1 September 2021

2021 RESERVE EVALUATION – BLACKSPUR OIL CORP

Highlights

- ✓ Blackspur Reserves as at June 30, 2021 - audited by InSite Petroleum Consultants Ltd:
  - **3P reserves 25.7 million boe**
  - **2P Reserves 21.4 million boe**
  - **1P Reserves 16.1 million boe**
  - **PDP Reserves 5.2 million boe**
- ✓ Focused asset base with Brooks and Thorsby leases and careful production management allowed Blackspur to maintain reserves steady after production of 1.2 million boe since 31 Dec 2019 and only 2 wells drilled prior to the Calima Acquisition
- ✓ Updated Reserve Report and Development Plan incorporates:
  - 64 development wells (23% of well inventory)
  - Development plan for proved and probable well locations are executed / drilled within a 5-year period
  - Abandonment, decommissioning, reclamation and salvage of facilities, as well as inactive assets and costs for each of the Company's existing and proposed wells
  - Prepared in accordance with the Society of Petroleum Engineers' Petroleum Resources Management System (SPE-PRMS)
- ✓ Blackspur estimates approximately 275 gross wells will develop the entire reserve position on its existing lands > 5 years out.
  - 93% of undeveloped Brooks and Thorsby acreage has no reserves booked currently, representing significant upside

Calima Energy Ltd (Calima, ASX: CE1) is pleased to announce InSite Petroleum Consultants Ltd ("InSite") has completed its reserves evaluation as at 30 June 2021 for Calima's wholly owned subsidiary Blackspur Oil Corp. ("Blackspur").

	Reserves as at 30 June 2021 (working interest after royalties)									
	30 June 2021			Production		Revisions		31 Dec 2019		
	Oil (mbbl)	Gas (mmcf)	Boe (mboe)	Oil (mbbl)	Gas (mmcf)	Oil (mbbl)	Gas (mmcf)	Oil (mbbl)	Gas (mmcf)	Boe (mboe)
PDP	3,261	11,435	5,167	(813)	(2,040)	788	650	3,286	12,825	5,423
PDNP	114	374	176	-	-	27	105	87	269	132
PU	7,068	21,934	10,723	-	-	-597	1,076	7,665	20,858	11,141
1P	10,443	33,742	**16,066**	(813)	(2,040)	217	1830	11,038	33,953	16,696
Probable	3,357	12,061	5,368	-	-	-284	-992	3,641	13,053	5,818
2P	13,800	45,803	**21,434**	(813)	(2,040)	-67	838	14,679	47,006	22,514
Possible	2,711	9,412	4,280	-	-	2,711	9,412	-	-	-
3P	16,521	55,216	**25,714**	(813)	(2,040)	2,645	10,251	-	-	-

Table 1: Reserve Statement

Development Plan

The development plan in the June 30, 2021 Reserve Report consisted of 64 gross wells to be drilled over 5 years. The schedule and breakdown in each reserve category is summarised in the table below.

Period	Rig Count	Development Well Count			
		Proved (PUD)	Probable	Possible	Total
Year 1	2	6	0	0	**6**
Year 2	2	11	1	0	**12**
Year 3	2	19	3	0	**22**
Year 4	2	13	1	0	**14**
Year 5	2	9	1	0	**10**
Total	10	58	6	0	**64**

Table 2: Rig and gross well count for each year

The 30 June 2021 development program includes 6 wells to be drilled in the remaining 6 months of 2021, three Thorsby wells and 3 Brooks open hole Sunburst wells pending continued strong commodity pricing. Blackspur working interest in each well dictates the reserves the Company can book during the well's productive life. On a net well count for the proved reserve category, Blackspur has a ~93% interest in the proved undeveloped wells in the 30 June 2021 development plan.

As at 30 June 2021, Blackspur held the rights to 115,720 net acres within the Brooks and Thorsby areas. The Company operates 63.4 net wells developing approximately 7,500 net acres of this position.

The year-end reserve development schedules encompass development of a modest portion of the total acreage position that Blackspur holds. Based on the existing leasehold position, allowing for the acreage associated with the existing producing wells, Blackspur estimates a total of approximately 275/230 (gross/net) wells will develop the entire reserve position. The total 30 June 2021 development schedule corresponds to 64 future wells, or 23% of the wells necessary. Approximately 94% of the undeveloped Brooks and Thorsby acreage does not have reserves booked, representing tremendous upside.

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

- The majority of the reserve estimates are 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.

- Blackspur 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 YE2020. 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 Blackspur'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 33.3% of the total proved reserves and 32.3% of the proved plus probable reserves, and 32.2% of proved plus probable plus possible reserves which used these methods. Volumetrics/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 29.3% of the Company's Probable reserves. The "wedge" between Proved plus Probable Developed and Proved plus Probable plus Possible Developed cases represents 31.9% of the Company's Possible reserves.

- Future horizontal step-out wells represent 74.5% of the Company's probable reserves.

- Future vertical step-out wells represent 1.3% for the Company's probable reserves.

- 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 percent 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 percent probability that the assigned reserves could be recovered, or more on an aggregated basis.

- The production and revenue forecasts contained in the June 30, 2021 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. A total of 64 gross well locations. The development plan assumes 2-6 wells per standard development unit and approximately 160 acre spacing.

- Anticipated Drilling, Completion & Tie-in well costs range from C$0.7 to C$3.4 million depending on whether it's a Sunburst, Glauconitic or Sparky well.

- The development plan assumes an initial estimate of 6-12 days respectively to drill new wells.

- Average royalty payable on future well locations allocated a reserve in this report is ~14% over the life of the wells. The land and royalties are either Crown or Freehold and the average royalty for the PDP forecast for the second half of 2021 is 17.5%.

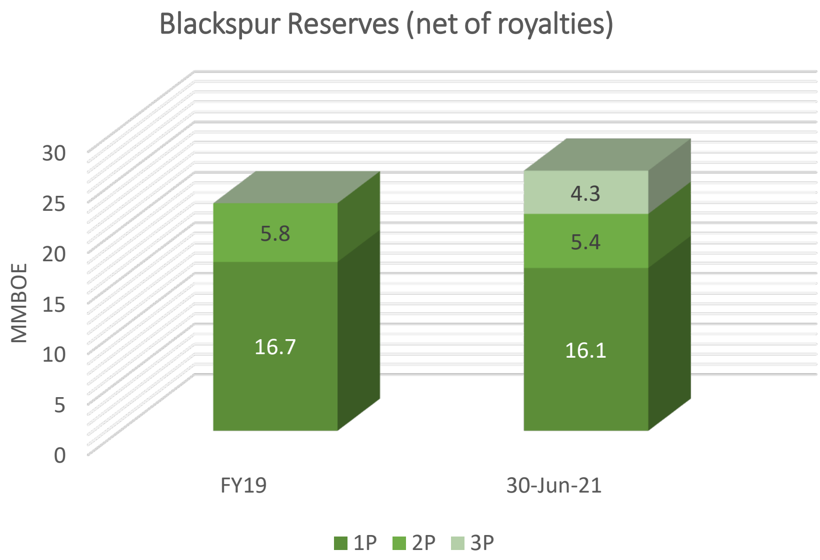
Each year, for the purposes of estimating undeveloped reserves, a development schedule is generated which must be appropriate and reasonable for Blackspur to execute. This development plan is prepared in consultation with InSite and takes into consideration market conditions and Blackspur's operational 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 at Cushing, Edmonton and Western Canadian Select, as well as the netback prices for 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.



Graph 1: Reserve Summary

Brooks

Calima has an established core position of land (~83 net sections or 53,093 net acres) and significant infrastructure that creates a foundation for growth and expansion, and importantly with year-round access. The Brooks asset averaged net daily production of 2,033 boe/d in June 2021.

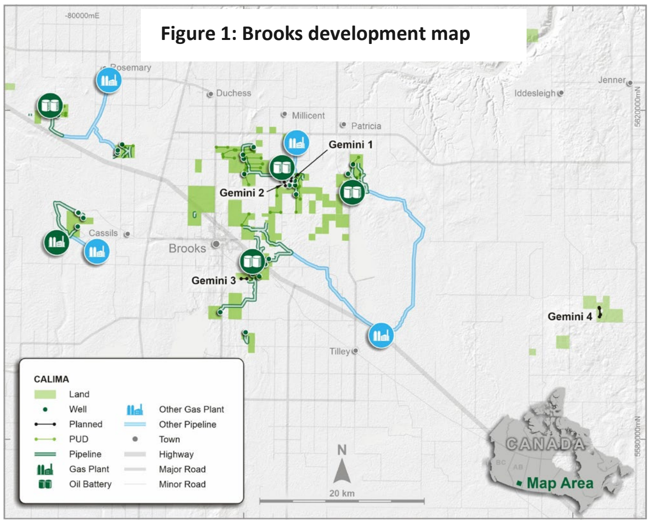


Figure 1: Brooks development map

Blackspur + Calima have drilled >50 wells to date in this area and production comes from the Sunburst and Glauconitic Formations. Blackspur's existing Brooks infrastructure can process up to 7,000 bbl/d oil providing significant upside with limited infrastructure spend. The Brooks reservoirs have a low CO_2 content at 2; and our multi-well pad drilling reduces our environmental footprint. The Sunburst Formation can be developed at low well cost of less than C$1m, delivering attractive rates of returns and most importantly, short paybacks, ~4-6 months at US$70 WTI and standard type curves.

Future growth from the Brooks asset will come from the 140 net locations that have already been identified. These locations include ~35 booked (30.5 net) PUDs. Only 22% of the identified locations have been booked for the purposes of InSite's Reserve Report. Although the current program is solely focussed on Sunburst drilling, at current oil prices the Company is excited to begin adding Glauconitic Formation horizontal locations to its upcoming drilling plans. These Glauconitic wells can be very impactful to corporate production levels and reserve bookings. Additional reserves are also expected to be realised through implementation of enhanced oil recovery projects. Figure 1 below shows a full field development in all formations.

In January 2020, Blackspur initiated a waterflood in the Countess J2J Pool which is expected to show results in the near term and Insite has recognized 1P and 2P waterflood reserves. Waterflood operations require upfront capital and usually take time before field performance improves and the benefits are realized. However when operational, provide a stable, low decline production base generating strong cash flows. The company has forecast the fill-up and re-pressurization time to be approximately 24-30 months from pilot initiation in January 2020. The Company forecasts:

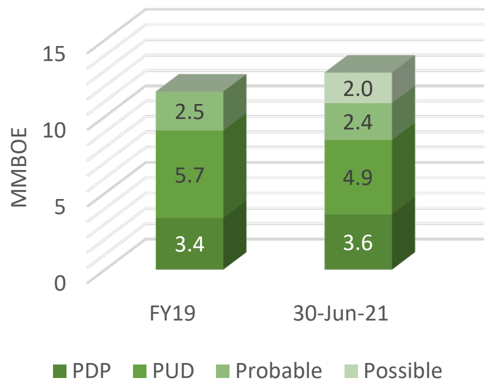
- The recovery factor from primary production at 14%, leaving significant recoverable reserves; Water injection into vertical wells can increase the recovery factor up to 25%

Less than 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:

- The 7 well drilling campaign in the first half of 2021 is completed focusing on the Sunburst open hole (non-fractured) horizontal play type.
- In addition 3 open hole Sunburst wells are planned in the reserve report in the second half of 2021.
- 35 PUDs (30.5 net) and 2 probable 100% locations
- 3 PUD to PDP conversions in 2021
- Reserves of: 1P - 8.5 mmboe, 2P - 10.9 mmboe, 3P - 12.9 mmboe

Graph 2: Brooks Reserves (net of royalties)



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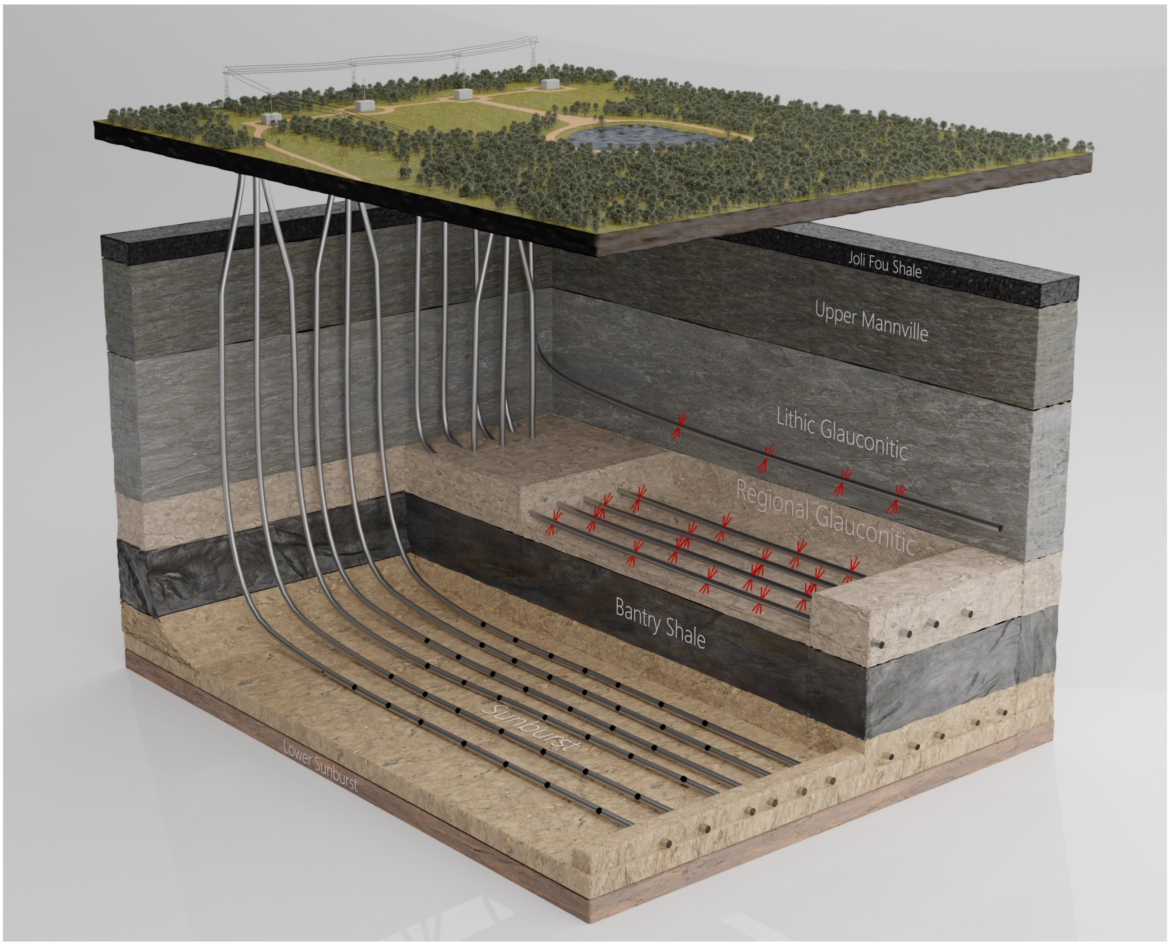


Fig 2: Brooks Full Development

Thorsby

Thorsby provides a consolidated land base of ~108 net sections (69,620 net acres) that will be efficiently developed through a network of multi-well pads, all of which have year-round access. There are approximately 89 net locations internally identified on the Company's lands with only 30% booked. Thorsby average production was ~850 boe/d in June 2021 (100% WI) solely from the Sparky Formation. Blackspur had drilled 11 wells prior to the Blackspur Acquisition in the Thorsby area. Blackspur facilities have oil processing capacity of 3,000 bbl/d oil.

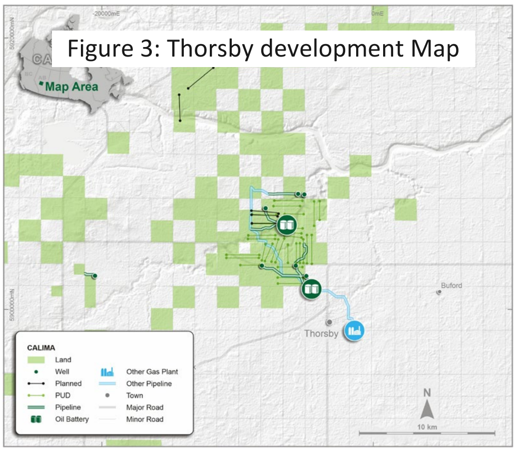


Figure 3: Thorsby development Map

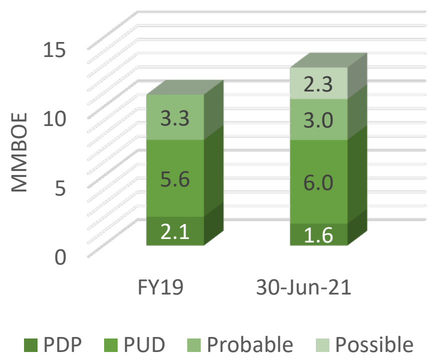
Blackspur's successful delineation campaign and optimisation of the drilling and completion techniques changed the fundamental type curves of the undeveloped wells. InSite amended the development plan to utilise longer horizontal wells (1.5-2 miles) with higher intensity fractures. Thus reducing gross well locations while the future undeveloped well production performance per well is improved resulting in an 8.5% increase in the proven undeveloped reserves versus YE2019.

The Company has commenced a three well Thorsby drilling campaign and the Company has completed the drilling of the first well, Leo #1 and has commenced drilling Leo #2. All three wells are classified as development wells, as they 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 has been increased on all of the three wells due to positive results achieved by neighbouring license holders. Modelling suggests that production will be in the upper range of type curves and enhanced EUR's .

Production from the Leo drilling program is planned to come on stream in the fourth quarter of 2021.

- 3P production profile over a prolific reserve lifecycle
- 23 PUD's and 4 probable 100% locations
- Reserves of: 1P - 7.6 mmboe, 2P - 10.6 mmboe, 3P - 12.8 mmboe

Graph 3: Thorsby Reserves (net of royalties)



Whilst the Thorsby area has the potential for Duvernay and Nisku, these intervals have not been incorporated into the Reserve Report.

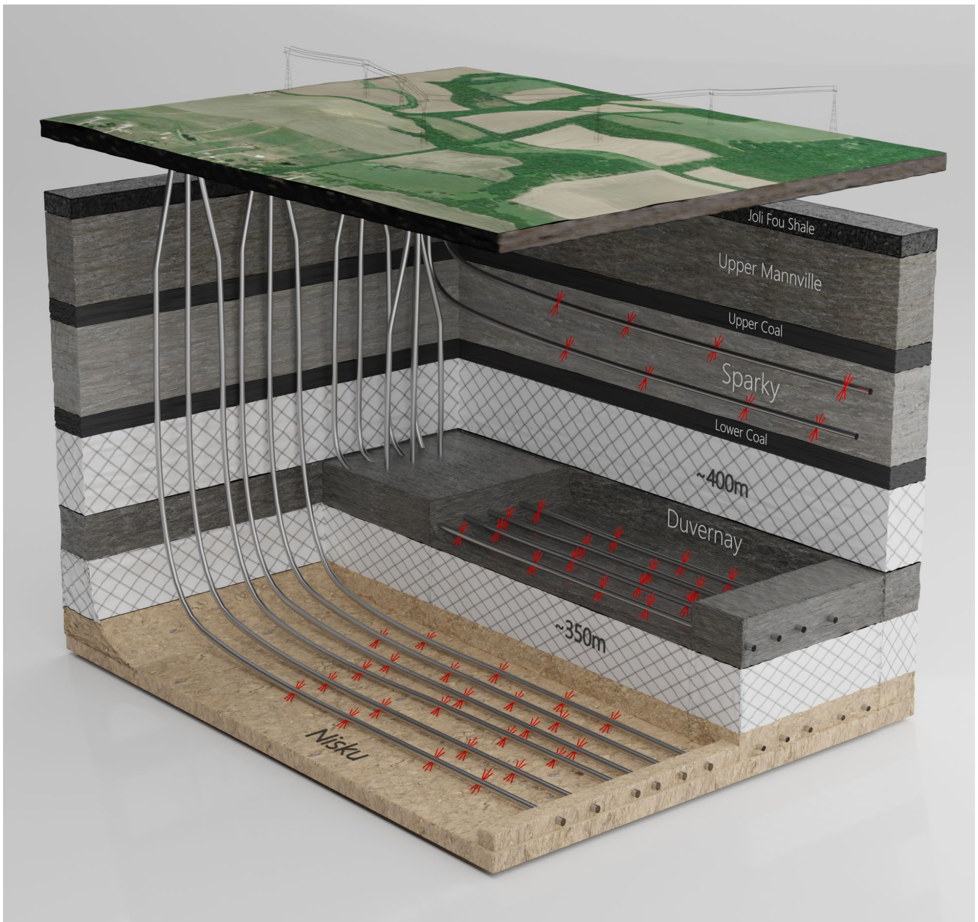


Fig 4: Thorsby Full Development

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3P Reserves

The Company is very pleased with its maiden 3P evaluation. A proved, probable and possible (3P) reserve evaluation category was added for all wells and locations booked at June 30, 2021 totalling 25.7 million boe's. 3P EURs are determined using volumetric calculation as well as production performance / type curve reserve estimates where applicable. This resulted in a significant possible reserve addition of 4.3 million boe net of royalties. 3P reserves were split as follows; Brooks 3P reserves of 12.9 million boe and Thorsby 3P reserves of 12.8 million boe.

This release has been approved by the Board.

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

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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 June 30, 2021 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 June 30, 2021 Reserves Report and the values contained therein are based on InSite's June 30, 2021 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 25 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 EBITDA:	Adjusted EBITDA is calculated as net income (loss) before interest and financing expenses, 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 EBITDA as a measure of operational performance and cash flow generating capability. Adjusted EBITDA impacts the level and extent of funding for capital projects investments or returning capital to shareholders.

Term	Meaning
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
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 EBITDA 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 EBITDA:	EBITDA 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 EBITDA (Leverage)	a measure of financial liquidity and flexibility calculated as Net Debt divided by Hedged Adjusted EBITDA
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

Term	Meaning
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
tCO2:	Tonnes of Carbon Dioxide
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
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
EBITDA	Earnings before interest, 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	Average oil production rate over the first 30 days		

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

InSite prepared the reserve estimate based on the price deck below. In addition, a price sensitivity was run utilizing the average 30 June 2021 price deck from GLJ Petroleum Consultants, McDaniel & Associates Consultants Ltd., and Sproule with the details at the end of this release.

Summary of Forecast Pricing Assumptions - Insite
(Effective July 1, 2021)

	Oil			FX	Natural Gas		
	WTI Cushing Oklahoma ($USD)	Western Cdn Select ($CAD)	Blackspur Oil Price ($CAD)		Henry Hub ($USD)	AECO Spot ($CAD)	Blackspur Gas Price ($CAD)
Year	$/bbl			$CAD/$USD	$/mmbtu		
2021 (H2)	71.50	72.38	**74.08**	0.80	3.40	3.40	**3.59**
2022	67.00	64.75	**66.37**	0.80	3.15	3.04	**3.21**
2023	62.50	57.13	**58.66**	0.80	2.90	2.73	**2.88**
2024	63.75	58.27	**59.75**	0.80	2.96	2.78	**2.94**
2025	65.03	59.43	**60.88**	0.80	3.02	2.84	**3.00**
2026	66.33	60.62	**62.03**	0.80	3.08	2.89	**3.06**
2027	67.65	61.83	**63.22**	0.80	3.14	2.95	**3.13**
2028	69.01	63.07	**64.43**	0.80	3.20	3.01	**3.19**
2029	70.39	64.33	**65.66**	0.80	3.27	3.07	**3.26**
2030	71.79	65.62	**66.96**	0.80	3.33	3.13	**3.32**

Table 7
INSITE PETROLEUM CONSULTANTS LTD. FORECAST PRICES AND COSTS ASSUMPTIONS
June 30, 2021

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
2021	71.50	74.50	0.800	89.38	83.38	72.38	72.38	67.38	87.54	41.69	35.02	11.20
2022	67.00	70.00	0.800	83.75	76.75	65.75	64.75	59.75	81.36	42.21	32.24	9.93
2023	62.50	65.56	0.800	78.13	71.13	59.91	57.13	53.91	76.10	42.68	29.87	8.84
2024	63.75	66.87	0.800	79.69	72.55	61.10	58.27	55.10	77.63	43.53	29.74	9.03
2025	65.03	68.21	0.800	81.28	74.00	62.33	59.43	56.33	79.18	44.40	30.34	9.22
2026	66.33	69.57	0.800	82.91	75.48	63.57	60.62	57.57	80.76	45.29	30.95	9.42
2027	67.65	70.96	0.800	84.57	76.99	64.84	61.83	58.84	82.38	46.19	31.57	9.62
2028	69.01	72.38	0.800	86.26	78.53	66.14	63.07	60.14	84.02	47.12	32.20	9.83
2029	70.39	73.83	0.800	87.98	80.10	67.46	64.33	61.46	85.71	48.06	32.84	10.04
2030	71.79	75.31	0.800	89.74	81.70	68.81	65.62	62.81	87.42	49.02	33.50	10.26
2031	73.23	76.81	0.800	91.54	83.33	70.19	66.93	64.19	89.17	50.00	34.17	10.47
2032	74.69	78.35	0.800	93.37	85.00	71.59	68.27	65.59	90.95	51.00	34.85	10.70
2033	76.19	79.92	0.800	95.23	86.70	73.02	69.64	67.02	92.77	52.02	35.55	10.93
2034	77.71	81.52	0.800	97.14	88.43	74.48	71.03	68.48	94.63	53.06	36.26	11.16
2035	79.27	83.15	0.800	99.08	90.20	75.97	72.45	69.97	96.52	54.12	36.98	11.40
2036	80.85	84.81	0.800	101.06	92.01	77.49	73.90	71.49	98.45	55.20	37.72	11.64
2037	82.47	86.51	0.800	103.08	93.85	79.04	75.38	73.04	100.42	56.31	38.48	11.88
2038	84.12	88.24	0.800	105.15	95.72	80.62	76.88	74.62	102.43	57.43	39.25	12.14

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
2021	3.40	3.40	3.20	3.20	3.05	3.20	3.25	4.35	3.35	4.15	60.00
2022	3.15	3.04	2.83	2.83	2.68	2.84	2.88	4.01	2.99	3.84	61.20
2023	2.90	2.73	2.52	2.52	2.37	2.53	2.57	3.72	2.68	3.58	62.42
2024	2.96	2.78	2.57	2.57	2.42	2.58	2.62	3.79	2.73	3.65	63.67
2025	3.02	2.84	2.62	2.62	2.47	2.64	2.67	3.87	2.79	3.72	64.95
2026	3.08	2.89	2.67	2.67	2.52	2.69	2.72	3.95	2.84	3.80	66.24
2027	3.14	2.95	2.72	2.72	2.57	2.75	2.77	4.03	2.90	3.87	67.57
2028	3.20	3.01	2.78	2.78	2.63	2.81	2.83	4.11	2.96	3.95	68.92
2029	3.27	3.07	2.83	2.83	2.68	2.87	2.88	4.19	3.02	4.03	70.30
2030	3.33	3.13	2.89	2.89	2.74	2.93	2.94	4.28	3.08	4.11	71.71
2031	3.40	3.19	2.95	2.95	2.80	2.99	3.00	4.36	3.14	4.20	73.14
2032	3.47	3.26	3.01	3.01	2.86	3.06	3.06	4.45	3.21	4.28	74.60
2033	3.54	3.32	3.07	3.07	2.92	3.12	3.12	4.54	3.27	4.37	76.09

CALIMA ENERGY

Table 1
GLJ, McDaniel, Sproule
Crude Oil and Natural Gas Liquids
3 Consultants' Average (2021-07)
Effective July 1, 2021

			NYMEX WTI Near Month Futures Contrac Crude Oil at Cushing, Oklahoma		Brent Blend Crude Oil FOB North Sea	MSW, Light Crude Oil (40 API, 0.3%S) at Edmonton	Bow River Crude Oil Stream Quality at Hardisty	WCS Crude Oil Stream Quality at Hardisty	Heavy Crude Oil Proxy (12 API) at Hardisty	Light Sour Crude Oil (35 API, 1.2%S) at Cromer	Medium Crude Oil (29 API, 2.0%S) at Cromer	Alberta Natural Gas Liquids (Then Current Dollars)			
Year	Inflation %	CADUSD Exchange Rate USD/CAD	Constant 2021 $ USD/bbl	Then Current USD/bbl	Then Current USD/bbl	Then Current CAD/bbl	Then Current CAD/bbl	Then Current CAD/bbl	Then Current CAD/bbl	Then Current CAD/bbl	Then Current CAD/bbl	Spec Ethane CAD/bbl	Edmonton Propane CAD/bbl	Edmonton Butane CAD/bbl	Edmonton C5+ Stream Quality CAD/bbl
2021 Q3-Q4	0.0	0.8033	71.33	71.33	73.58	83.20	72.72	72.22	66.41	83.75	80.98	11.21	36.19	41.59	87.64
2022	2.3	0.8017	65.67	67.20	69.80	78.27	67.59	66.85	61.13	78.45	75.67	10.10	33.82	42.97	82.38
2023	2.3	0.8000	61.06	63.95	66.82	74.06	62.68	61.73	55.88	74.20	71.61	8.72	31.62	44.34	78.45
2024	2.0	0.8000	59.20	63.23	66.14	73.05	61.62	60.70	54.96	73.18	70.64	8.71	31.02	43.79	77.52
2025	2.0	0.8000	59.20	64.50	67.47	74.51	62.85	61.91	56.06	74.64	72.05	8.89	31.64	44.66	79.07
2026	2.0	0.8000	59.20	65.79	68.81	76.00	64.10	63.15	57.19	76.14	73.50	9.07	32.27	45.56	80.66
2027	2.0	0.8000	59.20	67.10	70.19	77.52	65.38	64.42	58.34	77.66	74.97	9.26	32.92	46.47	82.27
2028	2.0	0.8000	59.20	68.44	71.59	79.07	66.69	65.70	59.51	79.21	76.46	9.45	33.58	47.40	83.91
2029	2.0	0.8000	59.20	69.81	73.02	80.65	68.02	67.02	60.71	80.79	77.99	9.64	34.24	48.34	85.59
2030	2.0	0.8000	59.20	71.21	74.49	82.27	69.38	68.36	61.92	82.41	79.55	9.83	34.93	49.31	87.30
2031	2.0	0.8000	59.19	72.63	75.98	83.91	70.77	69.72	63.16	84.06	81.14	10.03	35.63	50.30	89.05
2032	2.0	0.8000	59.19	74.08	77.49	85.59	72.19	71.12	64.43	85.74	82.77	10.23	36.34	51.30	90.83
2033	2.0	0.8000	59.19	75.56	79.04	87.30	73.63	72.54	65.71	87.46	84.42	10.44	37.07	52.33	92.65
2034	2.0	0.8000	59.20	77.08	80.63	89.05	75.10	73.99	67.03	89.20	86.11	10.64	37.81	53.38	94.50
2035	2.0	0.8000	59.20	78.62	82.24	90.83	76.60	75.47	68.37	90.99	87.83	10.85	38.57	54.44	96.39
2036	2.0	0.8000	59.20	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

Table 2
GLJ, McDaniel, Sproule
Natural Gas and Sulphur
3 Consultants' Average (2021-07)
Effective July 1, 2021

	NYMEX Henry Hub Near Month Contract		Midwest Price at Chicago	AECO/NIT Spot	Dawn Price at Ontario	Alberta Plant Gate Spot			Saskatchewan Plant Gate			British Columbia	
Year	Constant 2021 $ USD/MMBtu	Then Current USD/MMBtu	Then Current USD/MMBtu	Then Current CAD/MMBtu	Then Current USD/MMBtu	Constant 2021 $ CAD/MMBtu	Then Current CAD/MMBtu	ARP CAD/MMBtu	SaskEnergy CAD/MMBtu	Spot CAD/MMBtu	Sumas Spot USD/MMBtu	Westcoast Station 2 CAD/MMBtu	Spot Plant Gate CAD/MMBtu
2021 Q3-Q4	3.42	3.42	3.28	3.46	3.31	3.22	3.22	3.24	3.41	3.28	3.52	3.38	3.14
2022	3.12	3.19	3.05	3.13	3.12	2.84	2.90	2.92	3.09	2.95	3.10	3.05	2.82
2023	2.79	2.92	2.78	2.72	2.85	2.38	2.49	2.51	2.68	2.54	2.79	2.66	2.42
2024	2.77	2.96	2.82	2.71	2.89	2.32	2.48	2.49	2.67	2.53	2.80	2.64	2.40
2025	2.77	3.02	2.88	2.76	2.95	2.32	2.53	2.54	2.72	2.58	2.85	2.69	2.46
2026	2.77	3.08	2.94	2.82	3.01	2.32	2.58	2.60	2.78	2.64	2.91	2.74	2.51
2027	2.77	3.14	3.00	2.88	3.07	2.33	2.64	2.65	2.83	2.70	2.97	2.80	2.56
2028	2.78	3.21	3.06	2.94	3.13	2.33	2.70	2.71	2.89	2.76	3.03	2.86	2.62
2029	2.77	3.27	3.12	3.00	3.19	2.33	2.75	2.77	2.95	2.82	3.09	2.92	2.67
2030	2.78	3.34	3.19	3.05	3.25	2.34	2.81	2.82	3.01	2.87	3.16	2.97	2.73
2031	2.77	3.40	3.25	3.12	3.32	2.33	2.86	2.88	3.07	2.93	3.22	3.03	2.78
2032	2.77	3.47	3.32	3.18	3.39	2.33	2.92	2.94	3.13	2.99	3.28	3.09	2.84
2033	2.78	3.54	3.39	3.24	3.46	2.33	2.98	3.00	3.19	3.05	3.35	3.16	2.90
2034	2.78	3.61	3.46	3.30	3.53	2.33	3.04	3.06	3.26	3.11	3.42	3.22	2.96
2035	2.77	3.68	3.52	3.37	3.60	2.33	3.10	3.12	3.32	3.18	3.49	3.28	3.01
2036	2.77	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.33	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gathering and processing charges are deducted.