net Assets/Equity		**6,462**	**13,722**	**14,624**	**15,530**
Net Cash/(Debt)		2,308	760	123	110
Gearing dn/(dn+e)		na	na	na	na

PRODUCTION		FY22A	FY23E	FY24E	FY25E
Crude Oil	kboe				
Nat Gas	mmcf				
TOTAL	**kboe**				
Sales Volumes	**kboe**				
Product Revenue	A$mn				
Cash Costs	A$mn				
Ave Price Realised	A$/boe				
Cash Costs	A$/boe				
Cash Margin					

RESOURCES	Net to LKO			Contingent 2C	Prospective 2U	(G/O)IIP Best
Gippsland Basin - VIC						
Wombat Field	PRL 2		Gas (Bcf)	329		
Trifon Field	PRL 2		Gas (Bcf)	390		
Barragwanath	PRL 2		Gas (Bcf)		701	
Lakes Entrance	PRL 2		Oil (Mb)		0.6	
	PEP 166		Gas (Bcf)			1,704
Otway Basin – VIC						
	PEP 167		Gas (Bcf)			0
Enterprise North	PEP 169	49%	Gas (Bcf)		100	
Focus Area	PEP 175		Gas (Bcf)		11,469	40,999
Otway Basin – SA						
Benara	PEP 154		Gas (Bcf)		25	
Benara East	PEP 154		Gas (Bcf)		15	
Nangwarry	PRL 249		CO_2 (Bcf)		13	
Surat Basin – QLD						
Wellesley	ATP 1183		Gas (Bcf)		0	
Bendee	ATP 1183		Oil (Mb)			1.0
Major East	ATP 1183		Gas (Bcf)		14	
Emu Apple	ATP 1183		Oil (Mb)			3.4
Eromanga Basin – QLD						
	ATP 642		Oil (Mb)			0.05
	ATP 662		Oil (Mb)			0.5
Cape Vogel Basin – PNG						
Buna	PPL 560		Gas (Bcf)		3,316	
Buna West	PPL 560		Gas (Bcf)		208	
Kumasi North	PPL 560		Gas (Bcf)		274	
Kumasi South	PPL 560		Gas (Bcf)		193	
North New Guinea Basin – PNG						
Matapau	PPL 549		Oil (Mb)			4.4

EQUITY VALUATION	Interest	Risked Range (A$mn) Low	Mid	High
Enterprise North	49%	54	108	158
Wombat	100%	20	72	120
Trifon	58%	10	40	60
Nangwarry	50%	5	10	15
Other Vic	Various	10	24	53
Other SA	100%	2	3	5
Other Q	100%	12	21	45
PNG	100%	5	5	5
			280	
Net Cash/(debt)			1	
Corporate costs			(2)	**P/NAV**
TOTAL			**278**	0.00
Ordinary Fully Paid Shares	58,431 M		**0.5**	**cps**

Source: RaaS Advisory; Priced as at 21-Nov-2023

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: 6th May 2021

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Contact Details, BR and RaaS
BR Head Office: Suite 5GB, Level 5, 33 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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