30 March 2023

37% PDP Growth in Brooks and Thorsby Reserves

Reserve Highlights

- Reserves at December 31, 2022 - audited by InSite Petroleum Consultants Ltd:
    - **3P reserves 24.4 million boe**
    - **2P Reserves 20.5 million boe**
    - **1P Reserves 16.1 million boe**
    - **PDP Reserves 7.0 million boe**

- Proved Developed Producing, ("PDP") reserves increased 37% to 7.0 million boe (net of royalties), 4% for our Total Proved ("TP") reserves, and 1% for our Total Proved plus Probable ("P+P") reserves year over year.
- In 2022, Calima's successful development capital program achieved a capital efficiency of $14,200 per boe/d for the 2022 calendar year.[1]
- The Company achieved a reserve replacement ratio of 192%, 145% and 160% of our PDP, TP, and P+P reserves respectively, while growing annual production by 23%.
- PDP, TP and TPP reserve life index ("RLI") of 6.3 years, 11.9 years and 14.7 years, respectively, reflects our long-life oil weighted assets with a deep inventory, providing for long-term sustainable and profitable growth.
- Our PDP Finding, Development and Acquisition ("FD&A") cost of A$11.51 per boe generated a recycle ratio of 4.2x on an unhedged basis and reflects strong operational execution by our team in 2022. Our TP and TPP recycle ratios increased 36% and 57%, respectively as compared to 2021. The Company's 3-year average PDP FD&A cost is A$14.23/boe. There were no production acquisitions or sales in 2022.
- Continuing to focus on maintaining low levels of abandonment liability provides significant corporate flexibility; in 2022 this was continued via the successful abandonment of 10 gross wells. Our industry-leading liability management ratio ("LMR") at year-end 2022 was 6.23
- The Company drilled 16 wells in 2022 of which 8 were proven undeveloped locations (PUD's) transforming location value into PDP cash flow generating assets which have materially greater market value.
- The focused asset bases of Brooks and Thorsby coupled with high graded infill drilling and prudent production management allowed Blackspur to maintain TP and P+P reserves steady after production of 1.43 million boe for the 2022 year.

Calima Energy Limited (ASX:CE1 / OTCQB:CLMEF) ("Calima" or the "Company") is pleased to present the results and in-depth analysis of its independent reserve report for its Thorsby and Brooks assets for Calima's wholly owned subsidiary Blackspur Oil Corp. ("Blackspur"). as at 31 December 2022. The evaluation encompassed 100% of Brooks and Thorsby reserves and was completed by independent reserve evaluator InSite Petroleum Consultants Ltd. ("InSite") in accordance with the Society of Petroleum Engineers' Petroleum Resources Management System (SPE-PRMS). 2022 represents the Company's 10th year of successful reserves development.

In 2022, the Company invested A$49.7 million to drill 16 wells and expand the waterflood in the Lower Mannville J2J oil pool ("J2J pool"), upgrade facilities in the Brooks area, complete well maintenance programs on producing assets, perform mandated well abandonments, and purchase land and seismic. Corporate production increased by approximately 23% year-over-year, averaging 3,921 boe/d in 2022. The commencement of 2023 saw the full impact on production from the 5 well Q4 2022 development program with the Company's average production for 2023 currently averaging ~4,500 boe/d. In Q1 2023, the Company successfully drilled and completed two additional wells at Brooks (Pisces #8 and #9); the impact of these wells will be realised primarily in the Q2 2023

[1] Capital efficiency is calculated as the total annual exploration & development and acquisition and disposition capital expended in the year, less capitalized G&A divided by the initial production, from the 16 wells drilled in 2022, averaged over the first 60 days .

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corporate production. 2022 year-end reserves reflect the quality and sustainability of our low decline base production, complemented by the drilling of new wells throughout the year. In 2022, the Company focussed on reducing financial risk and improving the long-term sustainability of our assets.

Our 2022 year-end reserves continue to be strong across all categories enhanced by our diverse inventory. Most notably the large inventory and oil in place in both the Brooks and Thorsby assets is a tremendous resource supporting multi-year growth potential to complement our high netback conventional asset base. We have a significant inventory of locations providing the Company with years of profitable and sustainable growth in cash flow, reserves, and production.

Reserves as at 31 December 2022 (working interest after royalties)														
	31-Dec-22			Production		Additions		Revisions		Acquisition		31-Dec-21		
	Oil/NGL (mbbl)	Gas (mmcf)	Boe (mboe)	Oil/NGL (mbbl)	Gas (mmcf)	Oil/NGL (mbbl)	Gas (mmcf)	Oil/NGL (mbbl)	Gas (mmcf)	Oil/NGL (mbbl)	Gas (mmcf)	Oil/NGL (mbbl)	Gas (mmcf)	Boe (mboe)
PDP	4,236	16,454	6,978	-802	-2,583	1,396	5,224	363	2,677	0	0	3,279	11,136	5,135
1P	10,163	35,477	**16,076**	-802	-2,583	1,108	2,608	-266	2,799	0	0	10,122	32,654	15,564
Probable	2,720	10,035	4,392	-	-	67	169	-340	-1,119	0	0	2,993	10,984	4,824
2P	12,883	45,512	**20,468**	-802	-2,583	1,175	2,777	-606	1,680	0	0	13,115	43,638	20,838
Possible	2,474	8,820	3,944	-	-	194	180	-240	-427	0	0	2,521	9,067	4,032
3P	15,357	54,332	**24,412**	-802	-2,583	1,368	2,958	-846	1,253	0	0	15,636	52,705	24,420

Table 1: Reserve Statement

Development Plan

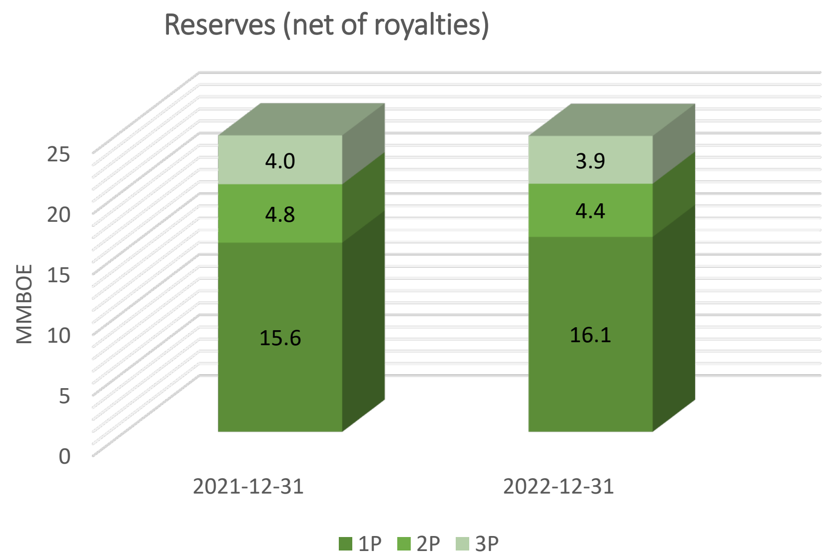
The development plan in the December 31, 2022 Reserve Report consists of 54 (gross) wells, 48 PUD's and 6 probable locations, to be drilled over 5 years. The schedule and breakdown in each reserve category is summarised in the table below. The development plan is scheduled for proved and probable well locations to be drilled within a 5-year period. All future development capital ("FDC") for the TP and P+P reserve categories is included and reflects an increase year over year due to inflation.

Period	Rig Count	Proved	Development Well Count		
		(PUD)	Probable	Possible	Total
Year 1	2	10	0	0	10
Year 2	2	15	0	0	15
Year 3	2	18	6	0	24
Year 4	2	5	0	0	5
Year 5	2	0	0	0	0
Total	10	48	6	0	54

Table 2: Rig and gross well count for each year

In the 31 December 2022 year-end InSite report, the 2023 development program includes 10 wells to be drilled including, 2 Thorsby Sparky wells, 4 Brooks Sunburst wells, and 4 Brooks Glauconitic wells (2 are now drilled as part of the Pisces campaign). On a net well count for the proved reserve category, Blackspur has a ~95% interest in the proved undeveloped wells in the 2023 development plan.

At 31 December 2022, The Company held the rights to ~117,000 net acres within the Brooks and Thorsby areas and the Company operates 90 producing wells. The year-end reserve development schedule encompasses development of a modest portion of the total acreage position that Blackspur holds. Based on the existing leasehold position, including the acreage associated with the existing producing wells, Blackspur estimates a total of approximately 220 net wells will be required to develop the entire reserve position. Significant undeveloped Brooks and Thorsby acreage has no reserves booked currently, representing material upside to the existing report. The total 2023 development schedule corresponds to 54 future wells (50.75 net), or 23% of the wells necessary to develop the entire acreage position. Blackspur continues to focus on abandoning and reclaiming our non-producing assets and in 2023 will spend a minimum of A$780,000. This spending achieves a reserve valuation that is in a much stronger and resilient position on a value per barrel basis compared to companies with high ADR liabilities. Management estimates that total undiscounted and uninflated existing ADR is A$23.6 million (A$8.6 million NPV10 BT, with costs inflated at 2%/yr thereafter). This includes all ADR associated with both active and inactive wells, pipelines, and facilities. Consistent with the 2021 year-end evaluation, InSite's 2022 Reserve Report incorporates full corporate abandonment, decommissioning, and reclamation costs ("ADR") in the PDP category. Based on public information, the Company stands out among its industry peers as being within the top tier of Alberta oil and gas operators for its industry-leading liability management ratio ("LMR") of 6.23. Less than 10% of our PDP net present value is impaired by ADR.



Graph 1: Reserve Summary

Brooks

Brooks asset overview	31 December 2022
Land position and production	
Core land position (net acres)	**~69,000**
Core formation targets	**Sunburst, Glauconitic**
Average working interest of the play (%)	**90%**
Number of wells drilled to date (net)	**>75**
Identified drilling locations (net) (1)	**138**
2023 current average production (boe/d)	**~3,500**
Reserves (mmboe)(2)	
Proved reserves	**8.4**
Probable reserves	**1.8**
Total proved plus probable reserves	**10.2**
Possible reserves	**1.9**
Total proved plus probable plus possible	**12.2**

(1) Consists of 59 Sunburst, 49 Glauconitic, and 30 Ellerslie Formation net drilling locations.
(2) Refer to Advisories and Guidance for additional information regarding the Company's reserves, may not always add in each location due to rounding.

The Brooks asset has an established core land position of ~69,000 net acres and significant infrastructure creating a foundation for growth and expansion with nearly year-round access. The Brooks reservoirs contain a low CO_2 content at ~2%, and the Company's multi-well pad drilling reduces the environmental footprint. Blackspur has an extensive network of existing infrastructure including oil treating facilities and water disposal across the entire Brooks area that can process up to 7,200 bbl/d oil, 25,000 barrels per day of water and 10.8 MMcf/d cumulatively across all of its various facilities. With over 75 wells drilled to date, the Brooks asset has averaged net daily production of ~3,500 boe/d from 1 Jan 2023 to date.

The Sunburst Formation does not require hydraulic fracture stimulation and can be developed at low cost (~C$1. 5MM per well) delivering attractive rates of return and short payouts (~90% and ~12 - 14 months respectively) at US$70 WTI and standard type curves. The Company drilled and placed on production 8 Sunburst (Gemini) wells in 2022.

The Glauconitic Formation is a shallower formation than Calima's core Sunburst conventional play and requires hydraulic fracture stimulation. The combination of the shallow target depth and short tie-in, results in an all-in cost for each well of C$2-$3M, depending on horizontal length and fracture intensity. The Glauconitic wells have proven to be very impactful to corporate production and reserve bookings in 2022. The Company drilled and placed on production 7 Glauconitic (Pisces) wells in 2022 and has drilled 2 additional wells in 2023 which came on production in March 2023. ~20% of the wells drilled in 2022 have already paid out their initial capital investment.

Future growth from the Brooks assets will come from the 138 net locations that have been identified. These locations include 28 booked (24.75 net) PUDs and 2 (2 net) probable locations. Only 19% of the identified locations have been booked for the purposes of InSite's Reserve Report. The 2023 Brooks drilling program will be focussed on Sunburst and Glauconitic drilling. At current oil prices the Company is able to continue drilling a risk adjusted balanced mix of Sunburst and Glauconitic Formation horizontal locations to prudently grown production and reserves. Additional reserves are also expected to be realised through implementation of enhanced oil recovery projects and specifically the full water-flood development of the Countess J2J Sunburst pool.

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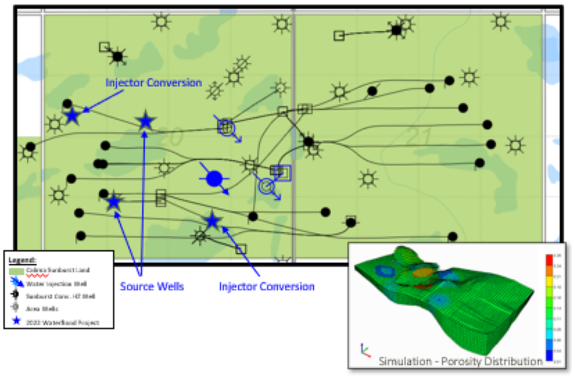
J2J Waterflood

In January 2020, the Company initiated a waterflood in the Countess J2J Pool which has been showing positive results. InSite has recognized 1P and 2P waterflood reserves associated with this waterflood. Waterflood operations require upfront capital and take time before field performance improves and these benefits start to be realized. Waterflood assets provide a stable, low decline production base generating strong cash flows and reserves over the long term.



The Countess Sunburst J2J Pool at Brooks ("the Pool") was discovered in 2003 and initially developed using vertical wells. Horizontal drilling was introduced to the Pool by the Company in 2014 which improved production rates and primary recoveries with strategically placed horizontal well legs throughout the reservoir. In Q1 2020 a pilot waterflood was initiated and an oil battery contructed. Based on the initial successful results of the pilot waterflood the Company continued the project in 2022 with the addition of one water injector and securing additional source water to allow a continued ramp up of in the voidage replacement. As well, a water tracer study was initiated to fine tune and better understand water movements throughout the pool and facilitate continued optimization.

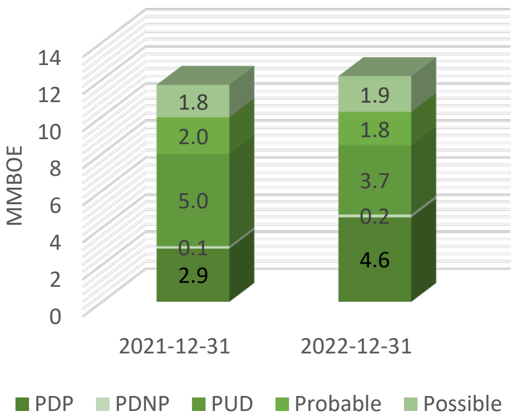
The Company is pleased to note that the initial stage of the Countess J2J waterflood has begun showing positive response in the producing wells via increased oil and total fluid rates, thus facilitating increasing pumping speeds on most producing wells. InSite continues to recognize 1P, 2P, and 3P waterflood reserves for the Pool. Further waterflood expansion would include additional water injectors to continue increasing the quantum and areal extent of water being injected in the Pool and increase reservoir pressure. This is expected to increase the waterflood response in the Pool, resulting in increased cash flow, PDP reserves, shallower declines, and continued increases in oil production.

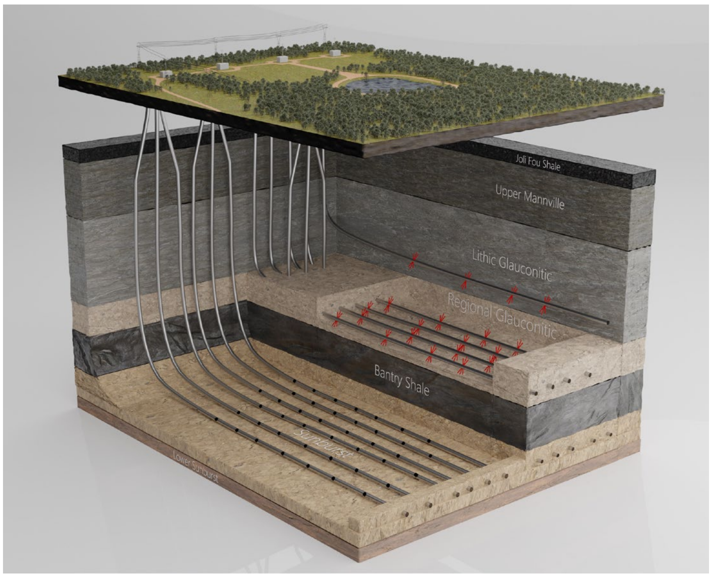
Ultimate primary recovery factor for the Pool before any waterflood implementation is estimated at 14% of the oil in place, and the current recovery factor, to date from the existing wells is estimated at 12%. This is inclusive of the benefits of the waterflood. Analogous Sunburst Formation pools under waterflood in the area, have achieved recovery factors of 25% or higher. Every 1% increase in recovery factor of the oil in place in the J2J Pool, results in greater than 100mbbl of incremental recoverable reserves for the Company. Approximately 2% of the potential increase in recoverable reserves in the Countless J2J Pool have been included in the Reserve Report.

There is no change to the fundamentals of the undeveloped wells and InSite has made no material changes to their assumptions on future undeveloped well production performance. The InSite reports incorporates:

- In 2022 15 wells were drilled with 8 conventional Sunburst horizontal play type and 7 Glauconitic stimulated horizontal wells.
- In 2023 four Sunburst wells and four Glauconitic horizontal wells are planned in the reserve report.
- 28 PUDs (24.75 net) and 2 probable 100% locations
- 8 PUD to PDP conversions in 2022
- Reserves of: 1P – 8.4 mmboe, 2P – 10.2 mmboe, 3P – 12.2 mmboe

Graph 2: Brooks Reserves (net of royalties)





Full Field Brooks Development –
this figure in the Mannville section shows a full field development in all formations.

Thorsby

Thorsby asset overview	31 December 2021
Land position and production	
Core land position (net acres)	**~48,000**
Core formation targets	**Sparky, Nisku**
Average working interest (%)	**100 & 50%**
Number of wells drilled to date (net)	**15**
Identified drilling locations (Net)(1)	**82**
2023 current average production (boe/d)	**~1,000**
Reserves (mmboe)(2)	
Proved reserves	**7.6**
Probable reserves	**2.6**
Total proved plus probable reserves	**10.2**
Possible reserves	**2.0**
Total proved plus probable plus possible	**12.2**

(1) Consists of 70 Sparky formation net drilling locations and 12 Nisku formation net drilling locations.
(2) Refer to Advisories and Guidance for additional information regarding the Company's reserves, may not always add in each location due to rounding.

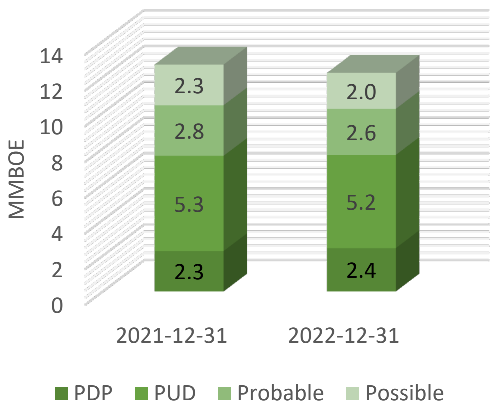
Development and Upside

Thorsby has a large inventory with 70 Sparky Formation and 12 Nisku Formation wells identified, including 20 PUD and 4 probable Sparky locations. The Company's existing Sparky Formation wells are characterised by current low decline rates expected averaging ~17% per year over the next 2 years. Whilst the Thorsby area has the potential for Duvernay and Nisku, these intervals have not been incorporated into the Reserve Report.

The Company's Thorsby position provides a consolidated land base that can be efficiently developed through a network of multi-well pads, all of which have nearly year-round access. The contiguous land base also contributes to lower operating costs through greater logistical efficiencies. The Company's facilities currently have oil processing capacity of up to 1,450 bbl/d oil (subject to emulsion water cut volumes at the battery).

One step-out well (Leo #4) (0.5 net) was drilled and completed in the prospective North Thorsby area in 2022.

The Company continues to successfully optimise the drilling and completion techniques and InSite's development plan utilises a mix of extended reach and 1 mile horizontal wells with higher intensity fractures, compared to the early-stage wells. This reduces gross well locations while the improving future undeveloped well production performance and reserves. There was minimal year over year changes to the proven undeveloped reserves apart from the increased capital costs reflecting current inflationary trends.



The Company may drill 2 development wells in Thorsby in 2023. Each are being drilled into the existing Sparky Formation oil pool, which was delineated by both existing Sparky wells and 3D seismic. The well length and frac intensity will be similar to the 2021 Leo drilling program.

- 3P production profile over a prolific reserve lifecycle
- 20 PUD's and 4 probable 100% locations

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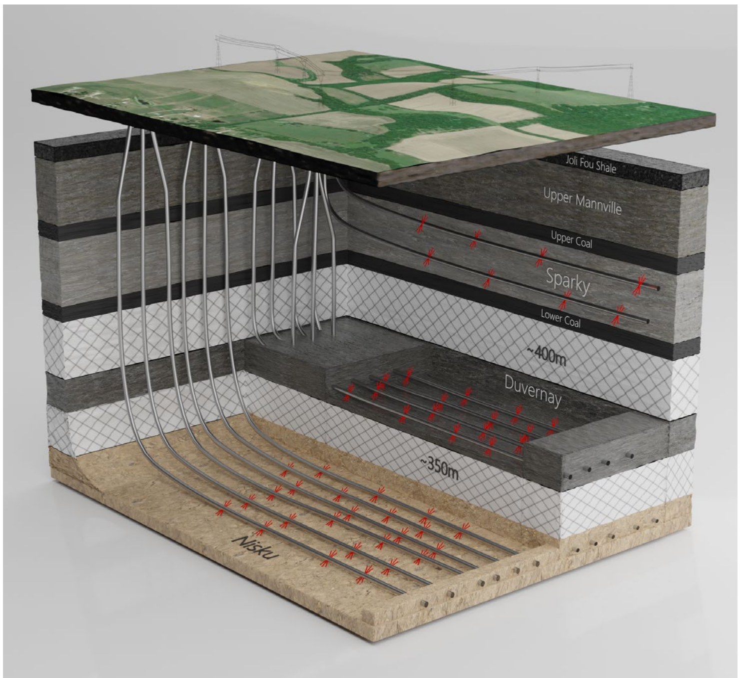
- Reserves of: 1P - 7.6 mmboe, 2P - 10.2 mmboe, 3P - 12.2 mmboe



Full Field Thorsby Development –
this figure in the Thorsby section shows a full field development in all formations.

3P Reserves
A proved, probable and possible (3P) reserve evaluation category was evaluated for all wells and locations booked at December 31, 2022 totalling 24.4 million boe's. 3P EURs are determined using volumetric calculation as well as production performance / type curve reserve estimates where applicable. The 2022 Possible reserves are 3.9 million boe, net of royalties. 3P reserves were split as follows: Brooks 3P reserves of 12.2 million boe and Thorsby 3P reserves of 12.2 million boe.

This release has been approved by the Board.

For further information visit www.calimaenergy.com or contact:

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Insite Assumptions

InSite assessed all future locations they determined to be commercial. The key assumptions used by InSite to generate the Reserve Report were:

- The majority of the reserve estimates were prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

- The oil price used for all reserves analysis in this report is stated in the table at the end of this release. The reserves are disclosed net to the point of sale (reference point) and are reported net of lease fuel.

- The Company is the operator for materially all its producing wells and all the future drills.

- Operating costs for developed producing wells are based on actual costs incurred through YE2022. Operating costs for future wells and years are based on the same data and estimated following a review of operating statements, operating budgets, as well as review of public records where available. Cross checks were conducted between the revenue statements and land data to ensure they agreed. Fixed and variable costs have been assigned to the Company's active assets with remaining reserves. Operating costs associated with inactive assets as well as producing wells with no reserves assigned have been entered as separate entities at the property level.

- In conducting InSite's reserve analysis, proved, probable and possible reserve volumes were determined by volumetric, material balance, and production decline curve methods. The volumetric reserves were determined by reviewing all well logs, core, and geological data. Recovery factors were assigned after analyzing the performance of similar wells in the area. Historical well production was reviewed to determine reserves calculated by production decline curve analysis. The order of preference in choosing the methodology to be used was primarily production decline curve analysis or material balance where sufficient data was available for such analysis with volumetrics being used where there was a lack of historical data.

- 100% of the proved producing reserves were calculated based on decline analysis, oil-cut analysis and other performance/volumetric related prediction methods, compared to 45% (44% net) of the total proved reserves and 40% (40% net) of the proved plus probable reserves, and 40% (40% net) of proved plus probable plus possible reserves which used these methods. Volumetrics/simulation/analogy/type curve analyses were used to calculate the remaining percentages of reserves in each category.

- The EUR assignments are largely influenced by the production performance of existing producing wells and their associated volumetric recovery. In the case of undeveloped drilling locations, reserve assignments and production profiles are based on analogy to the offsetting producers in the nearby vicinity and/or other analogous pools.

- The probable reserves contained in the report consist of two general types:
  - Performance-related (i.e. Proved plus Probable Developed) reserves represent the best estimate overall. Proved reserves are a more conservative estimate of the recovery from wells where Possible reserves represent a more optimistic and lower probability estimate.
  - Proved plus probable reserves can also include enhanced recovery reserves which are only partially recognized under proved reserves. The "wedge" or difference between the Proved Developed and Proved plus Probable Developed cases represents 25% (26% net) of the Company's Probable reserves. The "wedge" between Proved plus Probable Developed and Proved plus Probable plus Possible Developed cases represents 37% (38% net) of the Company's Possible reserves.

- Future horizontal step-out wells represent 73% (73% net) of the Company's probable reserves.

- Future vertical step-out wells represent 1.7% (1.7% net) for the Company's probable reserves.

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- The oil and gas reserve calculations and income projections upon which this report is based were determined in accordance with generally accepted evaluation practices and evaluation process was consistent with prior years.

- Proposed future well locations are allocated a reserve category based on proximity to existing wells and production.

- Probable reserves were assigned such that there is a 50% probability that the assigned reserves could be recovered, or more on an aggregated basis.

- Proved plus Probable plus Possible reserves were assigned such that there is a 10% probability that the assigned reserves could be recovered, or more on an aggregated basis.

- The production and revenue forecasts contained in the 31 December 2022 evaluation include abandonment and reclamation costs for each of the Company's existing and proposed wells that were assigned reserves in this report. These costs were determined using the Alberta Energy Regulator's Directive 011 as a base. The costs associated with abandonment, decommissioning, reclamation, and salvage of facilities, as well as inactive assets, have been entered as separately.

- The five-year development plan used for this reserve report is detailed in Table 2 above and assumes a multi rig program to develop a total of 54 gross well locations. The development plan assumes 2-6 wells per standard development unit and approximately 128 - 160 acre spacing.

- Anticipated drilling, completion & tie-in well costs range from C$0.8 to C$4.5 million depending on whether it's a Sunburst, Glauconitic or Sparky well.

- The development plan assumes an initial estimate of 6-14 days respectively to drill new wells.

- Average royalties payable on future well locations that were allocated reserves in this report is ~16% over the life of the wells. The land type and related royalties are either Crown or Freehold and the average royalty for the PDP forecast for 2023 is 19%.

- Each year, for the purposes of estimating undeveloped reserves, a development schedule is generated which must be appropriate and reasonable for the Company to execute on. This development plan is prepared in consultation with InSite and takes into consideration market conditions and the Company's operational capacity, including financing and historical drilling activity. The plan must also conform to the various ASX and SPE-PRMS requirements, the key points of which are:

    - the development plan is executed over a 5-year period from the effective date.
    - proved well locations must be drilled within 5 years of the date they were first certified as a reserve in previous reports.
    - The InSite evaluation has been prepared for the Company in accordance with reserves definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation ("COGE") Handbook and have been classified in accordance with the Society of Petroleum Engineers' Petroleum Resources Management System (SPE-PRMS) and reported in the most specific resource class in which the prospective resource can be classified under 2018 SPE-PRMS. The reserves presented in the InSite report are based on forecast prices and costs. The price forecast used for the reference price of oil based on Cushing, Edmonton and Western Canadian Select benchmarks, as well as the netback prices for natural gas for the major purchasers. All oil prices used in the evaluation have been adjusted from the reference price for quality and transportation; gas prices have been adjusted for heating value. Please

note that the effects of any oil or gas hedging activities by the Company have not been included in this report. The reserves are disclosed net to the reference point.

- In the context of belonging to a larger portfolio of properties and coupled with the principal of aggregation of reserves, the total portfolio reserves estimate carries a higher degree of confidence than the estimates for the individual properties.

Forward Looking Statements

This release may contain forward-looking statements. These statements relate to the Company's expectations, beliefs, intentions or strategies regarding the future. These statements can be identified by the use of words like "anticipate", "believe", "intend", "estimate", "expect", "may", "plan", "project", "will", "should", "seek" and similar words or expressions containing same. These forward-looking statements reflect the Company's views and assumptions with respect to future events as of the date of this release and are subject to a variety of unpredictable risks, uncertainties, and other unknowns. Actual and future results and trends could differ materially from those set forth in such statements due to various factors, many of which are beyond our ability to control or predict. These include, but are not limited to, risks or uncertainties associated with the discovery and development of oil and natural gas reserves, cash flows and liquidity, business and financial strategy, budget, projections and operating results, oil and natural gas prices, amount, nature and timing of capital expenditures, including future development costs, availability and terms of capital and general economic and business conditions. Given these uncertainties, no one should place undue reliance on any forward-looking statements attributable to Calima, or any of its affiliates or persons acting on its behalf. Although every effort has been made to ensure this release sets forth a fair and accurate view, we do not undertake any obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Qualified petroleum reserves and resources evaluator statement

The petroleum reserves and resources information in this announcement in relation to Blackspur Oil Corp is based on, and fairly represents, information and supporting documentation in a report compiled by InSite Petroleum Consultants Ltd. (InSite) for the December 31, 2022 Reserves Report. InSite is a leading independent Canadian petroleum consulting firm registered with the Association of Professional Engineers and Geoscientists of Alberta. These reserves were subsequently reviewed by Mr. Graham Veale who is the VP Engineering with Blackspur Oil Corp. The InSite December 31, 2022 Reserves Report and the values contained therein are based on InSite's December 31, 2022 price deck (https://www.insitepc.com/pricing-forecasts). Mr. Veale holds a BSc. in Mechanical Engineering from the University of Calgary (1995) and is a registered member of the Alberta Association of Professional Engineers and Geoscientists of Alberta (APEGA). He has over 27 years of experience in petroleum and reservoir engineering, reserve evaluation, exploitation, corporate and business strategy, and drilling and completions. InSite and Mr. Veale have consented to the inclusion of the petroleum reserves and resources information in this announcement in the form and context in which it appears.

Oil and Gas Glossary and Definitions

Term	Meaning
Adjusted EBTDA:	Adjusted EBTDA is calculated as net income (loss) before income taxes, depletion, depreciation and amortisation, and adjusted to exclude certain non-cash, extraordinary and non-recurring items primarily relating to bargain purchase gains, gains and losses on financial instruments, transaction and advisory costs and impairment losses. Calima utilises adjusted EBTDA as a measure of operational performance and cash flow generating capability. Adjusted EBTDA impacts the level and extent of funding for capital projects investments or returning capital to shareholders.
Adjusted working capital:	Adjusted working capital is comprised of current assets less current liabilities on the Company's balance sheet and excludes the current portions of risk management contracts and credit facility draws. Adjusted working capital is utilised by Management and others as a measure of liquidity because a surplus of adjusted working capital will result in a future net cash inflow to the business which can be used for future funding, and a deficiency of adjusted working capital will result in a future net cash outflow which will require a future draw from Calima's existing funding capacity.
ARO / Asset Retirement Obligation:	the process of permanently closing and relinquishing a well by using cement to create plugs at specific intervals within a well bore
Available funding:	Available funding is comprised of adjusted working capital and the undrawn component of Blackspur's credit facility. The available funding measure allows Management and other users to evaluate the Company's liquidity.
Credit Facility Interest:	Borrowings under the Credit Facility incur interest at a market-based interest rate plus an applicable margin which varies depending on Blackspur's net debt to cash flow ratio. Interest charges are between 150 bps to 350 bps on Canadian bank prime borrowings and between 275 bps and 475 bps on Canadian dollar bankers' acceptances. Any undrawn portion of the demand facility is subject to a standby fee in the range of 20 bps to 45 bps. Security for the credit facility is provided by a C$150 million demand debenture
CO2e:	carbon dioxide equivalent
Conventional Well:	a well that produces gas or oil from a conventional underground reservoir or formation, typically without the need for horizontal drilling or modern completion techniques
Compression:	a device or facility located along a natural gas pipeline that raises the pressure of the natural gas flowing in the pipeline, which in turn compresses the natural gas, thereby both increasing the effective capacity of the pipeline and allowing the natural gas to travel longer distances
Corporate Decline:	consolidated, average rate decline for net production from the Company's assets
Exit Production:	Exit production is defined as the average daily volume on the last week of the period

Term	Meaning
Operating Income:	Oil and gas sales net of royalties, transportation and operating expenses
Financial Hedge:	a financial arrangement which allows the Company to protect against adverse commodity price movements, the gains or losses of which flow through the Company's derivative settlements on its financial statements
Free Cash Flow (FCF):	represents Hedged Adjusted EBTDA less recurring capital expenditures, asset retirement costs and cash interest expense
Free Cash Flow Yield:	represents free cash flow as a percentage of the Company's total market capitalisation at a certain point in time
Funds Flow:	Funds flow is comprised of cash provided by operating activities, excluding the impact of changes in non-cash working capital. Calima utilises funds flow as a measure of operational performance and cash flow generating capability. Funds flow also impacts the level and extent of funding for investment in capital projects, returning capital to shareholders and repaying debt. By excluding changes in non-cash working capital from cash provided by operating activities, the funds flow measure provides a meaningful metric for Management and others by establishing a clear link between the Company's cash flows, income statement and operating netbacks from the business by isolating the impact of changes in the timing between accrual and cash settlement dates.
Gathering & Compression (G&C):	owned midstream expenses; the costs incurred to transport hydrocarbons across owned midstream assets
Gathering & Transportation (G&T):	third-party gathering and transportation expense; the cost incurred to transport hydrocarbons across third-party midstream assets
G&A:	general and administrative expenses; may be represented by recurring expenses or non-recurring expense
Hedged Adjusted EBTDA:	EBTDA including adjustments for non-recurring and non-cash items such as gain on the sale of assets, acquisition related expenses and integration costs, mark-to-market adjustments related to the Company's hedge portfolio, non-cash equity compensation charges and items of a similar nature;
Hyperbolic Decline:	non-exponential with subtle multiple decline rates; hyperbolic curves decline faster early in the life of the well and slower as time increases
LMR:	The LMR (Liability Management Ratio) is determined by the Alberta Energy Regulator ("AER") and is calculated by dividing Blackspur's deemed assets by its deemed liabilities, both values of which are determined by the AER.
LOE:	lease operating expense, including base LOE, production taxes and gathering & transportation expense
Midstream:	a segment of the oil and gas industry that focuses on the processing, storing, transporting and marketing of oil, natural gas, and natural gas liquids
Net Debt:	Net debt is calculated as the current and long-term portions of Calima's credit facility draws, lease liabilities and other borrowings net of adjusted working capital. The credit facility draws are calculated as the principal amount outstanding converted to Australian dollars at the closing exchange rate for the period. Net debt is an important measure used by Management and others to assess the Company's liquidity by aggregating long-term debt, lease liabilities and working capital.
NGL / Natural Gas Liquids:	hydrocarbon components of natural gas that can be separated from the gas state in the form of liquids
Net Debt/Adjusted EBTDA (Leverage)	a measure of financial liquidity and flexibility calculated as Net Debt divided by Hedged Adjusted EBTDA
Net Revenue Interest:	a share of production after all burdens, such as royalty and overriding royalty, have been deducted from the working interest. It is the percentage of production that each party actually receives
Operating Costs:	total lease operating expense (LOE) plus gathering & compression expense
Operating Netback:	Operating netback is calculated on a per boe basis and is determined by deducting royalties, operating and transportation from oil and natural gas sales, after adjusting for realised hedging gains or losses. Operating netback is utilised by Calima and others to assess the profitability of the Company's oil and natural gas assets on a standalone basis, before the inclusion of corporate overhead related costs. Operating netback is also utilised to compare current results to prior periods or to peers by isolating for the impact of changes in production volumes.
Physical Contract:	a marketing contract between buyer and seller of a physical commodity which locks in commodity pricing for a specific index or location and that is reflected in the Company's commodity revenues Production Taxes: state taxes imposed upon the value or quantity of oil and gas produced
Promote:	an additional economic ownership interest in the jointly-owned properties that is conveyed cost-free to the operator in consideration for operating the assets
PDP/ Proved Developed Producing:	a reserve classification for proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods
PV10:	a standard metric utilised in SEC filings for the valuation of the Company's oil and gas reserves; the present value of the estimated future oil and gas revenues, reduced by direct expenses, and discounted at an annual rate of 10%
RBL / Reserve Based Lending	a revolving credit facility available to a borrower based on (secured by) the value of the borrower's oil and gas reserves
Royalty Interest or Royalty:	Interest in a leasehold area providing the holder with the right to receive a share of production associated with the leasehold area
Terminal decline:	represents the steady state decline rate after early (initial) flush production
Unconventional Well:	a well that produces gas or oil from an unconventional underground reservoir formation, such as shale, which typically requires hydraulic fracturing to allow the gas or oil to flow out of the reservoir
Upstream:	a segment of the oil and gas industry that focuses on the exploration and production of oil and natural gas
Working Capital Ratio:	The working capital ratio as the ratio of (i) current assets plus any undrawn availability under the facility to (ii) current liabilities less any amount drawn under the facilities. For the purposes of the covenant calculation, risk management contract assets and liabilities are excluded.
WI/ Working Interest:	a type of interest in an oil and gas property that obligates the holder thereof to bear and pay a portion of all the property's maintenance, development, and operational costs and expenses, without giving effect to any burdens applicable to the property

Abbreviation	Abbreviation meaning	Abbreviation	Abbreviation meaning
1P	proved reserves	**A$ or AUD**	Australian dollars
2P	proved plus Probable reserves	**C$ or CAD**	Canadian dollars
3P	proved plus Probable plus Possible reserves	**US$ or USD**	United states dollars
bbl or bbls	barrel of oil	**($ thousands)**	figures are divided by 1,000
boe	barrel of oil equivalent (1 bbl = 6 Mcf)	**($ 000s)**	figures are divided by 1,000
d	suffix – per day	**Q1**	first quarter ended March 31st
GJ	gigajoules	**Q2**	second quarter ended June 30th
mbbl	thousands of barrels	**Q3**	third quarter ended September 30th

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mboe	thousands of barrels of oil equivalent	**Q4**	fourth quarter ended December 31st
Mcf	thousand cubic feet	**YTD**	year-to-date
MMcf	million cubic feet	**YE**	year-end
PDP	proved developed producing reserves	**H1**	six months ended June 30th
PUD	Proved Undeveloped Producing	**H2**	six months ended December 31st
C	Contingent Resources – 1C/2C/3C – low/most likely/high	**B**	Prefix – Billions
Net	Working Interest after Deduction of Royalty Interests	**MM**	Prefix - Millions
NPV (10)	Net Present Value (discount rate), before income tax	**M**	Prefix - Thousands
EUR	Estimated Ultimate Recovery per well	**/d**	Suffix – per day
WTI	West Texas Intermediate Oil Benchmark Price	**bbl**	Barrel of Oil
WCS	Western Canadian Select Oil Benchmark Price	**boe**	Barrel of Oil Equivalent (1bbl = 6 mscf)
1P or TP	Total Proved	**scf**	Standard Cubic Foot of Gas
2P or TPP	Total Proved plus Probable Reserves	**Bcf**	Billion Standard Cubic Foot of Gas
3P	Total Proved plus Probable plus Possible Reserves	**tCO_2**	Tonnes of Carbon Dioxide
EBTDA	Earnings before tax, depreciation, depletion and amortisation	**OCF**	Operating Cash Flow, ex Capex
Net Acres	Working Interest	**E**	Estimate
IP24	The peak oil production rate over 24 hours of production	**CY**	Calendar Year
IP30/90	Average oil production rate over the first 30/90 days	**WTI**	West Texas Intermediate
WCS	Western Canada Select	**OOIP**	Original Oil in Place

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Appendix A: Insite Petroleum Consultants Ltd - Forecast Prices and Costs Assumptions

InSite prepared the reserve estimate based on the price deck below.

INSITE PETROLEUM CONSULTANTS LTD.
FORECAST PRICES AND COSTS ASSUMPTIONS
December 31, 2022

YEAR	WTI @ CUSHING	BRENT BLEND	CDN/US EXCHANGE RATE	WTI @ CUSHING	EDM REF PRICE	HARDISTY 25 API	WESTERN CANADA SELECT	HEAVY 12 API	CONDEN-SATE	BUTANE	PROPANE	ETHANE
	$US/BBL	$US/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL
2023	80.00	82.00	0.750	106.67	103.67	78.67	78.67	71.67	105.74	55.98	42.50	14.47
2024	77.00	80.50	0.750	102.67	97.67	79.67	75.17	72.67	101.57	52.74	41.02	15.05
2025	75.50	81.50	0.750	100.67	94.67	79.67	75.67	72.67	99.40	51.12	40.71	14.35
2026	77.01	82.00	0.750	102.68	95.18	82.18	78.18	75.18	100.89	51.40	40.93	14.58
2027	78.55	82.50	0.750	104.73	95.73	83.73	80.23	76.73	102.43	51.70	41.17	14.89
2028	80.12	84.15	0.750	106.83	97.65	85.41	82.65	78.41	104.48	52.73	41.99	15.20
2029	81.72	85.83	0.750	108.96	99.60	87.12	84.30	80.12	106.57	53.78	42.83	15.52
2030	83.36	87.55	0.750	111.14	101.59	88.86	85.99	81.86	108.70	54.86	43.69	15.84
2031	85.03	89.30	0.750	113.37	103.63	90.64	87.71	83.64	110.88	55.96	44.56	16.17
2032	86.73	91.09	0.750	115.63	105.70	92.45	89.46	85.45	113.10	57.08	45.45	16.51
2033	88.46	92.91	0.750	117.95	107.81	94.30	91.25	87.30	115.36	58.22	46.36	16.86
2034	90.23	94.77	0.750	120.31	109.97	96.18	93.08	89.18	117.67	59.38	47.29	17.21
2035	92.03	96.66	0.750	122.71	112.17	98.11	94.94	91.11	120.02	60.57	48.23	17.56
2036	93.87	98.60	0.750	125.17	114.41	100.07	96.84	93.07	122.42	61.78	49.20	17.93
2037	95.75	100.57	0.750	127.67	116.70	102.07	98.77	95.07	124.87	63.02	50.18	18.30
2038	97.67	102.58	0.750	130.22	119.03	104.11	100.75	97.11	127.36	64.28	51.18	18.68
2039	99.62	104.63	0.750	132.83	121.41	106.19	102.76	99.19	129.91	65.56	52.21	19.07
2040	101.61	106.72	0.750	135.48	123.84	108.32	104.82	101.32	132.51	66.87	53.25	19.47

YEAR	HENRY HUB	AECO C	ALBERTA 1 YR FIRM	ALBERTA SPOT	AGGRE-GATOR	ALBERTA AGRP	SASK SPOT	SUMAS SPOT	BC STN 2	DAWN	SULPHUR
	$US/MMBTU	C$/MMBTU	C$/MMBTU	C$/MMBTU	C$/MMBTU	C$/MMBTU	C$/MMBTU	C$/MMBTU	C$/MMBTU	C$/MMBTU	$/LT
2023	4.75	4.33	4.03	4.03	3.88	4.13	4.43	6.23	4.23	6.33	60.00
2024	4.50	4.50	4.20	4.20	4.05	4.30	4.60	6.44	4.40	5.75	61.20
2025	4.35	4.30	4.00	4.00	3.85	4.10	4.40	6.28	4.20	5.55	62.42
2026	4.40	4.37	4.07	4.07	3.92	4.17	4.47	6.39	4.27	5.62	63.67
2027	4.49	4.45	4.15	4.15	4.00	4.25	4.55	6.52	4.35	5.73	64.95
2028	4.58	4.54	4.24	4.24	4.09	4.34	4.64	6.65	4.44	5.85	66.24
2029	4.67	4.63	4.33	4.33	4.18	4.43	4.73	6.79	4.53	5.98	67.57
2030	4.76	4.73	4.43	4.43	4.28	4.53	4.83	6.92	4.63	6.10	68.92
2031	4.86	4.82	4.52	4.52	4.37	4.62	4.92	7.06	4.72	6.23	70.30
2032	4.96	4.92	4.62	4.62	4.47	4.72	5.02	7.21	4.82	6.36	71.71
2033	5.05	5.02	4.72	4.72	4.57	4.82	5.12	7.35	4.92	6.49	73.14
2034	5.16	5.12	4.82	4.82	4.67	4.92	5.22	7.50	5.02	6.62	74.60
2035	5.26	5.22	4.92	4.92	4.77	5.02	5.32	7.66	5.12	6.76	76.09
2036	5.36	5.32	5.02	5.02	4.87	5.12	5.42	7.81	5.22	6.90	77.62
2037	5.47	5.43	5.13	5.13	4.98	5.23	5.53	7.97	5.33	7.04	79.17
2038	5.58	5.54	5.24	5.24	5.09	5.34	5.64	8.13	5.44	7.19	80.75
2039	5.69	5.65	5.35	5.35	5.20	5.45	5.75	8.29	5.55	7.34	82.37
2040	5.81	5.76	5.46	5.46	5.31	5.56	5.86	8.46	5.66	7.49	84.01

Note: All prices escalated at 2% per year after 2040
All costs escalated at 2% per year after 2023
First year forecast is for12 months